21 October 2013 | 38 pages

Global

Exit Strategies

The beginning of the end of stranded western Canadian oil? WCS prices can strengthen versus WTI, Maya, Brent from end-2014

■ Commodities

- **Western Canadian crude oil has suffered from massive discounts to global prices as robust oil sands production growth has overwhelmed legacy pipeline infrastructure – but this is set to change.** The closely watched debottlenecking of the Cushing crude glut has strengthened WTI, benefiting Canadian prices. But real relief for Western Canadian Select (WCS) comes 2H'14 and onwards as other pipelines boost access to the US Gulf Coast (USGC).
- **Until now, the growth in Canadian oil production has been absorbed by the US Midwest, but due to bottlenecks south of Chicago, the USGC has only managed to receive a small amount.** The complex refineries of the USGC are a "natural" market for heavy Canadian oil, but its 8.6-m b/d of refinery capacity has not taken more than ~150-k b/d worth. Meanwhile, the US Midwest (PADD II) region received 1.8-m b/d of Canadian oil in 1Q'13, up 0.7-m b/d since 1Q'09.
- **But new options are coming thick and fast.** A step-up of heavy crude demand at BP Whiting in 4Q'13 helps absorb a year of Canadian production growth. The Flanagan South pipeline (+585-k b/d, 2H'14) from the Chicago area to Cushing, Eastern Gulf Crude Access from the Chicago area to St James, LA (420-660-k b/d, 2015?) and Keystone XL from Alberta to Cushing (700-830-k b/d, 2016?) allow progressively more WCS to access the USGC. These outlets mean that western Canadian prices can converge to a transport cost differential to the USGC, or even less, if take-or-pay is a factor. Maya-WCS could come in to $7-10/bbl from 2H'14 from current ~$20-25 levels, and stay narrow as other pipelines are built. Refinery maintenance or outages could still widen Maya-WCS at times.
- **Without Keystone XL, 2016-17 could be a challenging period – until Energy East.** Maya-WCS could need to widen to over rail costs of some $20 during that time if pipeline capacity is insufficient. But "Energy East", a 1.1-m b/d pipeline from Alberta to eastern Canada, should change the game yet again, allowing access to the Atlantic but also the Pacific Basin via the Panama Canal. This would end a long period of Canada as a captive supplier to the US. Westward pipelines remain doubtful despite Canadian government promises of a build-out starting in two years.
- **Waves of Canadian heavy crude oil arriving on the USGC can both complement and compete with the growing abundance of light sweet crude in the region.** Of the USGC's 4-m b/d of crude imports, some ~900-k b/d is medium crude, partially substitutable by blending light and heavy. The USGC's 2-m b/d of heavy imports could be progressively pushed out, although term volumes could be sticky. Later, heavy-to-light switching might be needed, which could be incentivized by light-heavy differentials narrowing to $6-9. But if Mayan prices weaken, USGC light sweet crude prices may need to fall further versus Brent to keep this heavy-light switching economic, posing a widening risk to Brent-LLS from 2015-17.

Eric G Lee
+1-212-723-1474
eric.g.lee@citi.com

Edward L Morse
+1-212-723-3871
ed.morse@citi.com

Aakash Doshi
+1-212-723-3872
aakash.doshi@citi.com

Seth M Kleinman
+44-20-7986-7084
seth.kleinman@citi.com

Christopher J Main
+44-20-3569-4309
chris.main@citi.com

Xing Xing
+1-212-723-3612
xing.xing@citi.com

Anthony Yuen
+1-212-723-1477
anthony.yuen@citi.com

Figure 1. Outlook for selected North American crude price differentials ($/bbl)

	4Q'13	2014	2015	2016
Brent-LLS	2	2	4	4
LLS-WTI	1	0	1	2
LLS-Maya	8	8	7	7
Maya-WCS	20	9	7	11
WTI-WCS	27	16	13	16

Source: Citi Research

The Beginning of the End?

Canada is one of the fastest growing oil producers in the world, having grown around 200-k b/d per year for the last few years and can continue growing at this pace for the next decade and beyond. This report looks at Canada's oil production prospects – particularly driven by heavy sour bitumen blends a well as light sweet shale oil – and its ability to reach key markets such as the US Gulf Coast and the Chicago area, as well as future prospects for export on the US Gulf Coast, Canadian east coast and the Canadian west coast. The competition for refinery demand on the US Gulf Coast and the balance of switching between burgeoning WTI/LLS-like and WCS-like crude are also considered, with the growing arrival of heavy volumes to the Gulf Coast even as a light sweet crude glut continues to loom there. This ability depends on the outlook for pipeline build-out in North America, particularly the Keystone XL pipeline, fraught with political opposition, as well as the growing use of oil transportation by rail. Rail is becoming an important marginal transportation route for crude oil out of Canada, with many proposals and plans hitting the news ticker on a regular basis. However, the sector is still reeling from the recent tragic railcar explosion in Lac-Megantic, Quebec. A key eastward pipeline in 2017 could allow access to the Atlantic Basin, and with an expansion of the Panama Canal, the Pacific Basin too, providing another waterborne outlet other than the US Gulf Coast. In 2018, westward pipelines may yet be expanded and built, allowing more direct access to the fast-growing markets of the Asia Pacific region.

The production, pipelines, rail and refinery outlook provides much of the fundamental analysis that informs price outlooks on syncrude and WCS price benchmarks, versus WTI, LLS, Mars and Maya. Other price markers at Hardisty/Edmonton such as Mixed Sweet Blend to Cold Lake and others are not considered in detail, as their dynamics should be closely related to syncrude (on the light sweet side) or WCS (on the heavy sour side). Offshore east coast crude grades Hibernia, Terra Nova and White Rose are not discussed; briefly, the offshore Hebron project can add some supply growth from 2017-18 amidst wider declines.

Overall, this report finds that new pipelines options are coming thick and fast. This can allow the Maya-WCS price differential to collapse to transport differentials or narrower, end-2014. But without Keystone XL, 2016-17 could see the WCS price spread between Hardisty and Chicago blow out, syncrude and Bakken in sympathy too, to price for rail flows, though this would be temporary, with the 2017 Energy East pipeline easing infrastructure bottlenecks for a while.

WCS and WTI become linked through a web of relationships – WCS reconnects with Maya as transport bottlenecks are worked out, while LLS-Maya balances on the USGC given refinery choices of crude slate

Although Maya should be depressed by waves of WCS arriving on the US Gulf Coast, it is a waterborne crude that is influenced by other, global factors. Amongst these factors is the rise of oil production in the US Gulf of Mexico, which saw prospects for growth temporarily halted in the wake of the BP Deepwater Horizon well blowout and oil spill; permitting and drilling activity in the Gulf of Mexico have risen to above pre-disaster levels. And Mexican production could begin to recover in the medium-term given the energy reforms taking place there (with discussion in the August 12, 2013 report, "Mexico Macro View: Let There Be Oil"). Colombia - and the wildcard, Venezuela – could provide further heavy, regional supply growth. Importantly, residual fuel oil takes a hit in 2015 as the ECA 0.1% sulfur limit for bunker fuel comes into effect on January 1. But rapid refinery capacity build-out in Asia and Middle East adds significant heavy crude demand.

As discussed in this report, WCS should arrive on the Gulf Coast in chunks in 2H'14 with Flanagan South (585-k b/d), 2015 with the proposed Eastern Gulf Access (420-k b/d), 2016 with Keystone XL (700-830-k b/d), after which 2017 should open up options to the eastern coast. 2018 could open up options to the western coast of Canada, allowing access to Asian markets. WCS and Maya should thus collapse to transport differentials by 2H'14, although the Southern Access

pipeline may be the weakest link that keeps a partial bottleneck until 2015. But if take-or-pay contracts drive price differentials, Cushing could be parity with the USGC, while Chicago could be parity with Cushing and the USGC too.

Without Keystone XL, there could be a hump period from 2016-17 (though Keystone XL is assumed to be complete by 2016, if approved) during which time the Hardisty-Chicago leg of the pipeline could be severely strained, causing WCS to blow back out to over $20 versus Maya to incentivize sufficient rail flows of railbit and likely, also dilbit. But the Energy East pipeline should more than remedy this in 2017.

WTI-WCS becomes linked by their respective relationships with LLS-Maya on the USGC, with the light-heavy differential facing gradual compression from organic growth of shale oil and the growth of light-heavy blending to push out medium crude imports, versus the widening effect of lumpy additions of heavy crude oil reaching the Gulf Coast. A question is how much this impacts Brent and Maya, both waterborne crudes; with limited exportability and a scramble to make use of cheap local hydrocarbons, US Gulf Coast light crude values may be challenged from 2015 onwards. The discussion on cushions has evolved as follows.

The remaining light sweet crude imports on the USGC should be able to be pushed out at current Brent-LLS differentials. There is some 100-k b/d left at July 2013. Light sour and mediums account for some 700-k b/d and 900-k b/d respectively. Heavy crude accounts for 2.1-m b/d.

Light sweet crude can be exported to eastern Canada with Brent-LLS at around parity, as both the US Gulf Coast and the North Sea require some $1-2 to ship to eastern Canada. Eastern Canada remains a 600-700-k b/d import market (mostly light sweet), though the Line 9 reversal can cut 300-k b/d out of this in 2H'14.

Light-heavy blending could start pushing out the 900-k b/d of medium, depressing medium prices versus both light and heavy; this is a cushion of ~300-k b/d of light crude and ~600-k b/d of heavy crude, which could strengthen Maya versus Mars and LLS. Light-heavy differentials could narrow.

As LLS depresses and Maya strengthens to compress the light-heavy differential, heavy refiners could add more light volumes to their crude slate, even if throughput and yields worsen as a result. The estimated switching point of LLS-Maya would be $7-9 to move a 30:70 light-heavy crude slate to 40:60, even with some suffering of light and middle distillate yields from running light crude in a heavy tower. At LLS-Maya of $5-7, it could make sense to switch from 30:70 light-heavy to 100% light in a heavy refinery, even with worse light and middle distillate yields; note that economics are helped by not idling downstream units, as VGO and residual fuel oil can be bought from the market to run in them. If, in the aggregate, or exogenously, these prices rise, this could mean LLS-Maya needs to be even tighter to incentivize switching. The 30:70 to 40:60 switch is a 10% increase in light demand in the heavy refineries on the US Gulf Coast, potentially some 300-k b/d. The 30:70 to 100:0 switch is a 70% increase in light demand in the same set of refiners, or potentially some >2-m b/d; this however is the extreme case. This 0.3-2.1-m b/d of potential switching – admittedly a wide range – may require a relatively narrow LLS-Maya differential.

At Brent-LLS of $3-6, Jones Act vessels can be brought into play to take USGC light sweet crude to the US East Coast, to replace light sweet imports there of ~500-k b/d. But this import market is also being increasingly replaced by railed crude from the Bakken, and may thus erode over time.

The TransCanada Energy East pipeline, expected 2017, changes the game again. With pipeline tariffs potentially in the $6-8 range, WCS and syncrude would have another way to reach waterborne markets, and not be dependent on the US Gulf Coast. Its 1.1-m b/d of pipeline capacity would add many years of corresponding western Canadian production growth. Given the east coast of Canada is reached before the west coast, and that more light volumes may flow eastwards, this should bolster Atlantic Basin crude benchmarks. Citi's initial assessment of the potential impacts of the Energy East pipeline is in the August 2, 2013 report, "West Meets East: New Pipelines from Canada, Russia, likely to reshape global oil price benchmarks" (Edward Morse, Eric G. Lee, et al). Westward pipelines, if approved, could provide even better netbacks for Canadian producers and see Canadian crudes challenge Russian supply in the Pacific Basin, and pressure Oman/Dubai prices in the region.

These developments should mean that a tough period for Canadian producers and corresponding provincial economies should ease as realized prices for producers (particularly WCS prices) improve significantly from 2H'14 onwards. While the non-approval of the Keystone XL pipeline could cause Canadian crude prices to fall in value versus WTI and waterborne crudes like Maya and Brent, this could be limited to a two-to-three year hump period after which the Energy East pipeline could not only allow these infrastructure bottleneck discounts to dissipate, but also allow Canada to diversify its export destinations away from the US, to which Canadian oil producers have been captive suppliers. The longer-term production outlook should not be too affected by this hump period, whether it turns out to be shorter (restricted to between now and 2014) or longer (from now through to 2017); the longer-term price risk really comes from global oil prices easing to a $70-90 range by the end of this decade in Citi's view, rather than short-term infrastructure bottlenecks.

