Deutsche Bank
Markets Research

Industry
Future of US Oil

Date
18 December 2012

North America
United States

Industrials
Integrated Oil

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F.I.T.T. for investors

2013 Preview - The Bucket List

US crude market in transition

We continue our Future of US Oil series with a preview of differential and crude flow trends we expect for North America in 2013. In our February, 2012 note we highlighted the tectonic shift taking place in the US, with a dramatic inflection towards production growth, falling domestic demand, misaligned infrastructure, a swing to net product exports, and the looming implications of the US crude export ban. As we now look toward the next phases, we add some granularity to the analysis, looking in more detail at key refining regions and basin-to-refining hub crude flows.

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2013: Year of the Pipeline – and when caterpillar markets turned to butterflies

The last two years have been about booming production growth facing inadequate infrastructure – WTI and other markers have blown out relative to coastal benchmarks due to a lack of pipelines. 2013 is the "year of the pipeline" – over 20 major/mid-sized pipelines will go into service this year (and ~20 next year), taking the US crude transportation market from heavily distorted to very efficient in less than 24 months.

But as the WTI (Cushing) discount crashes, watch LLS (Louisiana) undertow

While many of the key inland differentials will narrow as pipelines come onstream in 1H13, we think this will turn out to be something of a "head-fake" for US crude markets, as the unfolding implications of the US crude export ban start to play out. For reasons we lay out in detail in the note, we believe that LLS, already weakening versus Brent, will slip to a $3-5/bbl discount by YE13. By extension we expect Brent-WTI to fall from ~$20/bbl to $6-10/bbl, by 3Q13.

Houston: the biggest bucket at the bottom of the crude cascade

Cushing, Midland, Superior – these have been the hubs and chokepoints the markets have been scrutinizing over the last two years. Now the Gulf Coast will move front and center, as new pipelines start to dump enormous amounts of light crude from all of the major basins into the Houston region. It will be a hyper-competitive market – between 2011 and 2015, Houston inbound pipelines from the North and West will rise from ~100kbd to nearly 4Mbd. Capacity will jump over 1Mbd YoY in 2013.

Won't take long to push out the last waterborne imports

We calculate less than 500kbd of remaining waterborne light/medium sweet imports into the Gulf Coast as we close 2013. But Saudi and Kuwait are very likely to maintain market share into the US at any price, for a handful of non-economic reasons. Combined they still import over 1.5Mbd into the US, of which 150+kbd is light. **So the truly substitutable light import number is likely only 350kbd or less. To underline, those that consider this oil boom in the context of total US crude imports of 8.5mb/d are misguided, the real import substitution number before price pressure is 4% of that.** It will not take long to push this out. The last hurdle will be getting surging Texas crude eastward into the Louisiana refining complex, & the 300kbd Ho-Ho pipeline will in 3Q13. Surging unconventional crude will have to find a home, so Houston refiners will distort their crude slate to run more of it, but will need to be incentivized by an increasing discount. Rail/barge will move it to the four corners of the continent, with high transport costs. The domestic light glut will pressure prices regardless once the Gulf Coast disconnects from the global light market.

Companies Featured	
Valero Energy (VLO.N),USD34.04	Hold
Marathon Petroleum Corp (MPC.N),USD62.96	Hold
HollyFrontier (HFC.N),USD46.26	Buy
Phillips 66 (PSX.N),USD53.52	Hold
Tesoro Corporation (TSO.N),USD44.69	Hold
Western Refining Inc (WNR.N),USD31.04	Hold
CVR Energy (CVI.N),USD48.21	Hold
ConocoPhillips (COP.N),USD58.28	Hold
Hess Corporation (HES.N),USD52.25	Hold
Marathon Oil (MRO.N),USD30.70	Buy
Murphy Oil (MUR.N),USD60.03	Hold
ExxonMobil (XOM.N),USD88.87	Hold
Chevron (CVX.N),USD108.68	Buy
Canadian Natural (CNQ.TO),CAD27.64	Hold
Suncor Energy (SU.TO),CAD32.18	Hold
Occidental Petroleum (OXY.N),USD76.52	Hold

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Future of US Oil – 2013 Update

Executive Summary

We continue our Future of US Oil series with a preview of trends we expect for North American crude markets in 2013 and 2014. In our February, 2012 note we highlighted the tectonic shift taking place in the US, with a dramatic shift towards production growth, falling domestic demand for crude, misaligned infrastructure, wide differentials, a swing to net export of products, and the looming implications of the US crude export ban. Here we update and find that things have moved along more or less as we anticipated in that note. As we look to the next phases, we add to our analysis, looking in more detail at specific refining regions and basin-to-refining hub crude flows.

Key takeaways:

- **Year of the Pipeline.** While 2011/12 were all about a lack of appropriate infrastructure, 2013 is the "year of the pipeline". Over 20 mid-sized/major pipelines will be completed over the next 12 months (and another 20 by YE14). North American crude transportation will be very efficient within 24 months.
- **WTI wave crashes, LLS undertow.** While many of the key crude differentials will narrow as pipelines come onstream in 1H13, we think there will be something of a "head-fake," before the full over-supply effects of the US crude export restriction start to manifest more clearly by YE13 and into 2014.
- **Less time to substitute imports than consensus thinks.** Relatively limited quantities of light sweet crude imports are left to be displaced. Once waterborne light crude imports into the USGC are price-displaced (**probably by mid-to-late 2013**), LLS should increasingly weaken versus Brent, and start to pressure the whole North American crude complex away from global levels.
- **Houston is the biggest bucket.** The Texas Gulf Coast moves front and center, as new pipelines will start to dump enormous amounts of light crude from all of the major basins into the Houston region. Between 2011 and 2015, Houston inbound pipeline capacity will rise from 100kbd to nearly 4Mbd. This will be the physical clearing point of North American oil markets, even if owing to history and established liquidity ("path-dependence"), WTI will remain the key domestic paper market. Physically, LLS (and potentially a new Houston-area marker like the proposed ECHO contract) will ascend in importance. Parity pricing will be on the Gulf Coast going forward, with Houston as the most competitive market, the biggest bucket at the bottom of the North American crude cascade.
- **Saudi and Kuwait will stay, even when everyone leaves the party.** Saudi and Kuwait are more interested in long-term geopolitical ties, commercial relationships and market information than they are squeezing out the last near-term dollar. Thus they have and will maintain market share by being North American price-takers rather than seeking out higher paying Asian markets for their 1+Mbd of supply to the US. More than 150kbd of that is Arab Extra Light, which is comparable to what is called "Light" crude in the US, and will not be substituted.

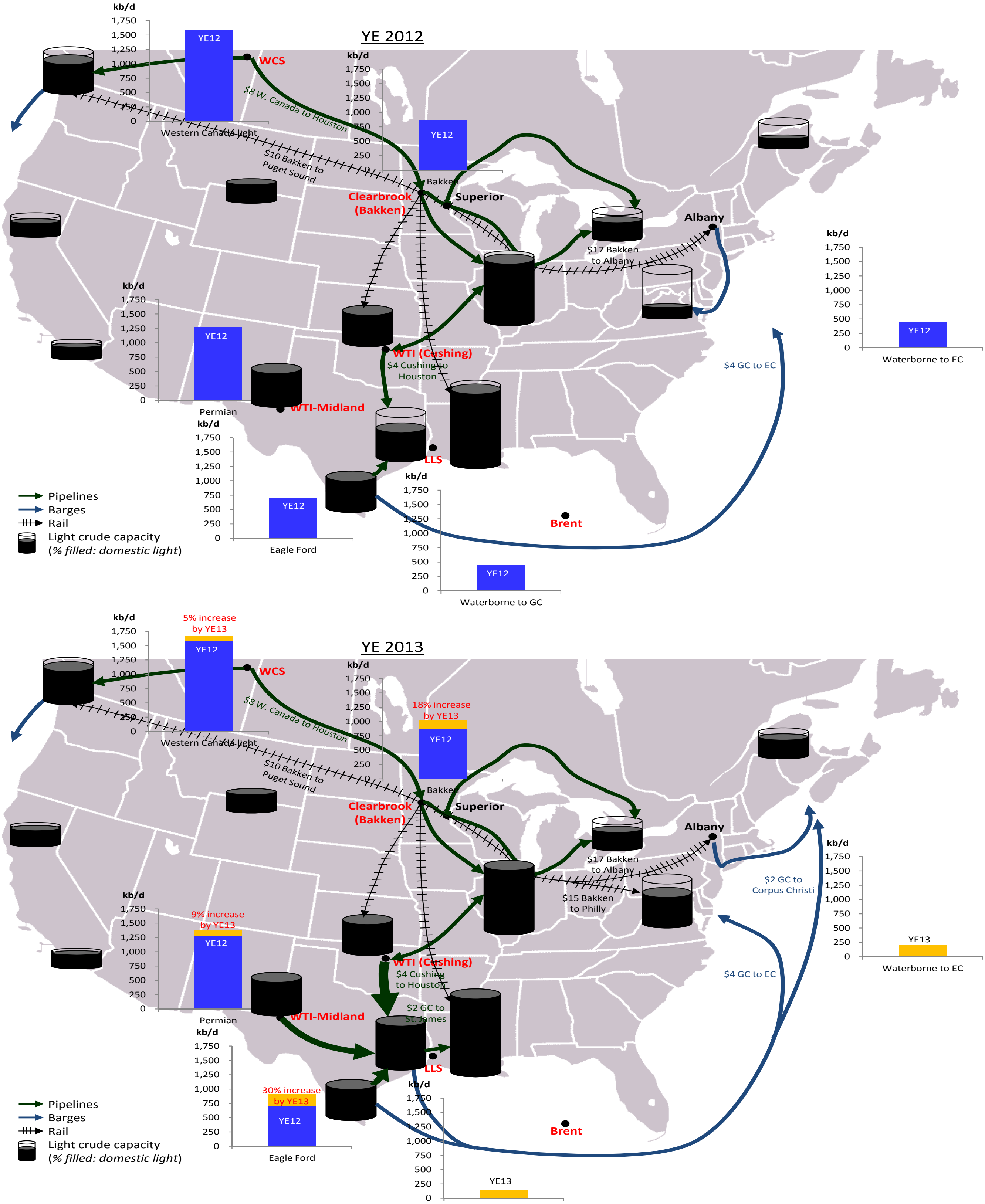
- **But Louisiana is where the last imported light barrels will be.** We see LLS weakening throughout the year, but that should accelerate once the last substitutable light crude imports are flushed out of the Central Gulf Coast, which won't be reachable by pipeline from Texas until the HoHo reversal in 2H13. We think the last remaining waterborne light is pushed out by YE13.
- **Trapped crude will move to the four corners of the continent.** Surging unconventional barrels can't be exported, and will have to find a home in the US or Canada. Refiners will adjust to run more, but barrels will also travel long distances to every North Am refinery in order to displace imported light/medium-sweet barrels. Don't be surprised when Eagle Ford barrels show up in Quebec or Bakken in a tiny West Virginia refinery. This means high marginal cost of transportation, and wider diffs to incentivize those moves.
- **Long-term demand for Canadian heavy will be very healthy,** and pipelines will eventually get it to where it needs to go. But over the medium-term, prices will be volatile and differentials, on average, wider than normal, until Enbridge expands its system in mid-2014.
- **Rail is now tri-coastal.** As the swing-mode of transportation out of the Bakken, and now possibly the WCSB (Western Canadian Sedimentary Basin), rail will increasingly tend to set many of the key differentials. Pipelines will carry most of the crude to the Gulf Coast, but rail will be the link to the East and West Coasts. Rail is more nimble and flexible, though less reliable and more expensive; it is the short term solution. Please refer to DB transport team's recent thematic "Shale: A Potentially Frack-Tastic Growth Driver" outlining the bullish rail implications of the boom.
- **We are raising our floor price target for WTI to $80/bbl for 2013** based on our view that efficiency gains in US unconventional oil production are being offset by increasing geological challenges (the core is increasingly drilled, new activity increasingly marginal) and peaking activity. Essentially, US oil production growth now faces a dual challenge of increasing below-the-ground as well as the above-the-ground issues we have highlighted. Growth will be strong, but our recent note "Why the US WON'T surpass Saudi in oil production" is strongly under-lined by this analysis, as integrated and refining analysts, and our E&P team's recent thematic "Adjusting to an Age of Surplus".

Figure 1: The US crude market in transition – six stages

Period	Stage	Key Issues	Investment Themes
2009	**US crudes at Transport/Quality Equilibrium**	• Nascent unconventional oil • Mid-Con still short crude • Crudes mostly trading off of transport/quality	• Negative US refining
2010-12	**Inland Corridor Over-Supply**	• Bakken booming, Eagle Ford begins fast ramp • crude backs up in Mid-Con • infrastructure misalignment apparent • Brent-WTI differential widens out • Midstream starts to attack problem, but build-out will take 24-36 months • Gulf Coast refiners increase product exports	• Long Mid-Con refiners • Infrastructure/MLPs
2012	**Basin Over-Supply**	• Surging growth in all key unconventional basins easily outstrips takeaway • Causes basin-level differential volatility and occasional blow-outs • Inland Corridor issue doesn't improve despite Seaway reversal • Crude by rail steps into the breach and becomes a major factor • Waterborne light crude import substitution accelerates	• Long Mid-Con refiners • Especially Permian and Rockies • Infrastructure/MLPs • Rail-related
2013-14	**"Year of the Pipeline"**	• Midstream comes to the rescue • By mid-'14 most inefficiency squeezed out of US crude macro-transportation • Diffs vs. coastal domestic crude narrow mostly to transportation/quality • Rail remains key component, taking crude to EC and WC • Some volatility remains as refining complex sorts out what to do with light volumes • Last of the waterborne light crude imports (ex-Saudi/Kuwait) pushed out of GC	• Headwind for US refiners • Structurally-advantaged Rockies - HFC
2013-16	**North American Light Crude Over-Supply**	• Next phase of distortions begin, caused by the US crude export ban • Unconventional plays continue to surge, plus resurgent US GoM production • No remaining substitutable waterborne light/medium sweet, US supply is trapped • US flooded with very light crude, prices down towards marginal cost of supply • This time all domestic light crudes fall vs Brent, including LLS • Plenty of GC demand for Canadian heavy, but it must price 8-12% below falling light • Entire North American crude pricing structure disengages from global prices	• All US refiners, if product exports • Upstream Brent over US exposure • Eagle Ford/Permian over Bakken • Canada - heavy over light/synthetic • GDP/US dollar
?	**Crude Export Ban Lifted?**	• Becomes apparent that US is producing more light than refining system can handle • Price is forcing producers to lay down rigs • Tangible slow-down/loss of jobs in multiple states • Pressure on Washington to lift or modify the curde export restriction will increase • While this could happen at any time, we think it will take at least a few years	• Long US producers • Negative US coastal refiners

Source: Deutsche Bank

Figure 2: YE12 to YE13 - Domestic light crude demand "buckets" filling up



Note: "Light crude capacity", as used here, denotes the current portion of each refining region's crude slate dedicated to light and medium sweet crudes. Refineries can and will expand the "bucket" for light if they are incentivized to do so by price. We discuss the limits to increasing the amount of light in the crude slate elsewhere in the note.
Source: EIA, Company data, Wood Mackenzie, Bloomberg Finance LP, Reuters, Dow Jones, Deutsche Bank estimates

Figure 3: Key 2013 infrastructure, project and refinery events by quarter, with expected impact on five crude benchmarks

	Event	Type of Event	IMPACT LLS	IMPACT WTI	IMPACT MID	IMPACT CLB	IMPACT WCS	Comment
1Q13	Seaway ramp to 400kbd	Pipeline	⇩	⇧	⇔	⇧	⇧	Initially drains light, then more heavy
	Longhorn reversed 75kbd	Pipeline	⇩	⇧	⇧	⇔	⇔	Relieves Midland logjam, puts pressure on LLS in Houston
	ENB Line 5 Exp 50kbd	Pipeline	⇔	⇔	⇔	⇧	⇧	Moves Canadian light/Bakken further East
	ENB Bakken Exp 120kbd	Pipeline	⇔	⇔	⇔	⇧	⇩	Increases tightness on Enbridge Mainline
	WTG Exp 110kbd	Pipeline	⇩	⇧	⇧	⇔	⇔	Permian exit capacity to Longview/Houston
	Ho-Ho to Nederland 300kbd	Pipeline	⇩	⇔	⇧	⇔	⇔	Starts to move Houston surplus eastward
	Kearl Ph 1 (IMO) 110kbd	Oil Sands Project	⇔	⇩	⇔	⇩	⇩	Huge dilbit surge onto Enbridge/Keystone
	Firebag 4 (SU) 62kbd	Oil Sands Project	⇔	⇩	⇔	⇩	⇩	Coincides with Kearl, technically 4Q first oil
	Heavy Jan PADD 3 TAs (~800kbd)	Refinery	⇩	⇔	⇔	⇔	⇔	Numerous Gulf Coast/Mississippi refineries
	Delaware City Rail Terminal (+70kbd)	Rail Terminal	⇔	⇔	⇔	⇧	⇧	Bakken intake from 40kbd to 110kbd
2Q13	Permian Express Ph 1 90kbd	Pipeline	⇩	⇧	⇧	⇔	⇧	More Inland Corridor drainage, increases flow to Houston
	Longhorn ramps to 225kbd	Pipeline	⇩	⇧	⇧	⇔	⇧	Fully ramped by mid-year
	Plains Bakken North 75kbd	Pipeline	⇔	⇔	⇔	⇧	⇩	Yet more Bakken crude onto Mainline
	EPD/PAA EF Phase 2 200kbd	Pipeline	⇩	⇔	⇔	⇔	⇔	EF pipeline to Corpus Christi, surplus to requirement
	Line 9 Segment Rev 50kbd	Pipeline	⇔	⇧	⇔	⇧	⇧	First step towards 240kbd to Montreal
	Kirby South Ph 1 (CNQ) 45kbd	Oil Sands Project	⇔	⇩	⇔	⇩	⇩	Another large in situ project
	Horizon 18-day TA (110kbd)	Upgrader	⇔	⇔	⇔	⇧	⇧	Tightens Northern light crude/ SCO, more room on Mainline
	Heavy April PADD 2 refinery TAs (~300kbd)	Refinery	⇩	⇩	⇔	⇩	⇩	Less Chicago demand pull + Kearl/FB/Kirby ramps
3Q13	Ho-Ho to St. James 300kbd	Pipeline	⇩	⇔	⇔	⇩	⇔	Critical pipeline that will help push out waterborne imports in LA
	Permian Express ramp to 150kbd	Pipeline	⇩	⇧	⇧	⇔	⇧	Brings Permian-Houston to ~450kbd
	Whiting restarts big CDU	Refinery	⇔	⇔	⇔	⇔	⇧	Big uptick in demand for Canadian heavy
	Christina Lake 2B (MEG) 35kbd	Oil Sands Project	⇔	⇩	⇔	⇩	⇩	Another in situ project
	Philadelphia Rail Terminal (150kbd)	Rail Terminal	⇔	⇔	⇔	⇧	⇧	Will be able to hand le 3 unit trains simultaneously
	Eddystone Rail Terminal (80kbd)	Rail Terminal	⇔	⇔	⇔	⇧	⇧	Enbridge JV, third Philly area terminal receiving Bakken
	Suncor U1 TA (125kbd)	Upgrader	⇔	⇔	⇔	⇧	⇧	Smaller of Suncor's two upgraders, good for SCO/Bakken
4Q13	Keystone XL South leg 500kbd	Pipeline	⇩	⇧	⇧	⇧	⇧	Eliminates any question of Cushing logjam for several years
	Christina Lake E (CVE) 40kbd	Oil Sands Project	⇔	⇩	⇔	⇩	⇩	Fifth major oil sands startup, cumulative 300kbd

Source: Bloomberg Finance LP, Company data, Dow Jones, Reuters, Wood Mackenzie, EIA, CAPP, Deutsche Bank

LLS: Louisiana Light Sweet, priced at St. James, LA. WTI: West Texas Intermediate, priced at Cushing, OK. MID: WTI Midland, priced at Midland, TX. CLB: Bakken crude, priced at Clearbrook, MN. WCS: Western Canadian Select, priced at Hardisty, AB.

Summary of North American differential estimate vs. Brent

We will discuss in detail the rationale for our benchmark forecasts throughout the note, but to get to the punch-line, here are our estimates for five key North American differentials, relative to Brent, at quarter-end:

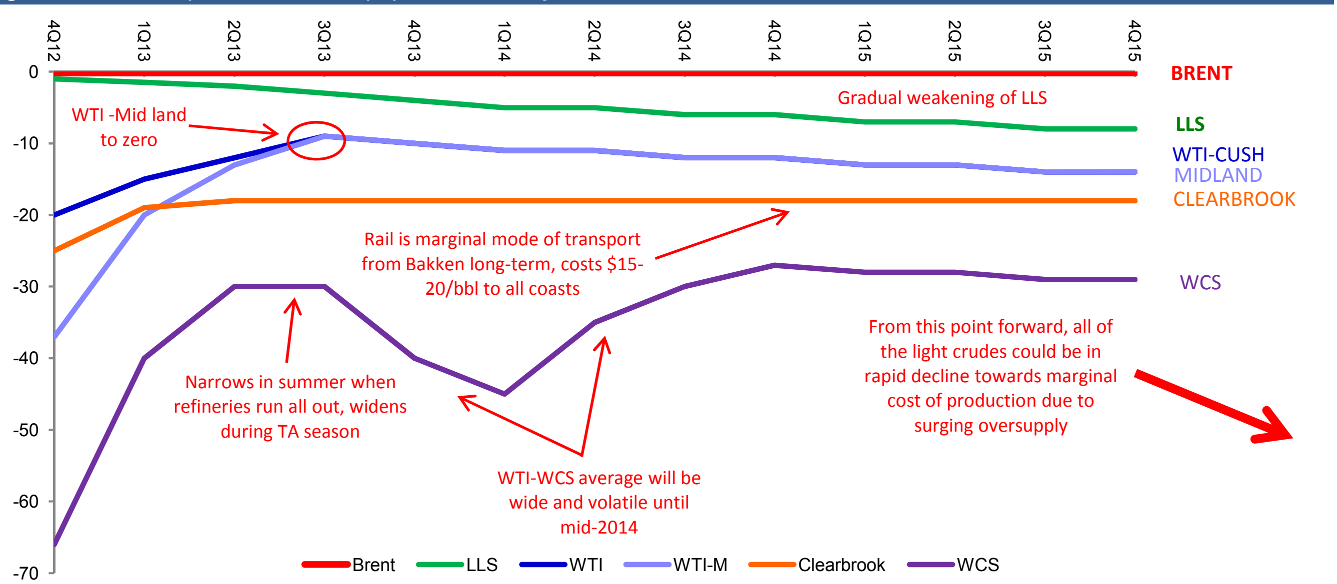
Figure 4: DB estimates for quarter-end for major North Am benchmarks vs. Brent

	4Q12	1Q13	2Q13	3Q13	4Q13	1Q14	2Q14	3Q14	4Q14
Brent	0	0	0	0	0	0	0	0	0
LLS	-1.00	-1.50	-2.00	-3.00	-4.00	-5.00	-5.00	-6.00	-6.00
WTI	-20.00	-15.00	-12.00	-9.00	-10.00	-11.00	-11.00	-12.00	-12.00
WTI-Midland	-37.00	-20.00	-13.00	-9.00	-10.00	-11.00	-11.00	-12.00	-12.00
Clearbrook	-25.00	-19.00	-18.00	-18.00	-18.00	-18.00	-18.00	-18.00	-18.00
WCS	-66.00	-40.00	-30.00	-30.00	-40.00	-45.00	-35.00	-30.00	-27.00

Source: Deutsche Bank estimates

Chart of the same forecast, with some annotations:

Figure 5: Summary of estimates by quarter for major North American crude markers vs. Brent



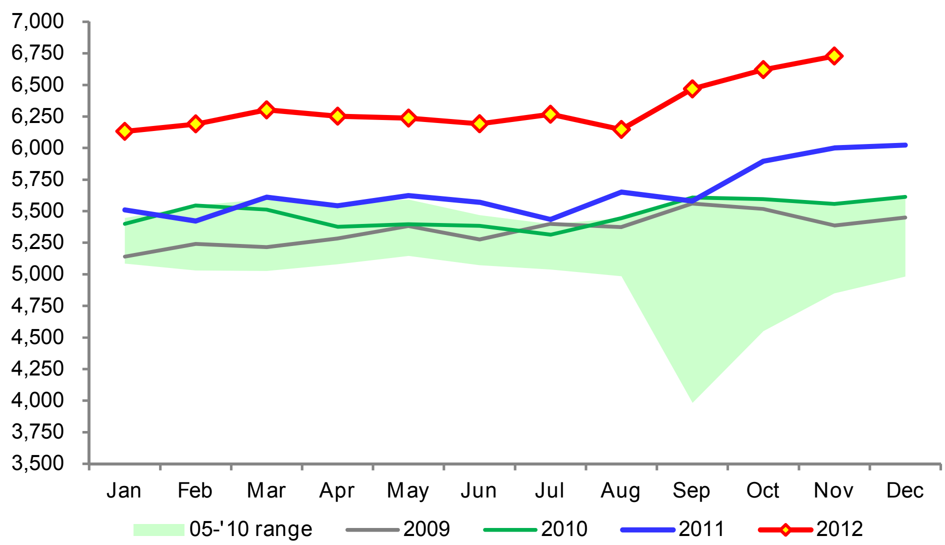
Source: Deutsche Bank estimates

Production, pipelines, politics

North American production update

North American production grew by about 1Mbd in 2012, about 300kbd above our beginning of the year forecast. US crude volumes climbed by about 700kbd, the largest annual rise since 1951. Canadian production rose by a bit more than typical forecasts, largely to due unconventional growth in Southern Alberta and Saskatchewan.

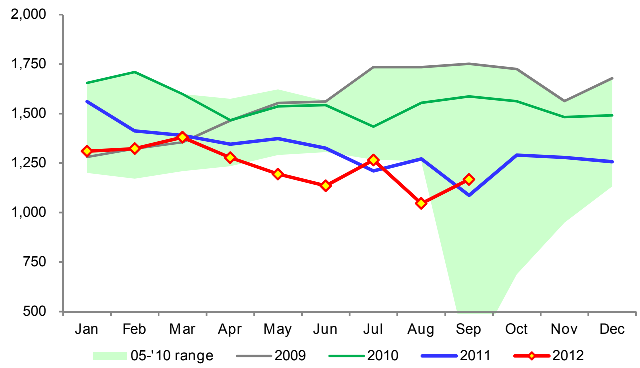
Figure 6: US crude production by month



Source: EIA, Deutsche Bank

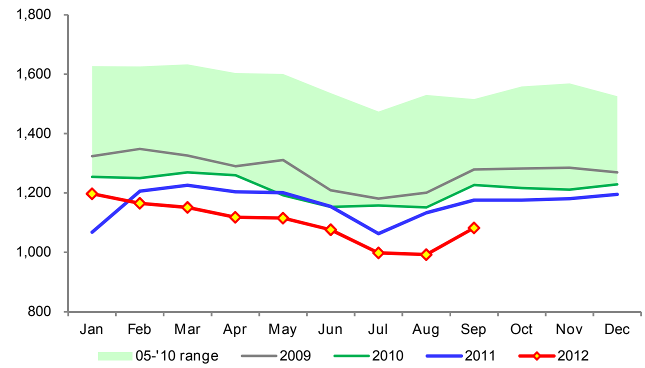
US production growth in 2012 was driven, not surprisingly, by production surges in Texas (Eagle Ford and Permian) and North Dakota. This growth masked a meaningful decline in US Gulf of Mexico (which is showing signs of arresting and reversing the decline heading into 2013) and weak PADD 5, with both Alaska and California trending down YoY.

Figure 7:US Gulf of Mexico production



Source: Deutsche Bank

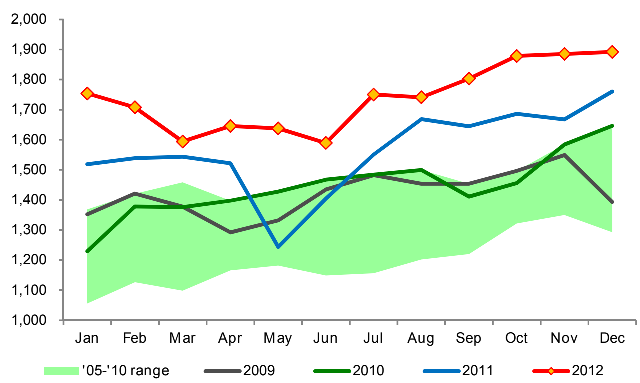
Figure 8: US PADD 5 production



Source: Deutsche Bank

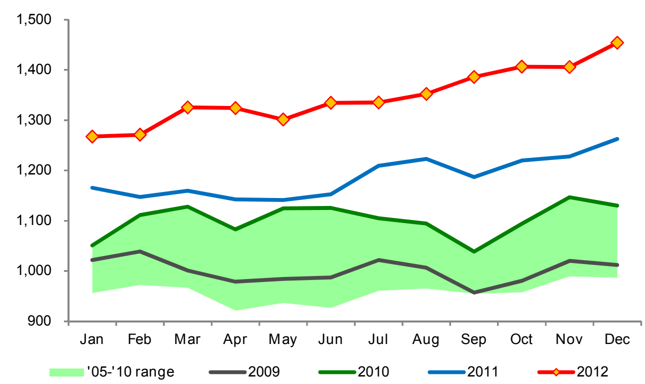
Canadian growth was robust and exceeded expectations in 2012 as well, for both light and heavy. East Coast Canada volumes were lighter than expected due to unplanned and longer-than-planned turnaround activity. But upside surprise in WCSB growth more than offset.

Figure 9: Western Canadian light crude production



Source: NEB, CAPP, Deutsche Bank estimates

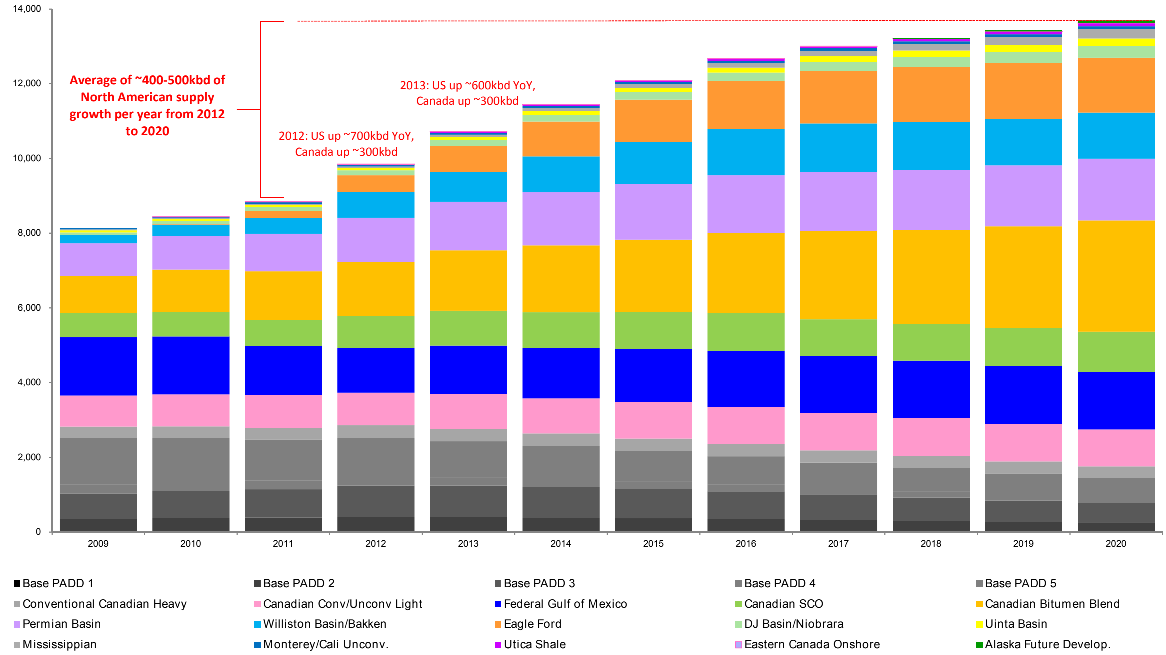
Figure 10: Western Canadian heavy crude production



Source: NEB, CAPP, Deutsche Bank estimates

We have updated our North American forecast, combining our model with the DB E&P team's model, published on December 17 in a detailed thematic report outlining the case for strong but below-consensus growth from North America over the next half decade plus, with an anticipation of growth in 2013 similar to 2012. We expect North American volumes to rise 800-900kbd in 2013, and about 450kbd on average, over the next 8 years out to 2020. We model production from eight US unconventional plays, using average type curves estimated by the DB US E&P team.

Figure 11: North American crude production outlook (kbd)

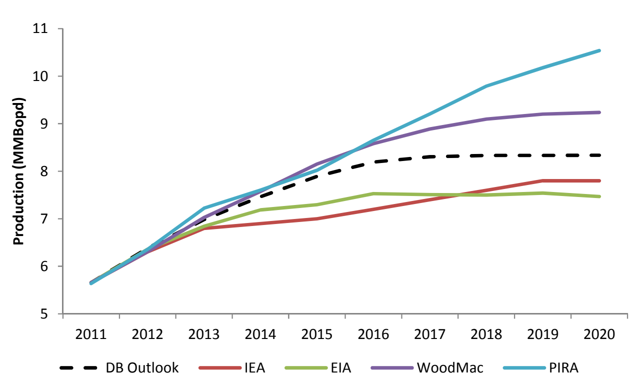


Source: EIA, IEA, Company data, Wood Mackenzie, CAPP, Bloomberg Finance LP, Deutsche Bank

Our North American growth expectation over the next eight years breaks down roughly 55/45 between the US and Canada, and roughly 65/35 between light and heavy, though the year-to-year mix varies widely depending on project start-up schedules and the pace of development in unconventional plays. It is worth noting that almost all of the growth is driven by "frontier" modes of oil extraction opened up by technology and a relatively high oil price – oil sands, unconventional, deepwater and ultra-deepwater.

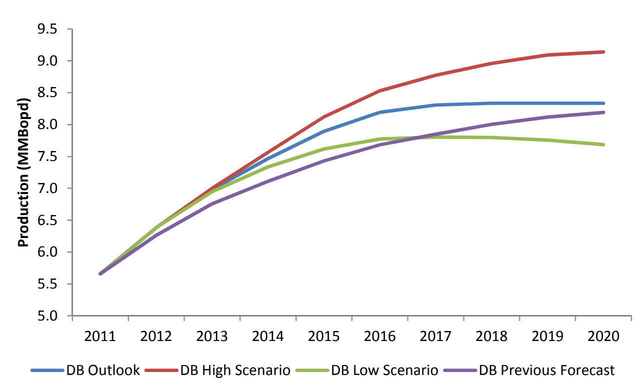
Our production view is moderate relative to some of the more aggressive forecasts from our peers and energy consultancy outfits like PIRA and Wood Mackenzie, but it is above the EIA and IEA estimates.

Figure 12: DB US production forecast vs. other estimates



Source: IEA, EIA, PRIA, Wood Mackenzie, Deutsche Bank estimates

Figure 13: DB high, low, base case and prior forecasts



Source: Deutsche Bank estimates

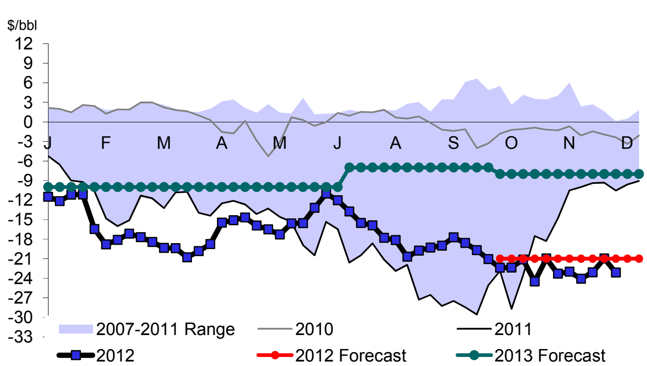
Our new production forecast does raise near-year estimates versus our February thematic note, though the 2020 forecast is close to the same. We've adjusted near- and medium-term estimates higher reflecting the increased performance of the major unconventional basins, but we believe that price will ultimately act as a regulator of growth, as long as the crude export ban is in place, and therefore believe that the feasible plateau level of production remains the same as we envisioned it in February, we may just get there more quickly than we had originally expected. Our E&P teams work suggests that below-the-ground issues may also limit the eventual plateau level. For more on that please see their in-depth note published on December 17, 2012.