Breaking bottlenecks

Massive resource potential, fast production growth… but stranded

The WCS discount to WTI has fluctuated in a progressively wider band since 2009, at $5-10 at the narrowest, and hitting ever wider discounts of $31 in 2010, $33 in 2011, $36 in 1Q'12 and $42 at end-2012 to early 2013 (see Figure 3). With WTI also at significant discounts to Brent, this meant WCS saw as much as a $65 discount versus Brent in December 2012. But given significant pipeline debottlenecking in the US midcontinent, the WTI discount to Brent came in from over $20 in 1Q'13 to parity in July 2013, and back at the $3-5 level by September 2013. (It has recently moved back out to $8-9 as refiners engage in seasonal maintenance, but as this comes back and the southern leg of Keystone XL begins line fill and starts up, this should narrow again.) This narrowing has helped WCS move back into the $20-30/bbl range since 2Q'13, although it had tested $55 below Brent in 1Q'12 and a low of $65 below Brent in 4Q'12.

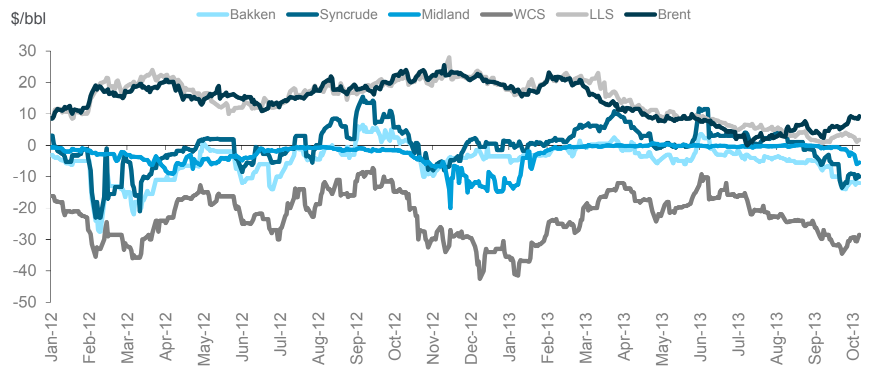
Figure 2. Outlook for selected North American price differentials ($/bbl, 4Q'13-2016)

	4Q'13	1Q'14	2Q'14	3Q'14	4Q'14	2015	2016
WCS Chicago-WCS	6	5	4	4	4	4	4
WCS Cushing-WCS	15	10	10	7	7	7	7
Maya-WCS Cushing	5	0	0	0	0	0	4
Maya-WCS	20	10	10	7	7	7	11
LLS-WTI	1	0	0	0	0	1	2
Brent-LLS	2	2	2	2	3	4	4
LLS-Maya	8	8	8	8	7	7	7
WTI-WCS	27	18	18	15	14	13	16
Brent	110	110	105	110	105	103	98
LLS	108	108	103	108	102	99	94
WTI	107	108	103	108	102	98	92
Maya	100	100	95	100	95	92	87
WCS	80	90	85	93	88	85	76

Source: Citi Research

Syncrude – the light sweet crude oil created by upgrading Canadian oil sands bitumen or conventional heavy crude oil – had traded in a +/- $5 differential to WTI before 2010, but spiked up in 2011 to $10-15 above WTI as the CNRL Horizon upgrader suffered an outage lasting from January to August 2011 due to a fire. Since then prices tested lows of over $20 below WTI in 1Q'12 as Bakken production surged and Cushing stocks ballooned from below 30-m bbls to over 45-m bbls by May 2012. The reversal of the Seaway pipeline in May, along with high refinery runs, helped keep Cushing stocks around 45-50-m bbls over 2H'12, though stocks rose to over 50-m bbls in 1H'13 before drawing down since July 2013 (see Figure 4). Since then, syncrude has traded back in a -$5 to +$10 differential versus WTI, with spikes from upgrader or pipeline issues in Alberta, though current refinery maintenance is keeping syncrude weaker. WCS has moved in sympathy with syncrude but at progressively wider discounts to WTI as oil sands production has grown by ~200-k b/d per year over the last few years, even as pipelines south and east of Chicago, and south of Cushing, have remained inadequate to bring Canadian crudes to the US Gulf Coast market, where the complex refining sector is well suited to take heavy sour crudes.

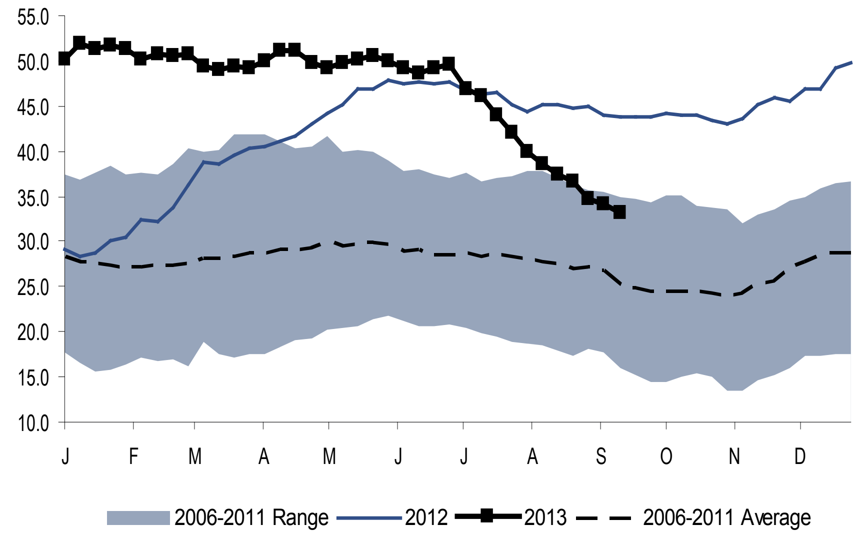
Figure 3. Price differentials versus WTI of key North American crude streams, 2011-2013



Source: Bloomberg, Citi Research

Citi has written extensively on how evolving pipeline and rail infrastructure is driving the Brent-WTI outlook, with the most recent views developed in the May 2013 report "The End of the Beginning" and the July 2013 report "Parity Like It's 1999?". The most recent price outlook, based on an update of the same analyses as the two reports mentioned above, can be found in the September 2013 "Commodities Super Cycle Sunset: FX Effects – 4Q'13 Commodities Macro Market Update". These reports told the story of the rapid growth of North American crude oil production, primarily driven by shale/tight oil and the oil sands, and how they overwhelmed legacy pipeline infrastructure. This resulted in a glut of crude oil in the US midcontinent, most visibly at Cushing, Oklahoma, where crude oil inventories – usually at the ~25-m bbl level over the five-years prior – bloated to as much as 45-50-m bbls, staying at these levels through 2H'12 to 1H'13 (see below). This state of oversupply and correspondingly elevated storage demand – at the very location where WTI is priced and delivered – put immense pressure on WTI flat price and curve structure, with corresponding blowouts on crude prices further "upstream" of Cushing. Only at the end of June 2013 did newly built, expanded or reversed pipelines allow the evacuation of this distressed crude from the Cushing storage hub, allowing WTI flat price to rally versus Gulf Coast light sweet crudes like Light Houston Sweet and LLS, in turn rallying versus Brent. However, WCS and syncrude are driven by bottlenecks that remain – and are evolving – between Alberta and variously: Chicago/Patoka/Wood River, Cushing, eastern Canada, and via rail to refineries on the US West, East and Gulf Coasts.

Figure 4. Crude oil inventories at Cushing, OK (m bbls) – the crude glut of the last two years drove WTI to record discounts to Brent, pressuring other North American crudes including syncrude and WCS with it



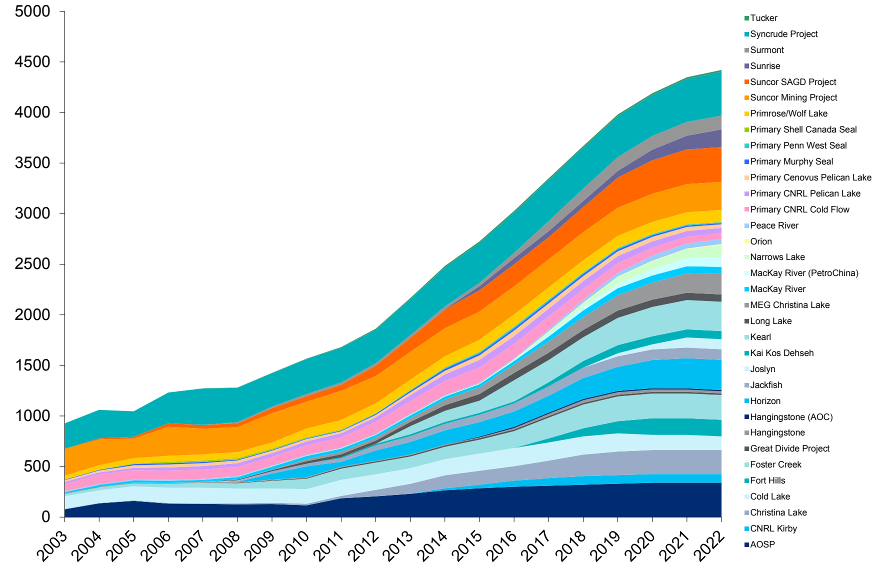
Source: EIA, Citi Research

What drives WCS and syncrude prices? The main factors are production and upgrading in western Canada; competition of syncrude versus other light sweet crudes, particularly in Chicago; refinery conversions to take heavier crude; and in particular, pipeline connectivity to bring western Canadian crudes to major demand centers with waterborne access.

The Canadian oil sands production outlook is very robust, and project economics are focused on the long-term, and should be able to weather a short-term challenging price environment

As for Canadian crude production (discussed in greater detail later), there should continue to be significant growth over the next few years (that can be temporarily disrupted or delayed by weather, flooding or pipeline disturbances from time to time). Projects at the earlier stages, particularly those with higher project breakevens like Joslyn and Fort Hills, have seen delays and suspensions as the economics looked challenged by persistent, large discounts of western Canadian crude prices to waterborne grades. But with the prospects for WCS differentials improving, further projects may be given the go-ahead, keeping supply growth robust.

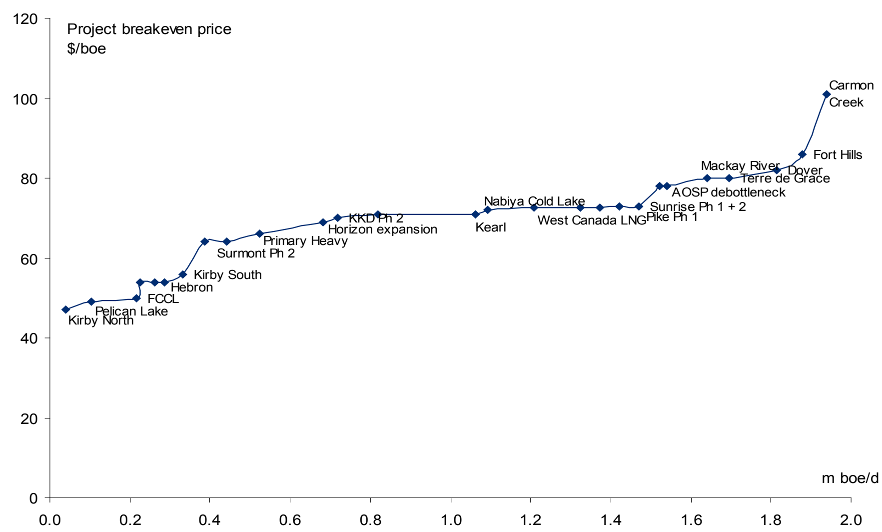
Figure 5. Canadian oil sands potential by project (2003-2022)*



Source: Wood Mackenzie, Citi Research *These are announced plans, projects could be delayed/cancelled

The oil sands production outlook is very robust, and though western Canadian crude prices have been challenging, project economics are focused on the long-term; if infrastructure bottlenecks are considered to be (relatively) short-term, the project outlook should be able to remain mostly on track. The graph below shows project breakeven prices for proposed oil sands projects to 2020 - it assumed a fixed Brent-bitumen differential of $33, or ~$25 Brent-WCS with WCS-bitumen at ~$8. $25 Brent-WCS is at the low end of volatile $20-60 levels YTD, but as this report discusses, $25 could be on the higher end come end-2014. The WCS breakeven of the highest breakeven project – Carmon Creek– implies WCS at $75, which seems achievable in the next few years, although Citi sees Brent prices falling to the $70-90 level by the end of the decade, which would challenge this.

Figure 6. Project breakeven prices for proposed oil sands projects



Source: Citi Research

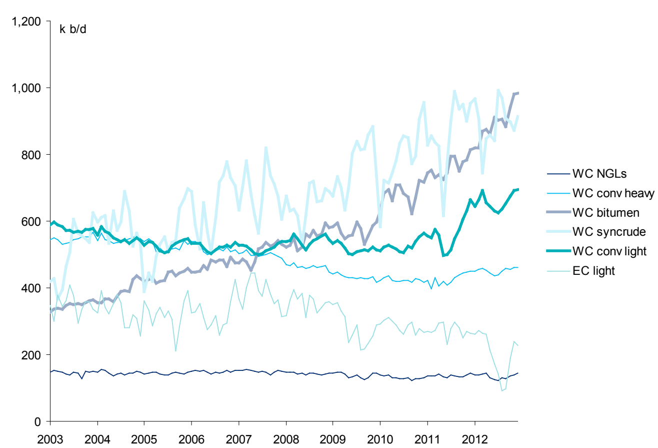
The major driver of supply growth is from the notorious oil sands, a large chunk of Canada's substantial reserves of 174-bn bbls, according to the *BP Statistical Review of World Energy 2013.* Going forward, much of the growth is in non-upgraded bitumen, supplied to US and Canadian refiners as diluted bitumen (dilbit) or bitumen in heated rail cars. Western Canada produced some 1.5-m b/d of dilbit in 2012, and can grow modestly in 2013 given project delays (in particular, to Kearl), but could grow +150- to 200-k b/d per year in the next few years at least.

Canadian bitumen is also upgraded into light, sweet syncrude, for which production is in the 800- to 900-k b/d level. Syncrude production is likely to see only limited growth from the ramping up of existing projects, but basically flat, as planned upgrader facility projects have been canceled or put on hold, due to a surge in US light sweet production emanating from its shale revolution.

Conventional heavy volumes add to dilbit/WCS volumes, adding another ~350-k b/d, growing modestly. What Canada tends to call "Conventional Light" also includes shale and tight oil, and could show upside to light sweet crude production growth, perhaps on the order of +50-k b/d every year; this supply is driven by the Cardium and Alberta Bakken/Exshaw shale plays. IEA's Medium-Term Oil Market Report 2013 sees Canadian tight oil production at 300-k b/d at end-2012, with the Cardium in particular up 80-k b/d y/y (24%) in 4Q'12.

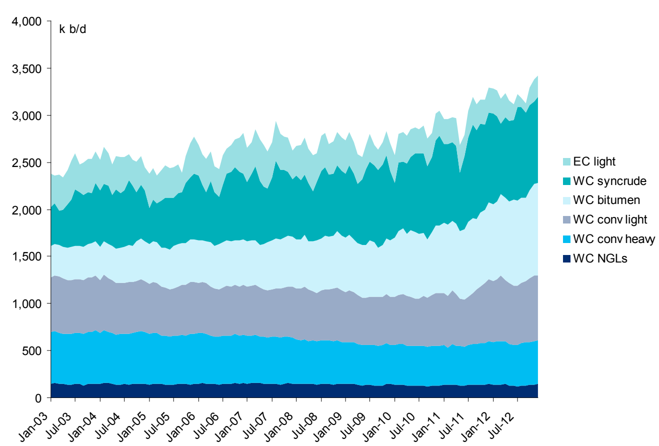
Eastern Canada produces modest light volumes of around 200-k b/d, and is basically declining over time, although the Hebron project adds some volumes from 2017-18.

Figure 7. Canadian crude production by region and type



Source: NEB, Citi Research

Figure 8. Canadian crude production by region and type, stacked



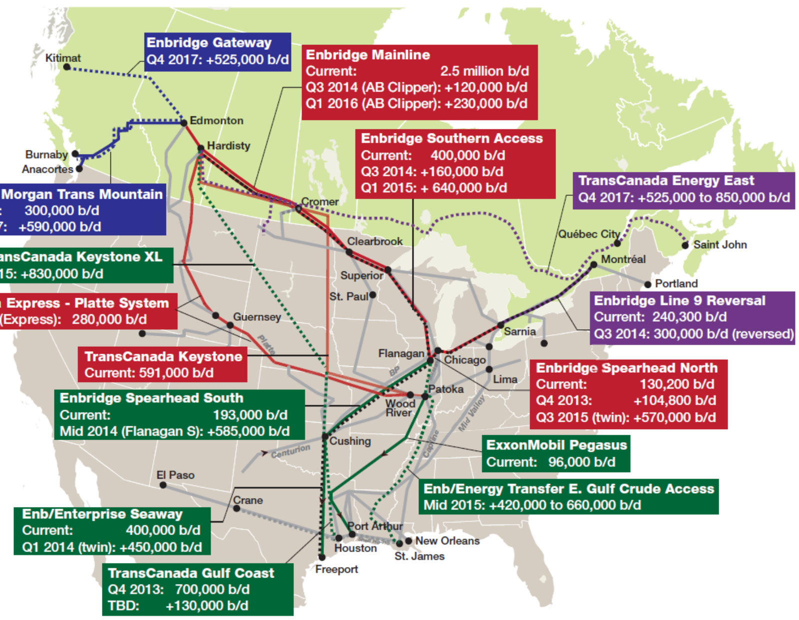
Source: NEB, Citi Research

Refinery conversions to take heavier crudes help

On the demand side, the last of three major refinery upgrade projects to shift to a diet of heavier sourer crude is almost complete; the BP Whiting refinery has already converted its third crude distillation unit (CDU) to run sour crude, and once the associated delayed coker unit is ready – perhaps by November 2013 – the Chicago-area refinery should be processing an incremental +250-k b/d more heavy oil than before. Before this coker is ready, BP Whiting continues to run light crude. (The earlier two upgrade projects, the WRB Wood River and Marathon Detroit refineries, were completed in late 2011 and late 2012 respectively.) The completion of BP Whiting's "modernization" project should provide a welcome bump to Chicago-area demand, but beyond this, refinery reconfiguration should not significantly drive greater demand for western Canadian crude; this remains driven mainly by improving pipeline access south of Chicago, eastwards across Canada, and by rail to the US Gulf, West and East Coasts.

Outside of PADD II, the Sturgeon refinery in western Canada recently broke ground, and could be complete in three years. It starts at 50-k b/d of capacity, ramping to 150-k b/d. Lyondell Basell's Houston refinery could be increasing heavy processing capacity from 60-k b/d to 175-k b/d by 2015. Husky's Lima refinery is being considered for an upgrade project to process more heavy crude in 2017, to take up to 40-k b/d of its 160-k b/d of refinery capacity.

Figure 9. North American crude oil pipelines and proposals



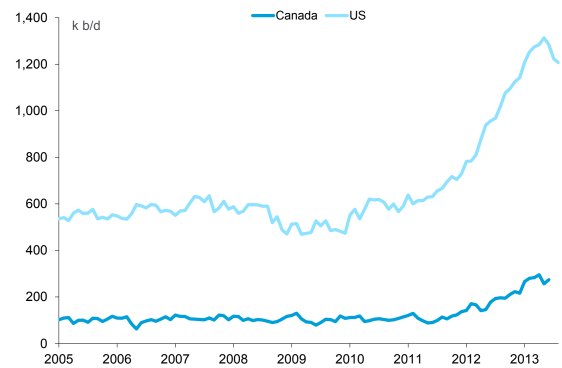
Source: CAPP

For now, pipeline connectivity is not quite there yet, though there are many debottlenecking projects in the works… but some key ones face intense political obstacles

Thus, the majority of the discussion returns to infrastructure, which poses binding constraints to the ability of fast-growing western Canadian crudes to reach major refinery demand centers. An exposition of the major pipeline routes, demand centers and price points is in order. The map above shows major routes on the North American pipeline system, and key planned additions to come in the next few years. There are many pipeline debottlenecking projects in the works, though some key ones face political obstacles – in particular, the westward pipelines Northern Gateway and Trans Mountain, as well as Keystone XL.

And so far, there has also been competition for pipeline space on the Mainline system from growing production from the Bakken shale in the Williston Basin. The Bakken has seen oil production grow spectacularly, with significant volumes getting to markets via rail. The differential of light sweet crude prices inland versus Brent-related pricing on the US West, East and Gulf Coasts can drive varying shifts between shipping Bakken crude by rail or pipe.

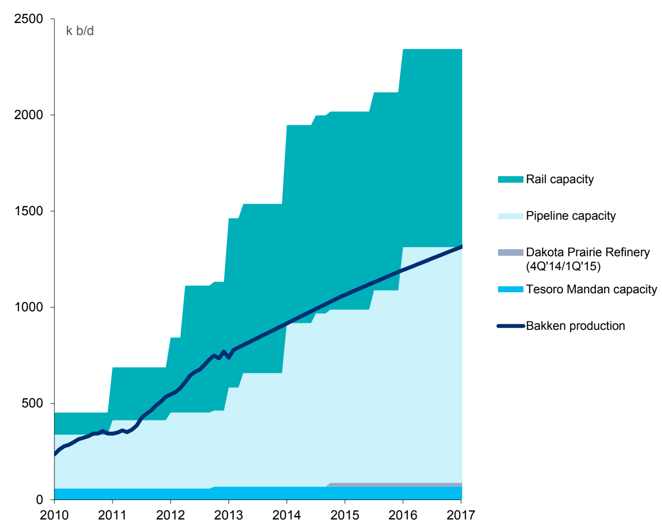
Figure 10. US and Canada railcar transportation of crude and petroleum products (2005-13)



Source: AAR, Statistics Canada, Citi Research

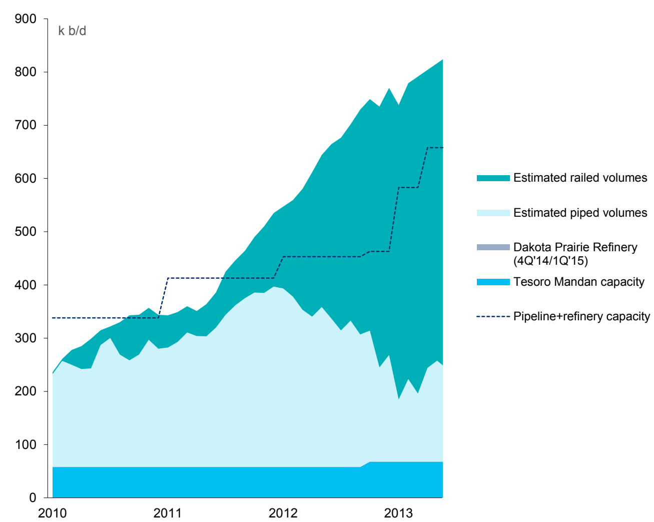
Crude-by-rail has been more than a stopgap measure; it also provides important optionality. In the US, crude-by-rail volumes have been around ~0.7-m b/d, with the take-off starting in 2011-12, while Canada is seeing some 200-300-k b/d, with the take-off in 2012-13 there. The graph above shows the upward trajectory of crude and petroleum products transported on railcars; the growth since previous plateau periods reflect the new crude-by-rail needs, with the rest likely mostly petroleum products. As for rail economics, railed bitumen, or "railbit", can compete with dilbit sent by pipelines due to lower needs for expensive diluent. However, the tragic Quebec rail accident has put safety issues concerning crude-by-rail back in the spotlight.