Pipelines, pipelines, pipelines – the Cushing bathtub finally drains

To state the obvious, the last two years have been a mostly downhill rollercoaster ride for WTI relative to Brent and coastal US crudes, with 4Q12 a recent peak. The rollercoaster should head uphill for long stretches in 2013, as a procession of Inland Corridor draining pipelines either directly or indirectly alleviate the logjam in Cushing and PADD 2.

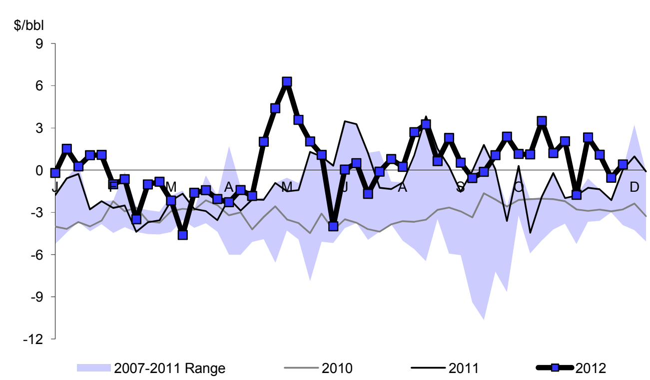
In total there should be over 20 large or medium-sized macro pipelines going into service in the US and Canada in 2013, with 5-6 of those addressing the Inland Corridor/Cushing logjam issue. Three important ones come in 1Q: the long-awaited Seaway ramp-up to 400kbd (incremental 250kbd), reversal of Magellan's Longhorn pipeline, which will initially bring 75-90kbd of Permian crude to Houston, then ramp to 225kbd by mid-year, and expansions to Sunoco Logistics' West Texas Gulf system that will enable about 80kbd of Permian crude to get to Houston and Nederland. In early 2Q we should also see the startup of Sunoco Logistics' Permian Express Phase 1, 90kbd initially ramping to 150kbd by mid-2013.

Figure 14: WTI-Brent differential



Source: Deutsche Bank, Bloomberg Finance LP

Figure 15: Brent-LLS differential



Source: Deutsche Bank, Bloomberg Finance LP

New projects pop up all the time as the MLPs attack emerging inefficiencies in the market, but our fairly comprehensive list of planned and in-process pipelines is below.

Figure 16: North American pipeline queue – more than two dozen project startups over next ~18 months

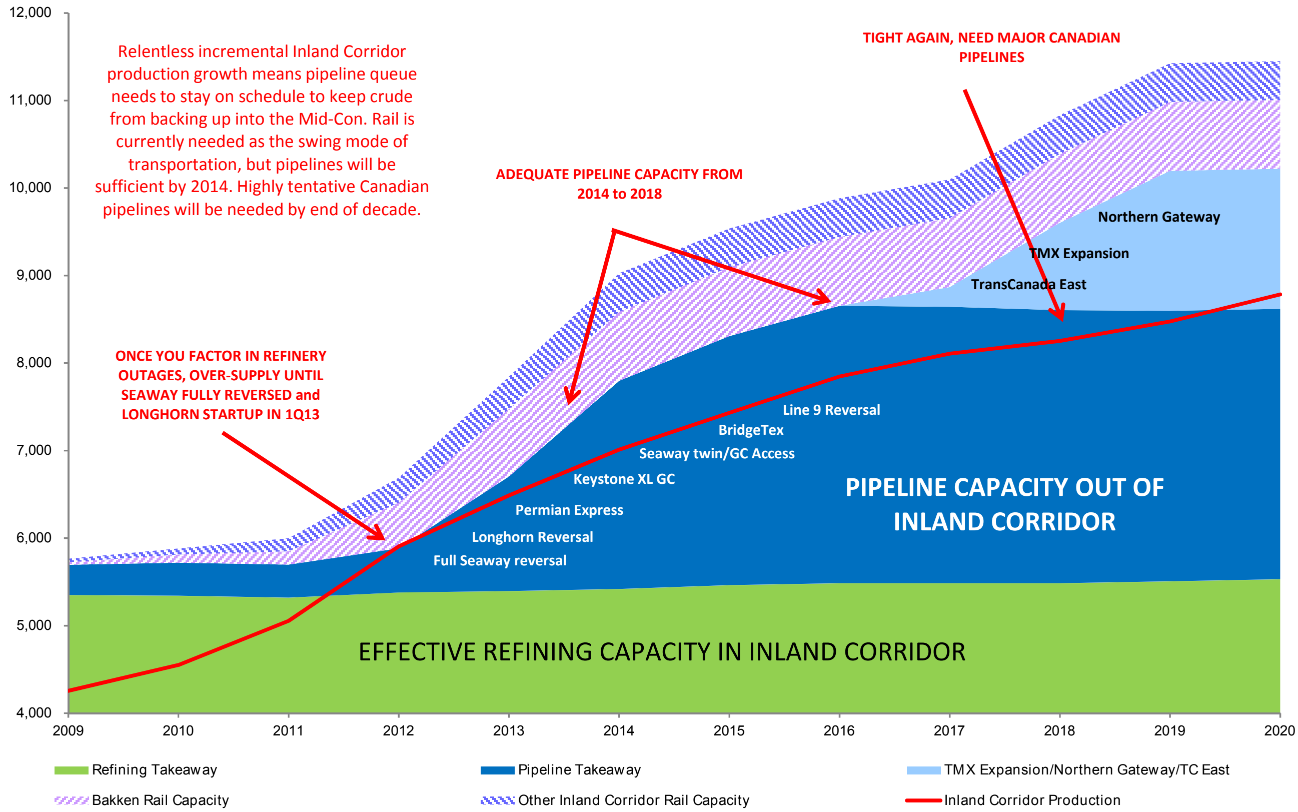
Pipeline	Operator	From	To	Basin	Mid-Con Exit?	Length (mi)	Init. Cap. (kbd)	Ult. Cap. (kbd)	Diam. (in)	Target Date	Status	Est. Cost ($m)	Comments
Nustar Koch Pettus Pipeline	Koch	Pettus, TX	Corpus Christi, TX	Eagle Ford		66	30	50	10	3Q11	In Service	NA	Eagle Ford to local refineries in Corpus Christi, or barge terminals on coast
White Cliffs Expansion	SemGroup	Platteville, CO	Cushing, OK	Niobrara/DJ		526	40	40	12	4Q11	In Service	NA	Expanded to 70kbd from 30kbd, only current exit pipeline out of Niobrara
Koch Arrowhead Expansion	KPL/Harvest	Eagle Ford, TX	Corpus Christi, TX	Eagle Ford		95	50	90	20	1Q12	In Service	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	In Service	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	In Service	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	In Service	NA	Dedicated line to Valero refinery
EPD Eagle Ford Trunkline	Enterprise	Lyssy, TX	Sealy,TX (Houston)	Eagle Ford		147	350	350	24	2Q12	In Service	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	In Service	1,400	Ramp to 400kbd in 1Q13, carrying mostly light crude initially, may shift towards heavy later
KMCC Pipeline	KM	Cuero, TX	Houston, TX	Eagle Ford		178	300	300	NA	2Q12	In Service	220	EF to Houston, both new build and converted gas pipes, connects to condensate facility
Koch Pipeline	Koch	Pettus, TX	Corpus Christi, TX	Eagle Ford		95	120	250	20	2Q12	In Service	NA	Eagle Ford to Corpus Christi; leg to Pettus started up in April, Corpus Christi leg in 2012
West Texas Houston Access	Sunoco	Midland, TX	Houston, TX	Permian	√	476	40	44	NA	2Q12	In Service	NA	Open season Feb-Mar 2012, would take Permian crude out of Mid-Con to OTI Terminal
TexStar/Velocity/NuStar EF	NuStar	Gardendale, TX	Corpus Christi, TX	Eagle Ford		167	142	200	16	3Q12	In Service	NA	Two 100kbd pipes converge at Gardendale, then NuStar takes it to CC
PAA/EPD Eagle Ford	PAA	Eagle Ford, TX	Corpus Christi, TX	Eagle Ford		162	350	350	24	4Q12	Construction	300	JV includes Connection to EPD to Houston; JV also building marine terminal & 1.5Mbbl of storage
Waupisoo (Line 18) Exp. Ph. 1	Enbridge	Cheecham, AB	Edmonton, AB	WCSB		236	65	65	NA	4Q12	Construction	400	Two phases, 65kbd in late 2012/early 2013, then the rest in 2H13
Wood Buffalo	Enbridge	Athabasca, AB	Cheecham, AB	WCSB		59	550	550	30	4Q12	Construction	400	Transports diluted bitumen to Cheechum Terminal, connects to Lines 18 & 19 to Edmonton/Hardisty
Longhorn Reversal	Magellan	Crane, TX	Houston, TX	Permian	√	518	75	225	18	1Q13	Construction	375	Permian crude to coast instead of Cushing, 75kbd will flow in 1Q13, ramp to capacity by mid-year
Enbridge Line 79	Enbridge	Stockbridge, MI	Freedom Junction, MI	Inland Corridor		64	80	80	20	1Q13	Construction	190	Will increase amount of crude that can be moved from Line 6B to Detroit and Toledo, expandx Line 17
Enbridge Line 5 Expansion	Enbridge	Superior, WI	Sarnia, ON	Northern tier		645	50	50	30	1Q13	Construction	95	Expands existing line from 490kbd to 540kbd
West Texas Longview Access	Sunoco	Midland, TX	Longview, TX	Permian		458	30	30	NA	1Q13	Construction	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	140	24	1Q13	Construction	150	50/50 JV, new 140 mi stretch connects to existing pipeline owned by Copano, will carry condensate
Enbridge Bakken Expansion	Enbridge	Beaver Lodge, ND	Cromer, Manitoba	Bakken		124	120	325	NA	1Q13	Construction	560	$370m project to connect Bakken to Enbridge mainline
West Texas - Nederland	Sunoco	Midland, TX	Nederland, TX	Permian	√	567	40	40	NA	1Q13	Construction	NA	Will carry primarily sour crude to Sunoco storage in Nederland
Woodland	Enbridge	Woodland, AB	Cheecham, AB	WCSB		87	210	210	36	1Q13	Construction	300	Kearl to Cheechum Terminal
Ho-Ho Pipeline Reversal	RD Shell	Houston, TX	Houma, LA	Gulf Coast		320	300	300	22	1H13	Construction	NA	Will take Texas crudes east, Port Arthur early 1Q13, St. James 2H13
Permian Express Phase 1	Sunoco	Wichita Falls, TX	Nederland, TX	Permian	√	476	90	150	NA	2Q13	Construction	NA	Open season 07/12; Will take 6-9 months to startup, ramp to 150kbd by mid-2013; 3-7 yr commitments
PAA Mississippian	PAA	Alva, OK	Cushing, OK	Mississippian		170	150	175	NA	2Q13	Construction	NA	LT contract with SandRidge, will use Medford-Cushing pipeline right of way
Butte Loop	True	Baker, ND	Casper, WY	Bakken		323	50	50	16	2Q13	Construction	NA	Exit from Bakken to Guernsey, connects with Platte, which goes to Wood River
Plains Bakken North	PAA	Trenton, ND	Regina, SK	Bakken		103	50	75	12	2Q13	Construction	180	Will connect to Wascana Pipeline in Montana, then Enbridge system in Saskatchewan
EPD EF Phase II Extension	Enterprise	Wilson, TX	Gardendale, TX	Eagle Ford		220	200	350	24	2Q13	Construction	NA	Extends existing line, combined with PAA Eagle Ford, CHK 100kbd anchor
Line 9 segment-reversal	Enbridge	Sarnia, ON	North Westover, ON	Inland Corridor	√	132	50	50	30	2Q13	Sanctioned	100	First leg of reversal, received reg approval but was delayed
Woodford to Wynnewood	Blueknight	Woodford, OK	Wynnewood, OK	Woodford		65	NA	NA	NA	3Q13	Planned	37	Will transport XTO Woodford production to Wynnewood to connect to pipeline to Cushing
Waupisoo (Line 18) Exp. Ph. 2	Enbridge	Cheecham, AB	Edmonton, AB	WCSB		236	245	245	NA	3Q13	Construction	400	Two phases, 65kbd in late 2012/early 2013, then rising to 310kbd in 2H13
Seaway-ECHO connectivity	Enbridge	Houston, TX	ECHO Terminal, TX	USGC		65	NA	NA	NA	3Q13	Sanctioned	NA	Lateral pipeline to connect to Enterprise's ECHO terminal hub
Glass Mountain Pipeline	SemGroup/Gavilon	Cleo Springs , OK	Cushing, OK	Mississippian		210	140	180	NA	4Q13	Planned	NA	Will feed SemGroup's 1Mbbl storage facility at Cushing; anchored by Chesapeake production
Keystone XL GC Project	TransCanada	Cushing, OK	Port Arthur, TX	Inland Corridor	√	485	700	830	36	4Q13	Sanctioned	2,000	Split project into two, piece to GC won't require State Dept permitting
Norealis	Enbridge	Norealis, AB	Cheecham, AB	WCSB		106	90	90	24	4Q13	Sanctioned	500	Will transport blended bitumen from oil sands projects to the far northeast of the region
High Prarie Pipeline	Saddle Butte	Alexander, ND	Clearbrook, MN	Bakken		450	150	150	16	4Q13	Proposed	NA	Plans for 4Q13 startup, but ENB has refused access to Mainline at Clearbrook, Saddle Butte suing
TransCanada Heartland Ext.	TransCanada	Ft Sask'wan, AB	Hardisty, AB	WCSB		130	600	600	NA	2013+	Proposed	NA	Intra-WCSB pipeline
Line 6B Replacement	Enbridge	Griffith, IN	Stockbridge, MI	Inland Corridor		285	260	260	36	2013/14	Construction	2,400	Will increase 6B capacity to 500kbd, allow greater flow from Mainline through Chicagoland to Sarnia
Keystone XL Houston Lateral	TransCanada	Port Arthur, TX	Houston/Tex City, TX	Gulf Coast		47	500	500	NA	1Q14	Planned	300	Will move KXL crude to Houston area refineries
Athabasca (Line 19) Exp.	Enbridge	Athabasca, AB	Hardisty, AB	WCSB		336	225	225	30	1Q14	Sanctioned	250	Expands existing line from 345kbd to 570kbd
White Cliffs Twinning	SemGroup	Platteville, CO	Cushing, OK	Niobrara/DJ		526	80	100	NA	1H14	Planned	300	Completed successful open season in Oct '12, with Noble/Anadarko anchoring project
Trunkline Conversion/Reversal	Energy Transfer	Tuscola, IL	Nederland, TX	Inland Corridor	√	770	400	600	30	2Q14	Speculative	1,500	Conversion of a S-N gas line into a N-S crude line, must convince FERC; incl later to St. James
Seaway Twinning	Enterprise	Cushing, OK	Freeport, TX	Inland Corridor	√	512	450	450	30	Mid-2014	Planned	NA	Will be built in sync with Flanagan South and Southern Access expansion, mixed heavy/light service
BridgeTex Pipeline	Magellan/Oxy	Colorado City, TX	Houston, TX	Permian	√	440	278	300	NA	Mid-2014	Planned	1,200	Announced moving forward in Nov '12; incl. 400mi of greenfield pipeline; storage on both ends
Seaway Pt Arthur Connectivity	Enbridge	ECHO Terminal, TX	Port Arthur, TX	USGC		85	NA	NA	NA	Mid-2014	Sanctioned	NA	Lateral to connect Seaway to Port Arthur refining hub
Alberta Clipper Expansion	Enbridge	Hardisty, AB	Superior, WI	WCSB		1,000	120	350	36	3Q14	Planned	600	Capacity will rise from 450kbd to 570kbd, can be expanded to 800kbd
Flanagan South/GC Access	Enbridge	Flanagan, IL	Cushing, OK	Inland Corridor		590	585	800	36	Mid-2014	Construction	2,800	Key pipeline add to bring Canadian heavy sour to GC via Cushing and Seaway; in construction
Southern Access Expansion	Enbridge	Superior, WI	Flanagan, IL	Northern tier		500	200	800	36	3Q14	Sanctioned	NA	Expansion of Southern Access needed to move Canadian to GC Access
Spearhead North Expansion	Enbridge	Flanagan, IL	Griffith, IN	Inland Corridor		110	105	105	NA	3Q14	Sanctioned	NA	Will allow greater volumes to flow to Detroit/Sarnia, part of Eastern Access program
Pony Express	KM/Tallgrass	Guernsey, WY	Cushing, OK	Niobrara		710	230	230	NA	3Q14	Proposed	NA	Converts 500 mi of under-utilized gas pipeline into crude pipe; will deliver to Ponca City and Cushing
Cochin Reversal Project	Kinder Morgan	Windsor, ON	Ft. Saskatchewan, AB	Inland Corridor		1,600	95	95	NA	3Q14	Planned	NA	Will pickup EF condensate in Chicago from Explorer Pipeline, take to WCSB for use as diluent
Niobrara Falls Project Ph 1	NuStar	Dixon, TX	Wichita Falls, TX	Permian/GrWash		238	125	125	14	2014	Proposed	NA	Open season to 12/12; reversed product pipeline, Permian/Granite Wash to Basin/Permian Express
Line 9 reversal to Montreal	Enbridge	Sarnia, ON	Montreal, QC	Inland Corridor	√	524	240	300	30	2014	Planned	100	Second phase, submitting regulator filing in December, 2012
Permian Express Phase 2	Sunoco	Colorado City, TX	Nederland, TX	Permian	√	515	200	200	NA	2014	Proposed	NA	Expansion of line starting at Colorado City; would allow further access to Louisiana refineries
Athabasca Pipeline Twinning	Enbridge	Kirby Lake, AB	Hardisty, AB	WCSB		338	450	800	30	1Q15	Planned	1,200	Twinning of primary north-south regional pipeline
Keystone XL Northern Leg	TransCanada	Hardisty, AB	Cushing, OK	WCSB/Bakken		1,667	700	830	36	2015	Planned	5,300	$7.6B project. We expect permit in 1Q13, startup sometime between 2Q14 and 2015.
Woodland Extension	Enbridge	Cheecham, AB	Edmonton, AB	WCSB		236	400	800	36	2015	Proposed	1,200	Extends Woodland from Cheecham to Edmonton along Waupisoo right of way, expandable to 800kbd
Westward Ho	RD Shell	St. James, LA	Houston, TX	USGC		320	300	300	22	2015	Proposed	NA	Twin of Ho-Ho heading in opposite direction, will run from St. James
Southern Access Extension	Enbridge	Flanagan, IL	Patoka, IL	Inland Corridor		165	200	400	24	2015	Planned	NA	Will allow Mainline bbls to go to Cushing or Patoka, could use bigger pipe if interest sufficent
Sandpiper Project	Enbridge	Tioga, ND	Superior, WI	Bakken		600	225	325	24	2015	Proposed	2,500	Would move Bakken crude from Western Williston Basin to Superior
Portland Montreal Reversal	PMPL	Montreal, QC	Portland, ME	Inland Corridor	√	261	200	200	18	2015+	Speculative	100	Would extend Line 9 all of the way to the Maine coast, where crude could be exported to Europe
TMX expansion - twinning	Kinder Morgan	Edmonton, AB	Vancouver, BC	WCSB	√	715	300	450	30	2017	Planned	4,100	9 shippers w/ 20 yr contracts for 510kbd, hurdles remain despite brownfield status
Northern Gateway Pipeline	Enbridge	Bruderheim, AB	Kitimat, BC	WCSB	√	731	500	500	36	2018+	Planned	5,500	Still trying to get reg approval, NEB hearing in Jan., opposition from First Nations/environmentalists
Niobrara Falls Project Ph 2	NuStar	Platteville, CO	Dixon, TX	Niobrara		437	75	75	10	NA	Speculative	NA	Niobrara to Texas, would connect with Basin and Permian Express
East Coast Pipeline Project	TransCanada	Hardisty, AB	St. John, NB	WCSB	√	1,800	625	625	NA	NA	Speculative	6,500	Could reach Montreal, St. John's, New Brunswick, St. Lawrence waterway, Portland, ME
Norther Gateway Condensate	Enbridge	Kitimat, BC	Bruderheim, AB	WCSB		731	193	193	NA	NA	Planned	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	NA	Speculative	NA	Would extend Keystone system into far eastern PADD 2
EPNG/Mojave conversion	Kinder Morgan	Permian, TX	Los Angeles, CA	Permian	√	1,115	400	400	NA	NA	Speculative	NA	Conversion of part of the EPNG nat gas system to crude use, would service SoCal refineries
White Cliffs ExLoop	SemGroup	Platteville, CO	Cushing, OK	Niobrara		526	NA	NA	NA	NA	Proposed	NA	Niobrara exit capacity - has been discussed but nothing announced
TSO Uinta	TLLP	Uinta Basin, UT	Salt Lake City, UT	Uinta		NA	NA	NA	NA	NA	Proposed	NA	Would be a heated pipeline to carry black/yellow wax to TSO's Salt Lake City refinery

Source: EIA, CAPP, Company data, Dow Jones, Reuters, Upstream, ND Pipeline Authority, Deutsche Bank estimates

We believe the current round of 2013-15 pipelines should be more than enough to cure WTI at Cushing of its discount to coastal crudes for a half decade or so. More major pipelines will eventually need to be built to avoid another broad Mid-Con logjam by about 2017-18 though – the Canadian West Coast-East Coast projects are the most likely candidates, and we would anticipate that some other basins in the US could emerge with higher than expected production and require exit capacity to a coast. And of course rail will continue to alleviate pressure in the Inland Corridor.

Below we highlight our Inland Corridor supply-takeaway balance.

Figure 17: Inland Corridor back in balance soon – LLS-WTI will narrow to transportation differential (kbd)



Source: EIA, company data ,various news reports, Deutsche Bank estimates

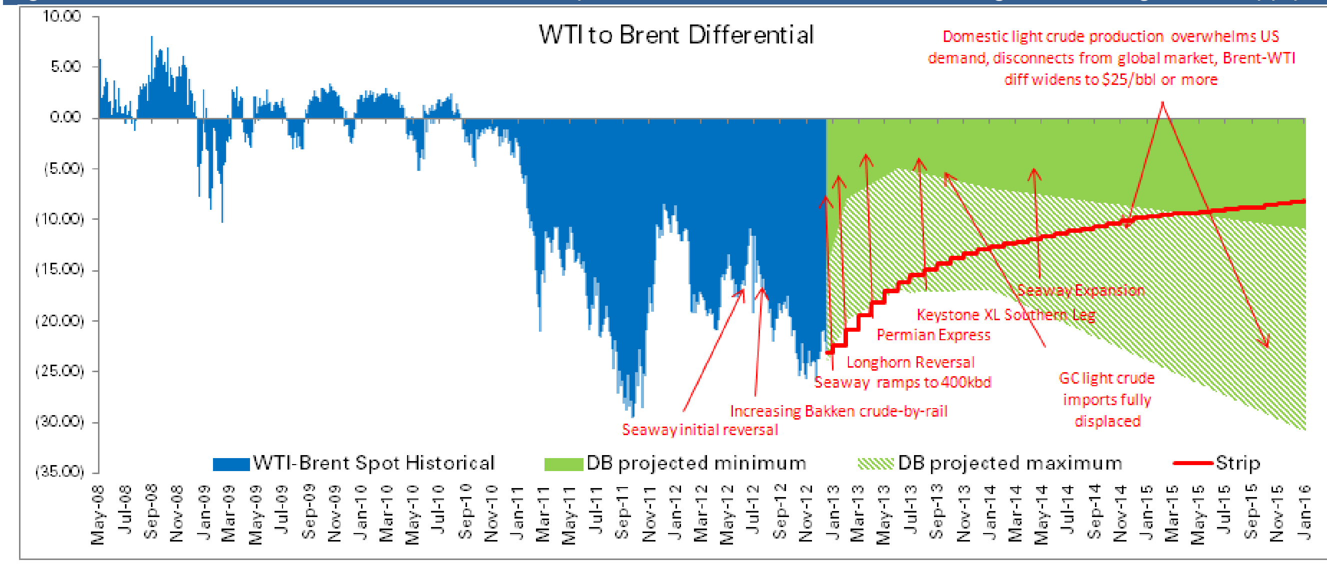
Figure 18: Inland Corridor supply-takeaway balance (kbd)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
CRUDE SUPPLY												
Western Canadian Sedimentary Basin												
Blended Bitumen	996	1,134	1,296	1,441	1,614	1,794	1,932	2,146	2,366	2,509	2,718	2,977
Upgraded SCO	646	660	705	846	931	959	988	1,017	979	981	1,025	1,088
Conventional Heavy	308	309	312	337	334	335	331	329	327	320	318	316
Conv/Unconv Lt/Med	563	570	606	652	739	782	814	827	835	834	832	827
WCSB Total	**2,513**	**2,673**	**2,918**	**3,276**	**3,618**	**3,869**	**4,066**	**4,319**	**4,506**	**4,643**	**4,893**	**5,207**
US Mid-Continent												
North Dakota Bakken	223	310	423	685	796	960	1,117	1,240	1,296	1,287	1,245	1,235
Niobrara/DJ Basin	66	70	106	136	163	181	201	218	242	268	294	313
Permian	870	892	1,005	1,193	1,305	1,419	1,492	1,544	1,581	1,610	1,633	1,652
Other PADD 2	341	359	372	379	379	368	353	336	309	284	261	238
Other PADD 4	242	246	231	235	226	215	200	184	167	152	138	126
US Mid-Continent Total	**1,742**	**1,877**	**2,137**	**2,629**	**2,869**	**3,142**	**3,363**	**3,521**	**3,595**	**3,602**	**3,572**	**3,563**
TOTAL INLAND CORRIDOR	**4,255**	**4,551**	**5,056**	**5,905**	**6,487**	**7,012**	**7,429**	**7,840**	**8,101**	**8,245**	**8,465**	**8,771**
Incremental YoY		295	505	849	582	524	418	411	261	143	220	306
TAKEAWAY CAPACITY												
INLAND CORRIDOR REFINERY TAKEAWAY												
WCSB Refineries	**583**	**583**	**583**	**583**	**583**	**583**	**608**	**633**	**633**	**633**	**658**	**683**
Rockies Refineries	**701**	**701**	**701**	**706**	**713**	**739**	**762**	**762**	**762**	**762**	**762**	**762**
"Group 3" Refineries	**1,230**	**1,220**	**1,195**	**1,195**	**1,195**	**1,195**	**1,195**	**1,195**	**1,195**	**1,195**	**1,195**	**1,195**
Permian Refineries	**689**	**691**	**691**	**692**	**693**	**693**	**693**	**693**	**693**	**693**	**693**	**693**
Chicagoland Refineries	**1,326**	**1,326**	**1,326**	**1,382**	**1,382**	**1,382**	**1,382**	**1,382**	**1,382**	**1,382**	**1,382**	**1,382**
Detroit/Ohio Valley Refineries	**961**	**961**	**961**	**965**	**975**	**975**	**975**	**975**	**975**	**975**	**975**	**975**
Ontario Refineries	**453**	**453**	**453**	**453**	**453**	**453**	**453**	**453**	**453**	**453**	**453**	**453**
Total to Refineries	**5,943**	**5,935**	**5,910**	**5,976**	**5,994**	**6,020**	**6,068**	**6,093**	**6,093**	**6,093**	**6,118**	**6,143**
Assuming 90% Utilization	**5,349**	**5,342**	**5,319**	**5,378**	**5,395**	**5,418**	**5,461**	**5,484**	**5,484**	**5,484**	**5,506**	**5,529**
PIPELINE EXIT ROUTES												
Mid-Con/Alberta to Gulf Coast												
ExxonMobil Pegasus	64	96	96	96	96	96	96	96	96	96	96	96
Seaway Reversal	0	0	0	100	400	400	400	400	400	400	400	400
Keystone XL Gulf Coast Project	0	0	0	0	175	700	700	830	830	830	830	830
Seaway Twinning	0	0	0	0	0	225	450	450	450	450	450	450
Mid-Con to GC Total	**64**	**96**	**96**	**196**	**671**	**1,421**	**1,646**	**1,776**	**1,776**	**1,776**	**1,776**	**1,776**
Permian to Gulf Coast												
Sunoco WTG Houston Access	0	0	0	10	40	40	40	40	40	40	40	40
Amdel	0	0	0	15	27	27	27	27	27	27	27	27
Magellan Longhorn reversal	0	0	0	0	175	225	225	225	225	225	225	225
Sunoco WTG Nederland	0	0	0	0	30	40	40	40	40	40	40	40
Sunoco Permian Express Phase 1	0	0	0	0	90	150	150	150	150	150	150	150
Magellan/Oxy BridgeTex Pipeline	0	0	0	0	0	140	278	278	278	278	278	278
Sunoco Permian Express Phase 2	0	0	0	0	0	0	50	200	200	200	200	200
Permian to GC Total	**0**	**0**	**0**	**25**	**362**	**622**	**810**	**960**	**960**	**960**	**960**	**960**
Alberta to 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	0	225	450	450	450
Northern Gateway	0	0	0	0	0	0	0	0	0	250	525	525
Alberta to Canadian PC Total	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**525**	**1,000**	**1,275**	**1,275**
Alberta/Mid-Con to Eastern Canada												
Line 9 reversal to Montreal	0	0	0	0	50	160	240	300	300	300	300	300
TransCanada East	0	0	0	0	0	0	0	0	0	300	625	625
Alberta/Mid-Con to EC Total	**0**	**0**	**0**	**0**	**50**	**160**	**240**	**300**	**300**	**600**	**925**	**925**
Total Pipeline Exit Capacity	**364**	**396**	**396**	**521**	**1,383**	**2,503**	**2,996**	**3,336**	**3,561**	**4,336**	**4,936**	**4,936**
Assuming 95% Utilization	**346**	**376**	**376**	**495**	**1,314**	**2,378**	**2,846**	**3,169**	**3,383**	**4,119**	**4,689**	**4,689**
TOTAL REFINERY & PIPELINE TAKEAWAY	**5,695**	**5,718**	**5,695**	**5,873**	**6,708**	**7,796**	**8,307**	**8,653**	**8,867**	**9,603**	**10,195**	**10,218**
Excess Takeaway Capacity	**1,439**	**1,167**	**640**	**(32)**	**221**	**784**	**878**	**813**	**765**	**1,358**	**1,731**	**1,447**

Source: EIA, Company data, Reuters, Dow Jones, various news reports, Wood Mackenzie, CAPP, ND DMR, ND Pipeline Authority, Deutsche Bank estimates

With a string of pipelines helping to clear the Cushing/Inland Corridor issue, WTI should move towards a transportation cost differential to LLS by mid-year. Our view is that LLS will gradually be weakening versus Brent, thus we believe that WTI will close towards Brent for much of the year, but then start to move wider with all US crudes by the end of the year. With LLS potentially at a $3-5/bbl discount to Brent by YE13, WTI would be at something like a $8-12/bbl discount. Beyond 2013 we would expect all US light crudes to continue to disengage from Brent as price will incentivize US refiners to distort their crude slates to run more light.

Figure 19: Brent-WTI differential – narrows to transportation cost in 2013, then widens again due to light oversupply



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

Eventually unconventional growth will push light crudes into a clear oversupply, which will cause the price of WTI and other light crudes to plummet to the marginal cost of production, forcing marginal operators to lay down their rigs to stabilize the market. We see that price collapse occurring in the 2015-16 timeframe, but could happen sooner or later depending on the pace of US production (unconventional, Gulf of Mexico) and the unknown level of light that the refiners are willing to absorb.

Crude export restriction

We won't re-hash the details of the US crude export restriction, but would direct you to our February 28, 2012 "Future of US Oil" note for some commentary on the history and legislation behind the ban. The restriction is part of the Export Administration Regulations (EARs) administered by the Bureau of Industry and Security (BIS), a part of the US Department of Commerce. In order to export crude, the EAR (Section 754) requires a permit, which can only be granted for a handful of legislatively outlined reasons. The BIS will review applications on a case-by-case basis, but exercises little discretion, and will only grant licenses if an exception "box" can clearly be checked. The primary exceptions carved out in various pieces of legislation are exports to Canadian refineries, exports from Alaska, exports of a limited amount (25kbd) of heavy crude from California, and an exchange for an equivalent value of refined products.

While we have seen press reports of various shippers requesting permits to export, most have been to Canadian refineries, which we highlighted in our note in February is an explicit carve-out in the EAR. So "surprising" headlines about US crude exports so far have really just been business as usual actions, though it is a significant and meaningful trend to see an increase in US exports to Eastern Canadian refineries.

Given the looming over-supply of light crude, we may start to see some shippers "float test balloons" to see what the BIS does, or to force some political discussion on the issue. Again, BIS has historically been primarily a "box-checking" agency focused on administration of legislatively-prescribed criteria for export permits – the EAR covers a wide range of products, not just crude. In our view, they are highly likely to punt any sort of policy-making into the political arena.

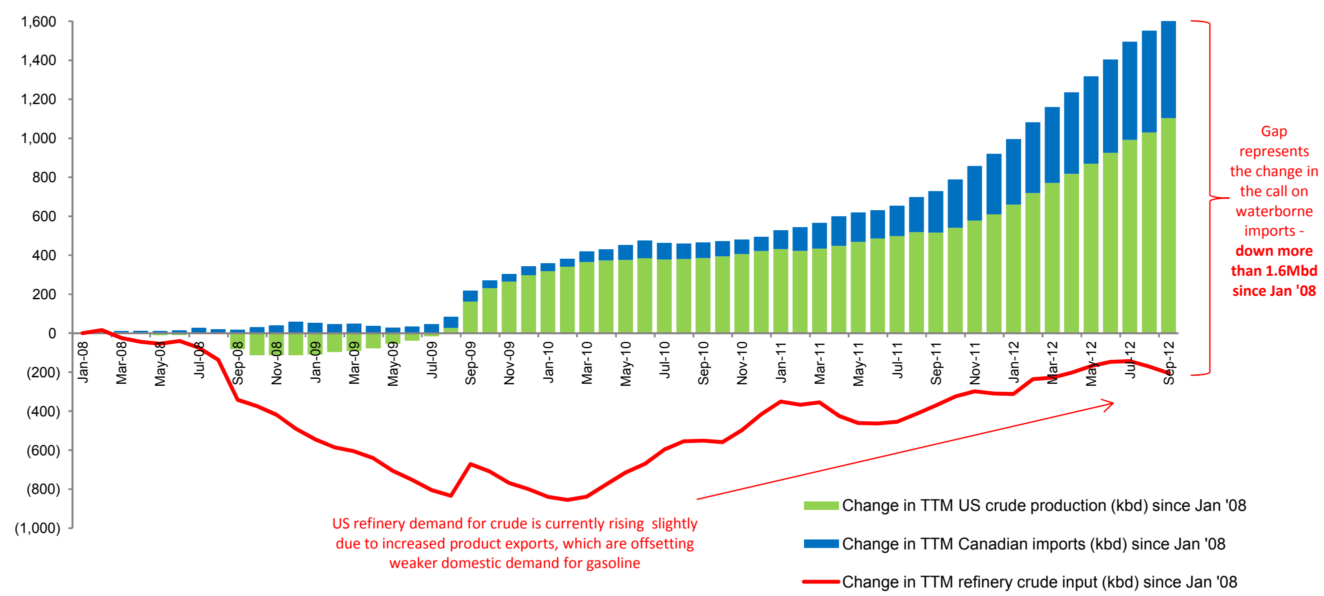
While there are certainly strong arguments for lifting or modifying the crude export restriction, there are sizeable energy-security contingents in both major US political parties, and we think it is pretty clear that the leaders of those groups won't let waterborne crude exports start up without discussion. When the headlines of the BP/Shell/Vitol export applications were reported by Reuters and others back in September, it only took a few days for Congressman Ed Markey (Dem-MA, former Chairman of the House Select Committee on Energy Independence and Global Warming) to make a public statement expressing concern.

Thus while it would not surprise us to see an increasingly high profile and high level discussion start to take place on the issue of crude exports, particularly since a similar debate has already started to heat up on the subject of LNG exports, we think it will take several years, at minimum, for a political solution to crude exports to emerge. In the meantime we will likely see efforts to "get around" the restriction, such as the export of some types of condensate or perhaps exchanges of crude for products. Those could have an impact on the margin, but we think this will ultimately need a public debate and political resolution, thus our analysis proceeds under the assumption that the US crude export restriction will stay in place for the foreseeable future.