Figure 11. Bakken projected production versus takeaway capacity



Source: Company reports, North Dakota Pipeline Authority, Citi Research

Figure 12. Actual Bakken production to date, by takeaway type



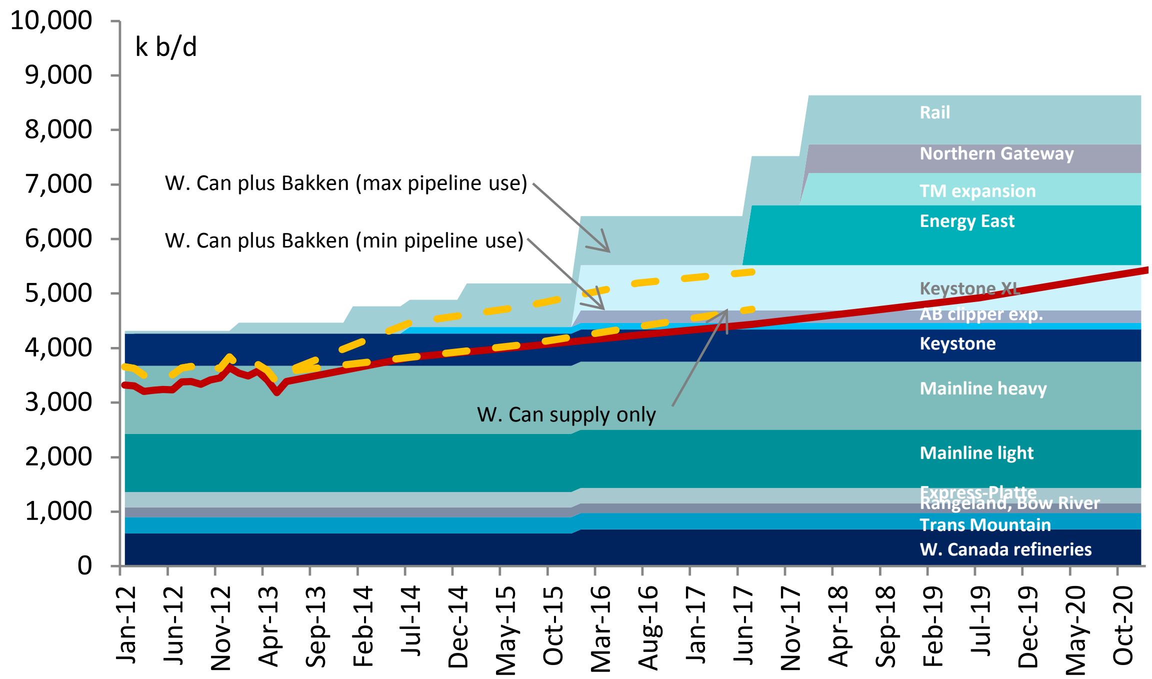
Source: North Dakota Pipeline Authority, Citi Research

Out of Alberta – exit capacity is ample for now, but 2016-17 could be tough for WCS and syncrude without Keystone XL…

Out of Alberta. Exit capacity is ample for now, though 2016-17 could be tough for WCS and syncrude without Keystone XL. This means that even WCS Hardisty-WCS Chicago – which has remained fairly stable (Figure 20) – could blow-out at times, and Bakken and/or WCS arbs versus Brent would need to price for rail flows. Note that the Mainline system is a complex pipeline network; a closer examination conducted later reveals bottlenecks between certain hubs that may mean Mainline capacity for evacuating Canadian crude may be significantly lower downstream than the amount that leaves Alberta.

WCS and syncrude are priced at Hardisty and Edmonton, respectively, in Alberta, Canada. There are currently several major routes leaving the area, after local refinery demand is satisfied (with 683-k b/d of capacity, running at around 600-k b/d of refinery throughput).

Figure 13. Western Canadian and Bakken pipeline supply versus pipeline takeaway (2012-2020)

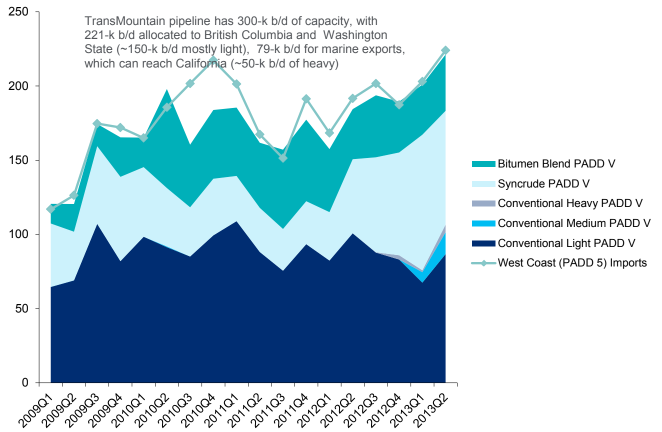


Source: CAPP, North Dakota Pipeline Authority, company reports, Citi Research

The Kinder Morgan Trans Mountain pipeline (300-k b/d capacity) is the only westward pipeline, with 221-k b/d allocated to refineries in British Columbia and Washington State, and 79-k b/d allocated for waterborne exports via Westridge. This provides the main route for Canadian crude exports to the US PADD V region, which takes some 200-k b/d of Albertan oil (see Figure 14). The prospective expansion of Trans Mountain (+590-k b/d) and newly proposed Northern Gateway (+525-k b/d) are still mired in political opposition as the projects await government approvals, and may not be ready until 2017-18, if at all.

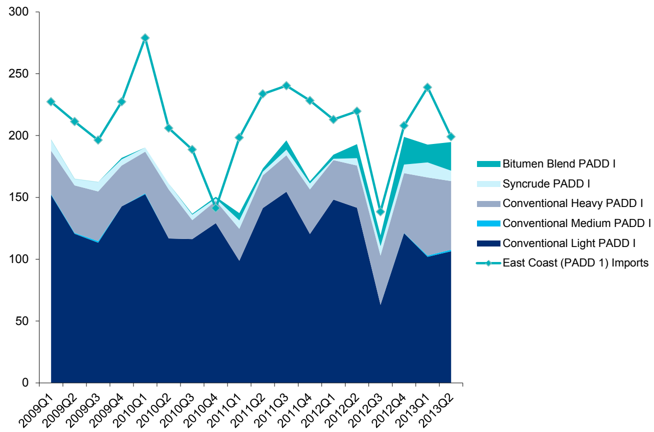
Railed volumes should help progressively, with 2012 seeing an annual average of 46-k b/d of crude exported from Canada by railcar, versus 2.1-m b/d by pipeline, 170-k b/d by water and ~1-k b/d by truck. The latest data from Statistics Canada to June 2013 see ~275-k b/d of crude oil and fuel oil being transported by rail in Canada, which is some 175-k b/d above “normal” levels prevailing in 2011 and earlier (Figure 10); all of the excess since then should indicate the growth of Canadian crude-by-rail.

Figure 14. PADD V imports Canadian crude by pipe, water, rail (k b/d)



Source: EIA, NEB, Citi Research

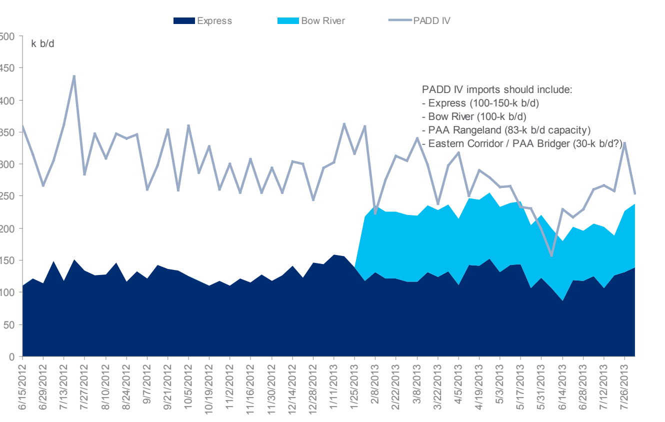
Figure 15. PADD I mainly imports from eastern Canada offshore (k b/d)



Source: EIA, NEB, Citi Research

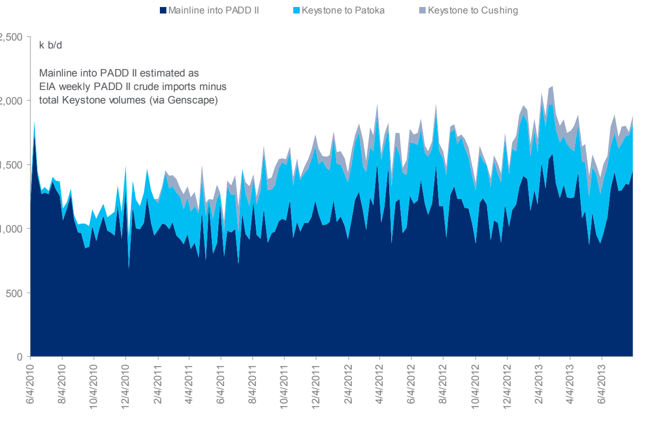
Following this, there are three major routes into the US: the 2.5-m b/d Mainline system, 591-k b/d TransCanada Keystone, and 145-k b/d Spectra Express. (Though the Express pipeline has a nameplate 280-k b/d of capacity, it is part of the Express-Platte system, and limited by 145-k b/d of downstream capacity from Wyoming onwards, on the Platte section of the pipeline). Volumes along the smaller 100-k b/d Bow River, 83-k b/d Western Corridor and 30-k b/d Eastern Corridor pipelines add further Canadian outlets into the US PADD IV (Rockies) region (Figure 16). These pipelines are close to capacity except for the Mainline system, which currently moves around 1.5-m b/d of oil (see Figure 17) but has 2.5-m b/d of capacity, but the system as a whole has various bottlenecks between different hubs that can limit real, useable capacity to below this nameplate number.

Figure 16. US PADD IV crude imports from Canada are mainly via Express and Bow River



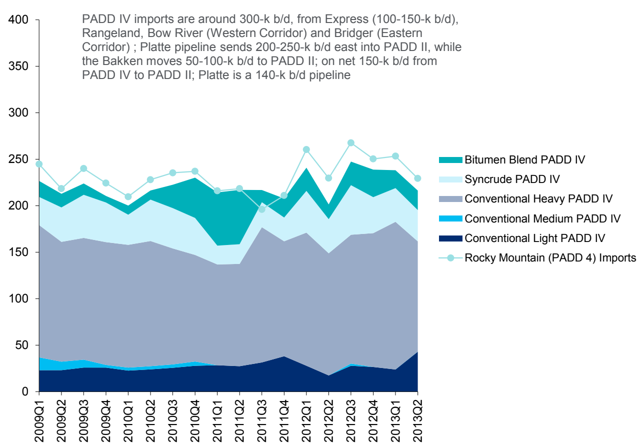
Source: EIA, Genscape, Citi Research

Figure 17. PADD II crude imports from Canada are via Mainline and Keystone, which supplies both Cushing and Patoka



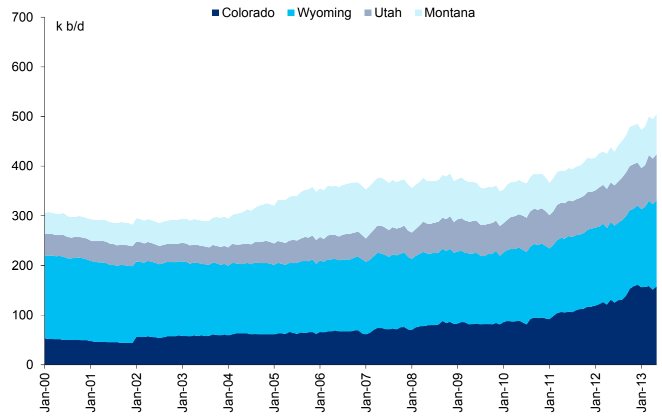
Source: EIA, Genscape, Citi Research

Figure 18. PADD IV crude imports versus refinery receipts



Source: EIA, NEB, Citi Research

Figure 19. …even as local PADD IV crude production is on the rise, and heading to Cushing