US and Gulf Coast import trends

Surging US production against a relatively flat demand at the refinery level means crude imports continue to decline. Note that refinery demand, even with net product export growth is still below 2008's level.

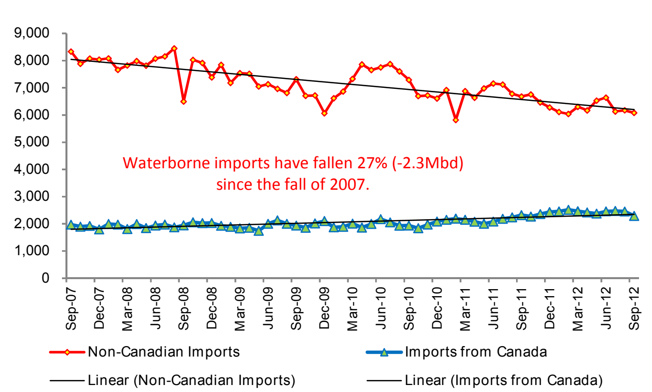
Figure 20: Change since 2008 in rolling 12 month refinery crude demand vs US production & Canadian imports (kbd)



Source: EIA, Deutsche Bank

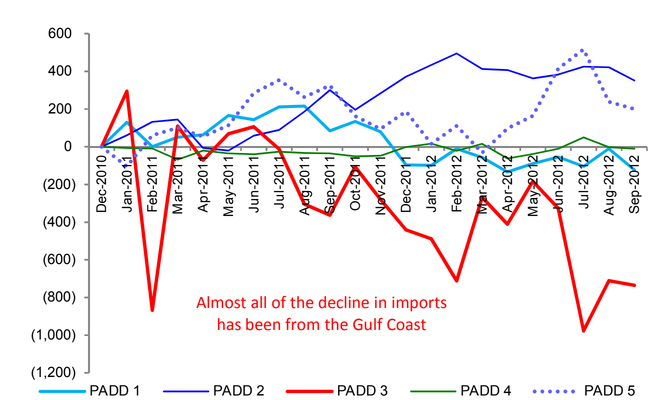
The decline in waterborne imports is dramatic. Total US imports have fallen 1.9Mbd (-19%) over the last five years (as of September), but with Canadian imports up about 18% over that period, total waterborne imports have fallen by 2.3Mbd, or about 27%. And as you would expect, most of that has come out of the Gulf Coast.

Figure 21: Non-Canadian imports falling quickly



Source: EIA, Deutsche Bank

Figure 22: All of the decline has been in PADD 3

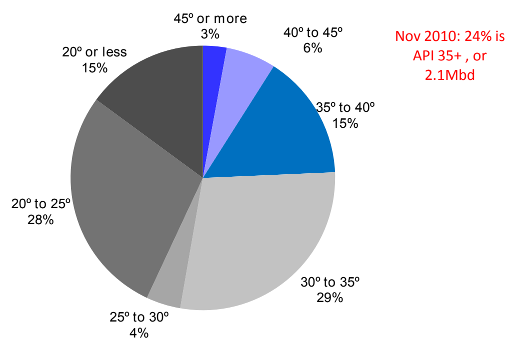


Source: EIA, Deutsche Bank

We would expect to soon see PADD 1 and PADD 5 waterborne import declines start to show up in the EIA data, as increasing volumes of Bakken (and now Eagle Ford) crude makes its way to the East and West Coast by rail and barge.

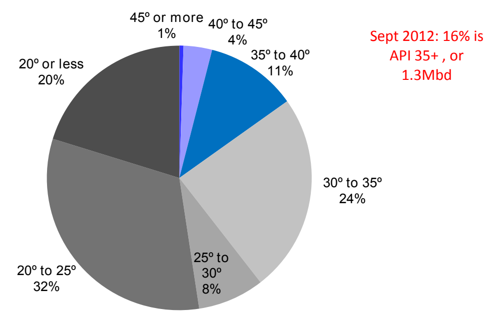
Given that over 80% of North American production growth in 2012 was light crude (compared, to 60% in 2011, 50% in 2010), it comes as no surprise that the decline in imports has been mostly light crude. The import mix for the US has shifted dramatically in just two years. In the fall of 2010 nearly a quarter of crude imports, about 2.1Mbd, were API 35° or higher. In the most recent EIA data, for September, 2012, only 16% of imports were light crude, about 1.3Mbd. We believe light crude imports are probably down another 100kbd in the 2-3 months since the September EIA report.

Figure 23: US Imports by quality, November 2010



Source: EIA, Deutsche Bank

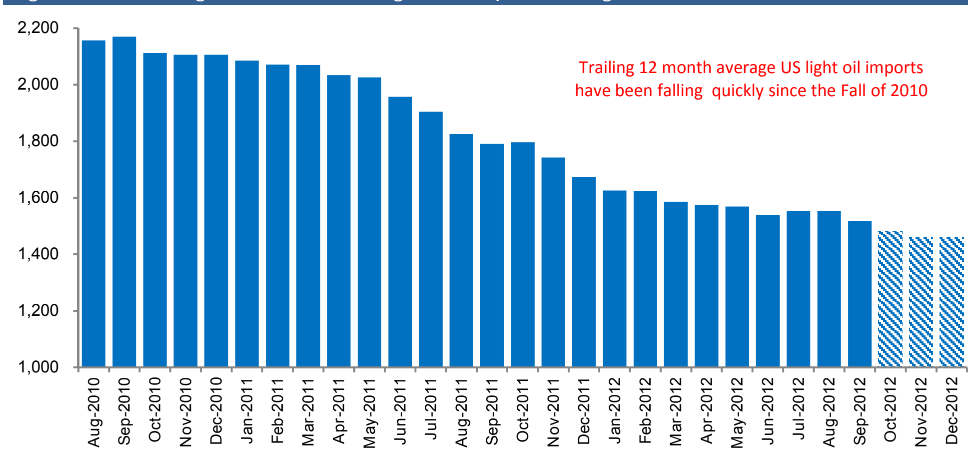
Figure 24: US imports by quality, September, 2012



Source: EIA, Deutsche Bank

Keep in mind that the EIA import data includes Canadian crude, which like domestic US crude is essentially trapped (US by law, Canada by an absence of infrastructure), and must go to the US. Thus Canadian crude also pushes out waterborne imports. We believe there is 400-500kbd of Canadian in the light crude import numbers, out of roughly 1.3Mbd total. The trailing 12 month view of US light crude imports below shows how rapid the decline has been over the last two years.

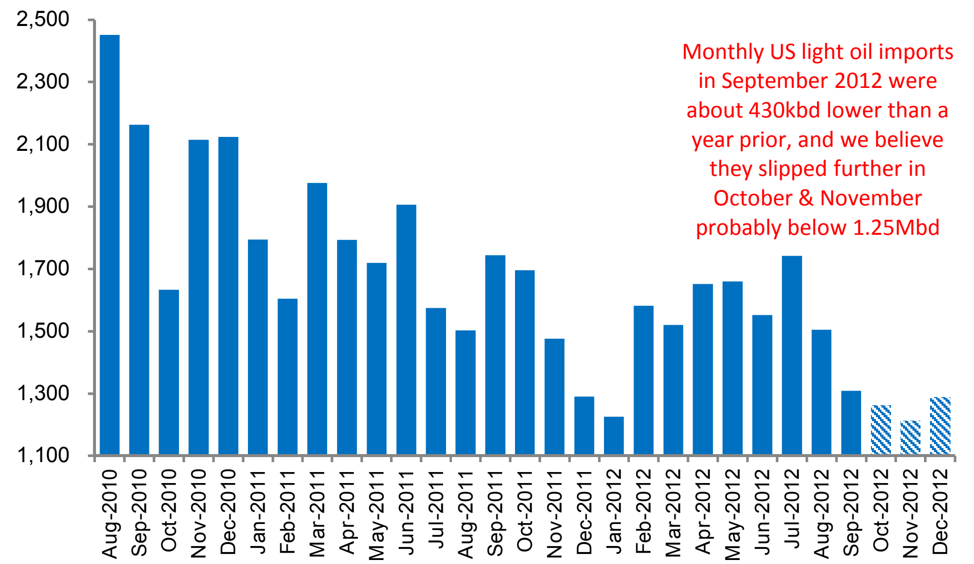
Figure 25: Trailing 12-month average US imports of light (API 35°+) crude (kbd)



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 Bakken and Eagle Ford (and soon, Permian) crude have moved to the Gulf Coast via rail and pipeline. EIA import data by crude quality is published on a 2 month lag, so the numbers for October and November have not been published, but the weeklies show an overall decline in imports for both months, and we assume that the decline is primarily lighter crudes. The monthly trend since the Fall of 2010, including our expectation for 4Q, is below.

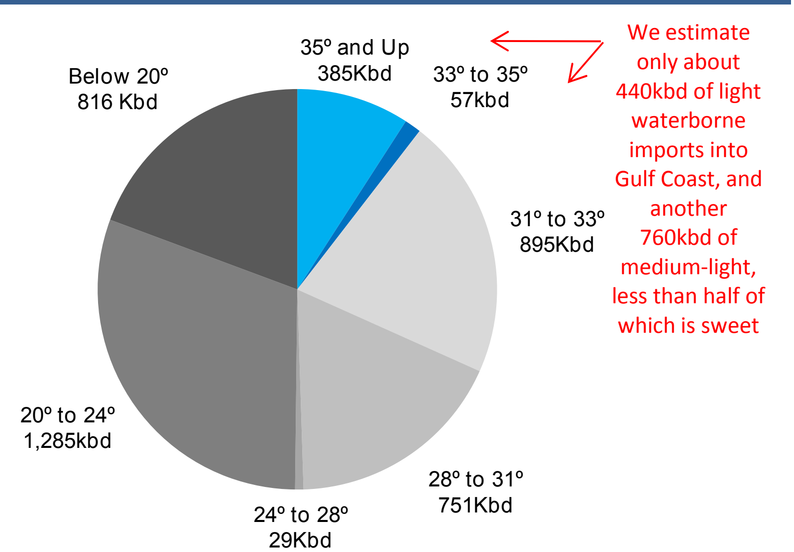
Figure 26:Monthly US light crude imports, with DB estimate for 4Q12 (kbd)



Source: EIA, Deutsche Bank

We are left with the following end-of-year snapshot of remaining waterborne imports into the Gulf Coast.

Figure 27: Estimated PADD 3 waterborne imports by API quality



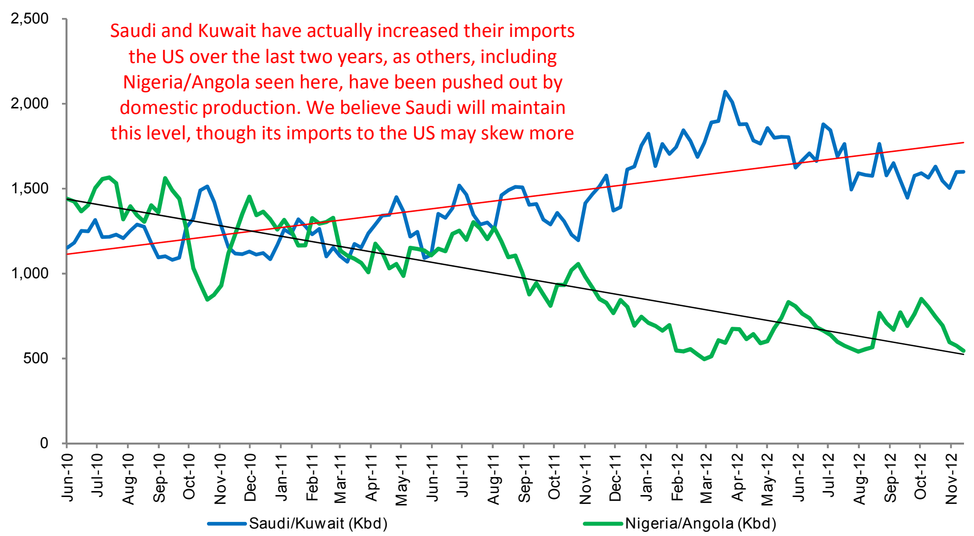
Source: Company data, EIA, Wood Mackenzie, Deutsche Bank estimates

We think just over 10% of the ~4.2Mbd of remaining Gulf Coast waterborne imports are light crude. Based on conversations with, and public comments from major refiners, we believe that number is in the correct ballpark. With numerous pipelines about to point the unconventional spigots towards Houston, and to a lesser extent Louisiana (rail terminals substituting there for pipelines, to a large extent), we expect all of the substitutable light crude to be displaced by the end of 2013.

Saudi will maintain market share regardless of price

An interesting and important facet of the US's falling waterborne imports is that Saudi and Kuwait have maintained or even increased their exports into the market over the last two years, even as most other light crude producers are being gradually pushed out of the market.

Figure 28: Saudi is staying, everyone else has to go – monthly imports for Saudi/Kuwait and Nigeria/Angola since 2010



Source: EIA, Deutsche Bank

We believe that Saudi will maintain its market share in North America, particularly through the Motiva JV (Shell/Aramco), but also through traditional customers such as ExxonMobil, Valero and Marathon. Our view is that Saudi wants to maintain its important geopolitical ties to the US and also remain firmly ingrained in important markets, for security, diplomatic and market-intelligence reasons. Saudi already prices crude sales to the Atlantic Basin below its prices to Asia, and it is important to keep in mind that Saudi sells at fixed prices to designated buyers, not on the open market on a spot basis. Given their industry-low production costs, both Saudi and Kuwait can sell at whatever the going domestic rate is and maintain share, while others get priced out of the market.

This has implications for the timing of light crude over-supply on the Gulf Coast, as there are actually fewer barrels to push out than the headline number. We think 100kbd or more of Saudi Arab Extra Light (API 39°) is included in the remaining 440kbd or so of light crude imports coming into the Gulf Coast at the moment, and it may not be displaced regardless of US prices.

Some other knock-on effects of this Saudi policy: 1) adding more oil into an oversupplied market with no export outlet will exaggerate a fall in price because the usual supply reaction (ie, laying down rigs) doesn't apply; 2) they will accept any market-based price, which will tend to widen the discount to international crudes since they don't "push-back" as the price falls; 3) they will supply less oil to meet rising Asian demand, exacerbating the "Asian premium."

Pressure to the marginal cost

US oil prices are under pressure towards marginal cost of supply

Our analysis indicates an over-supply of light sweet crude in the North American market. By extension of our analysis, we think the most discounted production basin in North America will be the Bakken, which is most distant from markets and hence realises the lowest realisation relative to marker crude WTI.

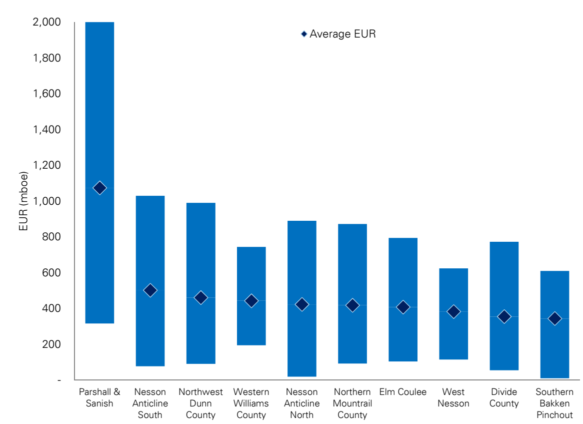
We believe that the marginal producing field in the Bakken needs a WTI-equivalent price of around $80/bbl, and this is our downside target on WTI. The economics for the Bakken are a balance between cost control and the potential ultimate recovery from each well, which is highly dependent on location. Our analysis indicates that the marginal play in this marginal is the Southern Bakken Pinchout, with an $80/bbl break-even (figure 31).

Figure 29: Bakken Well Profile

Well Profile		Production Profile:	
Avg Well Cost ($MM)	$9.5	Oil/Condensate	87%
Typical EUR (Mboe)	574	NGL	3%
30 day IP (boe/d)	950	Gas	10%
Initial Decline Rate	37%		
Terminal Decline Rate	7%	Avg Drill Time (days)	40
b factor	1.2	Well Spacing (acres)	640
IRR ($90/$4/30% WTI)	56%		

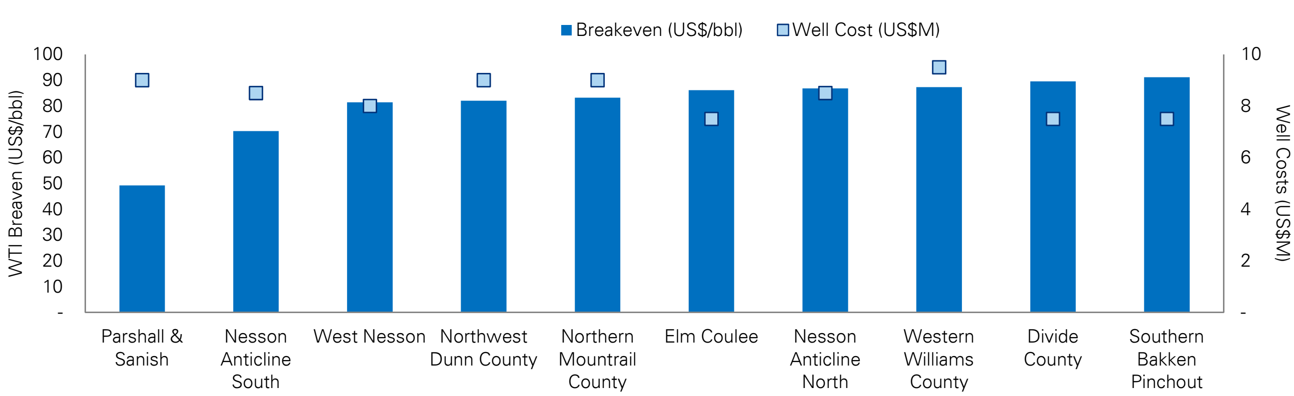
Source: Deutsche Bank, Company Reports, Wood Mackenzie

Figure 30: Bakken EUR



Source: Deutsche Bank, Company Reports, Wood Mackenzie

Figure 31: Bakken Breakeven Cost By County



Source: Deutsche Bank, Wood Mackenzie

Focus on the Gulf Coast

LLS – crude export ban implications continue to play out

Our focus this year will be on LLS – the trend for WTI has a general consensus and is largely in the stocks. There isn't a consensus on LLS on the other hand, partly because there are so many moving parts. Yet in our view the implications of the crude export ban and the unconventional surge can only mean one thing – eventual over-supply of light crude, and depressed prices for all domestic crudes, including LLS. The question then is really one of timing and scale – how quickly and how far will coastal crudes fall as we move forward.

While many of the differentials and distortions will be reduced in 2013 as the pipeline build out comes to fruition, we believe that coastal US crudes will further weaken relative to global light crudes this year. LLS, the coastal domestic US light crude benchmark, has already been weakening versus Brent, and we think that will continue as the Gulf Coast increasingly floods with unconventional light crudes.

The new pipelines going into service in the first half of 2013 will accelerate the process of pushing out waterborne light crude imports. In addition to weakening LLS, the competitive push and pull of the unconventional crudes and the remaining light imports have caused volatility in LLS, even as the overall trend is clearly downward. As the chart below illustrates, LLS began to weaken versus Brent in 1Q or 2Q 2011, as light crude imports into the Gulf Coast dipped under 1Mbd, and as the major unconventional plays began to hit stride and accelerate.

Figure 32: LLS weakening vs. Brent – historically at a $2-3/bbl premium

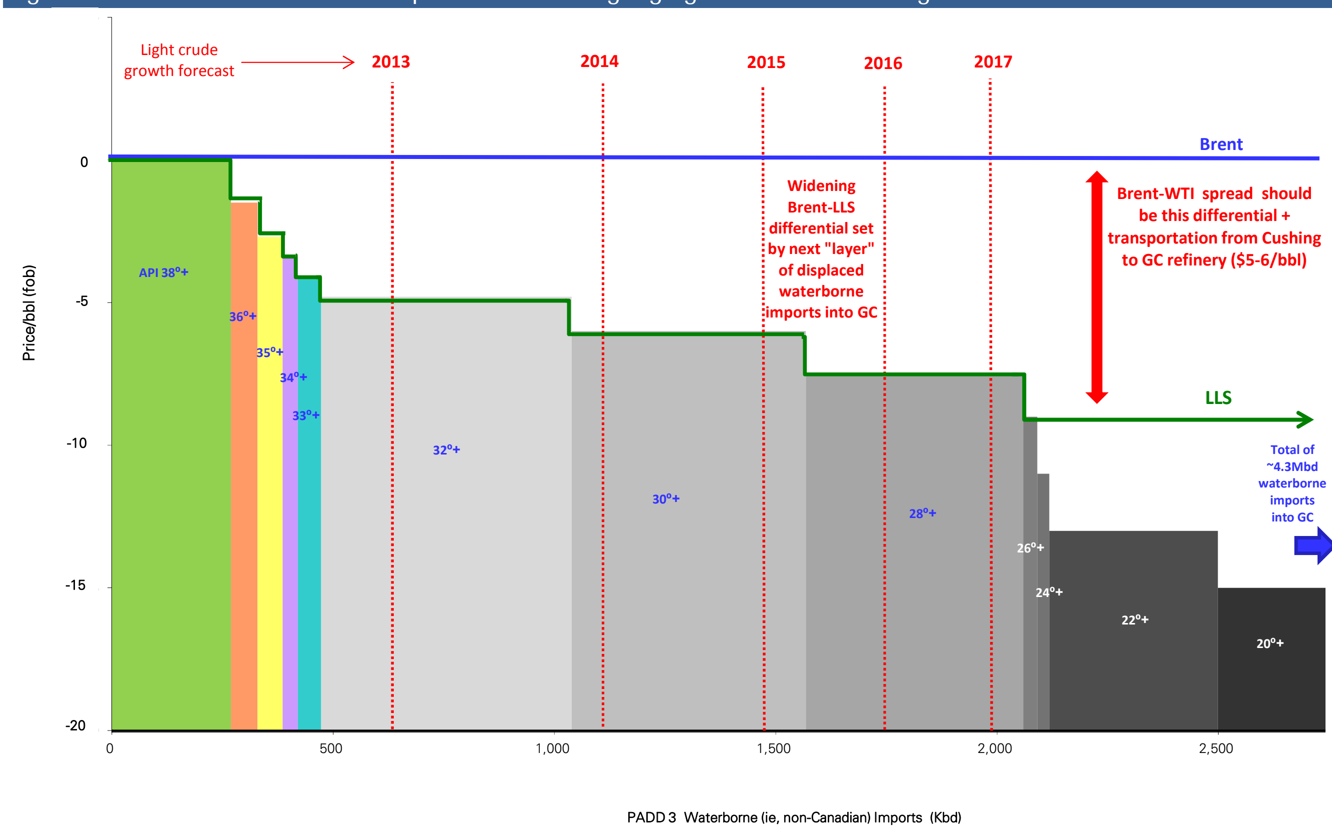
Source :Bloomberg Finance LP, Deutsche Bank

The pipelines from the Permian and Eagle Ford – capacity of about 1Mbd combined – light crude will continue to flood into Houston, and by the end of 2013 we expect all of the remaining light and medium barrels to be forced out (ex-Saudi and Kuwaiti barrels). While Houston refineries will try to run more of the increasingly cheap light barrels, some of the oversupply will find routes to other markets – moving east by pipeline (reversed Ho Ho) or barge (from Corpus Christi or Houston) to the Louisiana market, or the US or Canadian East Coast, or if prices fall enough, up the Capline pipeline into Eastern PADD 2.

While predicting the pace and degree of LLS's move away from Brent is difficult giving all of the moving parts, conceptually we believe it will be driven over the medium-term by the price level of the remaining competitive waterborne import barrels, increasingly heavier medium barrels coming into Houston and Louisiana marine terminals. We represent this process in Figure 33 below.

The pace of weakening in LLS will depend on the pace of import displacement. If we get shale play production surges beyond expectation, it will accelerate the process. If more unconventional barrels side-step the Gulf Coast, the process will slow. Eagle Ford condensate going to Canada as diluent, or "disappearing" into a splitter, must also be accounted for against the headline production numbers.

Figure 33: Gulf Coast waterborne import "cascade" – gauging the scale and timing of the Brent-LLS differential



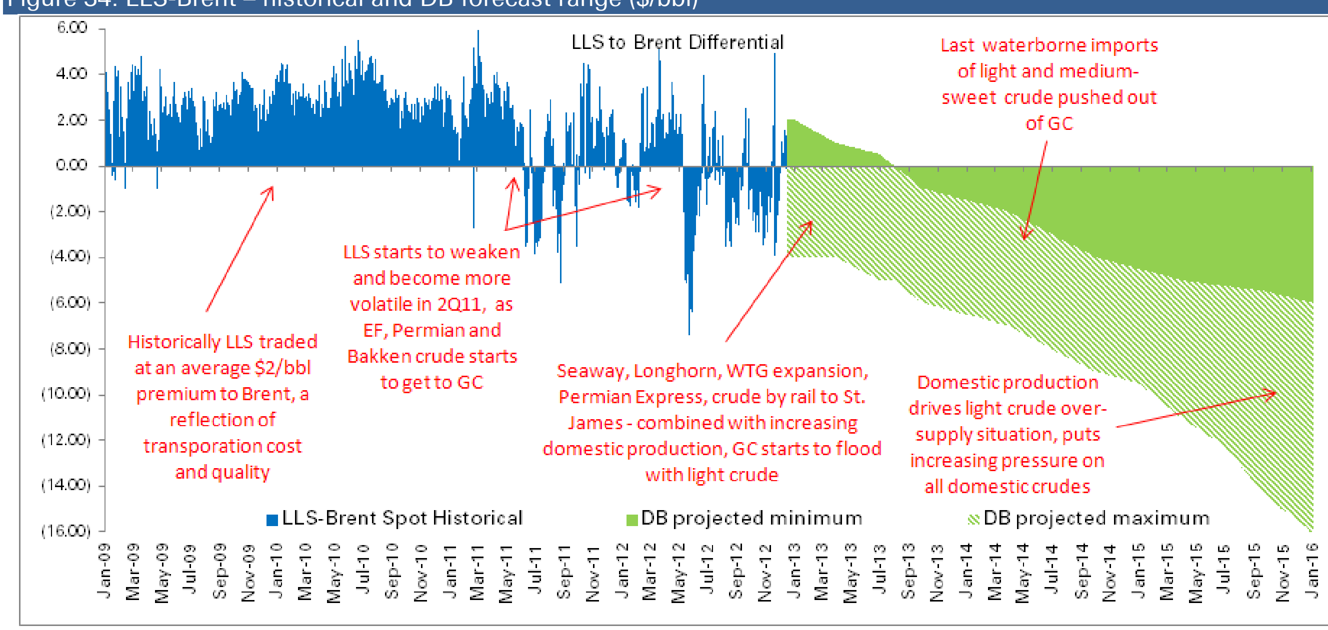
Source: EIA, Company data, Wood Mackenzie, Bloomberg Finance LP, various news reports, Deutsche Bank estimates

In our view the growth in the Eagle Ford and Permian is high enough that Bakken barrels moving to the East and West Coast may not slow the process. But Eagle Ford and Permian crude moving out of region to the East Coast or Eastern Canada will matter, but even with ~150-200kbd of Eagle Ford crude moving by tanker to Eastern Canada, we still believe the Gulf Coast will have a light crude surplus by the end of the year or early 2014.

We estimate the baseline decline of LLS relative to Brent in the conceptual graphic Figure 34. The chart represents the remaining waterborne imports coming into the Gulf Coast, by API quality. The color columns are the light and medium-light imports. The height of each column is the approximate price in the global market place for crude of that quality – each API degree is worth $0.50-$0.80/bbl, on average, though the relationship isn't linear. The width of each column is the amount of that crude quality coming into the Gulf Coast on tanker. Laid on top of this, in red, is our North American light crude forecast.

Movement of unconventional barrels to the East and West Coast, and the Canadian East Coast, would shift this line to the left, i.e., slow the push-out of waterborne imports. Right now there is close to 200kbd of crude moving from the Bakken to the East and West Coasts. We expect that number to rise another ~200kbd in 2013, and that incremental number would offset some of the growth in the numbers above. Marine transport of Texas crude to Eastern Canadian refineries will also be a 2013 release valve on the Gulf Coast, though we don't think there is enough Eagle Ford crude available to fully supply those refineries, more likely Bakken and Canadian light will move via rail (to Montreal, and to St. John via rail/barge) and eventually pipeline (Line 9 reversal will reach Montreal in 2014) to displace imported barrels in that market. We may see 100+kbd of crude moving from the Gulf Coast to Quebec City though.

Figure 34: LLS-Brent – historical and DB forecast range ($/bbl)



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

But several factors push the line to the right (accelerate the process) that we think offsets those East-West crude movements:

- Saudi and Kuwait, for various reasons discussed earlier in this note, are unlikely to be displaced at any price. They account for about 1.2Mbd of the Gulf Coast waterborne imports, ~100-200kbd of which is light crude. Thus there is considerably less to displace than meets the eye;
- Many of the pipelines coming in service in 2013 and 2014 will allow stored Mid-Con and Permian barrels that have backed up beyond bottlenecks to flow to the Gulf Coast, thus the surge into the Gulf will add to overall production growth, perhaps by a lot, though on a temporary basis;
- Production could easily surprise to the upside, last year's growth was 200kbd above our beginning of year estimate. Our forecast for next year and the next several years is robust, but below consensus. Any production beyond our forecast will force imports out more quickly and thoroughly than this.

Based on analysis of Gulf Coast refining, pipelines and expected crude flow, we believe LLS will continue to weaken versus Brent, likely widening to $3-5/bbl below Brent by the end of 2013. We would expect LLS, and all North American crudes to continue to drift away from global oil prices in 2014 and beyond, as the light crude oversupply continues to grow.

Refiners will respond to the lower price by adjusting their crude slates towards light to a certain extent, which will slow the decline in price, but will nonetheless need discounted prices to incentivize them to make the shift. Eventually, perhaps by 2015/16, the refiners will reach the limits of their appetite for more light at any price (particularly since they will have increasing access to Canadian heavy, priced below light).

At that point we expect light prices to tumble to marginal cost of production in the marginal areas of the major production basins, likely the Bakken, which will cause producers to lay down rigs and put the brakes on the price decline. We think that begins to happen around $75-80/bbl WTI (~$80-85/bbl LLS), as we explained in our February 28, 2012 "Future of US Oil" note. Please refer to that note, or the DB E&P team's recent thematic "Adjusting to an Age of Surplus" (December 17, 2012).

To confirm that our conceptual view of LLS weakening is supported by a realistic view of 2013/14 crude flows, we have used a model that weds our production forecasts with our extensive refinery-by-refinery crude slate model. We make a number of simplifying assumptions and fill in some "known unknowns" with guesstimates (for example, how much condensate is heading to splitters in Corpus Christi or Houston?), but in general the exercise gives us a basis for our expectation that as crude fills local refining demand "buckets" for light crude, it will move eastward via new pipelines to displace all remaining waterborne light and medium-sweet imports in the three Gulf Coast refining regions, Corpus Christi, Houston/Port Arthur/Lake Charles and Central Gulf/Mississippi Valley.

In the next few sections we assess how much room there is in each of those regions to absorb growing domestic light crude supply, the growth in pipeline access to that supply, and where "overflow" will head next.

Our conclusions support our long-held view that substitutable light imports will be flushed out of the Gulf Coast by year-end 2013, and LLS will trade down several dollars versus today's Brent-LLS differential.

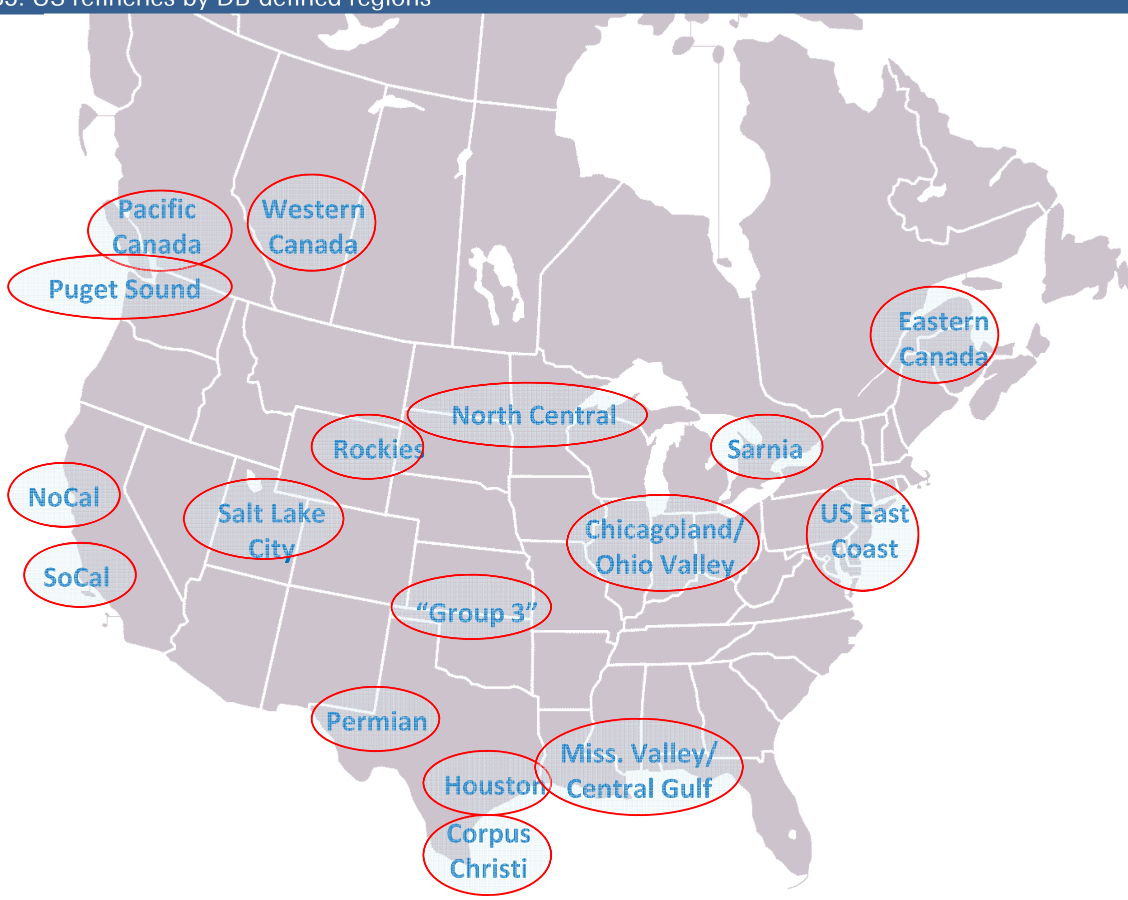
Refinery hubs and production transport costs

As North America becomes an increasingly "closed" system of domestic production feeding domestic refineries, crude slates will be driven largely by infrastructure access and proximity to production areas.

For the last two years we have been able to analyze the US in broad rough-cut geographic terms because the differential distortions were on a near-continental scale (ie, Brent-WTI is an 'inland corridor" phenomenon, encompassing the entire Mid-Con of the US and all of the Western Canadian basin). Mid-Con refiner will soon, to a certain extent, lose its meaning.

With a wide Brent-WTI, Chicago refineries and Wyoming refineries alike benefit. But once the coming wave of pipeline completions begins, the distinction between the Rockies and the Ohio Valley will become apparent. Similarly, transit costs to Houston are not the same as St. James, LA. A pipeline may get built to connect the Permian to SoCal, while NoCal remains an island reachable by rail but not pipe. So in our view we need to start looking with more granularity at each sub-PADD refining hub, and understand where its crude will come from, how much it can absorb, and what are the costs of getting the crude to the refinery gate.

Figure 35: US refineries by DB-defined regions



Source: Deutsche Bank

Of course, the ideal level of analysis would be refinery-by-refinery, but given the large number of plants in the US, that isn't practical in this format. Thus we have divided the refining universe into 17 fairly discrete refinery hubs, 13 in the L48 and 4 in Canada. The number of hubs we chose is somewhat arbitrary, but in general the refineries within each will have similar access to crudes, transportation costs, and product markets. The map above highlights how we define our hubs. Below we summarize approximate transportation costs by pipeline/rail from each major basin to each refining region.

Figure 36: Pipeline transportation costs from production basins to refining regions

REFINING REGION

PRODUCTION BASIN	Pacific Canada	Western Canada	Puget Sound	NoCal	SoCal	Salt Lake City	Northern Rockies	Permian	Corpus Christi	Houston/Port Arthur	Mississippi/St. James	North Central	"Group 3"	Chicago/Ohio Valley	Philly/East Coast	Sarnia	Eastern Canada
Western Canada	3	1	3	NA	NA	7	4	NA	NA	8	10	3	5	5	NA	5	NA
California	NA	NA	NA	1	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Bakken/Williston	NA	NA	NA	NA	NA	NA	2	NA	NA	7	9	1	4	7	NA	8	NA
Niobrara	NA	NA	NA	NA	NA	2	2	NA	NA	5	7	6	3	7	NA	8	NA
Permian	NA	NA	NA	NA	NA	NA	NA	1	NA	4	6	NA	2	7	NA	8	NA
Oklahoma/Kansas	NA	NA	NA	NA	NA	NA	NA	2	NA	4	6	NA	2	6	NA	8	NA
Eagle Ford	NA	NA	NA	NA	NA	NA	NA	NA	1	2	4	NA	NA	7	NA	9	NA
US GoM/Gulf Coast	NA	NA	NA	NA	NA	NA	NA	NA	NA	1	2	NA	NA	2	NA	5	NA
Utica	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Note: Pipeline costs are for toll + delivery to refinery gate. Does not include local gathering costs.
Source: Company data, CAPP, EIA, Wood Mackenzie, Reuters, Deutsche Bank estimates

We do not include local gathering costs, as numerous public companies have in their presentations and comments, but rather estimate the cost from central pricing hubs in each basin to an average refinery gate in each refining region for pipelines, and for rail from a rail terminal to the refinery gate. Gathering costs range from a $1/bbl to $8/bbl, depending on which basin and the location within the basin. For rail we include loading/unloading fees, and for areas that require a second leg by barge (e.g., Philadelphia), we include barge loading/unloading and the barge fee.

Figure 37: Crude-by-rail transportation costs from production basins to refining regions

REFINING REGION

PRODUCTION BASIN	Pacific Canada	Western Canada	Puget Sound	NoCal	SoCal	Salt Lake City	Northern Rockies	Permian	Corpus Christi	Houston/Port Arthur	Mississippi/St. James	North Central	"Group 3"	Chicago/Ohio Valley	Philly/East Coast	Sarnia	Eastern Canada
Western Canada	5	1	7	14	18	14	8	18	18	14	16	7	11	11	20	12	14
California	8	14	7	2	2	6	15	10	13	15	18	17	12	17	20	17	22
Bakken/Williston	10	9	10	13	15	10	4	13	12	11	14	3	7	8	17	18	20
Niobrara	13	11	12	9	11	5	5	7	9	8	11	6	4	6	16	17	19
Permian	18	18	16	13	12	8	11	1	4	5	8	11	5	8	17	18	20
Oklahoma/Kansas	16	15	15	12	11	7	9	3	5	5	7	5	3	6	14	15	17
Eagle Ford	19	18	18	15	14	12	11	3	1	4	6	11	6	8	16	17	19
US GoM/Gulf Coast	20	19	19	16	15	12	11	5	3	1	1	10	5	6	14	15	17
Utica	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

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

The transportation cost estimates we list here are our rounded best guess based on public comments and conversations with refiners, midstream companies, producers, colleagues and industry experts.

Refinery capacity to absorb light crudes

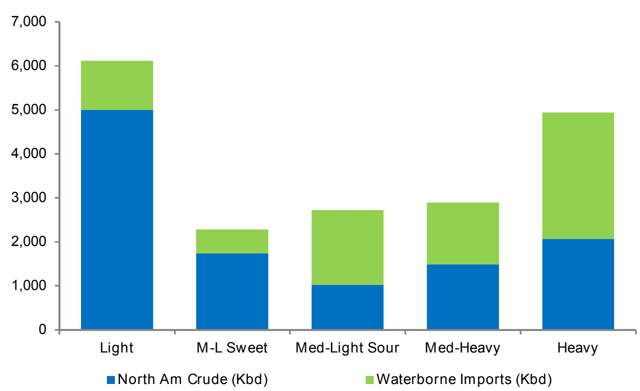
For more than a decade leading into the late 2000s, refiners invested on the basis of an increasing need to import crude, and the view that this would be cheaper, the more heavy and sour it was. With heavy-light differentials blowing out on the tightness of US light sweet supply, product specifications moving to ultra low sulphur, and growth in heavy crude from OPEC and Canada, the industry developed highly sophisticated complex refineries to use heavy crude.

Perversely, the US unconventional boom turned that long term planning on its head, and gave rise to a premium value to what were thought to be the most disadvantaged refineries – inland light-sweet.

One question we wanted to examine in this note, given the potential for an emerging light crude oversupply situation, was how much light and super-light crude the current North American refining complex could absorb, given its investment pattern in the opposite direction.

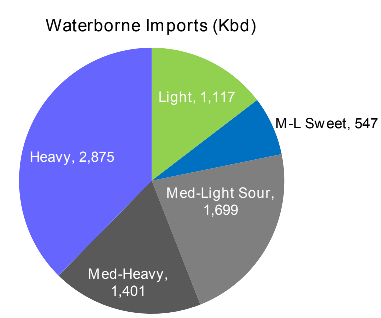
The initial threshold would be the current light and medium-light sweet portion of the refinery crude input mix, which we estimate in charts throughout this note using our refinery-by-refinery crude slate model. For the US Lower 48 + Canada, we believe that number is about 8.4Mbd.

Figure 38: Estimated North American crude slate



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

Figure 39: Estimated remaining waterborne imports

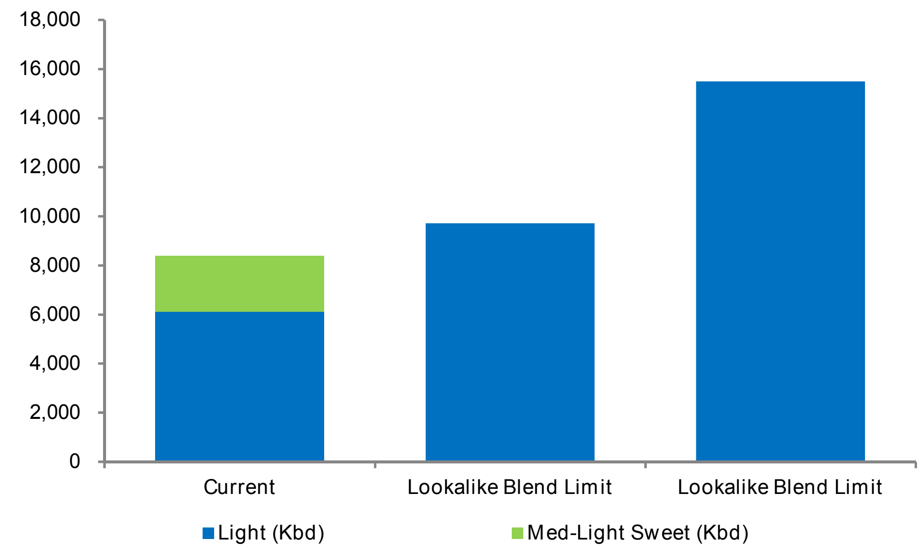


Source: Company data, Wood Mackenzie, EIA, various news sources, Deutsche Bank estimates

The extreme limit would be a hypothetical scenario where every refinery turned off their cokers and ran only light. For a complex refinery, due to configuration issues, this would mean a ~25% reduction in capacity. We modeled this extreme limit for all North American refineries, making a simplifying assumption of dividing the refineries into three groups: complex refineries, with a 25% reduction in capacity; medium-complexity refineries, with a 10% reduction in capacity, and simple light crude refineries, for which we assumed no reduction in capacity. We think conceptual limit is about 15.5Mbd for L48 + Canada, versus current total calendar day capacity of 18.9Mbd.

A third, more realistic hypothetical is to analyze the limits imposed by blending, essentially imagining a scenario where the refiners only run heavy (Canadian, Maya, etc.) and then whatever light or super-light they can. Our assumption in this analysis is that the refiners would target an average API similar to what they currently run. They would "dumbbell" their slate, which would be a negative versus their desired product yield, but would benefit them, in theory, because they would be running increasingly cheap domestic light crude. So in this analysis we converted API to specific gravity, and calculated the light-heavy only mix that would achieve the same average specific gravity. **This estimate suggests there is about 1.5Mbd of additional light capacity beyond current levels before refiners would have to start reconfiguring or shutting off cokers.**

Figure 40: Estimated current NA light/med-light sweet & estimated upper limits for light



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

We conclude that there is room, probably 1.5+Mbd, to run more light crude through North American refineries than occurs today. Having said that, some factors that suggest we may not get to that number:

1. The fact that the US and Canada also produce large amounts of medium-sour crudes that are also trapped and can't be substituted out of the mix,

2. Dumb-belling a crude slate produces more gasoline and less middle distillate than the API-equivalent slate a refinery is currently running, while US domestic demand for gasoline is structurally in decline and diesel demand is growing. Further, the diesel export market is larger and faster growing than the Atlantic Basin gasoline export market. There is some question within the industry about the scale of this dumb-belling effect – some have argued that the net impact will be modest, while others believe it could throw the industry-wide product yield off-kilter and crush the US gasoline market. We are agnostic in that debate, but do believe that ultimately refiners will need an increasingly wide discount to run more light on the margin. Thus, in our view, the limit to domestic light crude demand may be lower than even our back of the envelope blend limit calculation here. Or rather, the price incentive to get refiners to run more crude will be much steeper than consensus currently believes.

3. As referenced, the Saudis and Kuwaitis are likely to maintain a market share of US markets, and therefore pure price substitution will not occur, reducing the potential for light-sweet domestic substitution in refineries purely for price advantage.

Corpus Christi/Eagle Ford

We start our analysis of the Gulf Coast refining crude slate and crude flow with the Eagle Ford and Corpus Christi, and then will move East to follow the directional flow of Texas crude across the Gulf Coast refining regions.

Eagle Ford growth was so rapid (basically zero in 2009 to 700+kbd today) that legacy pipeline systems (mostly owned by Koch and Arrowhead that brought small amounts of local production to the Flint Hills refinery in Corpus Christi) were quickly overwhelmed, and for 2010 and 2011 the growing crude and condensate had to be moved via rail and truck, which of course meant that differentials to pipeline/coastal crudes were wide.

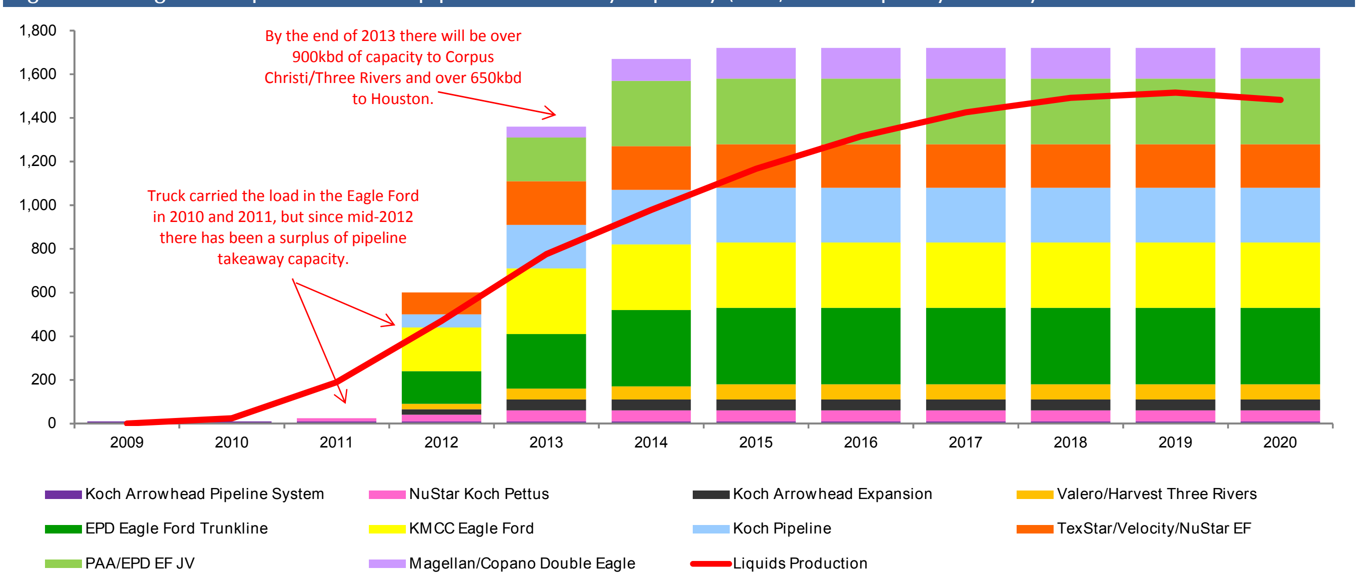
Figure 41: Eagle Ford pipeline project queue

Pipeline	Operator	From	To	Length (mi)	Cap. (kbd)	Ult. Cap. (kbd)	Target Date	Status	Comments
Nustar Koch Pettus Pipeline	Koch	Pettus, TX	Corpus Christi, TX	66	50	50	3Q11	In Service	Small converted pipeline to Flint Hills refinery
Koch Arrowhead Expansion	KPL/Harvest	Eagle Ford, TX	Corpus Christi, TX	95	50	90	1Q12	In Service	Eagle Ford to local refineries in Corpus Christi, or barge terminals on coast
Valero/Harvest Eagle Ford	Harvest	Atascosa, TX	Three Rivers Ref.	190	50	70	2Q12	In Service	Dedicated line to Valero refinery
EPD Eagle Ford Trunkline	Enterprise	Lyssy, TX	Sealy,TX (Houston)	147	350	350	2Q12	In Service	Trunkline from EF to Houston refinery complex, links to Rancho pipeline
KMCC Pipeline	KM	Cuero, TX	Houston, TX	178	300	300	2Q12	In Service	EF to Houston, both new build and converted, connects to condensate facility
Koch Pipeline	Koch	Pettus, TX	Corpus Christi, TX	95	250	250	2Q12	In Service	EF to Corpus Christi; leg to Pettus started up in April, Corpus Christi leg in 2012
TexStar/Velocity/NuStar EF	NuStar	Gardendale, TX	Corpus Christi, TX	167	150	200	3Q12	In Service	Two 100kbd pipes converge at Gardendale, then NuStar takes it to CC
PAA/EPD Eagle Ford	PAA	Eagle Ford, TX	Corpus Christi, TX	162	300	300	4Q12	Constr.	JV incl. connection to EPD Houston; building marine terminal & 1.5Mbbl of storage
MMP/Copano Double Eagle	Magellan	Eagle Ford, TX	Corpus Christi, TX	190	100	140	1Q13	Constr.	Condensate line, JV, new 140 mi stretch connects to existing Copano pipeline

Source: Company data, various news sources, Deutsche Bank estimates

Midstream infrastructure companies have quickly jumped on the transportation opportunity, and arguably over-built exit capacity out of the Eagle Ford, though given the reality that pipelines today won't proceed past the proposal stage without substantial multi-year shipper commitments (probably a minimum 70% committed, and for some projects even higher), we should take this large amount of macro pipeline capacity as a sign of producer confidence in a high Eagle Ford liquids volume plateau and growth rate.

Figure 42: Eagle Ford production vs. pipeline takeaway capacity (Kbd) - exit capacity unlikely to ever be an issue



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

Eagle Ford pipeline takeaway, currently about 1.25Mbd (versus current crude/condensate volumes of perhaps ~700kbd) is already surplus to requirements with plenty of room into which production can grow. Nonetheless two more major/mid-sized pipelines to Corpus Christi will startup up 1Q13, the PAA/EPD JV's 300kbd pipeline (which also includes a link to EPD's trunkline to Houston) and Magellan/Copano's 100kbd Double Eagle condensate pipeline. Thus by the the end of 2013, Eagle Ford pipeline will be about 1.7Mbd, enough to accommodate years-worth of Eagle Ford growth. Once the pipelines are built, about 650kbd of the capacity will be to the Houston area, with the balance, over 1Mbd, going to Corpus Christi.

As we think about where crude and condensate in the Eagle Ford will flow, we need to think first of what the local refining demand looks like currently, and to what extent they can adjust their crude slate to run more Eagle Ford crude if they are incentivized to do so by price and availability.

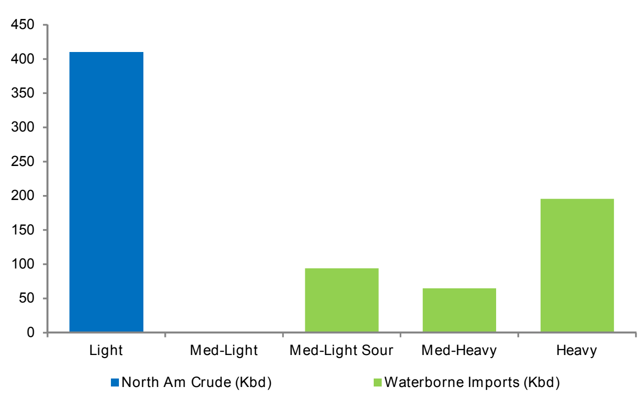
Figure 43: Corpus Christi/Eagle Ford refineries

Refinery	Operator	Cal Day Cap	Nelson Complex	WM Avg API	Coker Cap.
Corpus Christi Citgo	Citgo	163	13.66	24.7	45
Corpus Christi FHR	FHR	290	7.39	43.1	13
Corpus Christi VLO	VLO	205	15.60	33.3	17
San Antonio	NuStar	14	NA	38.7	0
Three Rivers	VLO	93	12.69	42.1	0
TOTAL		**765**			**75**

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

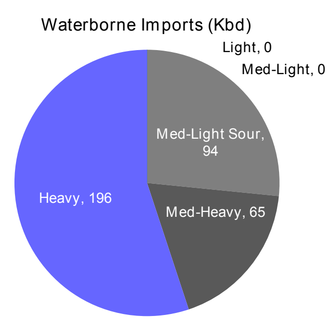
Unlike in the Permian or North Dakota, the refineries in Corpus Christi aren't truly "captured" by local crude. They can and have historically bought imported barrels, and have marine terminal access to receive domestic barrels by barge. Nonetheless, we assume that Corpus Christi/Three Rivers refineries will use all of the Eagle Ford crude/condensate they can. Thus the initial move of Eagle Ford barrels will be on the Corpus Christi bound pipelines, until those refineries get their fill of the super-light Eagle Ford crude and condensate.

Figure 44: Estimated crude slate for region



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

Figure 45: Estimated remaining waterborne imports

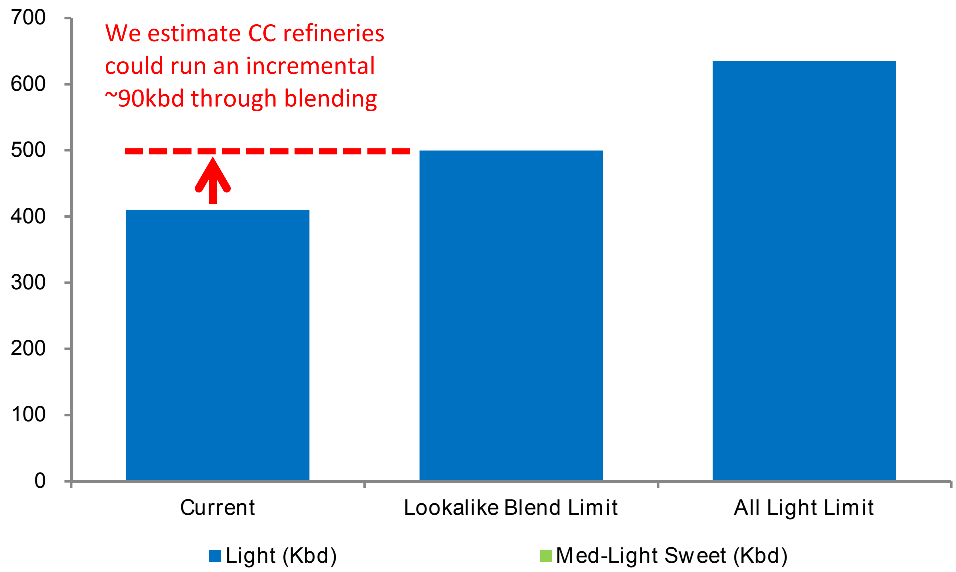


Source: Company data, Wood Mackenzie, EIA, various news sources, Deutsche Bank estimates

Consumption of Eagle Ford crude by Corpus Christi refineries has more than doubled over the last year, and essentially all of the waterborne light and medium-light sweet crude in the regional crude slate has been substituted (as of the September EIA data, Corpus Christi refineries were still receiving 50kbd+ of waterborne light/medium sweet imports, but we believe that the current amount is de minimis).

In other words the Corpus Christi domestic light crude demand “bucket” has been filled. Motivated by price, we think it is likely that the Corpus Christi refineries will expand their demand for Eagle Ford crude by making minor equipment adjustments (we know for example that the Koch/Flint Hills refinery went through some upgrades earlier this year to expand their ability to run Eagle Ford crudes) and by running heavier crudes on the sour side of their slate to allow them to “lookalike” blend more of the super-light local crude and crude-like condensate. We estimate this will expand the demand bucket by about 90kbd to roughly 500kbd.

Figure 46: Estimated current light/med-light sweet & estimated upper limits for light



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

A major complicating factor in understanding crude flows out of the Eagle is the wide variety of liquid hydrocarbons in the equation. Unlike the relatively consistent quality of Bakken and Permian crudes, Eagle Ford production is a wide variety of light and super-light crudes API 40°-45°, crude-like condensates (45°-55°) and naphtha-rich light condensates (API 55°-75°). Lease condensate is in the ballpark of half of the production out of the Eagle Ford right now.

The condensate, counted in production numbers coming from both the companies and the EIA, doesn’t entirely make it to the refinery gate. Field stabilizers (essentially just large tanks that allow high vapor pressure light-ends to evaporate and enter the NGL stream) reduce volume. Some condensate goes to splitters (simple distillation columns) that convert the condensate to light naphtha, heavy naphtha and other light hydrocarbons and send those components on to petrochem and gasoline blending pools. Those volumes disappear altogether from the “crude” supply numbers.

Still other volumes of condensate are moving via barge/Capline/Southern Lights to Canada to be used as diluent to move bitumen production via pipeline back into the US. That movement will probably increase given highly favorable condensate differentials (condensate is expensive in Alberta, but cheaper than light crude in the Eagle Ford). Kinder Morgan’s Cochin products pipeline conversion will provide another 95kbd of capacity for condensate-to-Canada (Houston to Chicagoland via the Explorer product pipeline, the Cochin to Alberta) around 3Q14.

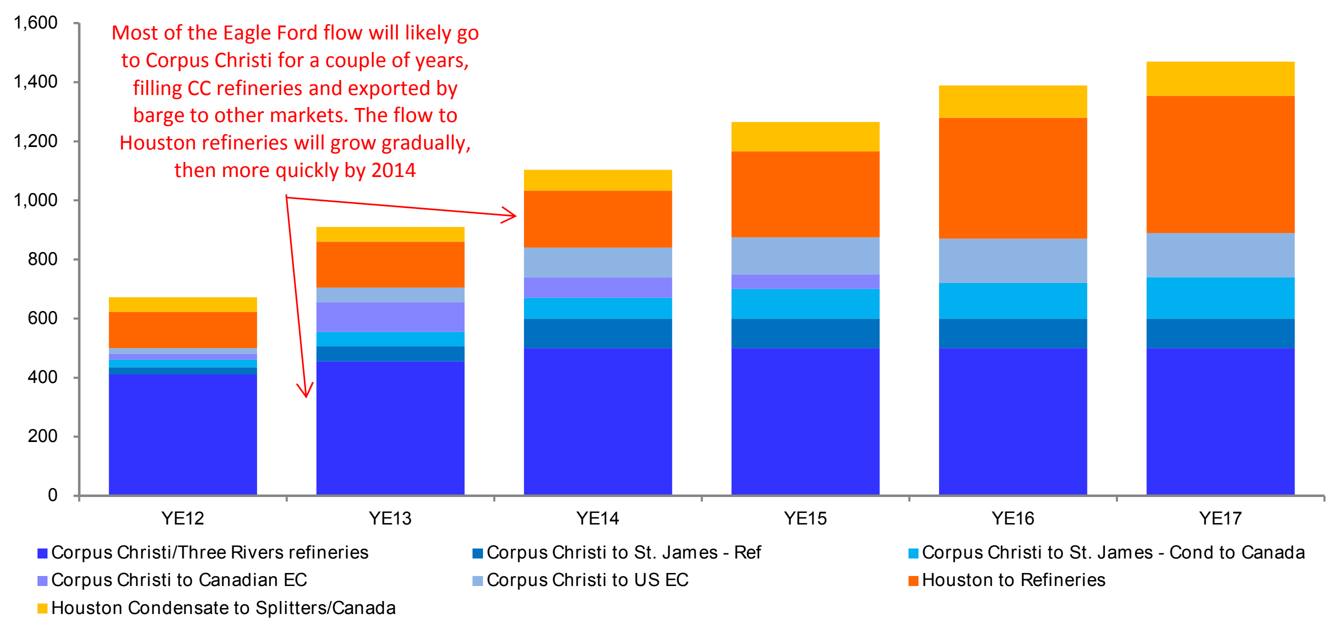
So a portion of the condensate supply flow "disappears" from the production-to-refinery flow. If we think of current Eagle Ford production of roughly 700kbd right now, and anticipate 400-500kbd of that supplying the Corpus Christi refineries, there is 200-300kbd of remaining supply to either flow to Houston or the Corpus Christi docks, or be lost into the NGL/Petrochem/diluent streams.

Neither the EIA nor producers have put reliable numbers around the crude/crude-like condensate/super-light condensate breakdown coming out of the Eagle Ford, though we are hopeful that some producers (particularly the ones with high-value crude and crude-like condensate) will start to do so.

Until then we are left with anecdote and guesstimation. For our model we are assuming splitters and diluent pull about 75kbd out of the flow, though the number could be meaningfully higher. Southern Lights (the Enbridge diluent pipeline that runs from Illinois to Alberta, capacity 180kbd, 77kbd committed, expandable to 330kbd) flow has been in the 50-90kbd range in 2H12, a portion of that is from refineries/chemical plants, but there is some flow up Capline from St. James, where Eagle Ford condensate is arriving by barge. We have no real idea how much Eagle Ford condensate is flowing through splitters, but we do know that Kinder Morgan is building a 25-50kbd splitter near the terminus of its 300kbd KMCC Eagle Ford-Houston pipeline, so the amount should increase.

The net result of these factors is that the flow to Houston refineries should remain relatively low for a while. We are currently modeling total flow to Houston in the 175-225kbd range in 2013, with perhaps 125-150kbd of that going to Houston refineries.

Figure 47: Eagle Ford outflow – Fill the Corpus Christi refineries first, then to CC port and Houston (kbd)



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

Shipments from Corpus Christi to other coastal refining regions (East Coast Canada, East Coast US, Louisiana) to capture opportunistic pricing advantages will ebb and flow depending on differentials and the pipeline pull to Houston. The flow to Houston will increase with Eagle Ford production, now that the Corpus Christi refinery domestic light crude demand bucket is full or close to full. Houston refinery demand though, isn't oriented towards light, and there will soon be a tremendous amount of in-bound pipeline capacity into the market from other light crude supply basins.

Until recently the posted prices in the Eagle Ford were still linked to WTI, but most of the larger producers were getting LLS minus ($6-7/bbl) for their Eagle Ford oil. It has been difficult establishing an "Eagle Ford price" because of the wide range of crudes and condensates being produced. Mid-October Platts introduced two new Eagle Ford crude markers in their daily market report. One is an average of a handful of posted Eagle Ford oil prices. The other, the "Platts Eagle Ford Marker," is calculated using refinery yields versus LLS. Thus they have introduced a pricing mechanism that can capture the quality/transportation factors that should determine the EF-LLS differential.

Permian

Before turning to the Houston refining market, we take a quick look at Permian production, takeaway capacity and expected outflow patterns (even though the Permian is landlocked), since much of the growth in the Permian will flow via new pipelines into Houston.

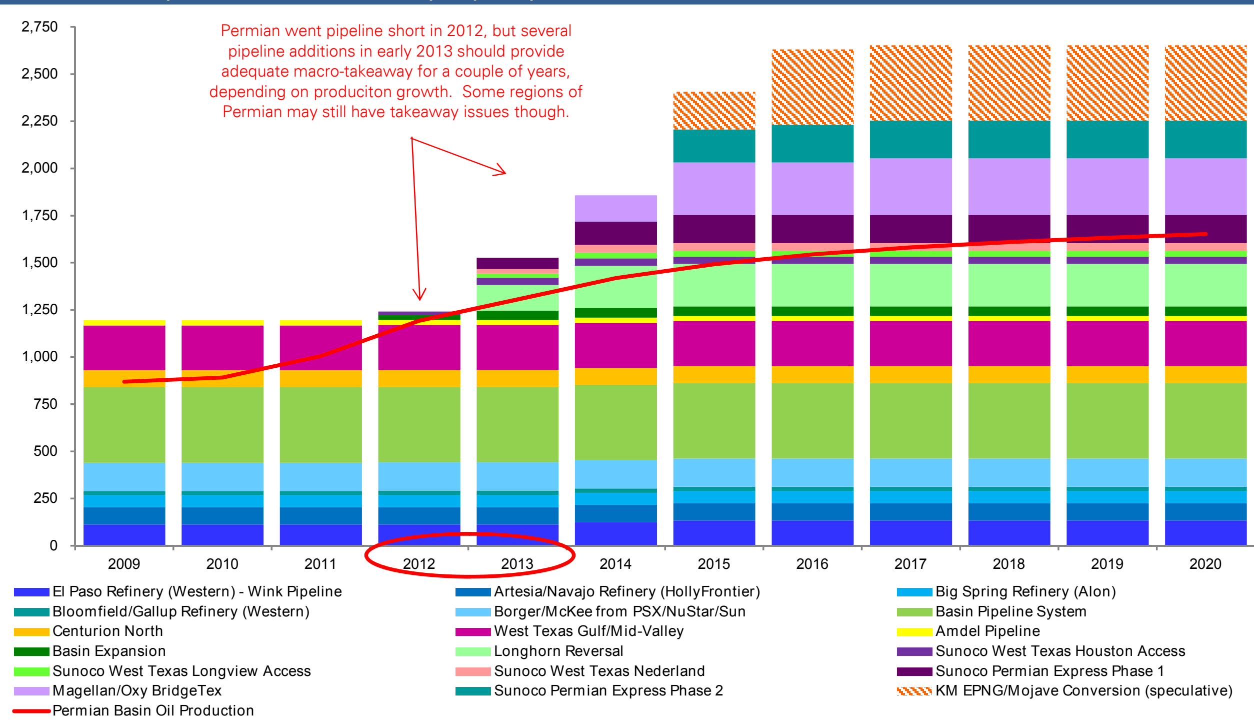
Figure 48: Permian pipeline project queue

Pipeline	Operator	From	To	Length (mi)	Init. Cap. (kbd)	Ult. Cap. (kbd)	Target Date	Status	Comments
Basin Pipeline Expansion	PAA	Colorado City, TX	Cushing, OK	519	50	50	1Q12	In Service	Capacity increased from max. 400kbd to max. 450kbd in leg to Cushing
West Texas Houston Access	SXL	Midland, TX	Houston, TX	476	40	44	3Q12	In Service	Takes Permian crude to OTI Terminal, partially in service mid-2012, full volumes in 1H13
Longhorn Reversal	Magellan	Crane, TX	Houston, TX	518	75	225	1Q13	Construction	Permian crude to GC, 75kbd will flow in 1Q13, ramp to capacity by mid-year
West Texas Longview Access	SXL	Midland, TX	Longview, TX	458	30	30	1Q13	Construction	Open season Feb-Mar 2012, would take Permian crude to MidValley pipeline (Ohio/Detroit)
West Texas - Nederland	SXL	Midland, TX	Nederland, TX	567	40	40	1Q13	Construction	Will carry primarily sour crude to Sunoco storage in Nederland
Permian Express Phase 1	SXL	Wichita Falls, TX	Nederland, TX	476	90	150	2Q13	Construction	Will take 6-9 months to startup, ramp to 150kbd by mid-2013; 3-7 yr commitments
BridgeTex Pipeline	MMP/OXY	Colorado City, TX	Houston, TX	440	278	300	Mid-14	Planned	Announced moving forward in Nov '12; incl. 400mi of greenfield pipeline; storage on both ends
Niobrara Falls Project Ph 1	NuStar	Dixon, TX	Wichita Falls, TX	238	125	125	2014	Proposed	Reversed product line, Permian/Granite Wash to Basin/Permian Express
Permian Express Phase 2	SXL	Colorado City, TX	Nederland, TX	515	200	200	2014	Proposed	Expansion of line starting at Colorado City; would allow further access to Louisiana refineries
EPNG/Mojave conversion	KM	Permian, TX	Los Angeles, CA	1,115	400	400	NA	Speculative	Conversion of part of the EPNG nat gas system to crude use, would service SoCal refineries

Source: Company data, various news sources, Deutsche Bank estimates

Despite being an old oil production province, the Permian is actually currently short pipeline takeaway capacity and has been slower to build out required infrastructure than the Eagle Ford, though that will largely be remedied in 2013. The interesting wrinkle in the Permian is that for the first time, a large portion of production will move directly to the Gulf Coast rather to the Cushing WTI hub.

Figure 49: Permian production vs. takeaway capacity (Kbd)



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

About 480kbd of incremental Permian exit capacity will go into service in 2013, 275kbd in the first half of the year. The reversed Longhorn pipeline (initial 75kbd, ramping to 225kbd by mid-year) is expected to begin operating sometime in January. Sunoco's West Texas Gulf expansions (110kbd across three project segments, 80kbd to Gulf

Coast) are planned for full startup by the end of 1Q13. Sunoco's Permian Express Phase 1 is on schedule to startup in 2Q13 at 90kbd, and ramp to 150kbd by mid-year.

The Permian has four "captured" refineries that basically only run local crude, plus three other refineries that run a lot of Permian, though they can also pull crude from other sources. Those are PSX Borger and VLO McKee from Cushing, and in the future potentially from the Niobrara and Granite Wash, if and when NuStar's Niobrara Falls project is built; and Delek's 60kbd Tyler, TX refinery, which has multiple sources, but sits near Sunoco's West Texas Gulf system that carries Permian crude.

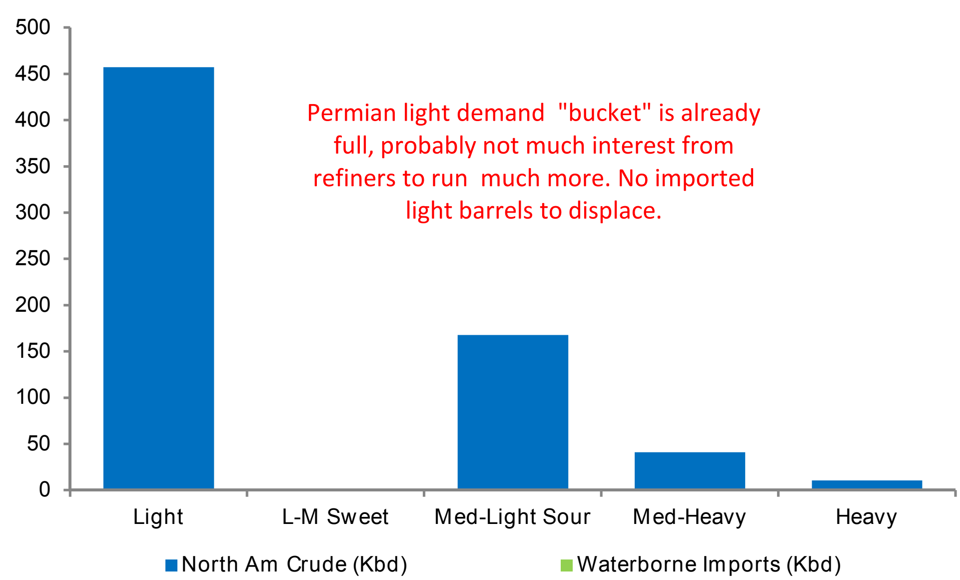
Figure 50: Permian refineries

Refinery	Operator	Cal Day Cap	Nelson Complex	WM Avg API	Coker Cap.
Big Spring	ALJ	67	8.55	31.7	0
Borger	PSX	146	13.53	30.3	26
El Paso	WNR	122	7.73	38.7	0
Gallup	WNR	25	NA	38.7	0
McKee	VLO	156	9.47	38.5	0
Navajo	HFC	100	7.98	37.3	0
Tyler	DK	60	8.04	39.7	7
TOTAL		**676**			**32**

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

These refineries already run 100% domestic crudes, largely light, and are unlikely to run meaningfully more light crude unless the bottom falls out of the light market without effecting the WTS price (unlikely). Thus the Permian refinery "bucket" is full, and incremental production out of the Permian will have to flow either to Cushing (and it is now and has been for a while) or to Houston.