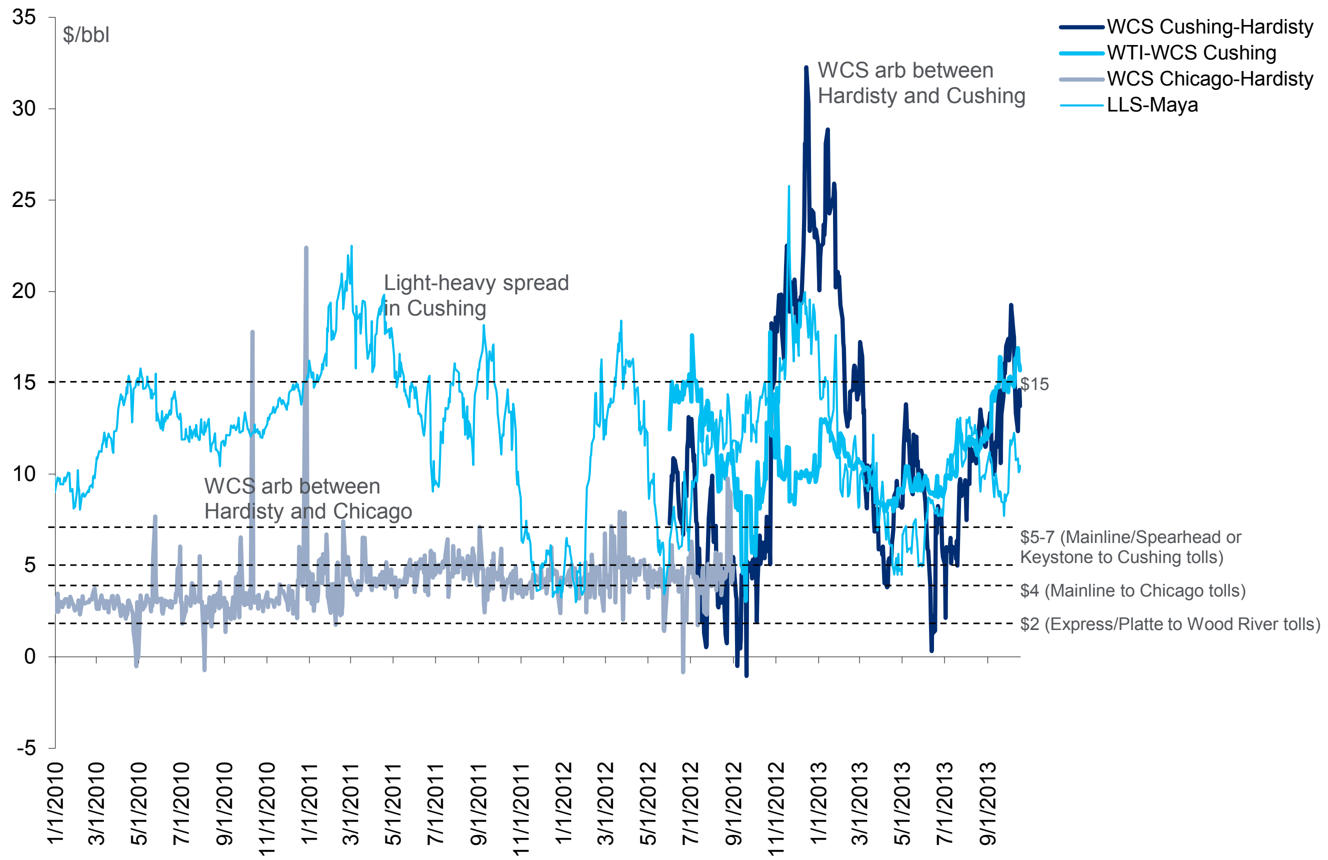


Source: EIA, Citi Research

The Rockies (PADD IV) region is saturated with Canadian oil… with its own regional crude production on the rise too, and piped volumes from the Bakken; but connectivity is improving to Cushing, which is well connected to the US Gulf Coast now

The PADD IV (Rockies) region imports Canada crude to satisfy almost 50% of its refinery demand for crude; it has total refining capacity of 646-k b/d, and it has imported a fairly stable 250-k b/d from Canada over the last few years, largely conventional heavy crude as well as syncrude, bitumen and light crude (see above). PADD IV has also received a range of 50- to 100-k b/d of light crude from the Bakken, via the Butte pipeline, which should show up in EIA data as intra-PADD pipeline flows from PADD II to IV (Figure 29). Otherwise, PADD IV continues to send on Bakken and Rockies-produced crude to the PADD II Midwest region via the 145-k b/d Express-Platte system to the Wood River/Patoka area, as well as pipelines into Cushing which allow growing PADD IV shale oil production to reach the Oklahoma crude hub; EIA intra-PADD flows show PADD IV to II pipeline flows rising and up to ~250-k b/d as of June 2013 (Figure 29); with perhaps ~145-k b/d accounted for by the Platte pipeline, some 100-k b/d should be pipeline flows from growing production in the DJ Basin, including along the White Cliffs pipeline into Cushing, which moves some 40-80-k b/d of flows according to Genscape data. Thus, local refineries look to be saturated by Canadian and local crude supply, and excess crude on top of PADD IV refinery needs are likely to transit through the region onwards to PADD II; if anything, growing local crude needs should saturate this market further. The 220-k b/d Pony Express pipeline, expected 2H’14, allows further outlets from Guernsey, Wyoming, and should help move further Bakken volumes to Cushing, freeing up more space for PADD IV.

Figure 20. WCS prices at Hardisty, Chicago and Cushing, and versus WTI (2010-13)

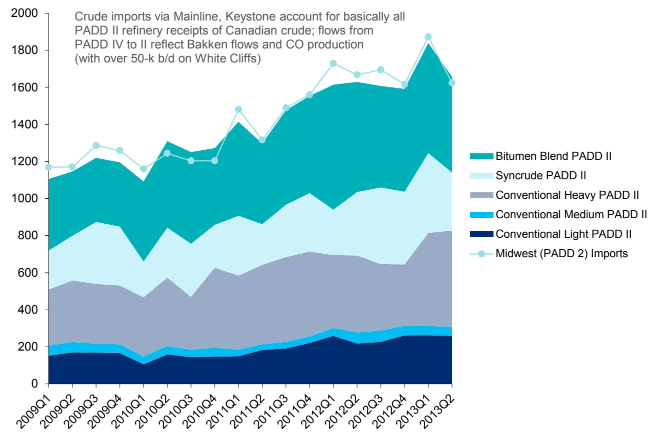


Source: Bloomberg, Platts, Citi Research

The bottlenecks have been predominantly south and east of the Chicago area so far

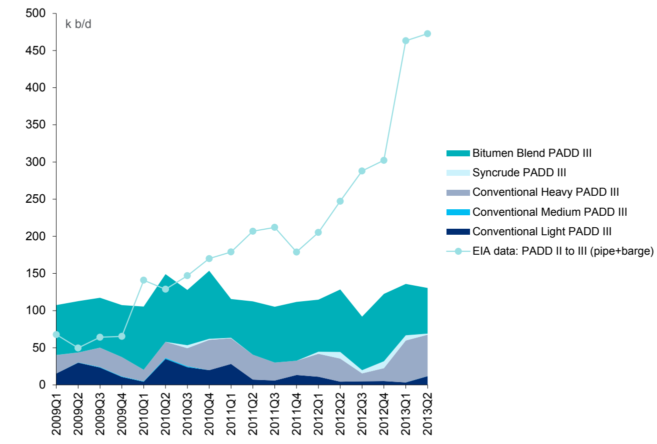
The Mainline system connects to the Chicago/Patoka/Wood River refining area in PADD II, and the fact that there is still spare Mainline capacity is reflected in the largely stable price of WCS ex-Chicago, which has been fairly consistently at the $4-7 level over WCS at Hardisty (see above), at least when data have been available. (Data appear to have been discontinued from end-August 2012.) This suggests that the bottlenecks have been south of Chicago, though Chicago has been well supplied; the pipeline toll from Alberta to Chicago is around $4 (Figure 23). Notably, the Mainline system also receives pipeline volumes from the Bakken, via entry points at Cromer, Manitoba, and Clearbrook, Minnesota. Growing Bakken volumes put pressure on syncrude and WCS, but with most of the Bakken now being evacuated by rail (though easing off a little recently with the narrowing in Brent-WTI), this has freed up pipeline capacity for Canadian crudes (Figure 11 and 12). (The Bakken also supplies Guernsey, Wyoming via the 160-k b/d Butte pipeline, competing with Canadian flows via Express and joining to the Platte pipeline to Wood River/Patoka.)

Figure 21. PADD II receipts of Canadian crude by type (2009-13) versus EIA data for PADD II imports



Source: EIA, NEB, Citi Research

Figure 22. PADD III receipts of Canadian crude by type (2009-13) versus PADD II to PADD III pipeline and barge flows

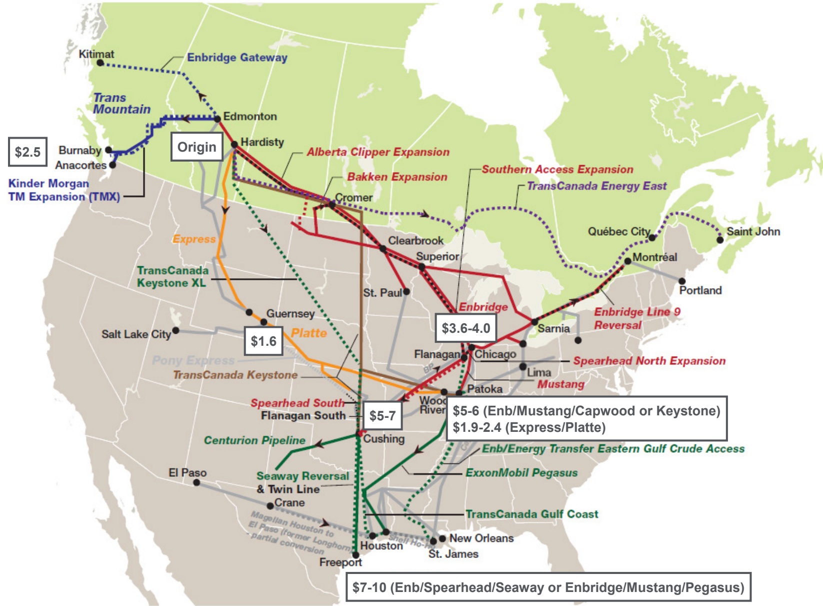


Source: EIA, NEB, Citi Research

PADD II has been absorbing the onslaught of Canadian production growth, with 1.1-m b/d of crude imports from western Canada in early 2009 rising to 1.8-m b/d by early 2013 (see above), though dropping back in 2Q'13 due to temporary upgrader maintenance that ended recently. This is out of 3.8-m b/d of refining capacity in the region, which is also served by 1.7-m b/d of domestic crude.

Meanwhile, PADD III has not seen more than ~100-150-k b/d of Canadian crude processed – mostly bitumen blend, but also conventional heavy – out of refining capacity of 8.6-m b/d. PADD III crude imports were 4-m b/d at July 2013, of which ~2.1-m b/d is heavy crude; there is plenty of room for WCS to take market share here and back out imports, though term supplies may be sticky. And note that Canadian crude is exportable from the USGC under current US crude export regulations, although exports may not be needed before Energy East allows Canada to export from its own east coast.

Figure 23. Pipeline transportation costs from western Canada to selected destinations

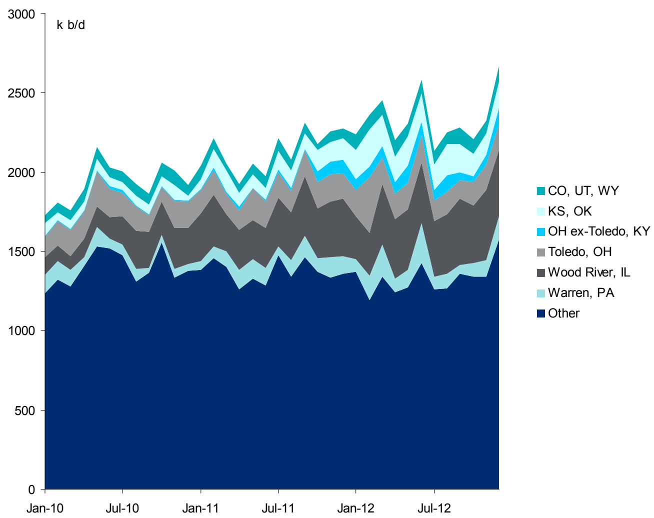


Source: CAPP, Citi Research

If there were no infrastructure bottlenecks, transport differentials could equilibrate at around ~$4 between Alberta and Chicago, $5-6 between Alberta and the Patoka/Wood River area, $5-7 between Alberta and Cushing, and $7-10 between Alberta and the Gulf Coast (see above).