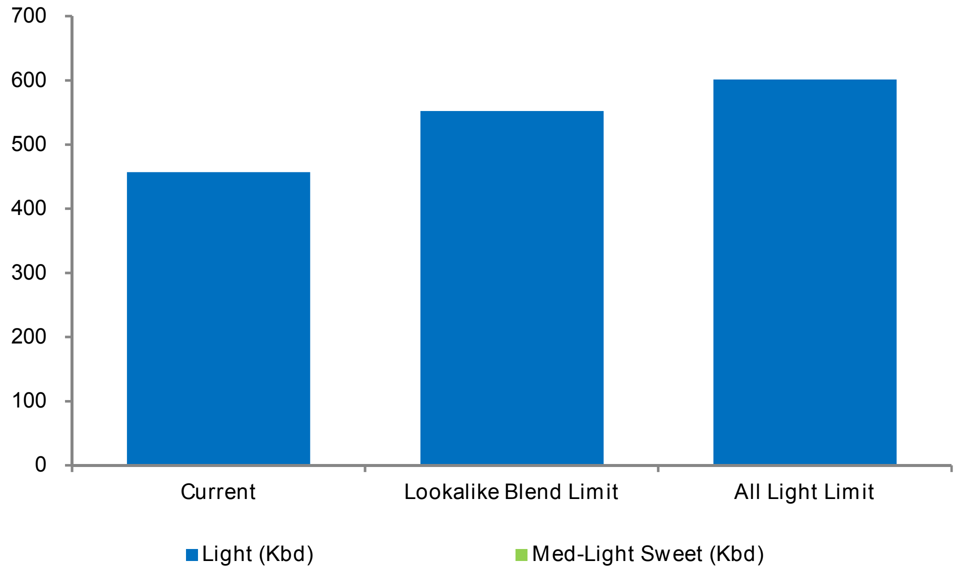
Figure 51: Estimated current crude slate for Permian region refiners



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

With access to more Canadian heavy crude, our "lookalike" blend limit calculation suggests that Permian region refineries could conceivably run another 90-100kbd of light crude, though given the ready access to WTS, we are skeptical that they will adjust their slates much going forward.

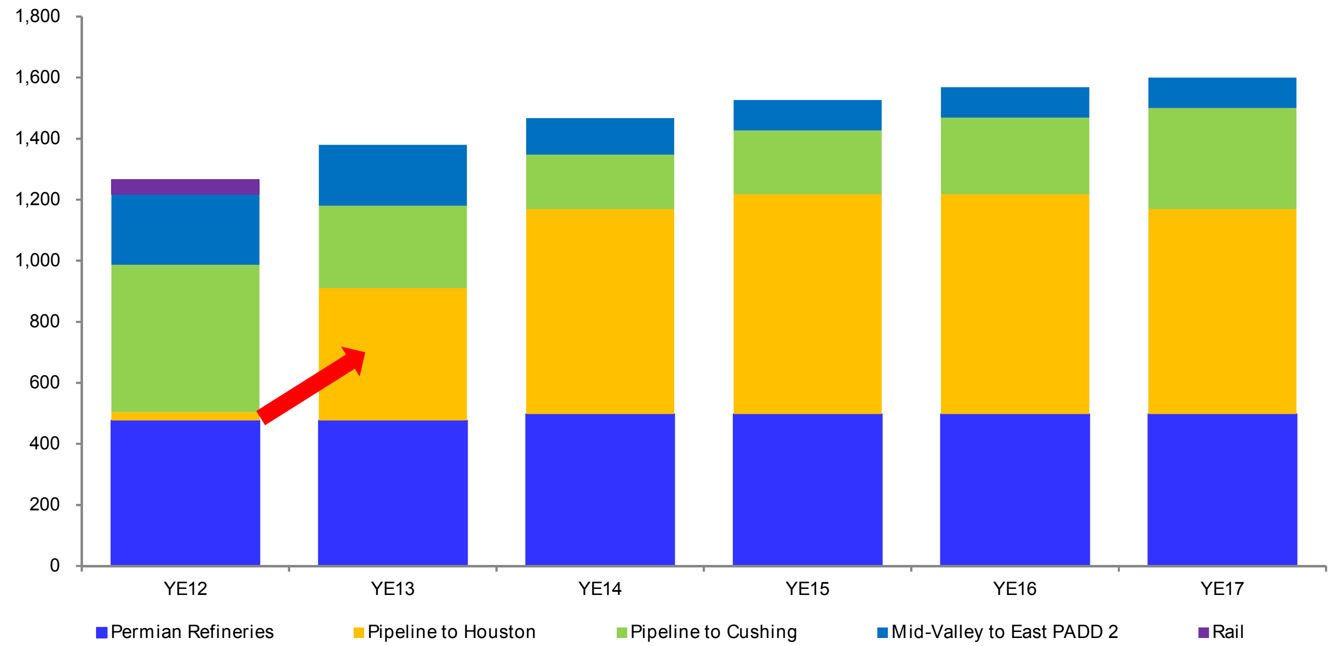
Figure 52: Estimated current light/med-light sweet & estimated upper limits for light



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

In terms of the crude flow out of the Permian, pipeline capacity to Houston, where Permian crude can likely get LLS-level pricing, will rise from the current de minimis amount, to about 480kbd by YE13. By YE14 it will be 960kbd, via four different pipeline systems.

Figure 53: Estimated Permian outflow – refineries already full, pipelines to Houston will be close to full from the get-go



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

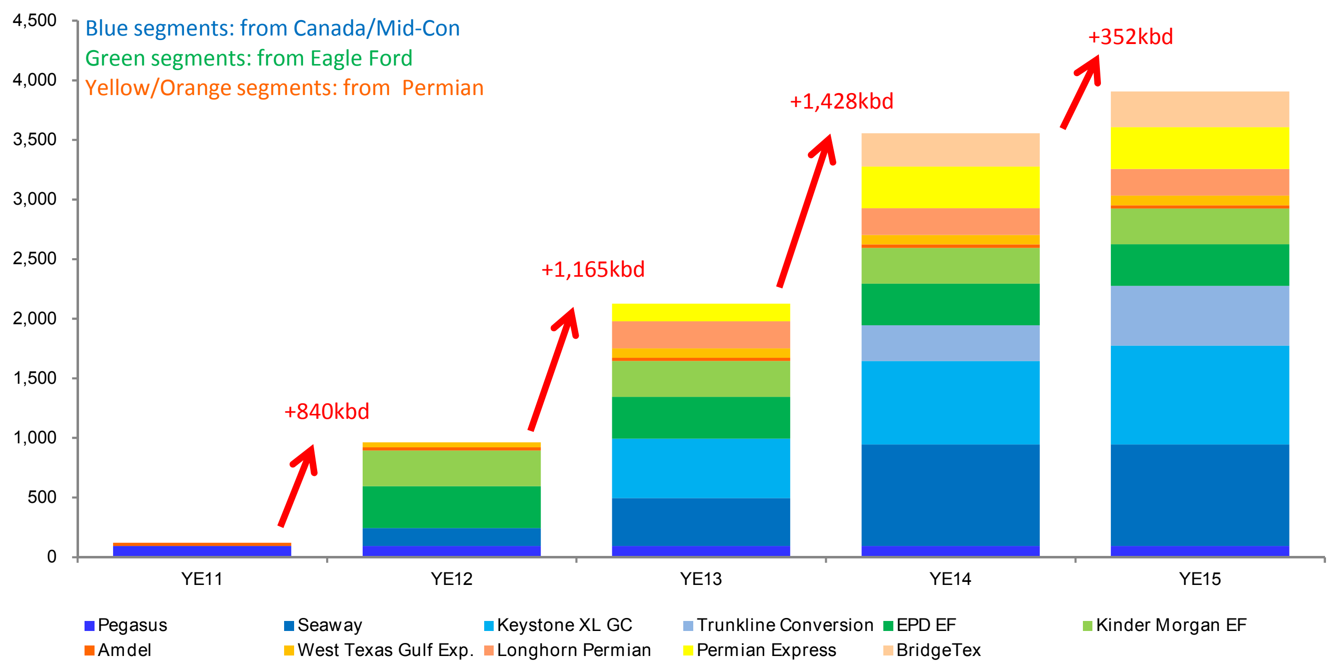
We expect these pipes to be close to full, at least until Houston becomes oversupplied, and for Basin and Centurion North, the northeasterly bound trunklines to Cushing, to have reduced throughput. While Eagle Ford flow to Houston will start out slow and build over time, Permian flow to Houston should be near capacity from the get go, due to Gulf Coast versus Inland pricing. It is Permian (and Cushing) barrels that will flush out the remaining Houston waterborne imports.

One interesting dynamic to watch will be how Permian barrels price as increasing amounts of crude from the basin is delivered straight to Houston. Arguably WTI-Midland will now start to trade off a transportation discount to LLS, perhaps $4-6/bbl, similar to WTI-Cushing's long-term differential to LLS, rather than trading at a ~$1/bbl discount to WTI-Cushing. Not a huge difference, but an extra dollar per barrel in the pocket of Permian producers over the long-term.

Houston/Beaumont/Port Arthur/Lake Charles

While some unconventional crude had been getting to Houston via rail, barge, minor pipelines and truck, the flow started to increase mid-year 2012 with the Seaway initial reversal, and the first two major pipelines into Houston from the Eagle Ford. In 2013, the floodgates will open, as Seaway ramps to 400kbd (+250kbd), three Permian pipelines add about 480kbd, and the Southern leg of Keystone XL another 500-700kbd. In 2014, the Enbridge system expands and Seaway is twinned, adding another 450kbd, OXY/Magellan's BridgeTex likely starts up (278-300kbd), along with Permian Express Phase 2 (200kbd), and potentially ETP's Trunkline conversion (300-500kbd from the Mid-Con to Texas). All told, it appears that Houston pipeline inflow capacity, roughly 100kbd at YE11, will rise to over 3.5Mbd and as high as 4Mbd by the end of 2015.

Figure 54: Houston pipeline inflow capacity – from 100kbd to 4Mbd in four short years (kbd)



Source: Company data, EIA, various news sources, Deutsche Bank estimates

The East Texas/West Louisiana refining region is highly complex, really a medium sour/heavy crude market, currently getting a majority of its crude input via waterborne imports across the crude quality spectrum.

Note: We include Lake Charles refineries (which are just across the Texas border into Louisiana) with the East Texas refineries for a couple of reasons. First, they are less than 60 miles from Beaumont/Nederland/Port Arthur (versus 200 miles to St. James, LA), and therefore close to the terminus of several pipelines that can (or will soon) carry domestic crude. Second, after the reversal of the Ho-Ho Pipeline, 300kbd of crude will be able to move East from the Houston area into Louisiana, and we expect these refineries to take some of that crude before it moves off to St. James.

All told there are 16 refineries in the region, all but three with cokers, and nearly 1Mbd of coking capacity total, with approximately 3Mbd of medium-heavy/heavy capacity. These numbers include 90kbd of new coking and over 250kbd of heavy capacity from the Motiva Port Arthur expansion, which, after a couple of false starts, will be fully operational in early 2013, assuming no more operational hiccups.

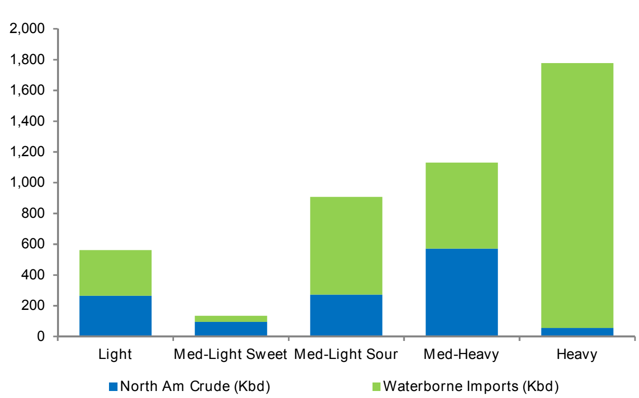
Figure 55: Houston/Beaumont/Port Arthur/Lake Charles refineries

Refinery	Operator	Cal Day Cap	Nelson Complex	WM Avg API	Coker Cap.
Baytown	XOM	561	12.15	28.9	96
Beaumont	XOM	345	13.24	32.9	48
Deer Park	RDS	327	9.34	24.9	89
Houston Lyondell	Lyondell	280	9.84	19.8	98
Houston VLO	VLO	88	14.09	38.1	0
Lake Charles CRC	CRC	78	2.41	NA	0
Lake Charles Citgo	Citgo	428	11.57	30.7	106
Lake Charles PSX	PSX	239	7.57	22.2	61
Pasadena	PRS	100	8.72	35.2	13
Port Arthur Motiva	RDS	600	13.29	32.9	155
Port Arthur TOT	TOT	174	9.89	27.4	50
Port Arthur VLO	VLO	292	7.98	24.1	100
Sweeny	PSX	247	11.16	22.6	71
Texas City BP	BP	407	12.08	30.3	43
Texas City MPC	MPC	76	8.14	37.8	0
Texas City VLO	VLO	225	10.46	26.3	52
TOTAL		**4,466**			**981**

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

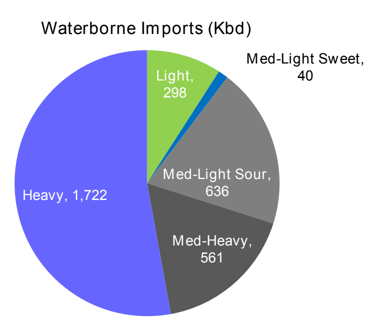
Based on our refinery-by-refinery crude slate model, we estimate that there about 300-350kbd of waterborne light and medium-light sweet barrels coming into the Houston-to-Lake Charles segment of the Gulf Coast, with roughly 50kbd of that from Saudi, which may or may not be displaced. Thus the current light and medium-sweet crude demand "bucket" in Houston is small, and about half full. The amount of domestic crude flowing into Houston new pipelines from the Mid-Con and Permian in 2013 should easily and relatively quickly displace the remaining substitutable imported light crude.

Figure 56: Estimated crude slate for region



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

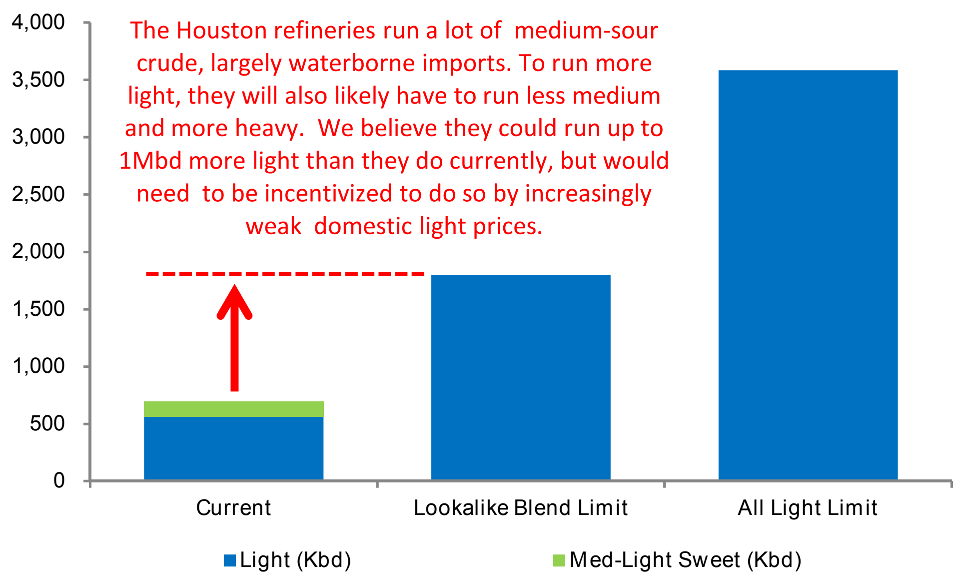
Figure 57: Estimated remaining waterborne imports



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

Over time, with falling light crude prices, Houston area refiners will be incentivized to run increasing amounts of unconventional crude, in other words, to increase the size of the demand bucket. The amount of light crude that these refineries *could* run is staggering. Even with a 25% reduction in throughput, an all-light crude slate for the whole region would mean an increase in light of over 2.5Mbd. As we discussed earlier in the note, a more realistic scenario is that the refineries will increase blending to get a lookalike crude slate that displaces medium sour crudes in favor of more light and more heavy, particularly as the Enbridge/Enterprise systems and Keystone XL open up the Gulf Coast market to large amounts of Canadian heavy. In our back-of-the-envelope "lookalike" blend limit calculation, which assumes the same average API, but cuts out the mediums, we think there may be room for close to another 1Mbd of light demand, if price incentivizes the switch.

Figure 58: Estimated current light/med-light sweet & estimated upper limits for light



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

With so many pipelines connecting the Houston/Port Arthur area to the primary North American production basins, the region is becoming the primary locus of competition among similar crudes. Already a huge storage hub, it seems reasonable given the flow of crudes that a Houston crude marker should emerge.

Enterprise's ECHO terminal, which opened in July, appears to be emerging as the pre-eminent Western Gulf storage/trading hub in the new era of US crude. Multiple pipelines from numerous basins will be able to reach ECHO – Seaway from Cushing, the EPD Eagle Ford Trunkline, Permian pipelines, Keystone XL once it is built, as well as waterborne crudes.

Earlier this year CME Group proposed a new ECHO crude contract, which could eventually become a rival to LLS as the Gulf Coast domestic benchmark. For reasons of liquidity and history, WTI is unlikely to be displaced as the key paper contract for the North American crude trade, and LLS is in ascendance as a marker vis-à-vis WTI, thus ECHO would have its work cut out for it, but given the volumes of light crude that will stored, blended and shipped through Houston, it seems likely to us that a Houston-based marker would eventually get traction.

Central Gulf/St. James/Mississippi Valley

The last remaining waterborne imports of light and medium-light sweet crude are likely to be in the somewhat inaccessible Central Gulf, which includes most of the Louisiana coastal refineries, Mississippi, Alabama, and refineries up the Mississippi Valley. Most of the crude run by the refineries comes ashore via pipeline from the Gulf of Mexico, by tanker into LOOP or marine dock, or increasingly by rail, brown water barge or coastal barge.

Figure 59: Central Gulf/Mississippi Valley refineries

Refinery	Operator	Cal Day Cap	Nelson Complex	WM Avg API	Coker Cap.
Alliance	PSX	247	9.36	35.3	27
Baton Rouge	XOM	502	12.00	29.3	122
Chalmette	Chalmette	193	9.72	27.5	30
Convent	Motiva	235	9.53	33.0	0
Cotton Valley	CLMT	13	NA	NA	0
El Dorado (AK)	DK	80	8.53	32.8	0
Garyville	MPC	490	11.09	30.1	85
Krotz Springs	ALJ	80	7.45	36.4	0
Memphis	VLO	180	9.05	34.6	0
Meraux	VLO	125	8.89	33.8	0
Norco NO	Motiva	234	13.07	34.7	28
Pascagoula	CVX	330	10.85	23.2	105
Port Allen	PRC	57	9.06	35.0	0
Princeton	CLMT	8	NA	NA	0
Sandersville	Hunt SRC	11	NA	NA	0
Saraland	RDS	80	4.45	37.5	0
Shreveport	CLMT	57	NA	32.0	0
Smackover	Cross	8	NA	NA	0
St. Charles	VLO	205	11.63	31.9	77
Tuscaloosa	Hunt	36	15.48	32.0	32
Vicksburg	Ergon	23	NA	NA	0
TOTAL		**3,193**			**505**

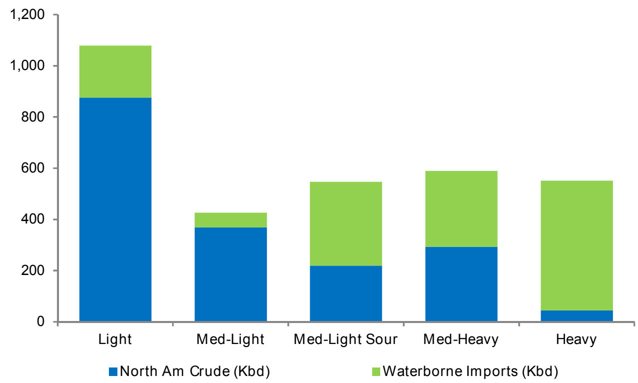
Source: Company data, Wood Mackenzie, EIA, various news sources, Deutsche Bank estimates

Unlike the East Texas/Lake Charles refineries, on the whole the Central Gulf and Mississippi Valley refineries tend to be less complex (though there are some very large complex refineries in the region, such as MPC's Garyville and XOM's Baton Rouge. There is less coker capacity (~500kbd) and heavy/medium-heavy crude capacity (~1.5Mbd) than to the West. These refineries currently run about 1.1Mbd of medium-heavy sour and heavy crude.

Light and medium-sweet crude is the biggest part of the crude slate, though as mentioned, meaningful amounts of medium-sour and heavy are in the mix. Total light crude run by these refineries at the moment is in the ballpark of 1.5Mbd. Less than 200kbd of that is waterborne imports, thus this "bucket" of light domestic demand is getting close to full, similar to the Houston area. Close to half of that remaining waterborne light crude is Saudi Extra Light or Light, and is unlikely to be displaced, as we have discussed elsewhere.

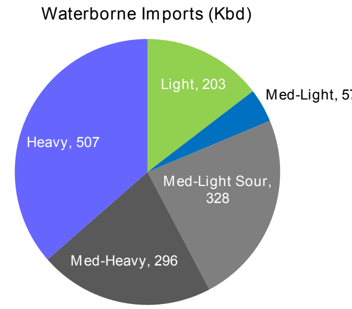
Thus by our calculation there may only be 100-150kbd of imported light crude that needs to be backed out before the Louisiana "bucket" overflows.

Figure 60: Estimated crude slate for region



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

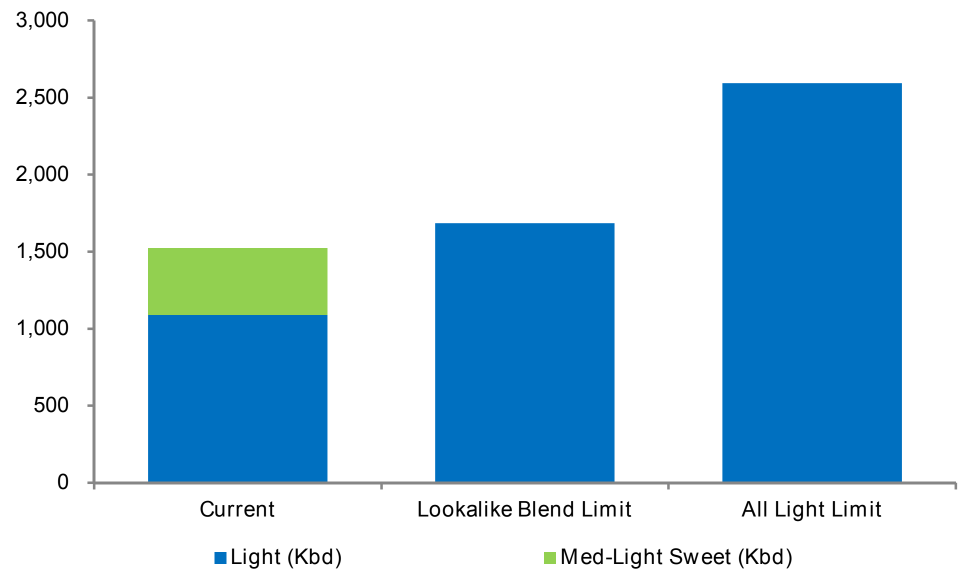
Figure 61: Estimated remaining waterborne imports



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

Unlike Houston, where a radical re-shaping of the crude slate via dumbbell blending could add a meaningful amount to domestic light crude demand, we see less potential for that in the Louisiana/Mississippi Valley region, partly because light is already a very large part of the slate. Our back-of-the-envelope calculation (which assumes refineries try to keep the same average API, but run only light and heavy to achieve it) suggests there is potential for another 400kbd of light versus today's mix.

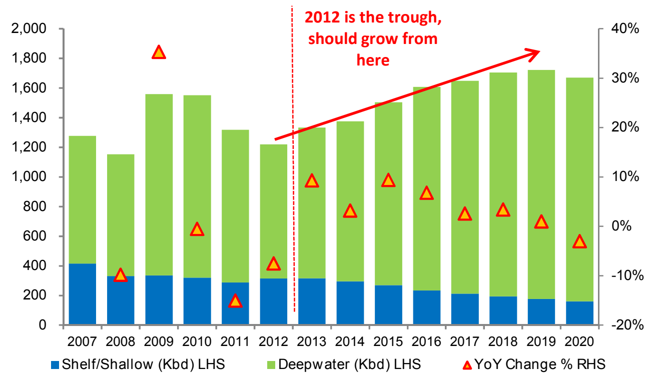
Figure 62: Estimated current light/med-light sweet & estimated upper limits for light



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

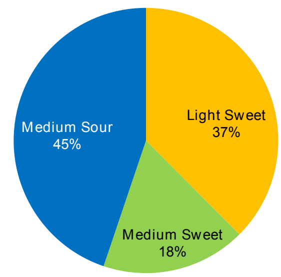
In terms of the Eastward flow of Texas light crudes, right now rail and barge are moving limited barrels to St. James. St. James is receiving larger quantities of Bakken crude (200-250kbd), some of which are moving up Capline to Memphis. St. James is also receiving modest amounts of Eagle Ford crude by coastal barge. Once the reversal of Shell's Ho-Ho pipline in 2H13 (one leg of the reversed pipeline, from Houston to Nederland, will begin to flow in 1Q13, but full reversal won't be until the second half of the year), about 300kbd of mostly Permian and Eagle Ford crude will begin to flow into Louisiana.

Figure 63: US Gulf of Mexico – more domestic growth



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

Figure 64: Approximate mix of Gulf of Mexico production



Source: Wood Mackenzie, EIA, Deutsche Bank estimates

After several years of falling Gulf of Mexico production, a reinvigorated deepwater industry drilling program will start to grow production again starting in 2013. This past year was the post-Macondo trough. We expect Gulf of Mexico volumes to increase every year from here to 2019. As with unconventional, this deepwater GoM production is trapped domestic crude, and will have to displace waterborne imported barrels in the same way. Gulf of Mexico crudes – LLS, HLS, Mars Blend, Poseidon, etc. – form the backbone of the Central Gulf crude slate, so a surge in GoM production could eventually make Louisiana awash in crude in a similar way to Houston. Gulf of Mexico production is less than half light-sweet though, there is a lot of medium-sour, thus the import substitution will occur across the quality spectrum.

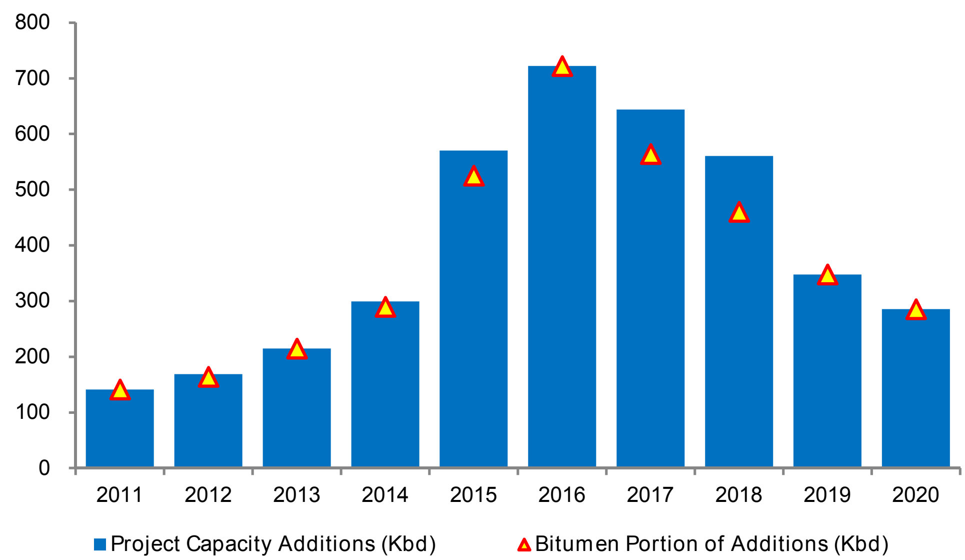
Those factors, coupled with continued barge and rail, should be enough to push out the remaining imported light barrels by the end of 2013 or early 2014.

Other basins: supply, takeaway & destinations

Western Canada

Canadian heavy crudes are in an odd situation in 2013/14 – demand for heavy crudes is growing due to numerous recent/upcoming heavy conversion/expansion projects (Wood River, Detroit, Motiva Port Arthur, Whiting), yet infrastructure may stand in the way of fully reaching that incremental demand until mid-2014. Thus over the medium-term we expect volatility and only marginal improvement in average relative realizations for Canadian producers.

Figure 65: 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 estimate

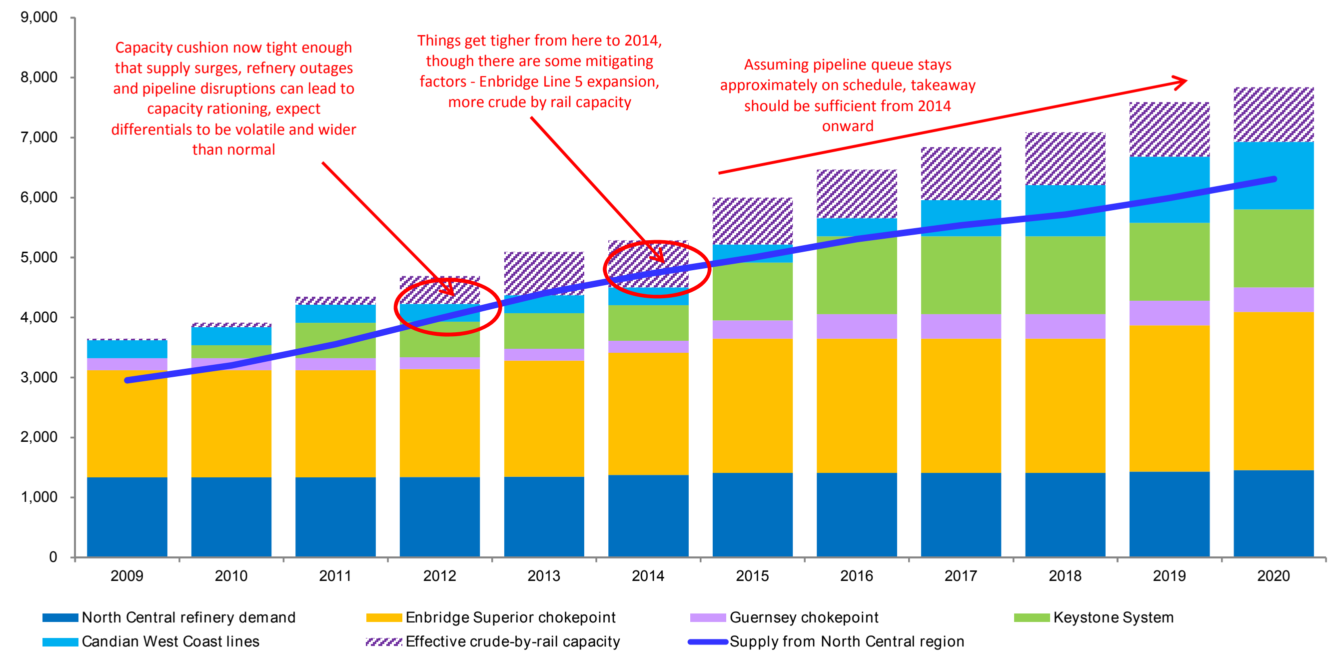
Oil sands growth continues to ramp aggressively with major in situ projects (or mining-only Kearl) starting up every quarter. Planned activity actually accelerates each year out to 2016, though given our subdued North American crude price outlook, we expect many projects in this queue to be delayed or shelved altogether.

Several years of dramatic growth are probably locked in at this point though, due to sunk cost and relatively low break-evens for project phases that piggyback on infrastructure and design of prior stages.

We do think that given the increasing likelihood of a severe light crude glut in North America, oil sands upgrader projects make little sense at this point – the last thing the continent needs is more synthetic light crude given the abundance of high quality light oil from the Bakken, Permian and Eagle Ford. So our expectation is that once Horizon Phase 2/3 and Sturgeon Phase 1 (the Redwater upgrader project) are built, that will be it for a while for upgraders, and other mining projects will use a process that allows direct transport to refineries without upgrading. Conceivably the construction of pipelines to the Canadian West Coast (TMX expansion and Northern Gateway) could revive upgrader projects, as synthetic light crude could be exported to Asia.

As mentioned, over the medium term, we see takeaway capacity out of the north central region (WCSB and Bakken) getting increasingly tight through mid-2014 when the Enbridge system expands from Superior to the Gulf Coast. Both Enbridge and Plains have Bakken projects that actually increase the Mainline tightness – pipeline takeaway out of the Bakken improves, but into a flow of surging Canadian production. Crude by rail continues to increase out of both the Bakken and Alberta, alleviating the pressure on pipelines somewhat, but we expect instances of full capacity at the key chokepoints when north central refineries are in turn around and/or new oil sands projects come on stream.

Figure 66: North Central supply-takeaway balance – problem solved by 2015 if pipelines stay on schedule (kbd)

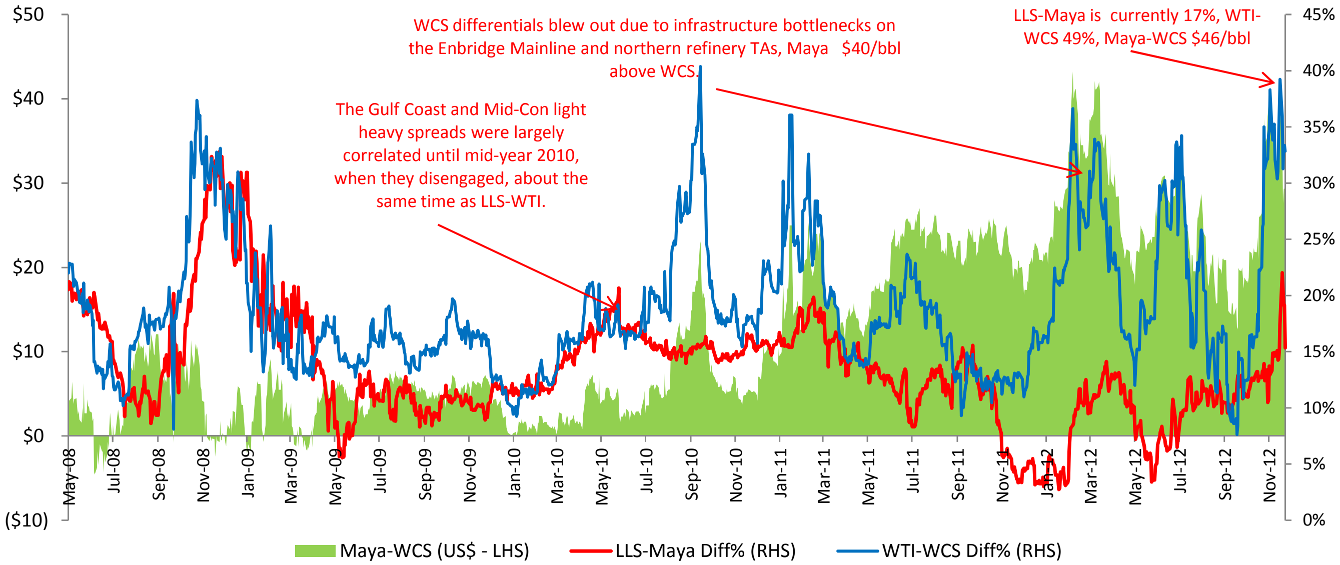


Source: Company data, EIA, CAPP, ND Pipeline Authority, Reuters, Dow Jones, Deutsche Bank

Longer-term it appears clear that Canadian heavy prices should start to converge (adjusted for transportation costs) with chemically similar Maya, particularly as it will soon be competing directly with waterborne Latin American heavy crudes.

Northern tier differentials have been volatile, as production surges and takeaway constraints have exaggerated the impact of refinery, upgrader and pipeline outages. To a large extent Chicago refinery crude slate economics drive northern tier crude prices, but increasing movement of crude by rail and pipeline bottlenecks are now playing a greater role. We expect northern differentials to remain very volatile, and on average be wider than normal, until a wave of pipeline expansions/additions are completed by mid-2014. After that infrastructure has been completed, our expectation is that northern differentials will be much less volatile and will gravitate towards a normal state around the cost of transportation to the Gulf Coast.

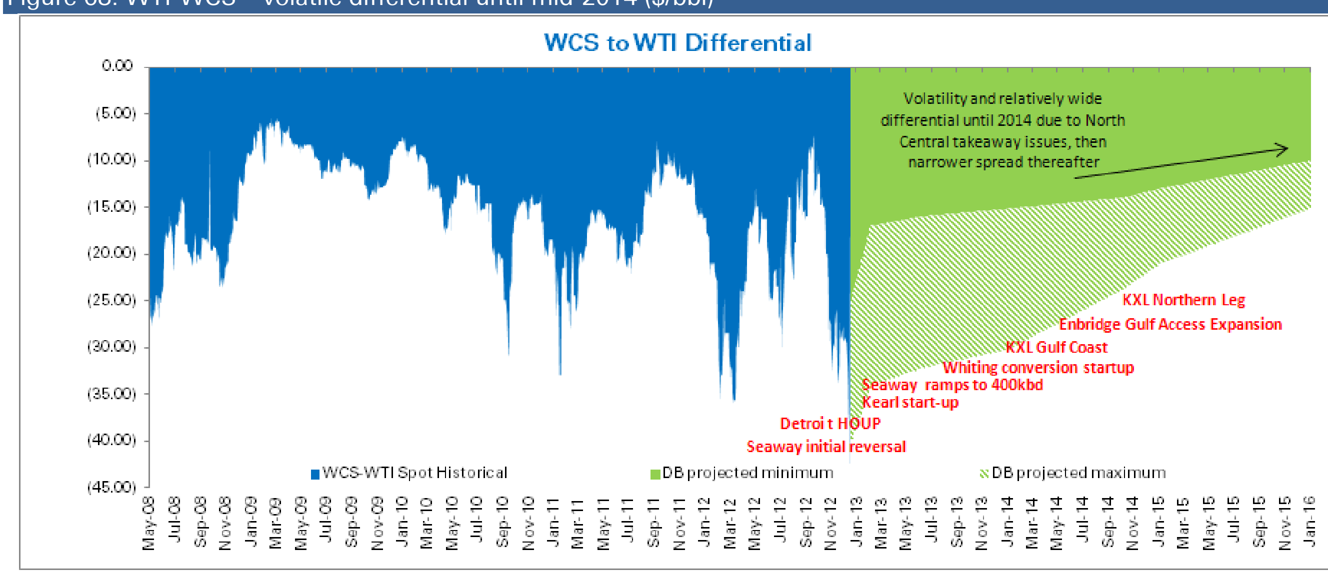
Figure 67: Light-heavy spreads – a tale of two diffs (LLS-Maya vs WTI-WCS since 2008)



Source: Bloomberg Finance LP, Deutsche Bank

The extreme gap between Maya and WCS differentials highlight these transportation issues and ability to reach faraway demand. In about eighteen months this will be cured for good as the Enbridge/Seaway system and Keystone XL will be able to move 1.5Mbd of Canadian heavy to the Gulf Coast where complex refineries will gladly increase their heavy slate or displace expensive Maya/Venezuelan.

Figure 68: WTI-WCS – volatile differential until mid-2014 ($/bbl)



Source: Bloomberg Finance LP, Company data, EIA, Deutsche Bank

Our WTI-WCS forecast anticipates a narrowing from the current very wide discount, but expect the differential to on average be wider than normal, and very volatile.

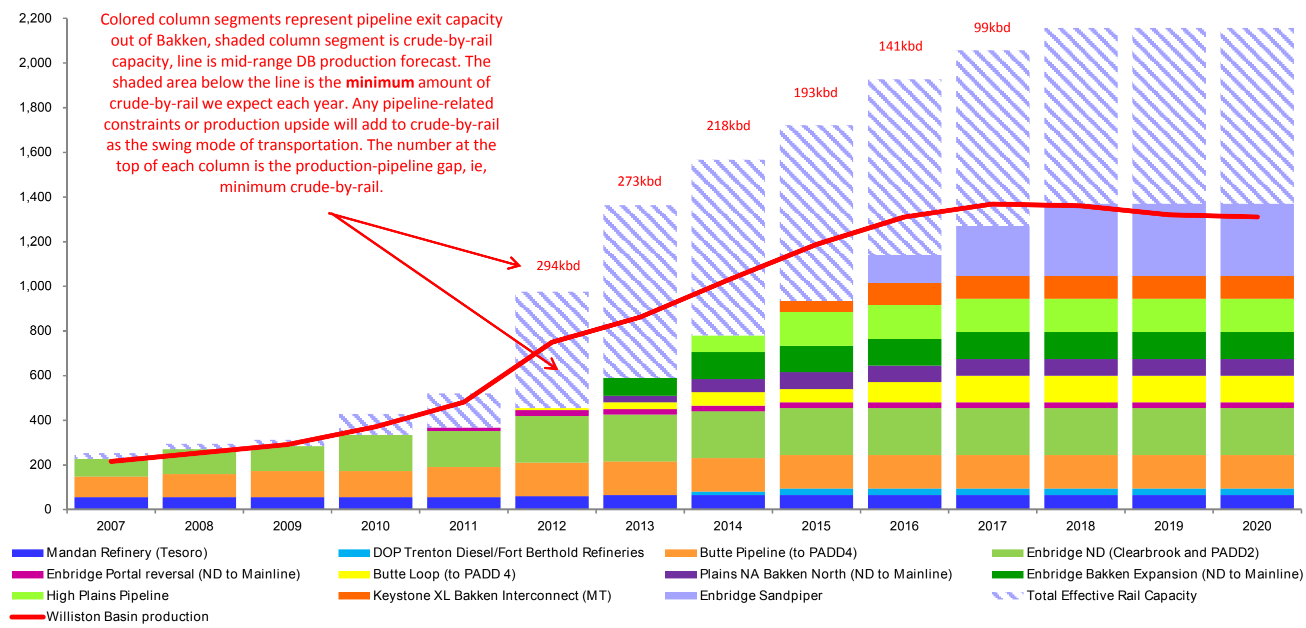
Bakken

Key issues and takeaways for the Bakken:

Bakken production is well ahead of pipeline takeaway out of the region, and even when basin takeaway increases this year (Plains and Enbridge pipelines that connect to Mainline), there isn't enough room on pipelines on the other side of the Superior, WI chokepoint for all of the Bakken and Canadian crude that wants to move South and East, so rail will be critical to meet exit needs.

In an over-supply situation, proximity to demand will matter a lot, since transportation costs and reliability are key differentiating factors. North Dakota is remote, Eagle Ford and Permian (and Oklahoma) are close to the refineries. So there is an inherent advantage there that will not disappear with time.

Figure 69: Williston Basin production vs. takeaway capacity – major role for rail (kbd)



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

Though geographically remote and infrastructure restricted, Bakken crude is the "best" of the unconventional light crudes – feedback from refiners who have been running Bakken on the East and West Coast has been uniformly positive. Whereas Eagle Ford crude and crude-like condensate is generally lighter than refiners would like, Bakken, at around API 40-41°, is near the ideal, marginally better than WTI, but less light-ends than Eagle Ford. Thus Bakken seems to be the "all things being equal" winner among the unconventionals.

Figure 70: Bakken pipeline project queue

Pipeline	Operator	From	To	Length (mi)	Init. Cap. (kbd)	Ult. Cap. (kbd)	Diam. (in)	Target Date	Status	Comments
Enbridge Bakken Expansion	Enbridge	Beaver Lodge, N	Cromer, Manitoba	124	120	325	NA	1Q13	Constr.	$370m project to connect Bakken to Enbridge mainline
Plains Bakken North	PAA	Trenton, ND	Regina, SK	103	50	75	12	2Q13	Constr.	Will connect to Wascana Pipeline in Montana, then ENB system in Saskatchewan
Butte Loop	True	Baker, ND	Casper, WY	323	50	50	16	2Q13	Constr.	Exit from Bakken to Guernsey, connects with Platte, which goes to Wood River
High Prarie Pipeline	Saddle Butte	Alexander, ND	Clearbrook, MN	450	150	150	16	4Q13	Proposed	Plans for 4Q13 startup, but ENB refused access at Clearbrook, Saddle Butte suing
Keystone XL Northern Leg	TransCanada	Hardisty, AB	Cushing, OK	1,667	700	830	36	2015	Planned	We expect permit in 1Q13, startup in 2015. Will pickup 100+kbd of Bakken crude
Sandpiper Project	Enbridge	Tioga, ND	Superior, WI	600	225	325	24	2015	Proposed	Would move Bakken crude from Western Williston Basin to Superior

Source: Company data, ND DMR, ND Pipeline Authority, Reuters, Dow Jones, Oil and Gas Journal, various other news sources, Deutsche Bank

Larger producers, such as Continental, use rail on a spot or short-term contract basis, maintaining flexibility. Many smaller producers, concerned about stranded barrels and a weak bargaining position for pipeline space, made volumetric commitments to underwrite construction of rail terminals and unit train lines. Many of these contracts were 3-5 years, though the total amount of committed rail barrels is unknown. We believe it is in low six figures per day, i.e., maybe 100-200Kbd.

The right Bakken strategy from a producer perspective appears to be the portfolio approach we've seen from Hess, Continental and EOG. Given the uncertainty around the pace of production from the various basins and differentials, the Bakken is the one basin among the big three where it isn't clear where the best netback opportunity is going to be, so it is important to maintain options and flexibility.

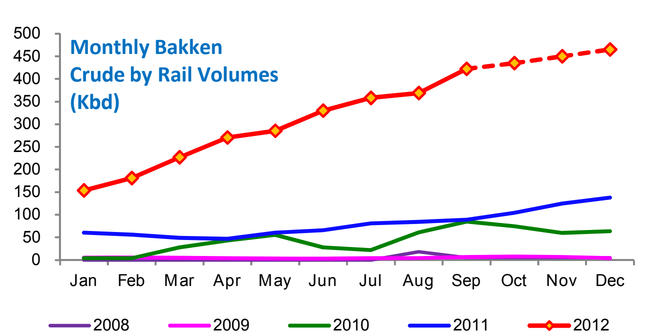
Figure 71: Bakken crude by rail loading terminals – active and planned

Terminal	Operator	Active/Planned	Capacity	Exp. Cap.	Location	Comments
EOG Stanley	EOG	Active	65	65	Stanley, ND	Used to run to Stroud, now mostly to St. James, LA
Dakota Plains New Town	Dakota Plains Holdings	Active	40	60	New Town, ND	Can handle 160 cars
Stampede Rail Facility	Pioneer Oil	Active	5	5	Stampede, ND	First crude-by-rail facility in ND
Small Rail Facilities	Multiple	Active	25	25	Various	Small mostly manifest terminals, pre-date Bakken ramp up
Van Hook Crude Terminal	USDG/PAA	Active	35	65	New Town, ND	12K bbl storage, will increase to 275k bbl; can handle up to 104 car unit trains.
Bakken Oil Express	Lario Logistics	Active	100	250	Dickinson, ND	Unit train to St. James, LA, acquired from EDOG Logistics in 4Q10
Dore	Watco/Kinder Morgan	Active (as 4Q11)	30	60	Dore, ND	Phase1, 10k ft of track, can handle lg unit train volumes
Hess Tioga	Hess	Active (as of 1Q12)	54	120	Tioga, ND	$48m to build Tioga terminal, initially 54kb/d, expandable to 150kbd
Rangeland COLT	Rangeland Energy	Active (as of 2Q12)	120	120	Epping, ND	40kb/d COLT Connector pipeline. TSO will run two 120-car unit trains.
Musket Dore	Musket	Active (as of 2Q12)	60	70	Dore, ND	Musket was shipping 10-16kbd via manifest, now runs 104 car unit train line
Great Northern Fryburg	Great Northern Midstream	Active	60	60	Fryburg, ND	$45m transload, crude delivered through BakkenLink Pipeline and tanker trucks
Zap Terminal	Basin TransLoad	Active/4Q12	20	40	Zap, ND	Replacing coal loading facility, track and facility is in place
Trenton Railport	Savage Cos.	Active/3Q12	60	90	Trenton, ND	Double loop track capable of holding two 118 car unit trains
Berthold Rail	Enbridge	3Q12/1Q13	10	80	Berthold, ND	Phase II startup in 1Q13, double-loop unit train facility, ability to stage 3 trains
Manitou Rail Terminal	Plains All American	4Q12	20	65	Ross, ND	Also has 75mmcfd gas processing plant, terminal can handle NGLs + crude
East Williston Flying J	NA	TBD	NA	NA	Williston, ND	Pending state approval
Gascoyne	NA	TBD	NA	NA	Gascoyne, ND	East of Bowman, preliminary work being done at site
Total			**704**	**1,175**		

Source: Company data, ND DMR, ND Pipeline Authority, Reuters, Dow Jones, Oil and Gas Journal, various other news sources, Deutsche Bank

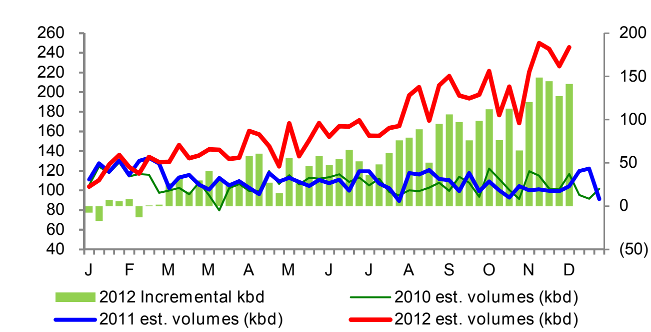
For now Bakken will be pulled South in relatively large quantities due to LLS minus pricing there, until the Houston/Louisiana "bucket" fills up. As the Gulf Coast moves into a situation of light crude surplus, Bakken crude will have less incentive to move South, and the flow to the East and West Coast, already growing quickly, will get even bigger.

Figure 72: Bakken crude loadings



Source:ND DMR/ND Pipeline Authority, Deutsche Bank estimates

Figure 73: US East Coast petroleum receipts by rail



Source: AAR, Deutsche Bank estimates

Bakken crude by rail initially went primarily to Stroud, OK, via the EOG unit train line. The next shift was to St. James, LA where about 250kbd are still moving today. The evolution over the last six months has been towards transit to first the East Coast, and now the West Coast. We think about 120kbd is heading to Eastern US refineries, with another 20-30kbd going to Eastern Canadian refineries. Both of those numbers will increase in 2013, as numerous refiners have announced plans to build crude unloading terminals, and/or ship more volumes by rail/barge.

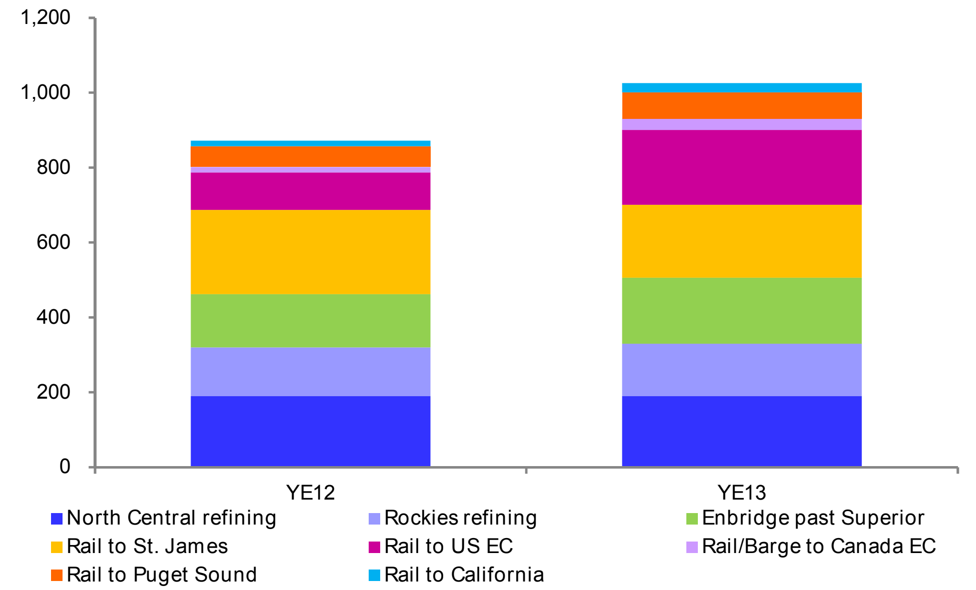
Figure 74: US and Canadian East Coast rail terminal projects

Terminal	Operator	Active/Planned	Capacity	Exp. Cap.	Location	Comments
Albany	Global Partners	Active/4Q12 exp.	70	150	Albany, NY	Started receiving Bakken bbls 10/11, 1.4Mbbl storage, barge terminal
Albany Buckeye	Buckeye Partners	Active/4Q12 exp.	135	135	Albany, NY	1.8mbbl of storage, will receive both crude/ethanol unit trains; multi-year contract w/ Irving
Yorktown	Plains All American	1H13	130	130	Yorktown, VA	Terminal/storage at former WNR Yorktown refinery; marine terminal, product pipelines
Delaware City Refinery	PBF	Active/exp. In 4Q12/1Q13	40	110	Delaware City, DE	Currently receiving 20-40kbd of Bakken and Western Canadian, ramp to 110kbd in 1Q13
St. John Refinery	Irving Oil	Construction	69	69	East St. John, NB	Would receive WCSB/Bakken crudes; though refinery may have opted for Albany rail/barge
Eddystone	Enbridge/Canopy	Construction/3Q13	80	160	Philadephia, PA	ENB will own 75% and operate. We expect PSX to ship here for Bayway.
Philadelphia Refinery	Carlyle/Sunoco	Active/2Q13/3Q13	25	150	Philadephia, PA	High-speed facility capable of processing two unit trains per day

Source: Company data, various news sources, Deutsche Bank

It is increasingly clear that the marginal mode of transportation out of the Bakken will be rail, likely to one of the coasts, thus in general we expect Bakken to gravitate towards the price needed to incentivize that move, i.e., $15-20/bbl below Brent, as long as there are still Brent barrels being consumed, or vs. LLS once all of the waterborne light barrels have been pushed out of the US.

Figure 75: Bakken crude outflow – increasing rail flow to the East and West Coast (kbd)



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

Niobrara

A few quick thoughts on the Niobrara, which has been disappointing production-wise, with a few successes in spots. It is now clear that the Niobrara won't be another major basin, but is still producing meaningful volumes and should continue to grow modestly, we think plateauing in the 300-400Kbd range.

Figure 76: Niobrara pipeline project queue

Pipeline	Operator	From	To	Length (mi)	Init. Cap. (kbd)	Ult. Cap. (kbd)	Diam. (in)	Target Date	Status	Comments
White Cliffs Expansion	SemGroup	Platteville, CO	Cushing, OK	526	40	40	12	4Q11	In Service	Expanded to 70kbd from 30kbd, only current exit pipeline out of Niobrara
White Cliffs Twinning	SemGroup	Platteville, CO	Cushing, OK	526	70	100	NA	1H14	Constr.	Completed successful open season in Oct '12, w/ Noble/Anadarko anchoring
Pony Express	KM/Tallgrass	Guernsey, WY	Cushing, OK	710	230	230	NA	3Q14	Proposed	Converts 500 mi of gas pipeline into crude; will deliver to Ponca City/Cushing
Niobrara Falls Project Ph 2	NuStar	Platteville, CO	Dixon, TX	437	75	75	10	NA	Speculative	Niobrara to Texas, would connect with Basin and Permian Express
White Cliffs ExLoop	SemGroup	Platteville, CO	Cushing, OK	526	NA	NA	NA	NA	Speculative	Niobrara exit capacity - has been discussed but nothing announced

Source: Company data, Reuters, Dow Jones, Oil and Gas Journal, various other news sources, Deutsche Bank

With only 1.5 local refineries, SU's Commerce City (plus 50-70% of capacity in HFC's Cheyenne refinery), a majority of the DJ Basin/Niobrara production needs to move East to find a market. SEMG's White Cliffs is the primary pipeline right now, moving about 70kbd to Cushing. Three major proposals have been put forward to take incremental production: a twinning of White Cliffs, NuStar's Niobrara Falls project, and Kinder Morgan's Pony Express. A fourth, OneOK's Bakken Crude Express, has been cancelled.

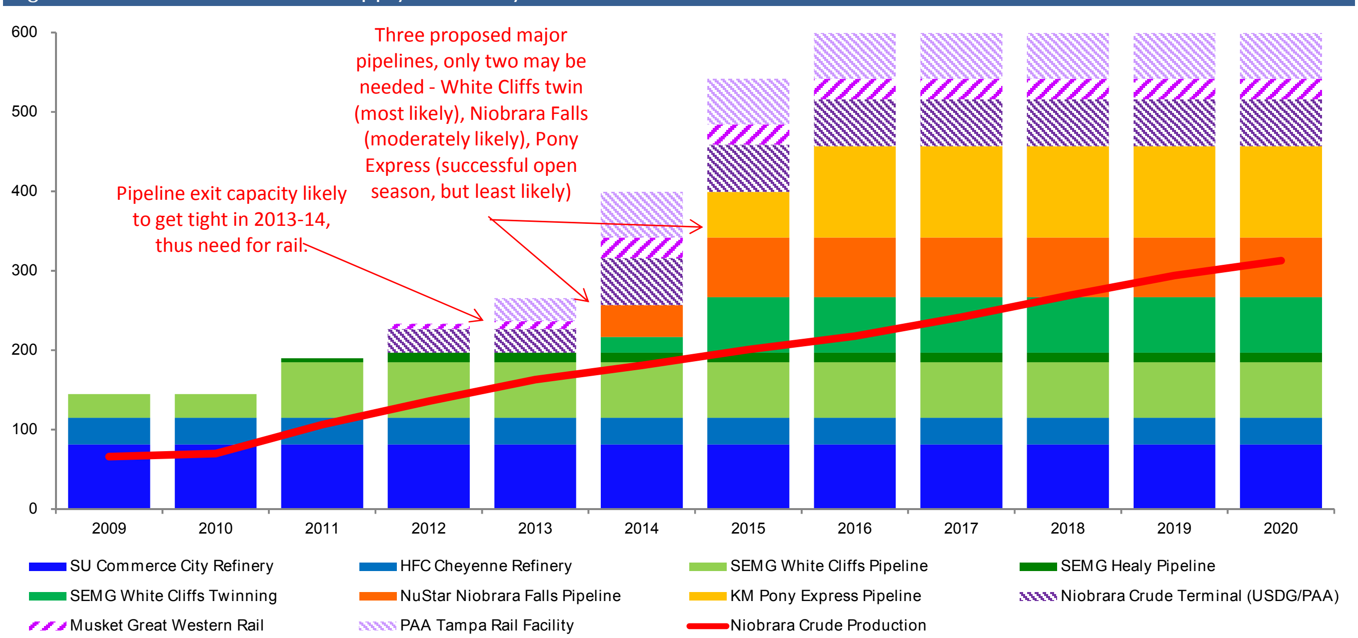
Figure 77: Niobrara rail terminal projects

Terminal	Operator	Active/Planned	Capacity	Expansion Cap.	Location	Rail Line	Comments
Niobrara Crude Terminal (NCT)	USDG/PAA	Active/4Q11	35	72	Carr, CO	UP	Just south of Wyoming. PAA bought from USDG
Musket Great Western	Musket	Active/3Q12	12	30	Windsor, CO	GWRR/UP/BNSF	48Kbbl of storage; initially manifest, but will build to take unit train
PAA DJ Basin Tampa Rail	PAA	3Q13	68	NA	Tampa, CO	BNSF	NE of Denver; can receive via truck and pipeline; firm contracts w/lg producers

Source: Company data, Reuters, Dow Jones, Oil and Gas Journal, various other news sources, Deutsche Bank

Two rail terminals are currently in operation, and Plains All American has announced a third to be built in Tampa, CO. PAA also recently purchased US Development Group's Niobrara rail terminal. Rail will allow Niobrara crude to bypass Cushing, but going forward that may not be worth the added transportation cost.

Figure 78: Niobrara/DJ Basin supply-takeaway balance



Notes: Assumes 92% refinery utilization, Commerce City10% of slate reserved for Canadian, Cheyenne 30% of slate for heavy, 50% of Pony Express reserved for Niobrara (other 50% for Bakken), rail availability of 85%,
Source: Company data, Reuters, Dow Jones, Oil and Gas Journal, various other news sources, Deutsche Bank

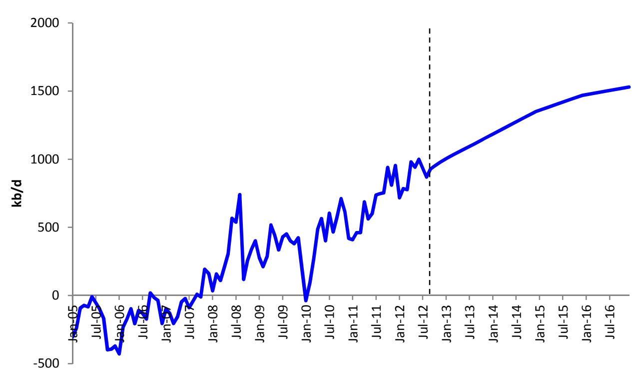
2013/14 Refiner Sensitivities

Key takeaways from a differential narrowing then widening view

Cheap crude in itself is not bullish for refining margins. Refiners had 20 years of terrible margins in a cheap crude environment.

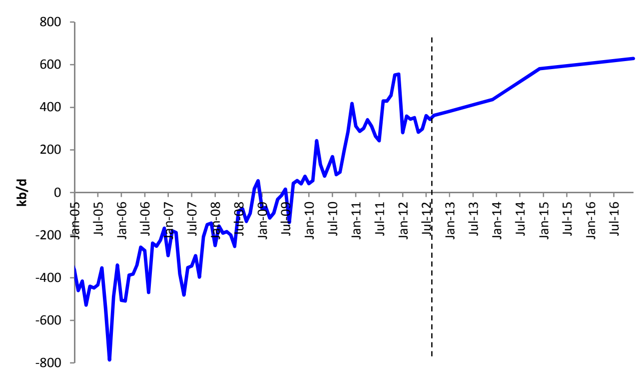
The first principle of refining profitability is demand. While US demand is weak, we expect exports of products, which are the key to the positive overall demand balance, to keep growing. We believe that exports can keep growing into 2015, providing the key bull case for US refining: overall demand growth.

Figure 79: 2013 Distillate Net Exports



Source: EIA, Deutsche Bank

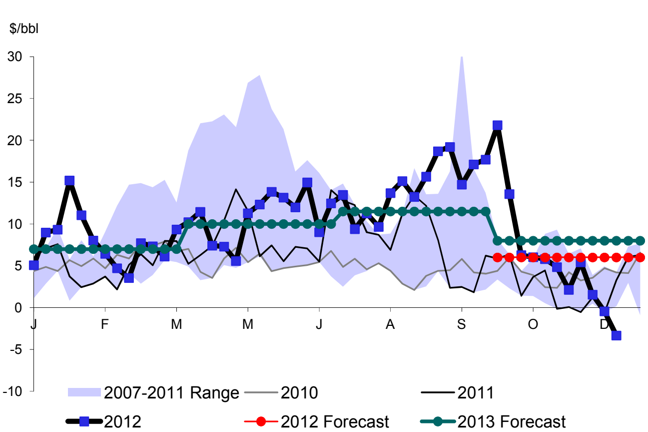
Figure 80: 2013 Gasoline Exports



Source: EIA, Deutsche Bank

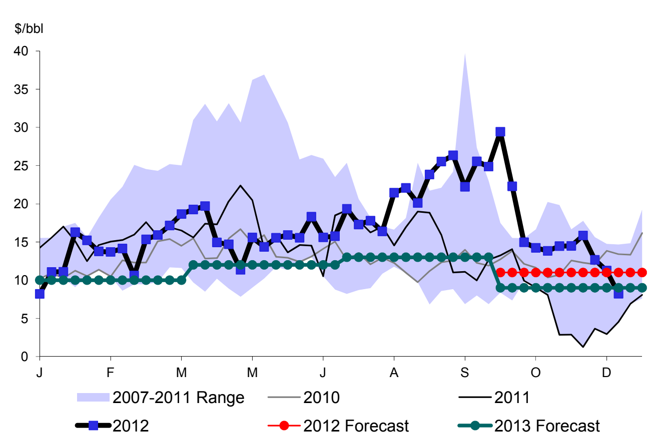
Given the strong total demand environment (including product export demand), it is notable that simple Gulf Coast refining margins – the marginal refining margin in the US – have gone negative. Therefore the entirety of the bull case for refining margins rests on differentials. Thus the importance of Brent-LLS in our analysis.

Figure 81: Gulf Coast 3-2-1 Margins



Source: Deutsche Bank, Bloomberg Finance LP

Figure 82: Gulf Coast Complex Margins



Source: Deutsche Bank, Bloomberg Finance LP

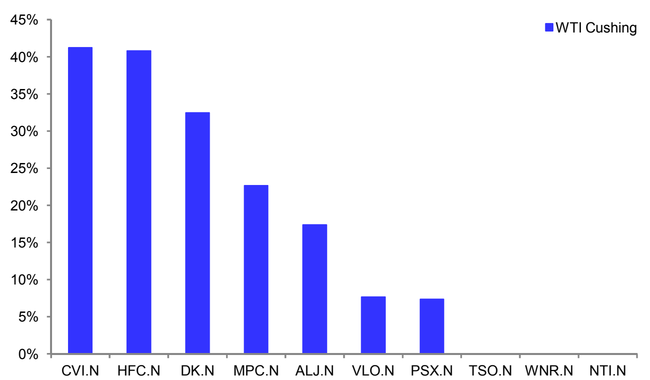
Our underweight is based on the fact that Gulf Coast margins are negative even before the start up of the massive Motiva refinery, and before Seaway narrows differentials.

Overall our view of differentials is clearly long term positive. The issue we face, as outlined above is the expected narrowing of these differentials over the coming months, starting in January 2013, and continuing until Gulf Coast import substitution is complete by end 2013. This is a difficult phase for refiners, because as we show, they are now discounting sustained differentials above mid-cycle earnings of the past 10 years.

Which refiners have the most exposure to changes in the key crude differentials discussed in this note? In the following pages, for the first time, we show the exposures, by refiner, by crude differential. All prices are relative to international marker Brent.

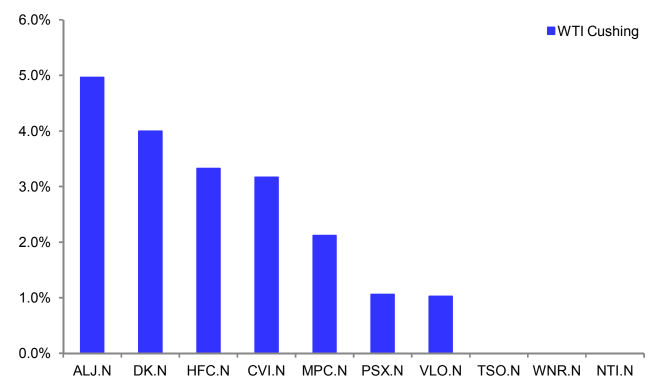
The following charts illustrate exposure by crude and EBITDA sensitivity to crude prices.

Figure 83: 2013 Crude Slate – Exposure to WTI



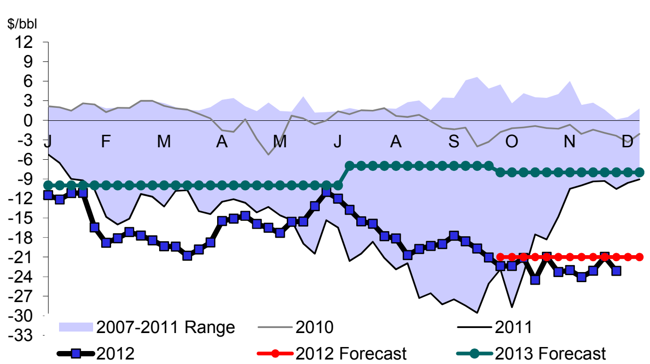
Source: Deutsche Bank

Figure 84: 2013 EBITDA Sensitivity -$1/bbl Change WTI



Source: Deutsche Bank

Figure 85: WTI vs Brent



Source: Deutsche Bank, Bloomberg Finance LP

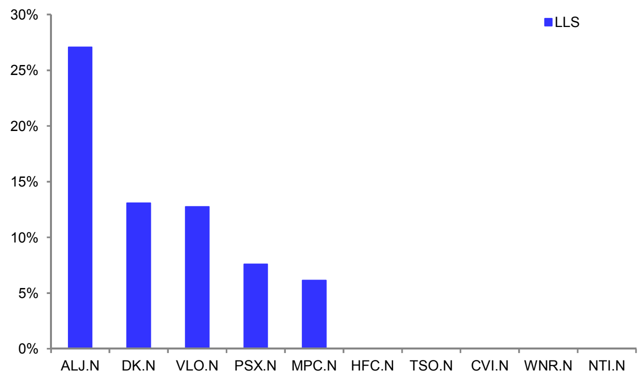
Figure 86: Key commentary

Bouncing along in line with our forecast, we expect this differential to narrow aggressively with the start up of Seaway, Permian pipelines, Keystone XL Southern leg, and ongoing rail growth.

Negative: CVI, HFC, DK

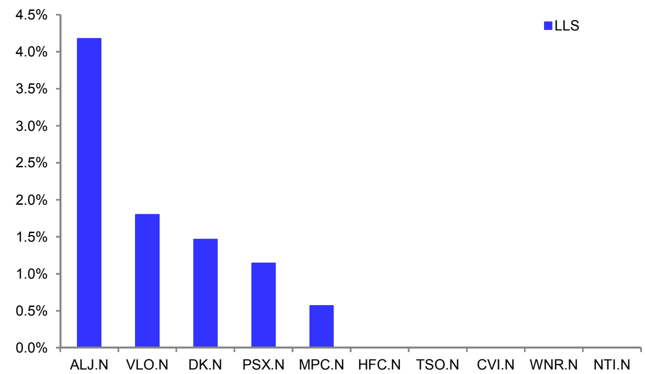
Source: Deutsche Bank

Figure 87: 2013 Crude Slate – Exposure to LLS



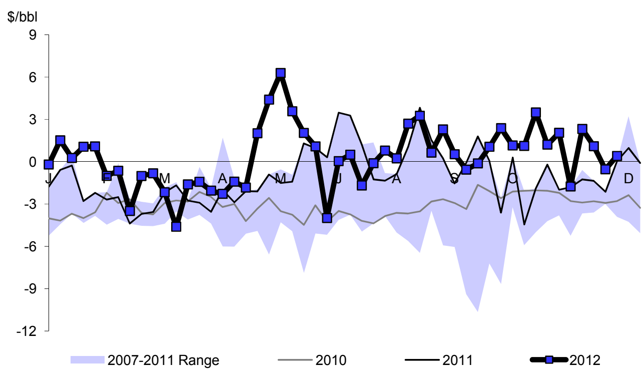
Source: Deutsche Bank

Figure 88: 2013 EBITDA Sensitivity -$1/bbl Change LLS



Source: Deutsche Bank

Figure 89: Brent vs LLS



Source: Deutsche Bank, Bloomberg Finance LP

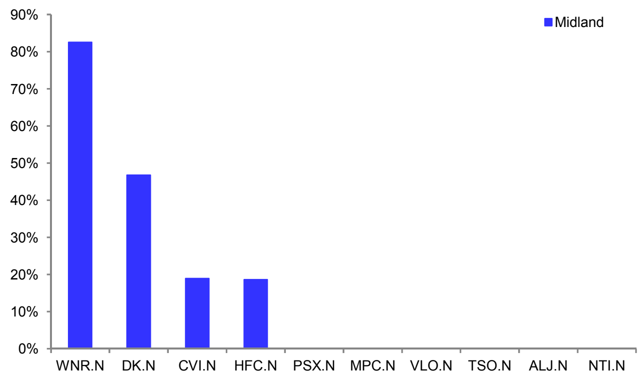
Figure 90: Key commentary

We expect, as outlined at length in this note, LLS to break away from Brent and back towards WTI as WTI-linked supply surgues down from Cushing and Midland.