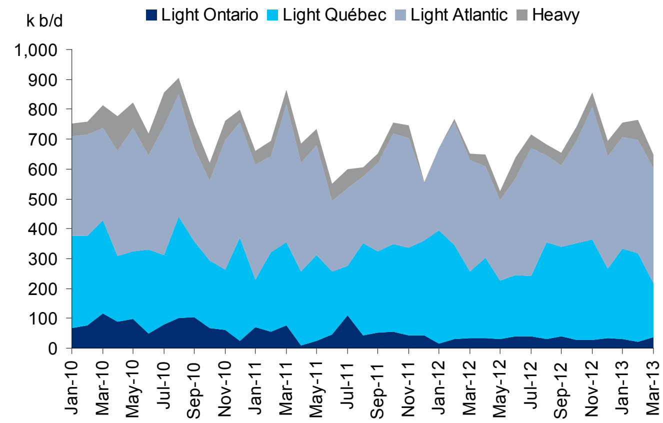
However, the price of WCS at Cushing ("WCS ex-Cushing") has fluctuated wildly, from parity with Alberta at times in mid-2012, to as much as a $30-35 premium to WCS ex-Hardisty at the end of 2012 and beginning of 2013 – this is as opposed to the pipeline tariffs implying a transportation arb of $5-7. The WCS arb to Cushing has since come in to the $5 level in 2Q-3Q'13 with syncrude strength, and even close to parity in mid-June, but has since widened back to over $10 since late July (Figure 3). The fluctuations are related to bottlenecks between Hardisty and Cushing; given that the two routes into Cushing are Mainline/Spearhead and Keystone, and that both Spearhead and Keystone (but not the upstream Mainline pipeline) are basically at capacity, this is not surprising. Refinery maintenance or outages in the Chicago and Cushing area also have driven wider differentials, with the November 2012 blowout particularly related to BP Whiting moving into long maintenance for its upgrade project.

Figure 24. Canadian exports to the US by key regions, 2010-13



Source: NEB, Citi Research

Figure 25. Eastern Canadian crude imports by region, quality



Source: NEB, Citi Research

With almost all the supply growth from non-upgraded bitumen, pipeline developments should help close the WCS Hardisty-WCS Cushing and Maya-WCS differentials from 2H'14…

A WCS timeline of infrastructure build-out

The timeline for WCS is driven by mostly gradual and some chunky growth of production, and pipeline build-out. With almost all the supply growth from non-upgraded bitumen – with new upgrader projects currently on the rocks – pipeline developments should help close the WCS Hardisty-WCS ex-Cushing price differential, and correspondingly, the Maya-WCS price differential, from 2H'14 onwards.

4Q'13 – the **BP Whiting upgrade project** should be completed, takes ~250-k b/d more heavy crude in Chicago area, even as the ExxonMobil Kearl project ramps up to 110-k b/d through year-end.

1H'14 – **Keystone XL south** (700-830-k b/d), Seaway twinning (450-k b/d) firmly connect Cushing to the USGC. WCS ex-Cushing should anchor to Maya prices, could be parity if take-or-pay, $4 tariff otherwise, but FERC may call for lower tariffs over time; WCS-WCS ex-Cushing remains challenged.

2H'14 – the **Alberta Clipper expansion** adds +120-k b/d heavy capacity to Chicago area/east Canada. The **Line 9 re-reversal** adds 300-k b/d pipeline access to Montreal, though this pipeline should carry light crude; this could reduce eastern Canada's light sweet crude import needs by half, from 600-700-k b/d today to ~300-k b/d. **Flanagan South** adds 585-k b/d capacity to Cushing, USGC, but utilization may be low until after the 2H'15 Phase 2 Southern Access expansion from 400-k b/d today to 1.2-m b/d. The **Pony Express** pipeline adds 220-k b/d, Guernsey, WY to Cushing, OK, mainly helping Bakken crude escape. Note that the Alberta Clipper expansion crosses an international border, much like Keystone XL, but the project has received permission on the US side, and is just awaiting approval on the Canadian side.

2015 – the potential **Eastern Gulf Crude Access** pipeline could start up (from Patoka, IL to St. James, LA) adding +420-660-k b/d to USGC, fed by extra upstream pipeline capacity from Southern Access Expansion, 300-k b/d from

Flanagan to Patoka, IL. Heavy crudes should also weaken as the new **2015 ECA 0.1% sulfur limit on marine bunker fuel** hits fuel oil prices; it comes into effect from January 1, 2015, although there may be some changes to this rule given opposition in the shipping industry to compliance measures.

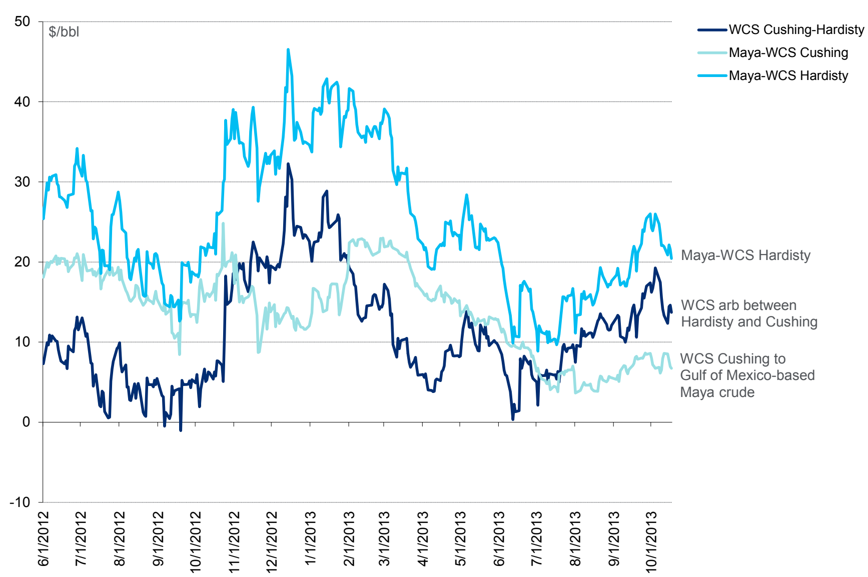
2016 – a further **Alberta Clipper expansion** adds another +230-k b/d. **Keystone XL**, if approved, could be completed by late-2015, 2016, adding 700-830-k b/d to Cushing/USGC; without it, the WCS Hardisty-Chicago leg could widen, offsetting improvements in connectivity south and east of Chicago. The local diesel-focused Sturgeon Refinery in Alberta should be complete, starting at 50-k b/d, ramping to 150-k b/d.

2017 – Energy East adds 1.1-m b/d capacity to eastern Canada, with 0.9-m b/d already committed.

2018 – Westward pipelines Trans Mountain +590-k b/d expansion, new Northern Gateway 525-k b/d pipeline?

2020 onwards – CAPP sees total Canadian oil production as potentially reaching 4.9-m b/d by 2020, 6-m b/d by 2025, 6.7-m b/d by 2030; combined with Canadian shale oil and US midcontinent shale oil production, further pipelines would be needed at some point in the next decade to keep pace with growing supply.

Figure 26. WCS Hardisty, WCS ex-Cushing versus Maya (2012-13)



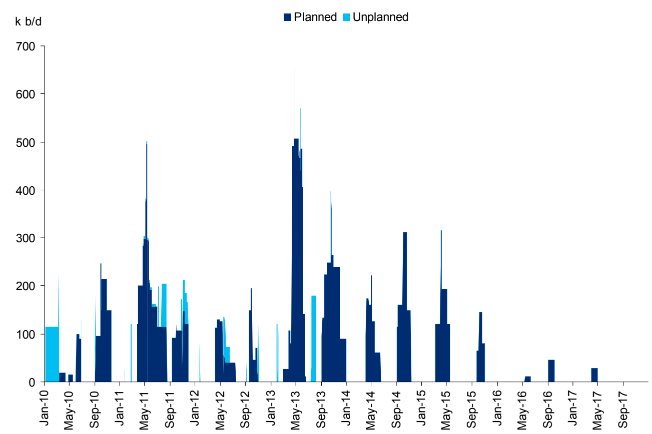
Source: Bloomberg, Platts, Citi Research

…and syncrude (and other) disruptions can also cause temporary rallies

Also important in magnitude at times are the co-movements of WCS and syncrude, which have been at a ~$20 differential without upgrader disruptions since 2011; over the period 2009-11, this was stable at the $10 level, before the blowout of Brent-WTI spread. But weakness or strength in syncrude is picked up in sympathy by WCS, even though upgrader outages or maintenance also widen the light-heavy spread at Alberta by decreasing supply of syncrude and leaving more non-upgraded bitumen available; two major periods of recent upgrader disruptions existed through most of 2011 as the Horizon upgrader was shut for seven months due to a fire in January of that year, with the syncrude-WCS differential moving out to the $30 level, before settling back at $20, and again in

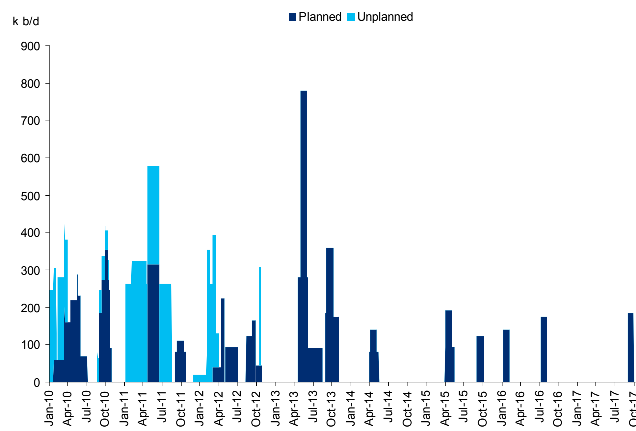
2Q'13 as the Syncrude and Horizon upgraders were in maintenance again, with the differential moving out to $40 at times. 4Q'12 to 1Q'13 also saw a wide syncrude-WCS differential, but this was driven by a collapse in WTI-WCS, as pipelines between the Permian Basin and Cushing reached capacity, causing West Texas Sour (WTS) and WTI Midland grades to plummet versus WTI Cushing. With heavy crudes like Maya with a pricing component based on WTS, and Canadian WCS having a linkage with Maya prices given similarities in quality, WCS fell too, though syncrude remained at around parity with WTI through 1Q'13. (See below for the syncrude upgrader facility maintenance history and forward-looking schedule, but note that upgrader disruptions can be very unpredictable.)

Figure 27. Western Canadian refinery CDU maintenance and outages



Source: IIR, Citi Research

Figure 28. Western Canadian upgrader maintenance and outages

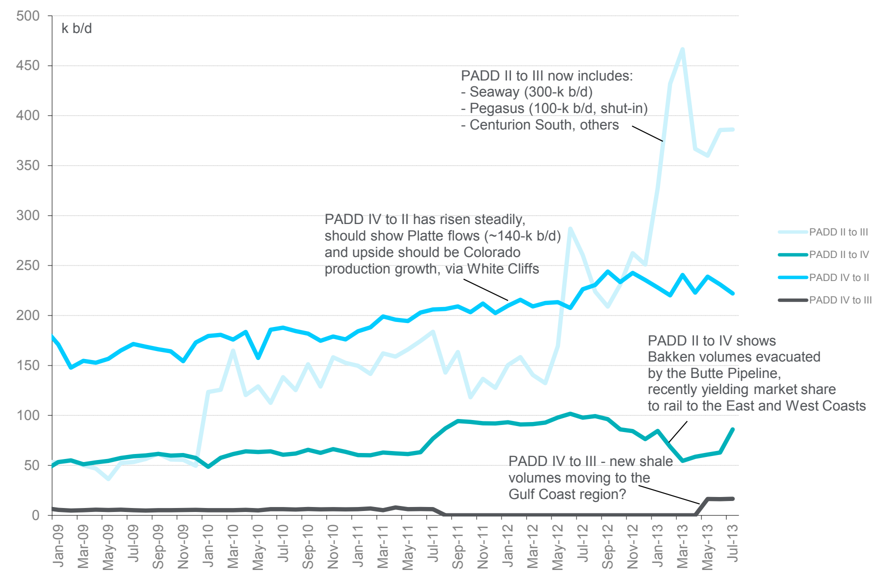


Source: IIR, Citi Research

As discussed in other Citi reports on the Brent-WTI price differential[1], pipelines south of Cushing are plentiful and can eventually be transporting mostly Canadian crudes to the Gulf Coast, where refinery receipts of bitumen, syncrude and other Canadian oils have only been at the 100-150-k b/d level. As seen in Figure 22, PADD II to PADD III pipeline and barge movements have risen to 450-k b/d by 1Q'13, but have since dropped down to the 350-k b/d level as the Pegasus pipeline has been shut-in. Nevertheless, this suggests the rest of the flows are domestic US production, and as the light sweet crude overhang in Cushing is drawn down, an increasingly large share of this pipeline capacity between PADD II to PADD III – the capacity of which is itself set to increase significantly end-2013 and early 2014 – should be accounted for by Canadian crudes. This should keep the differential between WCS ex-Cushing and Maya (both heavy sour crudes comparable on a quality basis) at the pipeline transportation arb, or even close to parity, if volumes are moving on a take-or-pay basis on the new Cushing-to-Gulf Coast pipelines (Figure 26). WCS ex-Cushing and Maya have already moved to a tighter $4 level since July, when pipeline capacity out of Cushing was credibly debottlenecking the Oklahoma storage hub, though this has moved back out to $7-8 recently as Brent-WTI has also widened; this should narrow again as the Keystone XL southern leg comes online this quarter.