Negative: relatively negative for those with zero exposure

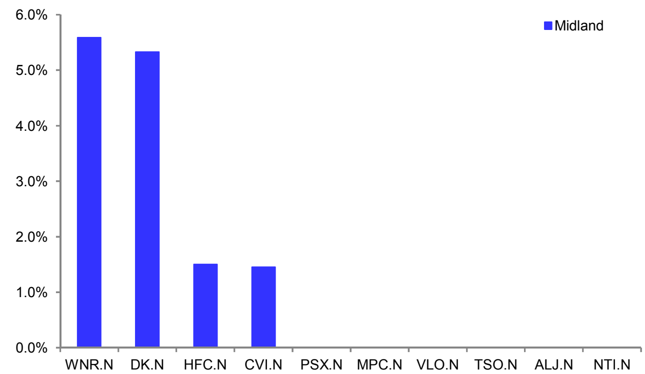
Source: Deutsche Bank

Figure 91: 2013 Crude Slate – Exposure to Midland



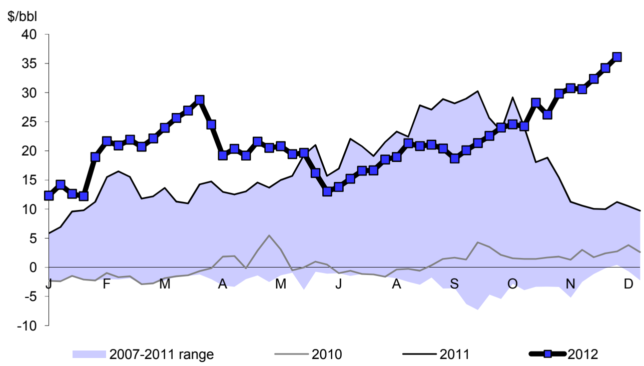
Source: Deutsche Bank

Figure 92: 2013 EBITDA Sensitivity -$1/bbl Chg Midland



Source: Deutsche Bank

Figure 93: Brent vs Midland



Source: Deutsche Bank, Bloomberg Finance LP

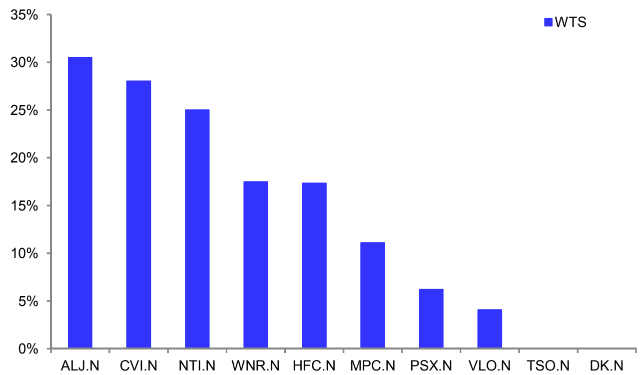
Figure 94: Key commentary

We expect Midland to rally from its extreme wide lows as Longhorn is reversed in Q1, directly attacking this spread. Longhorn will be followed by numerous other pipelines linking the Permian directly the GC – West Texas Gulf system expansions, Permian Express, and in 2014 Permian Express Phase 2 and BridgeTex.

Negtive: WNR, DK

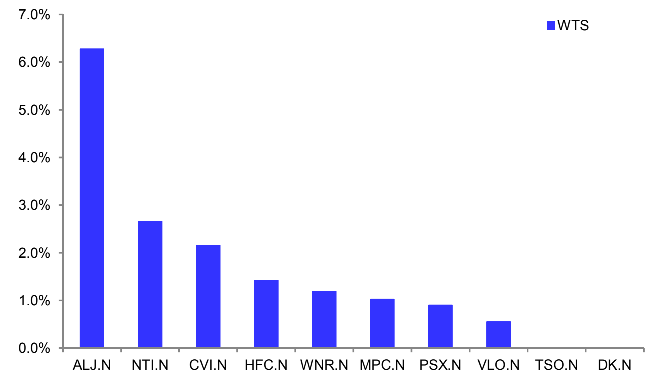
Source: Deutsche Bank

Figure 95: 2013 Crude Slate – Exposure to WTS



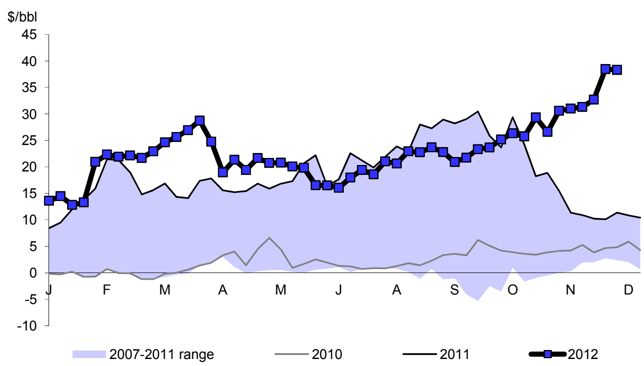
Source: Deutsche Bank

Figure 96: 2013 EBITDA Sensitivity -$1/bbl Change WTS



Source: Deutsche Bank

Figure 97: Brent vs WTS



Source: Deutsche Bank, Bloomberg Finance LP

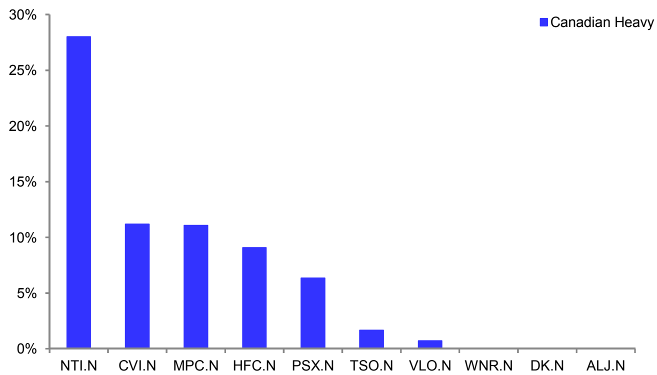
Figure 98: Key commentary

Alon is the most exposed to WTS, by a wide margin. Overall Alon looks to be the cheapest refiner with the highest leverage to spreads

As with other crudes, the outlook for WTS prices relative to Brent is narrowing followed by widening

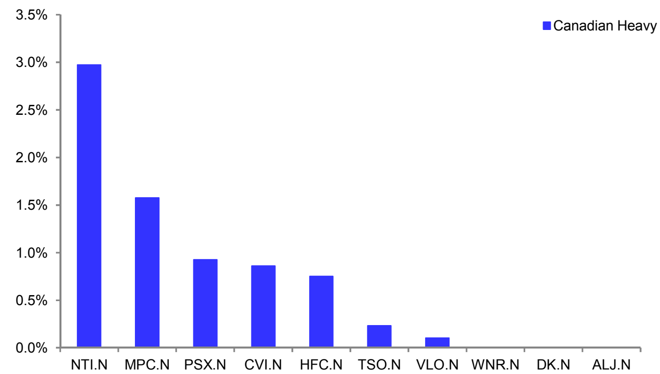
Source: Deutsche Bank

Figure 99: 2013 Crude Slate – Exposure to WCS



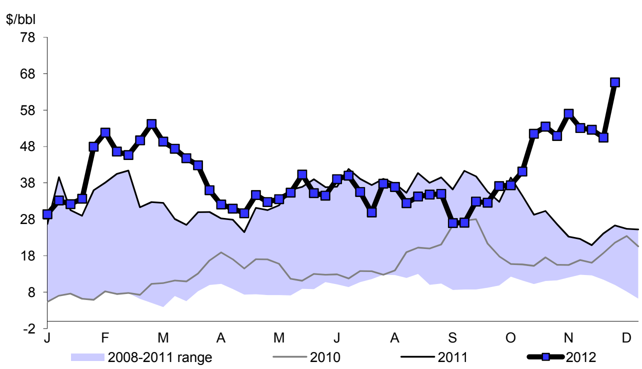
Source: Deutsche Bank

Figure 100: 2013 EBITDA Sensitivity -$1/bbl Change WCS



Source: Deutsche Bank

Figure 101: Brent vs WCS



Source: Deutsche Bank, Bloomberg Finance LP

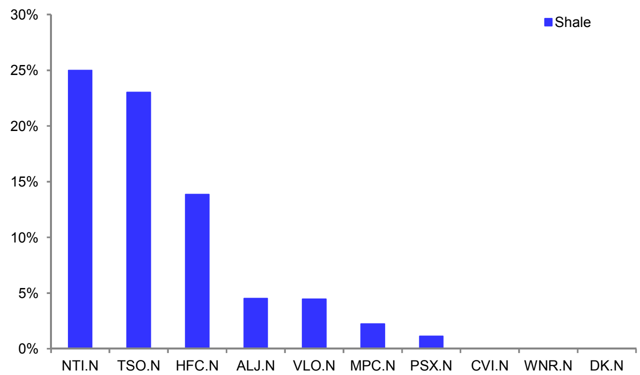
Figure 102: Key commentary

NTI is by far the most exposed to the extreme current discounts for Western Canadian Select, which is suffering from infrastructure bottlenecks and refining limitations.

MPC and PSX also enjoy this discount.

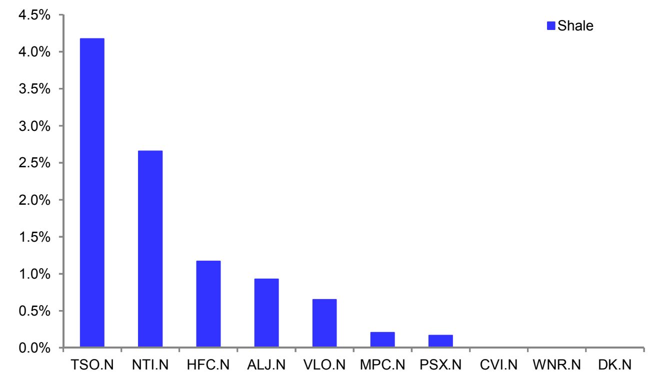
Source: Deutsche Bank

Figure 103: 2013 Crude Slate – Exposure to Bakken



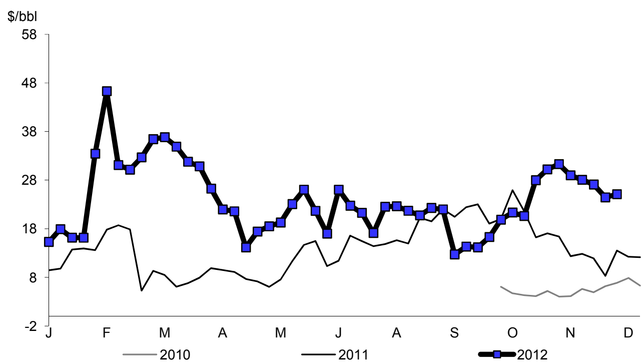
Source: Deutsche Bank

Figure 104: 2013 EBITDA Sensitivity -$1/bbl Chg Shale



Source: Deutsche Bank

Figure 105: Brent vs Clearbrook



Source: Deutsche Bank, Bloomberg Finance LP

Figure 106: Key commentary

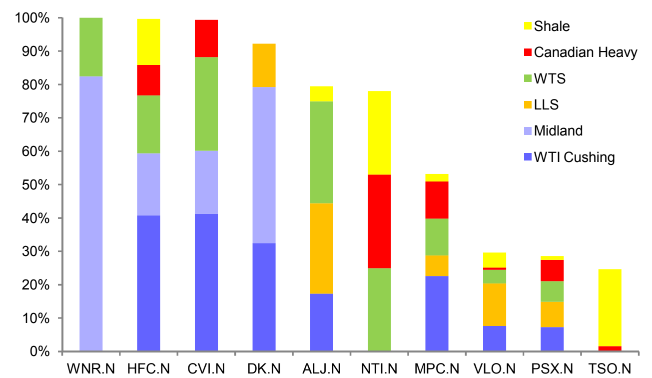
NTI, TSO and HFC are key winners when Clearbrook is heavily discounted.

With an incremental 800-900kbd of pipeline capacity from Cushing to Houston going in-service in 2013, and additional rail movements to EC/GC/WC, we expect this differential to narrow over the coming year.

Source: Deutsche Bank

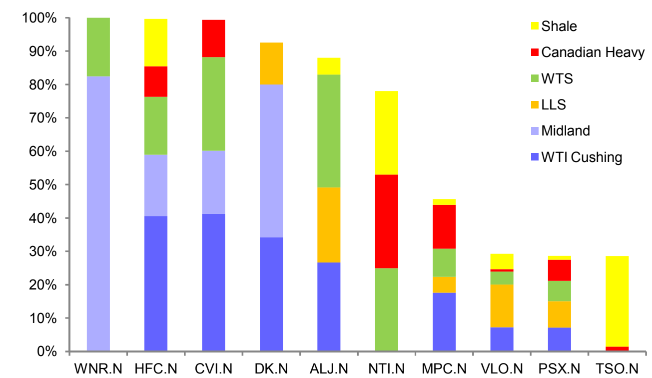
Overall, exposure and leverage is shown below. Again, WNR, HFC, and CVI are the most levered, with PSX and Valero least. Most vulnerable to crude differential compression in 2013 appear to be WNR and DK, given our forecast for Midland crudes. Robust WCS differentials (though narrower than the current super-wide level) should be a relative advantage to NTI, MPC, CVI and HFC.

Figure 107: 2012e Disadvantaged Crude Slate



Source: Deutsche Bank

Figure 108: 2013e Disadvantaged Crude Slate

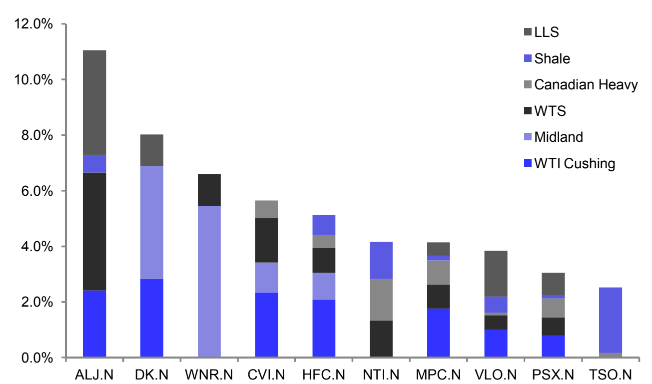


Source: Deutsche Bank

Longer term, VLO, PSX, MPC and DK should benefit from the gradual widening in Brent-LLS.

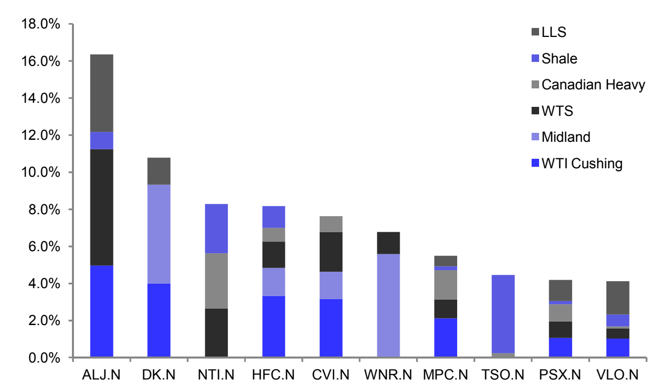
Summed up, we show below the EBITDA sensitivity to changes, graphically and in tables at the end of this section.

Figure 109: 2012e EBITDA Sensitivities to $1/bbl Change



Source: Deutsche Bank

Figure 110: 2013e EBITDA Sensitivities to $1/bbl Change



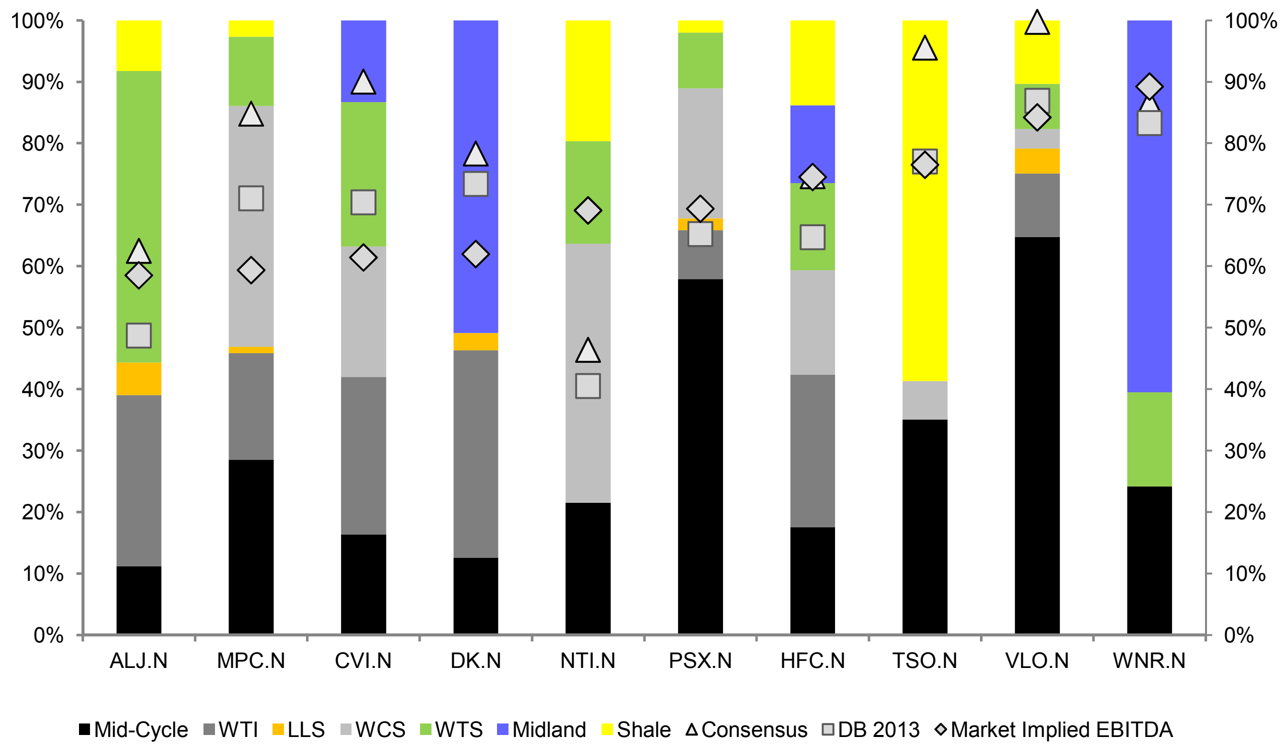
Source: Deutsche Bank

What is discounted in the market? The chart below shows mid-cycle EBITDA for the refiners based on 2001-2010 EBITDA annual capacity-adjusted average. The total is the implied EBITDA from differentials in 2013. The scale of the importance of differentials relative to mid-cycle is striking, with the least exposed company (PSX) showing 50% upside to mid-cycle from the current differential outlook for 2013.

The markers show where market implied valuations are, where current consensus is, and where DB's current forecasts are. The difference between DB and total implied profit is related to downtime, capture (above all), and corporate costs.

There is least controversy on WNR (where all three markers align) and most controversy on Marathon, where we are below market, and consensus is above market. Consensus is notably bullish PSX and relatively bearish NTI.

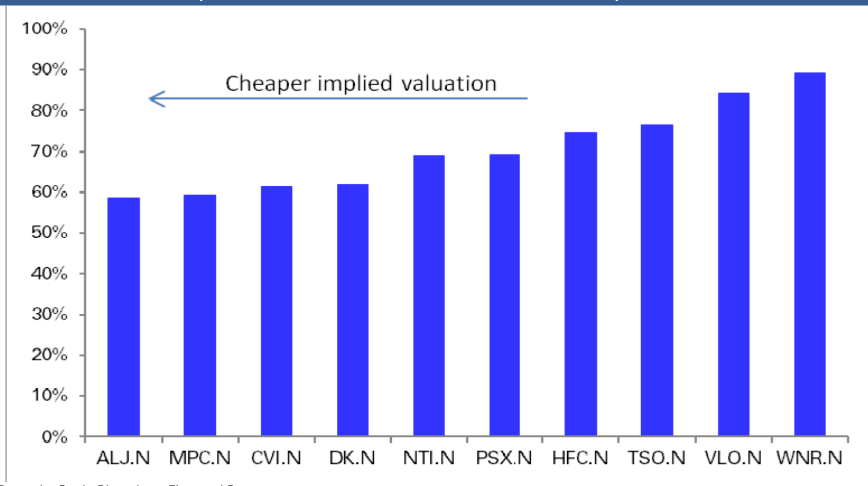
Figure 111: 2013 EBITDA Implied by Crude Differentials vs DB/Consensus/Market-Implied



Source: Deutsche Bank, Bloomberg Finance LP

The chart below shows relative valuation, equity market implied refining EBITDA assuming 3.5x EV/EBITDA multiple versus EBITDA implied from crude differentials.

Figure 112: Market-Implied EBITDA vs. EBITDA from Mid-Cycle + Crude Differentials



Source: Deutsche Bank, Bloomberg Finance LP

What if we are wrong? The tables below show EBITDA sensitivities.

Figure 113: EBITDA Impact of $1/bbl Change in Crude Prices 2013e ($m)

	Brent	LLS	WTI	Midland	WTS	WCS	Maya	Mars	Eagle Ford	Bakken	Niob	Uinta	ANS	WC	Africa	ME	LatAm	FSU	Other Canadian
PSX.N	96	57	53	-	45	46	28	35	-	8	-	-	26	59	85	42	78	14	58
MPC.N	-	27	101	-	49	75	27	108	4	6	-	-	-	-	37	125	4	0	10
VLO.N	59	97	55	-	29	6	53	77	35	-	-	-	8	24	100	102	79	30	2
HFC.N	-	-	61	28	26	14	-	-	-	1	11	9	-	-	-	-	-	-	0
TSO.N	5	-	-	-	-	4	-	-	-	43	20	-	49	47	2	18	28	6	12
CVI.N	-	-	26	12	18	7	-	-	-	-	-	-	-	-	-	-	-	-	0
WNR.N	-	-	-	43	9	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DK.N	-	6	16	21	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-
ALJ.N	-	11	13	-	16	-	-	6	-	2	-	-	-	-	-	-	-	-	-
NTI.N	-	-	-	-	8	9	-	-	-	8	-	-	-	-	-	-	-	-	7
Average	**16**	**20**	**33**	**10**	**20**	**16**	**11**	**23**	**4**	**7**	**3**	**1**	**8**	**13**	**22**	**29**	**19**	**5**	**9**

Source: Company data, Wood Mackenzie, Deutsche Bank estimates

Figure 114: EBITDA Sensitivities to $1/bbl Change in Crude Prices 2013e (%)

	Brent	LLS	WTI	Midland	WTS	WCS	Maya	Mars	Eagle Ford	Bakken	Niob	Uinta	ANS	WC	Africa	ME	LatAm	FSU	Other Canadian
PSX.N	1.9%	1.1%	1.1%	0.0%	0.9%	0.9%	0.6%	0.7%	0.0%	0.2%	0.0%	0.0%	0.5%	1.2%	1.7%	0.8%	1.6%	0.3%	1.2%
MPC.N	0.0%	0.6%	2.1%	0.0%	1.0%	1.6%	0.6%	2.3%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.8%	2.6%	0.1%	0.0%	0.2%
VLO.N	1.1%	1.8%	1.0%	0.0%	0.5%	0.1%	1.0%	1.4%	0.6%	0.0%	0.0%	0.0%	0.1%	0.4%	1.9%	1.9%	1.5%	0.6%	0.0%
HFC.N	0.0%	0.0%	3.3%	1.5%	1.4%	0.7%	0.0%	0.0%	0.0%	0.1%	0.6%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
TSO.N	0.3%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%	2.8%	1.3%	0.0%	3.2%	3.1%	0.1%	1.2%	1.8%	0.4%	0.8%
CVI.N	0.0%	0.0%	3.2%	1.5%	2.2%	0.9%	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%
WNR.N	0.0%	0.0%	0.0%	5.6%	1.2%	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%
DK.N	0.0%	1.5%	4.0%	5.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%	0.0%	0.0%	0.0%
ALJ.N	0.0%	4.2%	5.0%	0.0%	6.3%	0.0%	0.0%	2.2%	0.0%	0.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
NTI.N	0.0%	0.0%	0.0%	0.0%	2.7%	3.0%	0.0%	0.0%	0.0%	2.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.3%
Average	**0.8%**	**0.9%**	**1.5%**	**0.5%**	**1.0%**	**0.8%**	**0.5%**	**1.1%**	**0.2%**	**0.3%**	**0.1%**	**0.0%**	**0.4%**	**0.6%**	**1.1%**	**1.4%**	**0.9%**	**0.2%**	**0.4%**

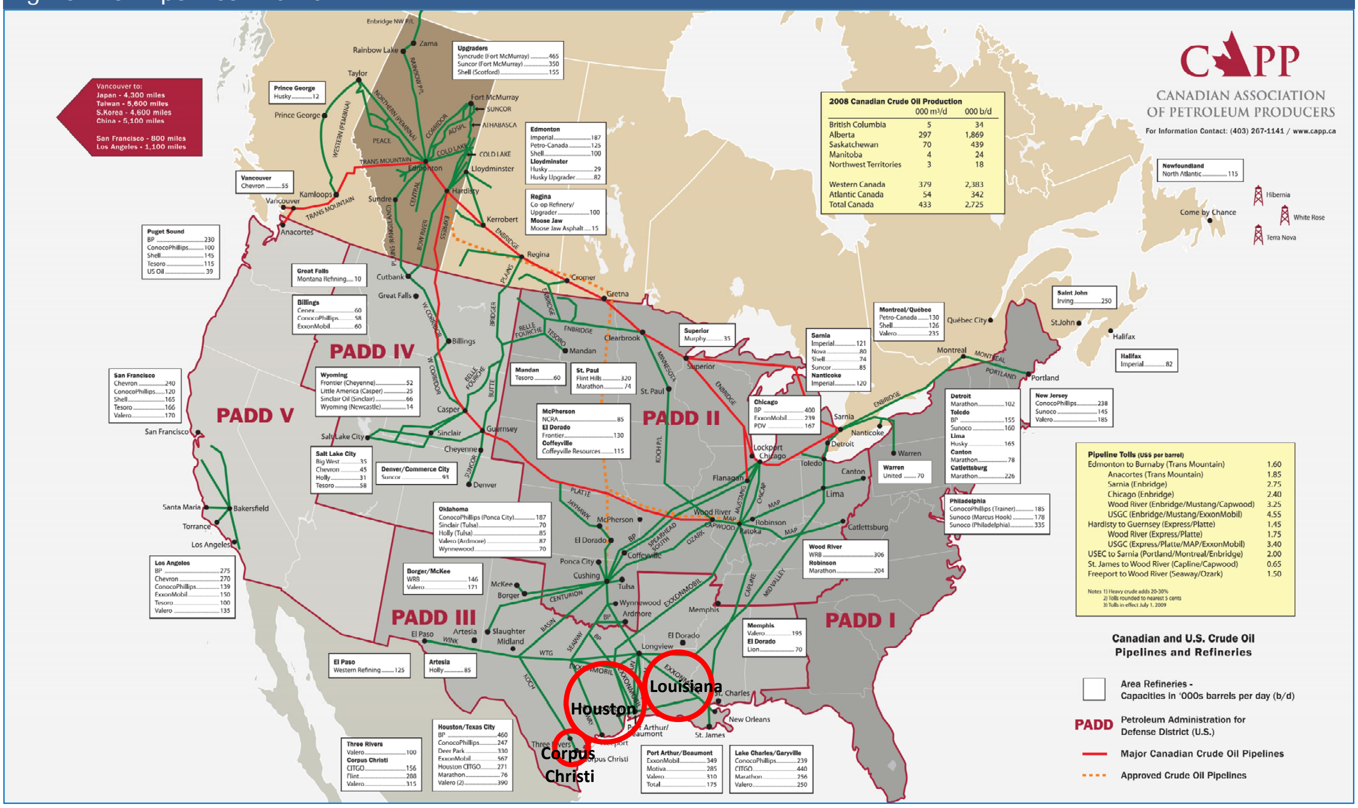
Source: Company data, Wood Mackenzie, Deutsche Bank estimates

Appendix A - Maps

North American pipeline map – mid-2012

This CAPP pipeline map will look quite a bit different by the end of 2014, with more than 20 new major and mid-sized pipelines going in service over the next 18 months or so.

Figure 115: Pipelines mid-2012



Source: CAPP, Deutsche Bank

Appendix B – Summary data for other refinery regions

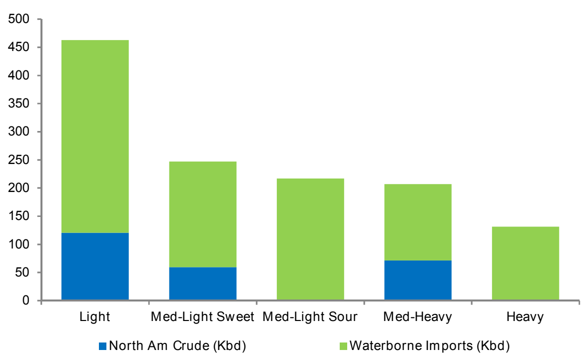
US East Coast

Figure 116: US East Coast refineries

Refinery	Operator	Cal Day Cap	Nelson Complex	WM Avg API	Coker Cap.
Bayway	PSX	238	9.00	34.7	0
Bradford	ARG	10	NA	NA	0
Delaware City	PBF	182	11.80	28.3	47
Newell	Ergon	20	NA	NA	0
Paulsboro NuStar	NuStar	70	NA	NA	0
Paulsboro PBF	PBF	160	13.33	31.5	27
Philadelphia	SUN	335	8.99	33.8	0
Trainer	DELTA	185	7.80	37.4	0
Warren	United	65	10.19	27.6	0
TOTAL		**1,265**			**96**

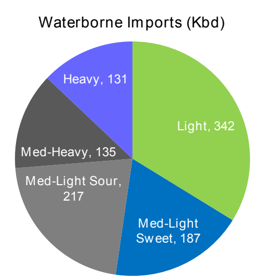
Source: Company data, Wood Mackenzie, EIA, various news sources, Deutsche Bank estimates

Figure 117: Estimated crude slate for region



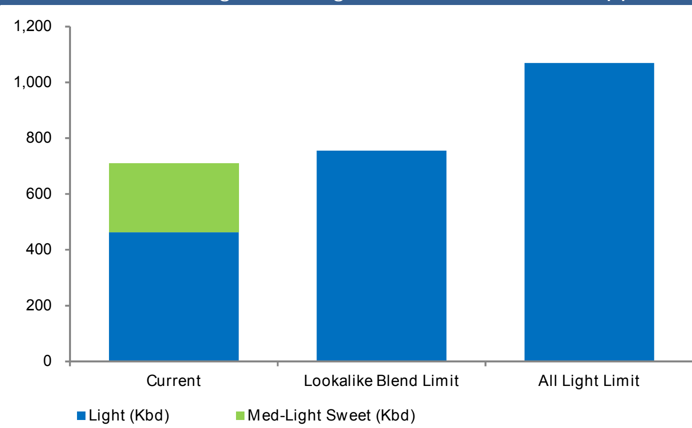
Source: Company data, Wood Mackenzie, EIA, various news sources, Deutsche Bank estimates

Figure 118: Estimated remaining waterborne imports



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

Figure 119: Estimated current light/med-light sweet & estimated upper limits for light



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

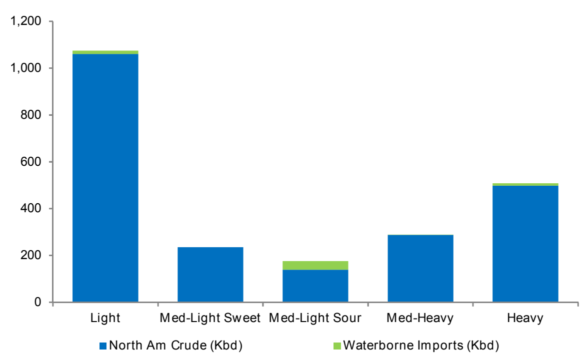
Chicagoland/Detroit/Ohio Valley

Figure 120: Chicagoland/Detroit/Ohio Valley refineries

Refinery	Operator	Cal Day Cap	Nelson Complex	WM Avg API	Coker Cap.
Canton	MPC	78	7.94	36.5	0
Catlettsburg	MPC	233	9.19	33.2	0
Detroit	MPC	120	6.91	30.8	0
Joliet	XOM	239	10.75	25.4	59
Lemont	Citgo	167	11.59	25.3	40
Lima	HSE	155	11.20	37.9	22
Mount Vernon	Coop	27	NA	NA	0
Robinson	MPC	206	10.93	34.5	29
Toledo BP	BP	131	9.52	29.0	34
Toledo PBF	PBF	160	10.73	36.4	0
Whiting	BP	405	9.79	33.7	37
Wood River	PSX	362	10.58	32.4	65
TOTAL		**2,283**			**286**

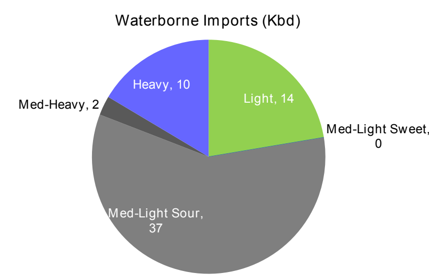
Source: Company data, Wood Mackenzie, EIA, various news sources, Deutsche Bank estimates

Figure 121: Estimated crude slate for region



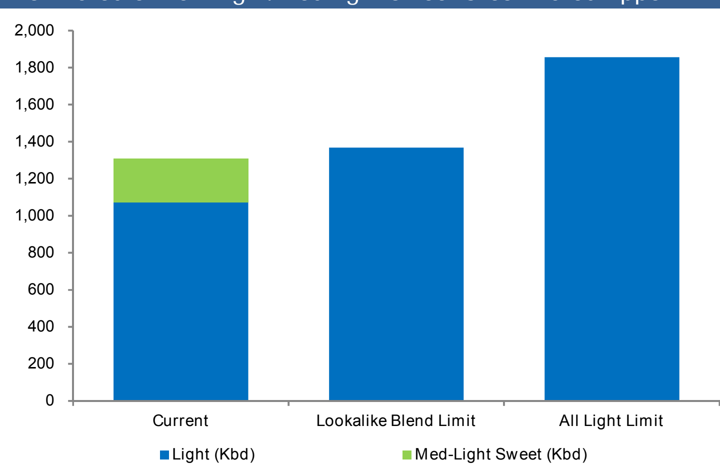
Source: Company data, Wood Mackenzie, EIA, various news sources, Deutsche Bank estimates

Figure 122: Estimated remaining waterborne imports



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

Figure 123: Estimated current light/med-light sweet & estimated upper limits for light



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

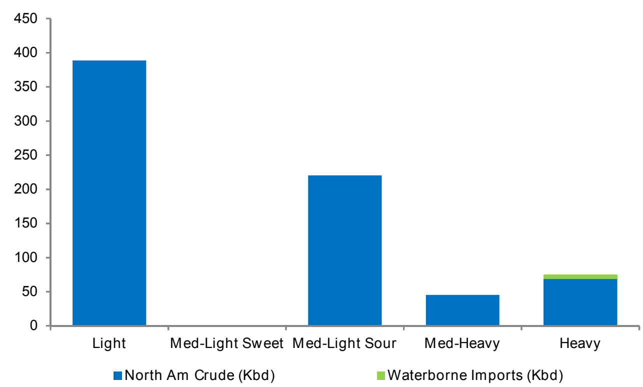
"Group 3" Mid-Con

Figure 124: "Group 3" Mid-Con refineries

Refinery	Operator	Cal Day Cap	Nelson Complex	WM Avg API	Coker Cap.
Ardmore	VLO	85	8.70	31.6	0
Coffeyville	CVR	115	9.32	31.0	25
El Dorado (KS)	HFC	135	10.42	31.7	19
McPherson	NCRA	86	14.57	32.4	22
Ponca City	PSX	198	8.74	34.0	28
Tulsa	HFC	125	10.89	38.6	11
Wynnewood	CVR	70	8.95	38.0	0
TOTAL		**814**			**105**