[1] "The End of the Beginning" (Eric G. Lee et al, May 2013), "Parity Like It's 1999?" (Eric G. Lee et al, July 2013, "Commodities Super Cycle Sunset: FX Effects – 4Q'13 Commodities Macro Market Update" (Edward L. Morse et al, September 2013).

Figure 29. US intra-PADD pipeline flows (2009-13)



Source: EIA, company reports, Citi Research

By 2015-16, western Canada should be well connected to the US Gulf Coast; by 2017, western Canada should be well connected to the eastern coast

What is the end game for Canadian prices? WCS ex-Cushing and Maya can be at the $4 level or even parity, given significant pipeline capacity between Cushing and the Gulf Coast. (Maya has a WTS Midland-related factor in its pricing formula, which caused problems when the Permian Basin was glutted, depressing WTS and in turn, Maya, but with west Texas debottlenecked and able to move freely to the Gulf Coast, this should no longer be a "distortion" for Maya pricing; recent discounts of Midland crudes should be temporary, but any bottlenecks at Cushing/Midland could also pressure Maya again at times.)

With Keystone XL and Seaway twin pipelines providing plenty of outflow capacity to the USGC, WCS ex-Cushing can close to a transport cost arb with Maya of ~$4, even parity if take-or-pay is a factor; WCS ex-Cushing-WCS Hardisty could close from $15 to $10 in 1H’14 as BP Whiting’s coker starts and heavy crude demand steps up, and close to transport costs (parity if take-or-pay) in 2H’14 as Flanagan South comes online, with all excess heavy crude going to the USGC via Cushing; Maya-WCS (Hardisty) can close from $25 today to ~$20 in 4Q’13, $10 in 1Q’14 as Cushing-USGC slams shut, $7 in 2H’14 as bottlenecks south of Chicago ease, with help from the Line 9 reversal. Without Keystone XL, the Hardisty-Chicago leg could blow out to allow Maya-WCS to support greater volumes of rail flows, or some ~$20, though some rail operators could be on the lower side due to sunk costs and competition, as well as the increasing push to use less diluent.

If LLS needs to discount further to compete with WCS on the USGC, WTI and syncrude could fall with it, until 2017 when Energy East allows eastern exit for Midwest light crudes like syncrude and Bakken. Before then, light-heavy blending to replace mediums, direct heavy-to-light switching as light-heavy diffs narrow, and waterborne flows between eastern Canada and the USGC characterize the balancing act, with a ~$6-9 LLS-Maya spread where refiners could find it economic to switch from running heavy to running light. Historically, WCS ex-Cushing has traded mostly at a discount of $8-12 versus WTI; greater access to USGC could narrow this, given limited heavy demand in the Cushing area.

The analysis of light-heavy competition on the US Gulf Coast can be found later, where refinery economics are considered in an attempt to make an initial estimate on where light-heavy differentials need to be in the more involved case of needing to incentivize heavy refineries to switch to using more light crudes.

Figure 30. Outlook for selected North American price differentials *with* Keystone XL pipeline ($/bbl, 4Q'13-2016)

	4Q'13	1Q'14	2Q'14	3Q'14	4Q'14	2015	2016
WCS Chicago-WCS	6	5	4	4	4	4	4
WCS Cushing-WCS	15	10	10	7	7	7	7
Maya-WCS Cushing	5	0	0	0	0	0	4
Maya-WCS	20	10	10	7	7	7	11
LLS-WTI	1	0	0	0	0	1	2
Brent-LLS	2	2	2	2	3	4	4
LLS-Maya	8	8	8	8	7	7	7
WTI-WCS	27	18	18	15	14	13	16
Brent	110	110	105	110	105	103	98
LLS	108	108	103	108	102	99	94
WTI	107	108	103	108	102	98	92
Maya	100	100	95	100	95	92	87
WCS	80	90	85	93	88	85	76

Source: Citi Research

Without Keystone XL, 2016-17 becomes a tough period when Hardisty-Chicago could be bottlenecked, discounting WCS Hardisty versus WCS at Chicago and Cushing and keeping rail arbs wide open; Bakken prices might need to do the same versus Brent

With or without Keystone XL

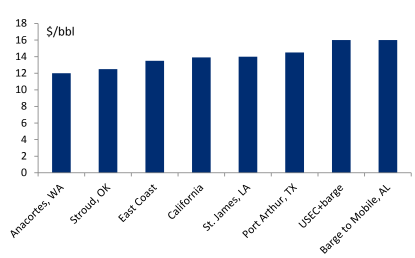
A scuttling of the much-maligned pipeline from Hardisty to Cushing would mean 2016-17 could be a challenging period for Canadian outflows to the Chicago area and beyond.

As shown on the supply versus takeaway graph below, taking out Keystone XL leaves the combined supply from western Canada and the Bakken – if all production moves on pipelines – potentially facing limited spare capacity. This is especially true given that the Mainline pipelines face downstream bottlenecks that may mean the system may have less ability to handle North American crude production growth then. However, if the Bakken – and western Canada – employ significant volumes of rail, and there is plenty of loading and unloading rail terminal capacity being built-out, this may help ease pipeline availability. The lower orange dotted line shows Bakken volumes if rail transportation is maxed out.

Meanwhile, the stacked areas show pipeline capacity, but on top of this could be significant amounts of rail loading capacity in western Canada – reaching some 600-k b/d by end-2014 from over 200-k b/d currently. Bakken should continue to need to price for rail, given pipelines should mostly trail production (see earlier Figure 11).

Canadian rail requires some ~$20 Maya-WCS to make rail to the USGC economic; this could mean Maya-WCS could move from the much narrower sub-$10 level – which should discourage rail flows – to the $20 level, to open the rail arb to the USGC. There are several nuances to this topic. Part of this covers fixed costs, which could be some $5-6, and greater competition as rail loading and unloading capacity continues to grow could pressure realized rail costs to fall. Secondly, manifest trains cost more per barrel than unit trains, and there could be a move to more unit train use. Thirdly, the move to ship less diluent by upgrading to heated rail

Figure 31. In contrast, rail costs from Bakken wellheads range from $12-16/bbl (though note that Clearbrook prices are some $6-7 above Bakken wellhead prices)



Source: Company reports, PIRA, Citi Research

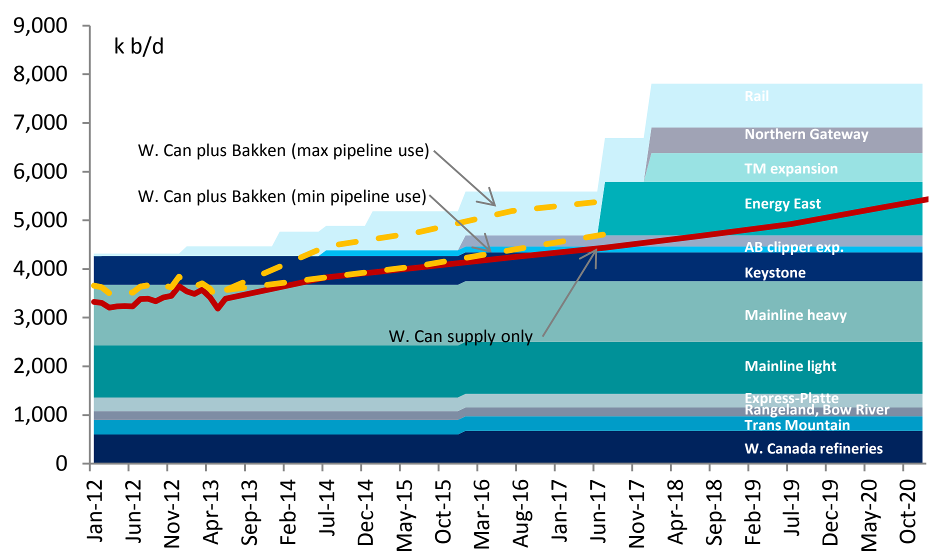
cars could also improve rail economics for the bitumen producer versus using pipelines; shipping "railbit" means blending some 0.24 bbls of diluent per barrel of bitumen rather than 0.39 bbls of diluent per barrel of bitumen for dilbit. For now, most of the unit train loading facilities only ship dilbit, while of the manifest loading facilities, only a quarter can handle railbit or close-to-raw bitumen. Given all of this, 2016-17 may thus need particularly heavy reliance on rail for either/both western Canadian and Bakken crudes on the leg to Chicago, without Keystone XL, but the cost could vary, and compress, given the factors above.

Figure 32. Outlook for selected North American price differentials *without* Keystone XL pipeline ($/bbl, 4Q'13-2016)

	4Q'13	1Q'14	2Q'14	3Q'14	4Q'14	2015	2016
WCS Chicago-WCS	6	5	4	4	4	17	13
WCS Cushing-WCS	15	10	10	7	7	20	16
Maya-WCS Cushing	5	0	0	0	0	0	4
Maya-WCS	20	10	10	7	7	20	20
LLS-WTI	1	0	0	0	0	1	2
Brent-LLS	2	2	2	2	3	4	4
LLS-Maya	8	8	8	8	7	7	7
WTI-WCS	27	18	18	15	14	26	25
Brent	110	110	105	110	105	103	98
LLS	108	108	103	108	102	99	94
WTI	107	108	103	108	102	98	92
Maya	100	100	95	100	95	92	87
WCS	80	90	85	93	88	72	67

Source: Citi Research

Figure 33. Western Canadian and Bakken pipeline supply versus pipeline takeaway without Keystone XL (2012-2020)



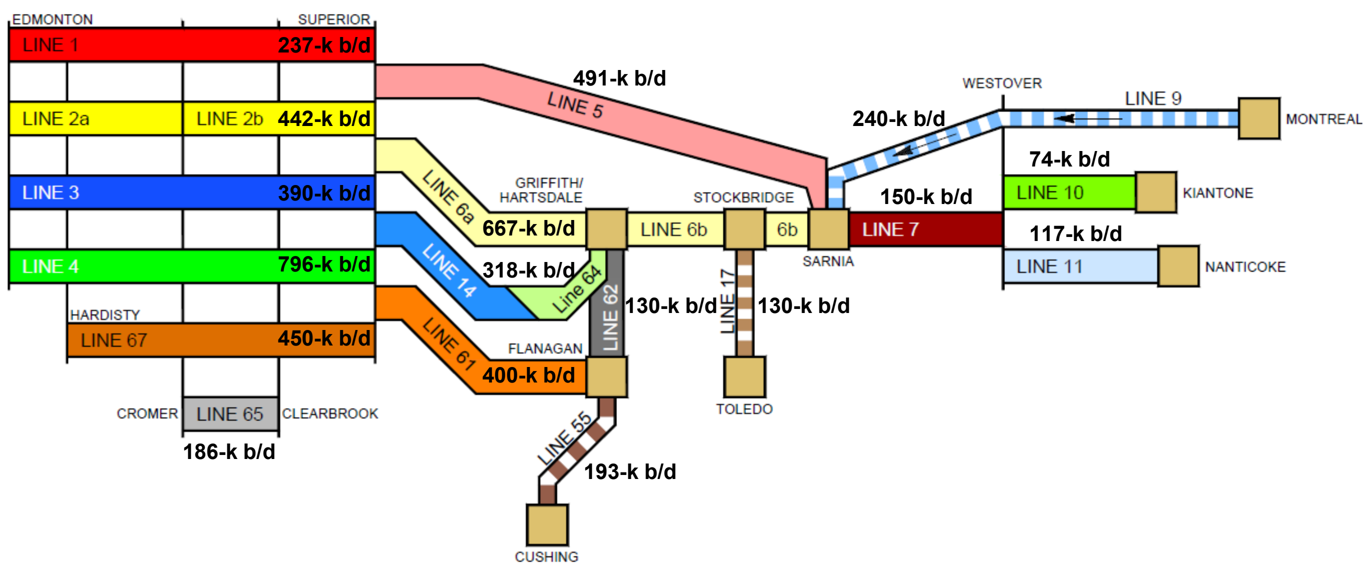
Source: CAPP, North Dakota Pipeline Authority, Citi Research

The weakest link(s): a note on key bottlenecks on the Mainline system

Although Flanagan South (585-k b/d) should be ready in 2H'14, it is fed by pipelines that have limited headroom; this could constrain the supply Flanagan South needs when it opens, meaning utilization could be less than expected at first. Flanagan South would run alongside Line 55 (Spearhead, 193-k b/d). (See below for pipeline map.)