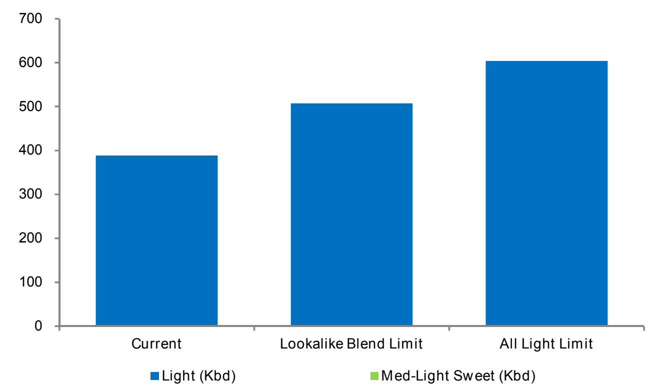
Source: Company data, Wood Mackenzie, EIA, various news sources, Deutsche Bank estimates

Figure 125: Estimated crude slate for region



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

Figure 126: Estimated light crude limits



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

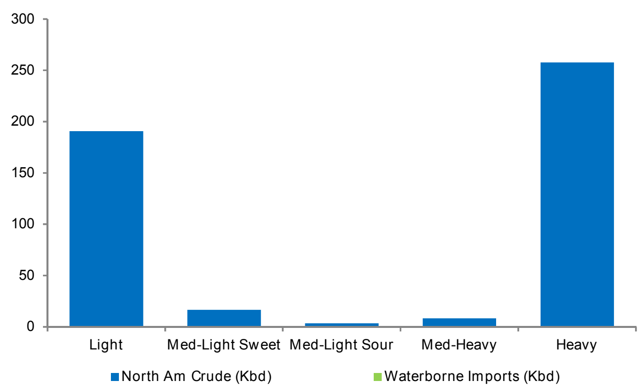
US North Central Mid-Con

Figure 127: North Central Mid-Con refineries

Refinery	Operator	Cal Day Cap	Nelson Complex	WM Avg API	Coker Cap.
Mandan	TSO	68	6.92	40.0	0
Pine Bend	Flint Hills	277	8.91	24.5	67
St. Paul	NTI	87	9.18	30.6	0
Superior	CLMT	45	8.69	31.0	0
TOTAL		**477**			**67**

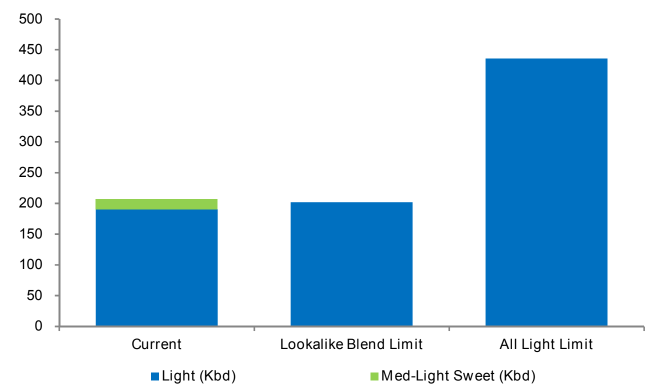
Source: Company data, Wood Mackenzie, EIA, various news sources, Deutsche Bank estimates

Figure 128: Estimated crude slate for region



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

Figure 129: Estimated light crude limits



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

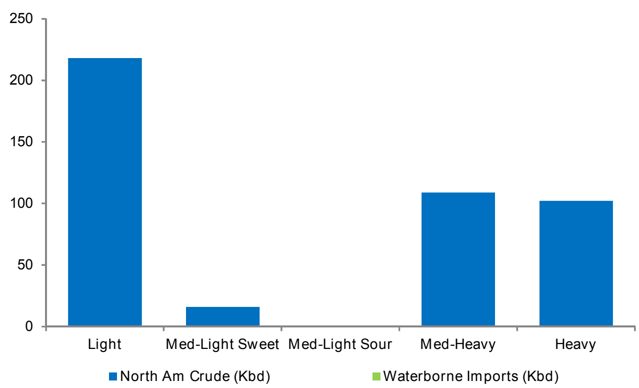
US Rockies

Figure 130: US Rockies refineries

Refinery	Operator	Cal Day Cap	Nelson Complex	WM Avg API	Coker Cap.
Billings PSX	PSX	58	11.69	28.6	22
Billings XOM	XOM	60	9.54	26.3	10
Cheyenne	HFC	52	9.09	34.3	15
Commerce City	SU	93	5.79	35.8	0
Great Falls	Connacher	10	NA	25.6	0
Laurel	CHS	60	9.14	24.0	15
Little America	Sinclair	25	NA	26.6	0
Newcastle	Black Elk	14	NA	26.6	0
Sinclair	Sinclair	74	8.92	36.8	18
TOTAL		**445**			**80**

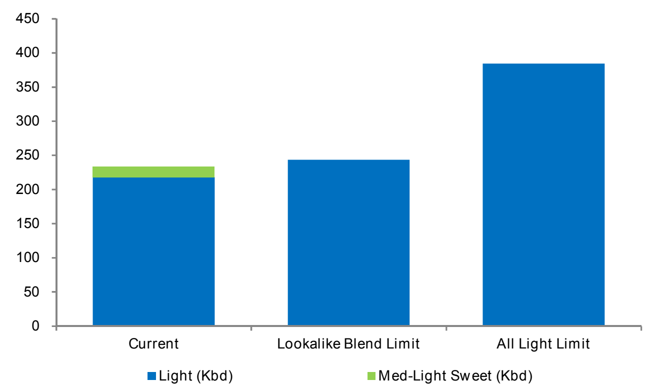
Source: Company data, Wood Mackenzie, EIA, various news sources, Deutsche Bank estimates

Figure 131: Estimated crude slate for region



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

Figure 132: Estimated light crude limits



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

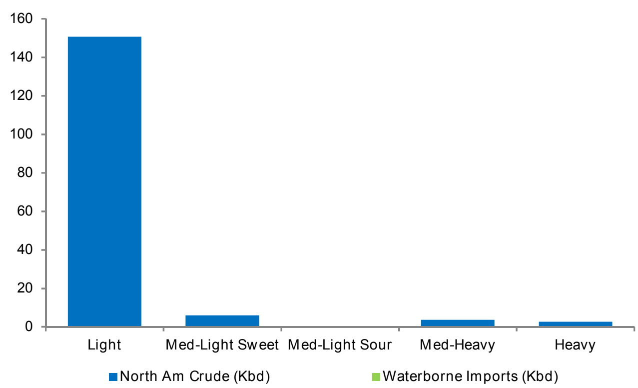
Salt Lake City

Figure 133: Salt Lake City refineries

Refinery	Operator	Cal Day Cap	Nelson Complex	WM Avg API	Coker Cap.
SLC Big West	Big West	29	9.22	41.6	0
Salt Lake City CVX	CVX	45	9.26	38.7	9
Salt Lake City TSO	TSO	58	6.78	41.5	0
Woods Cross	HFC	31	12.50	40.0	0
TOTAL		163			9

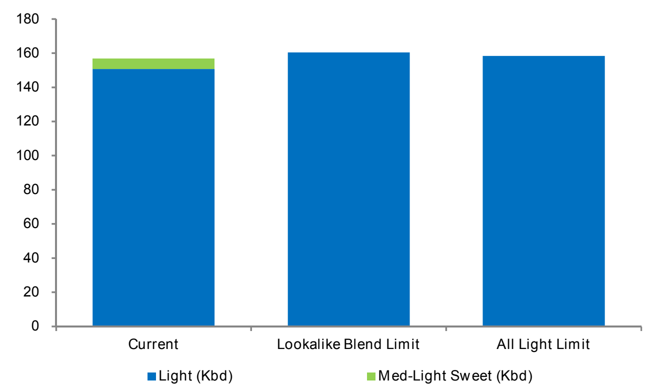
Source: Company data, Wood Mackenzie, EIA, various news sources, Deutsche Bank estimates

Figure 134: Estimated crude slate for region



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

Figure 135: Estimated light crude limits



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

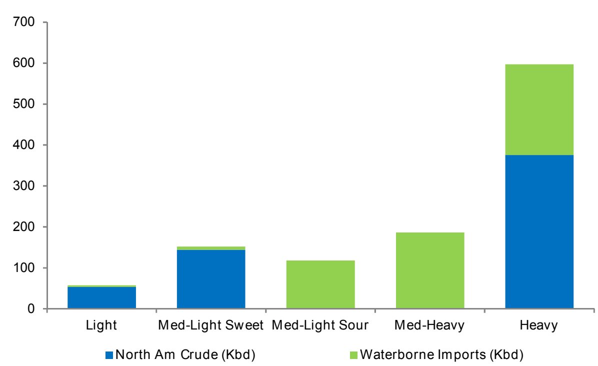
Southern California

Figure 136: Southern California refineries

Refinery	Operator	Cal Day Cap	Nelson Complex	WM Avg API	Coker Cap.
Bakersfield Kern	Kern	26	NA	30.6	0
Bakersfield SJR	SJR	15	NA	30.6	0
Carson	TSO	253	11.22	30.9	67
El Segundo	CVX	273	11.32	23.4	78
Los Angeles	PSX	139	12.67	18.9	51
Torrance	XOM	150	11.49	17.5	53
Wilmington TSO	TSO	94	13.50	19.5	42
Wilmington VLO	VLO	78	14.44	20.2	28
TOTAL		1,028			319

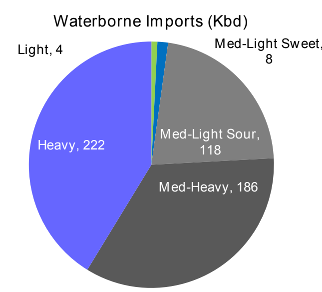
Source: Company data, Wood Mackenzie, EIA, various news sources, Deutsche Bank estimates

Figure 137: Estimated crude slate for region



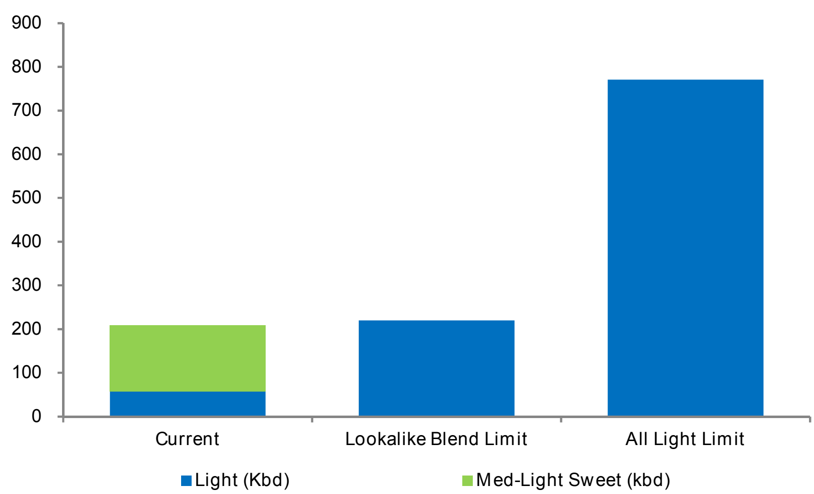
Source: Company data, Wood Mackenzie, EIA, various news sources, Deutsche Bank estimates

Figure 138: Estimated remaining waterborne imports



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

Figure 139: Estimated current light/med-light sweet & estimated upper limits for light



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

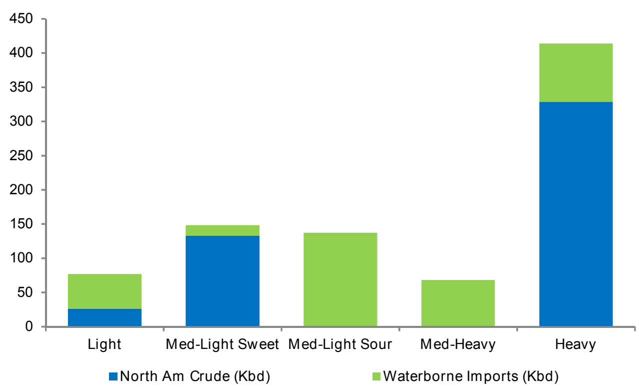
Northern California

Figure 140: Northern California refineries

Refinery	Operator	Cal Day Cap	Nelson Complex	WM Avg API	Coker Cap.
Benicia	VLO	132	12.30	26.7	28
Golden Eagle	TSO	166	12.07	20.5	53
Martinez	RDS	156	12.26	17.5	49
Richmond	CVX	245	22.94	33.4	0
Rodeo/SF	PSX	120	11.86	16.0	59
TOTAL		**820**			**189**

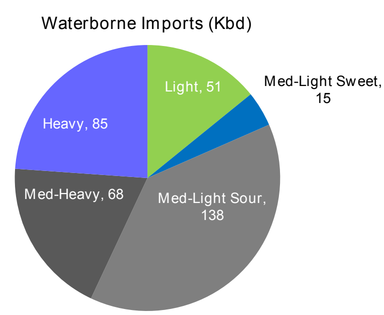
Source: Company data, Wood Mackenzie, EIA, various news sources, Deutsche Bank estimates

Figure 141: Estimated crude slate for region



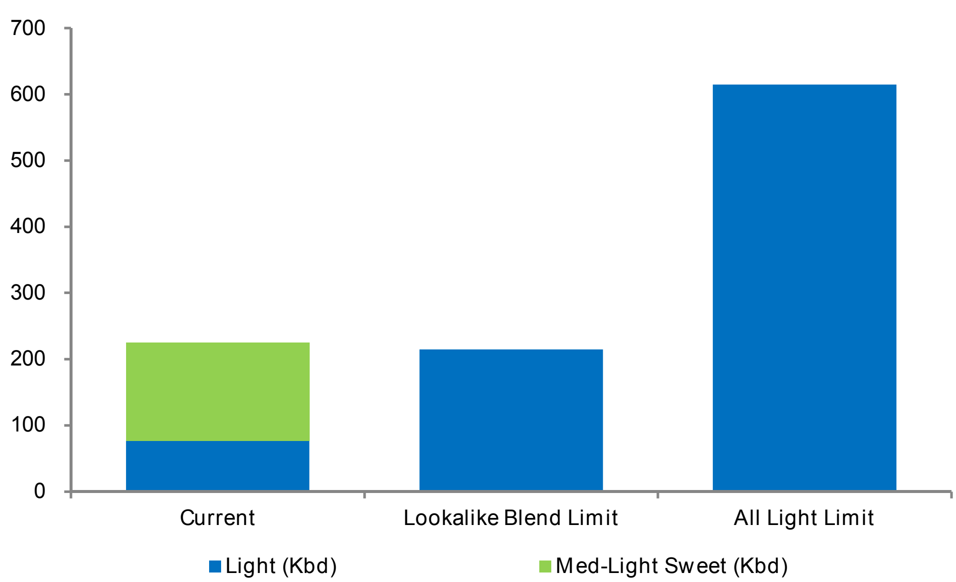
Source: Company data, Wood Mackenzie, EIA, various news sources, Deutsche Bank estimates

Figure 142: Estimated remaining waterborne imports



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

Figure 143: Estimated current light/med-light sweet & estimated upper limits for light



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

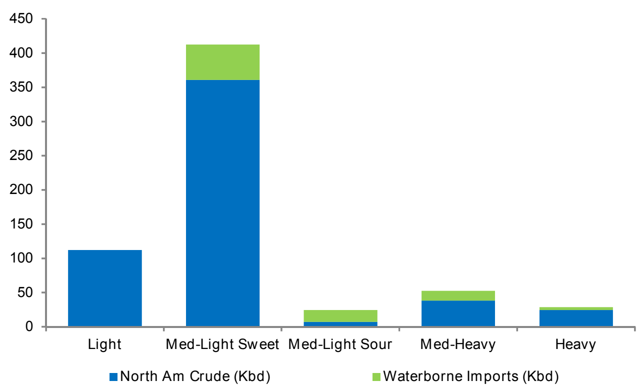
Puget Sound

Figure 144: Puget Sound refineries

Refinery	Operator	Cal Day Cap	Nelson Complex	WM Avg API	Coker Cap.
Anacortes	TSO	120	9.14	34.9	0
Cherry Point	BP	225	9.68	31.3	58
Ferndale	PSX	100	7.49	32.8	0
Puget Sound	RDS	145	9.63	31.7	25
Tacoma	USOR	39	5.31	26.4	0
TOTAL		**629**			**83**

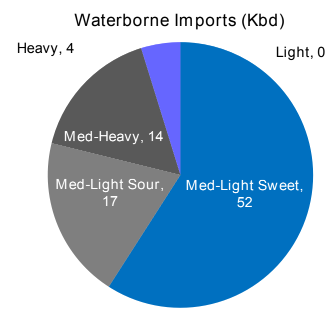
Source: Company data, Wood Mackenzie, EIA, various news sources, Deutsche Bank estimates

Figure 145: Estimated crude slate for region



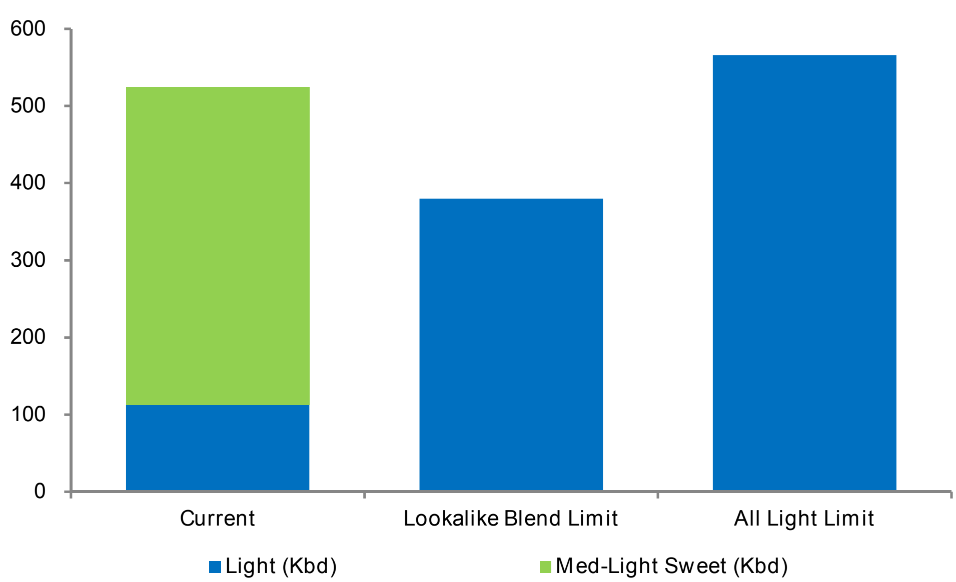
Source: Company data, Wood Mackenzie, EIA, various news sources, Deutsche Bank estimates

Figure 146: Estimated remaining waterborne imports



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

Figure 147: Estimated current light/med-light sweet & estimated upper limits for light



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

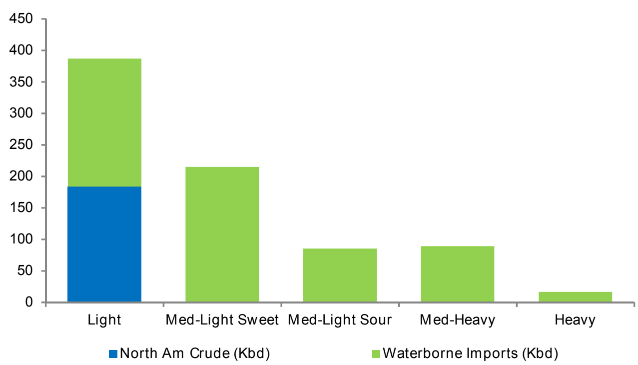
Eastern Canada

Figure 148: Eastern Canada refineries

Refinery	Operator	Cal Day Cap	Nelson Complex	WM Avg API	Coker Cap.
Come By Chance	KNOC	109	6.99	32.5	0
Dartmouth	IMO	78	7.34	34.7	0
Jean Gaulin	VLO	247	7.83	39.0	0
Montreal SU	SU	123	10.03	37.6	0
Montreal RDS	RDS	0	NA	NA	0
St. John	Irving	237	7.91	33.2	0
TOTAL		794			0

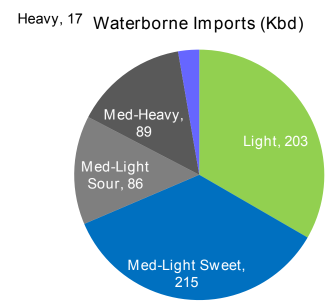
Source: Company data, Wood Mackenzie, EIA, various news sources, Deutsche Bank estimates

Figure 149: Estimated crude slate for region



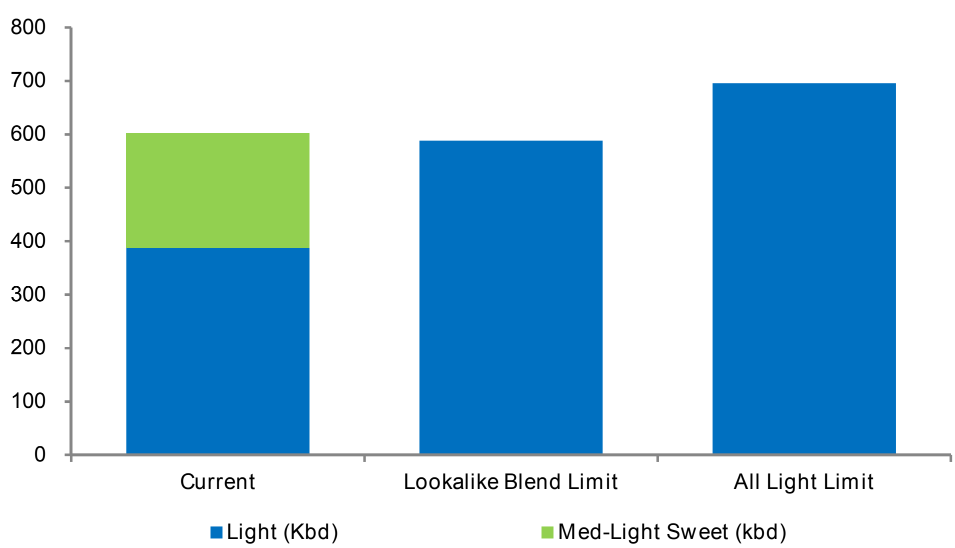
Source: Company data, Wood Mackenzie, EIA, various news sources, Deutsche Bank estimates

Figure 150: Estimated remaining waterborne imports



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

Figure 151: Estimated current light/med-light sweet & estimated upper limits for light



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

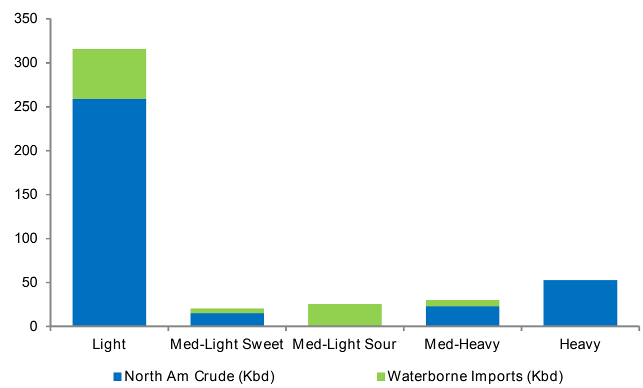
Sarnia

Figure 152: Sarnia/Ontario refineries

Refinery	Operator	Cal Day Cap	Nelson Complex	WM Avg API	Coker Cap.
Corunna	Nova	76	NA	32.4	0
Nanticoke	IMO	106	9.47	35.3	0
Sarnia IMO	IMO	114	11.46	31.2	25
Sarnia RDS	RDS	68	7.69	35.6	0
Sarnia SU	SU	80	10.62	30.0	0
TOTAL		**445**			**25**

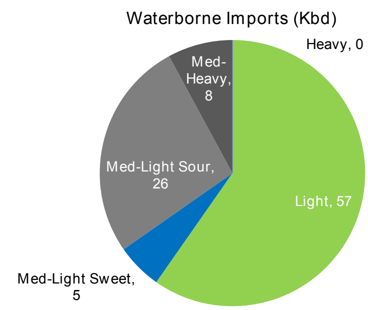
Source: Company data, Wood Mackenzie, EIA, various news sources, Deutsche Bank estimates

Figure 153: Estimated crude slate for region



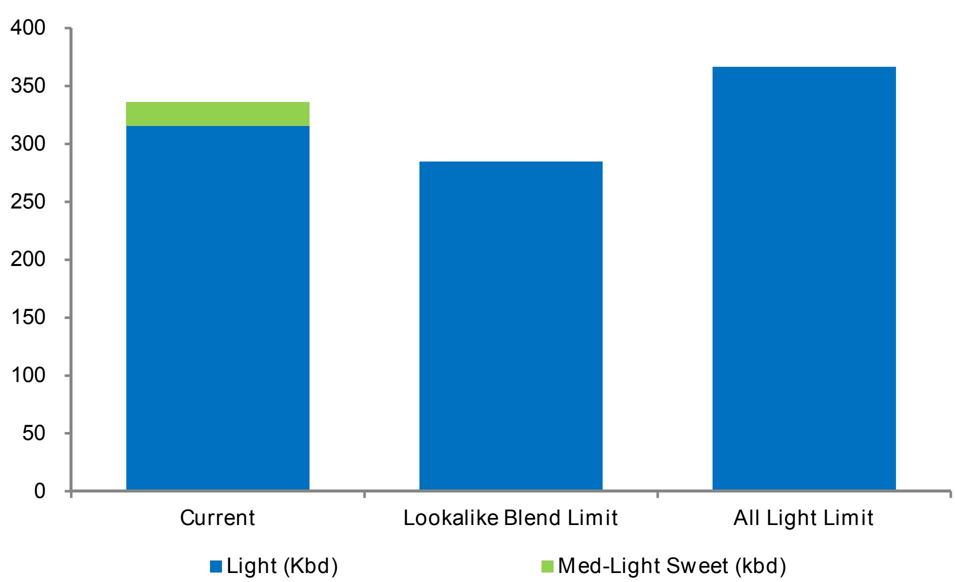
Source: Company data, Wood Mackenzie, EIA, various news sources, Deutsche Bank estimates

Figure 154: Estimated remaining waterborne imports



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

Figure 155: Estimated current light/med-light sweet & estimated upper limits for light



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

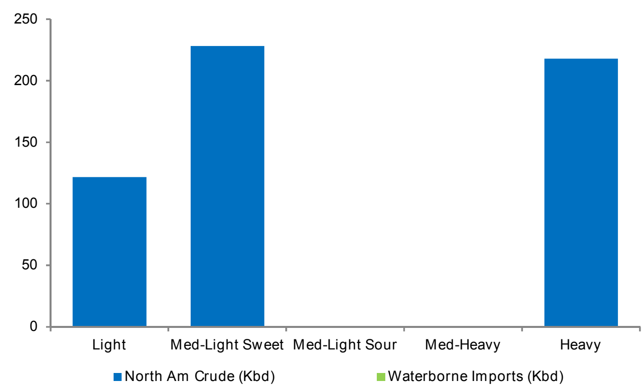
Western Canada

Figure 156: Western Canadian refineries

Refinery	Operator	Cal Day Cap	Nelson Complex	WM Avg API	Coker Cap.
Prince George	HSE	11	NA	NA	0
Edmonton IMO	IMO	177	8.74	31.0	0
Edmonton SU	SU	128	8.47	21.0	15
Lloydminster	HSE	24	NA	20.0	8
Regina	Coop	95	9.55	24.4	11
Scotford	RDS	133	6.74	33.0	0
TOTAL		568			33

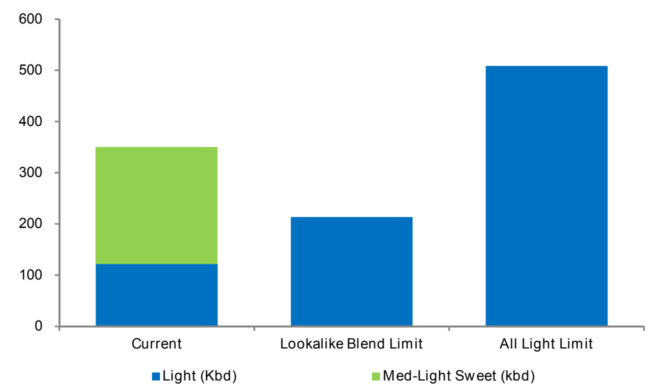
Source: Company data, Wood Mackenzie, EIA, various news sources, Deutsche Bank estimates

Figure 157: Estimated crude slate for region



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

Figure 158: Estimated light crude limits



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

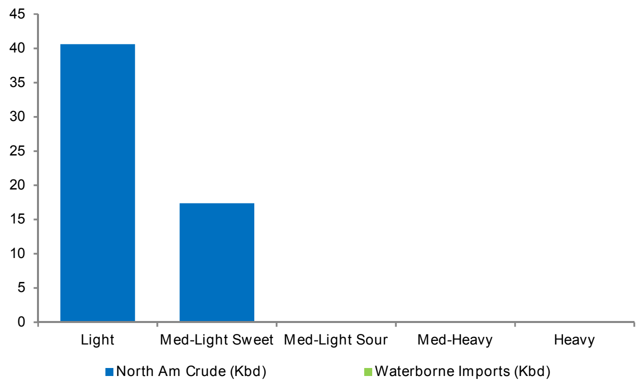
Pacific Canada

Figure 159: US East Coast refineries

Refinery	Operator	Cal Day Cap	Nelson Complex	WM Avg API	Coker Cap.
Burnaby	CVX	58	8.86	34.5	0
TOTAL		**58**			**0**

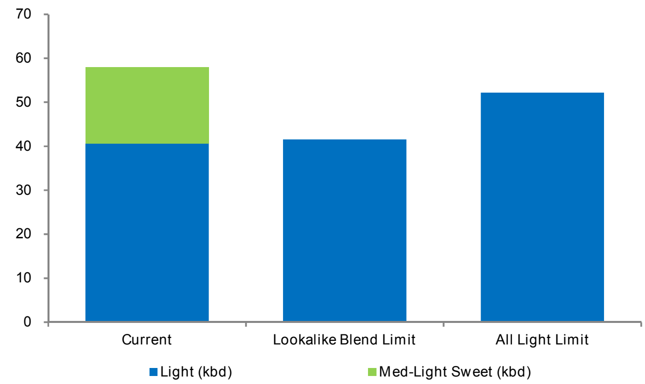
Source: Company data, Wood Mackenzie, EIA, various news sources, Deutsche Bank estimates

Figure 160: Estimated crude slate for region



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

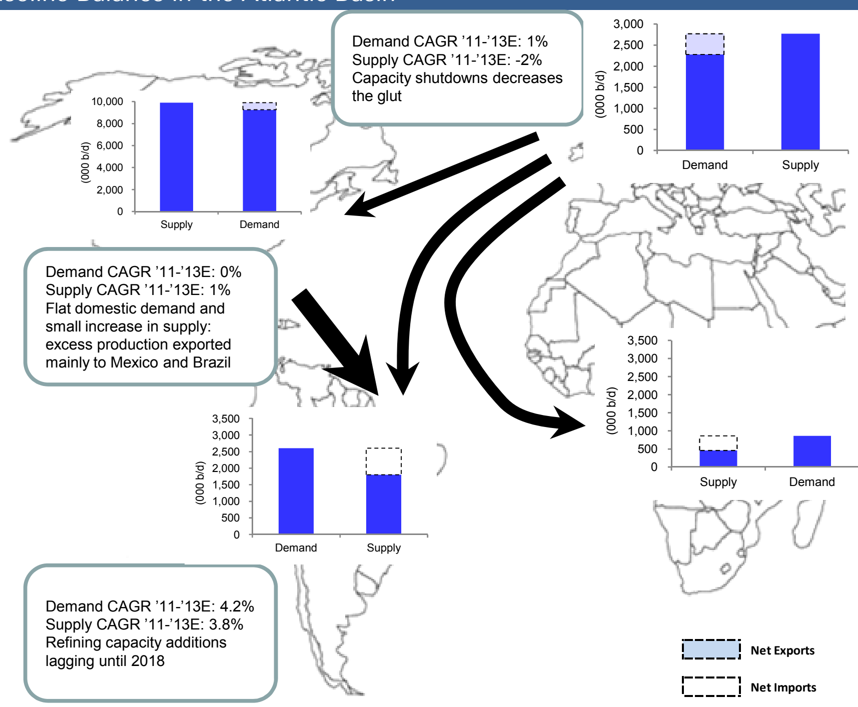
Figure 161: Estimated remaining waterborne imports



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

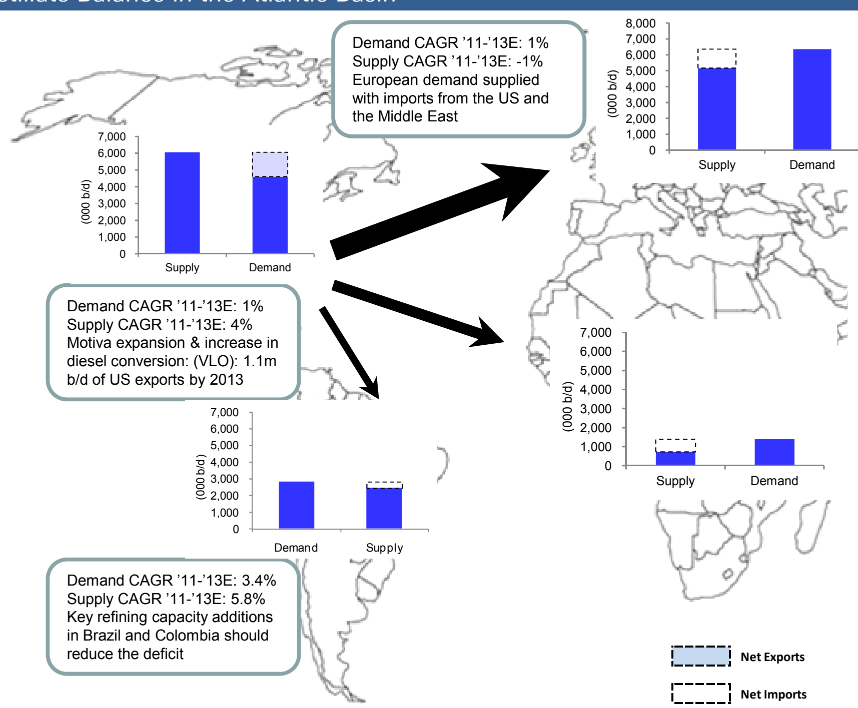
Appendix C – Atlantic Basin Product Trade

Figure 162: 2013E Gasoline Balance in the Atlantic Basin



Source: Deutsche Bank

Figure 163: 2013E Distillate Balance in the Atlantic Basin



Source: Deutsche Bank

Appendix 1

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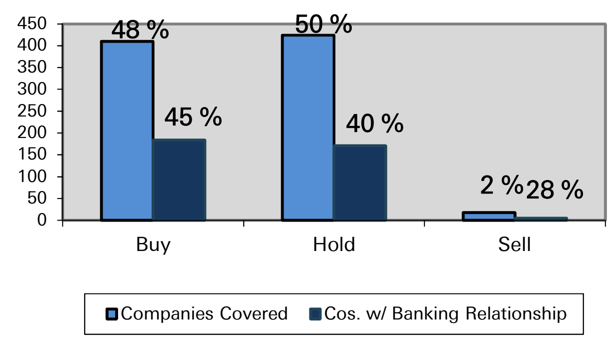
Equity rating key

Buy: Based on a current 12- month view of total share-holder return (TSR = percentage change in share price from current price to projected target price plus pro-jected dividend yield) , we recommend that investors buy the stock.
Sell: Based on a current 12-month view of total share-holder return, we recommend that investors sell the stock
Hold: We take a neutral view on the stock 12-months out and, based on this time horizon, do not recommend either a Buy or Sell.
Notes:

1. Newly issued research recommendations and target prices always supersede previously published research.
2. Ratings definitions prior to 27 January, 2007 were:

   Buy: Expected total return (including dividends) of 10% or more over a 12-month period
   Hold: Expected total return (including dividends) between -10% and 10% over a 12-month period
   Sell: Expected total return (including dividends) of -10% or worse over a 12-month period

Equity rating dispersion and banking relationships



North American Universe

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