The Mainline system has a total of 2.3-m b/d of capacity from Hardisty, AB to Superior, WI, made up of Lines 1, 2, 3, 4 and 67; Line 67 is the Alberta Clipper. But the Superior to Chicago-area leg is only 1.385-m b/d, from Lines 6, 14/64 and 61, arriving at Griffith or Flanagan, IL. These pipelines combined are reported to run at around 0.9-1.1-m b/d, implying only ~0.2-0.4-m b/d free capacity. And the pipelines directly feeding Flanagan, Line 62 and Line 61, are 130-k b/d and 400-k b/d respectively, or a total of 430-k b/d.

Figure 34. Selected pipelines on the Mainline system



Source: Enbridge Inc., Citi Research

Line 61, running from Superior, WI to Flanagan, IL, is being expanded as part of the Southern Access program, adding 160-k b/d in 2H'14 and 640-k b/d in 2H'15, bringing this leg to 1.2-m b/d of capacity. But just as Flanagan South is ready, there may only be 0.2-0.4-m b/d of headroom available – or less – meaning volumes of additional heavy from western Canada to Cushing and on to the USGC may yet not come until the full expansion in 2H'15. Alternatively, PADD II would face competitive bids from PADD III refiners to take Canadian crude, with some flows potentially shifting to the new pipelines to go to the Gulf Coast, if prices incentivize this. Nevertheless, the Southern Access pipeline may yet be an unforeseen additional bottleneck that means less heavy availability to the US Gulf Coast until later in 2015, delaying somewhat the pressure of additional Canadian heavy crude reaching the USGC. Until the expansions, it could also lead to bottlenecks west of Superior, and increased need for Canadian crude-by-rail.

Additionally, the Eastern Gulf Crude Access pipeline (420-660-k b/d, 2015?) from Patoka, IL to St James, LA, would be fed by the similarly named, but distinct, Southern Access Extension project; but this should be completed at the same time

as EGCA, as both are expected in mid-2015. The Southern Access Extension would add 300-k b/d from Flanagan, IL to Patoka, IL. This would join other sources of supply to Patoka from Keystone (591-k b/d) and Platte (140-k b/d). But this smaller expansion project, if delayed, could also lessen utilization on the EGCA pipeline.

Competition and complementarity between light and heavy crudes on the USGC

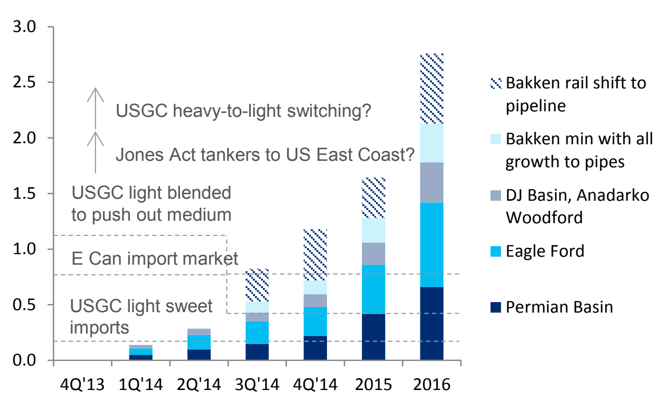
With abundant light sweet crude in the US from the Bakken, Permian Basin and Eagle Ford, refineries on the US Gulf Coast look to benefit from a narrowing light-heavy differential, but competition from heavy supplies is to come as western Canadian crudes arrive in increasing quantities in PADD III

Waves of light sweet crude arrive on the US Gulf Coast, pushing out light sweet imports, replacing eastern Canadian light sweet imports, and then pressuring light-heavy differentials to incentivize refinery switching from mediums to lookalikes made from light and heavy blends but waves of WCS should be reaching the USGC over 2014-16, keeping light-heavy differentials wide and putting more pressure on USGC light crudes versus global prices.

The new pipelines from the Permian Basin and from Cushing add a surge of light crudes to the USGC, including an initial boost from drawing down excess stocks in Cushing. Permian Basin and Eagle Ford production growth arrives directly on the US Gulf Coast; expanding pipes out of the Bakken allow greater flows to Cushing and the US Gulf Coast; Bakken should discount for rail arb; pipelines into Cushing from the DJ Basin, Anadarko Woodford should organically add light volumes to the US Gulf Coast via Cushing; light demand falls by ~250-k b/d due to converted BP Whiting. Meanwhile, US Midwest light crude gets diverted to eastern Canada with the Line 9 reversal in 2014, then via Energy East in 2017.

Importantly, the Line 9 reversal could reduce the ~600-700-k b/d eastern Canadian waterborne import market by up to 300-k b/d, meaning that US Gulf Coast light crudes could face greater refinery switching needs to use more light sweet crude in 4Q'14. Figure 35 shows an estimate of the amount of incremental light crude arriving on the US Gulf Coast; the hatched-shaded top portion of the stack shows additional volumes from the Bakken if pricing discouraged rail flows, but as shown earlier (Figures 11 and 12), Bakken should price for rail given production should outpace pipeline build-out.

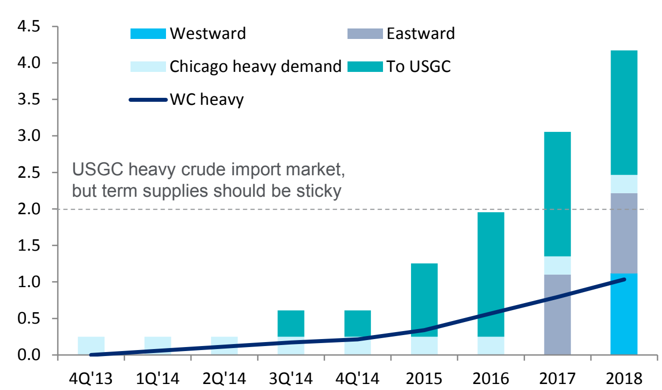
Figure 35. Incremental shale/tight oil availability on the USGC* (m b/d)



Source: Company reports, Citi Research

* Constrained by pipeline build-out; Bakken rail shift would require narrower Brent-Bakken differential

Figure 36. Incremental WCS supply growth versus incremental refinery demand and takeaway to West, East, Gulf Coasts (m b/d)**



Source: Company reports, CAPP, Citi Research

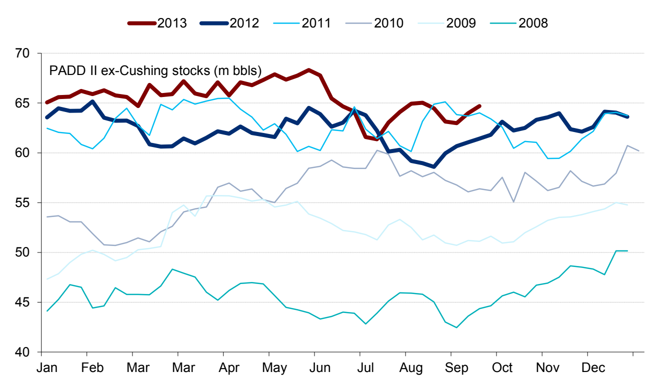
** Pipeline access to USGC takes the smallest bottleneck along evolving routes based on pipeline build-out

For Canadian heavy crude, the BP Whiting newly converted CDU (250-k b/d) helps absorb a year of heavy production growth; this means that the US Gulf Coast would need to compete more for existing Canadian production in PADD II, which should help boost WCS versus USGC Maya. See above for an assessment of incremental WCS supply growth, benchmarked to 4Q'13, against connectivity to coastal markets. It suggests that for more Canadian heavy to arrive on the USGC, incremental growth provides only smaller volumes above new BP Whiting needs in 2015; but heavy crude arrivals on the USGC are likely to be bolstered by the initial drawdown of higher-than-normal stocks in PADD II, as well as some PADD II demand potentially moving to the USGC as the WCS price discount to the Gulf Coast narrows. As mentioned, high PADD II inventories – still at a high 65-m bbl level – can mean the excess stocks draw down (Figure 37) and reach the USGC, boosting heavy crude arrivals there at first before leveling out. But generally, incremental Canadian heavy is added to the USGC slower than light shale oil additions (Figure 35 and 36).

Heavy crude should go towards pushing out USGC heavy imports, which currently run at ~2-m b/d, but term supplies should stick: Motiva (the Saudi Aramco-Shell JV) has the 600-k b/d Port Arthur, TX, 225-k b/d Convent, LA and 240-k b/d Norco, LA refineries. Citgo (under Venezuela's PDVSA) has the 165-k b/d Corpus Christi, TX and 425-k b/d Lake Charles, LA refineries. These represent 1.66-m b/d of refinery capacity. But it does seem that there is not insubstantial ability to absorb Canadian heavy crude on the USGC before needing to export.

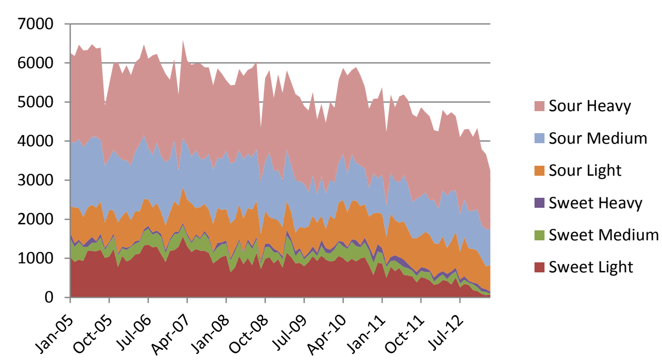
From 2017, the Energy East pipeline should allow exports from eastern Canada, likely pulling more light than heavy crude. Abundant shale oil should keep an arb open between Alberta to eastern Canada. Given pipeline costs on Energy East could be at an estimated ~$6-8 level, this would give western Canadian crudes – and US Midwest crudes – far stronger netbacks versus waterborne prices. Although it is on the less ideal coastline, the expansion of the Panama Canal could allow greater access to Asia Pacific markets, where growing complex refinery capacity could be an attractive market. Unusual arb dynamics could even mean Canadian heavy crude exported from eastern Canada, heading to the USGC.

Figure 37. PADD II ex-Cushing crude inventories (m bbls) are still high; as Flanagan South and other pipelines come online, these can be drawn down, a temporary boost to USGC heavy crude arrivals



Source: EIA, Citi Research

Figure 38. US Gulf Coast crude imports by quality (light >32, heavy <25 API gravity) – at July 2013, there are still ~100-k b/d light sweet, ~800-k b/d light sour, ~800-k b/d medium, and ~2-m b/d heavy imports



Source: EIA, Citi Research

Citi's Brent-WTI outlook sees WTI moving to parity with LLS end-2013, and perhaps even pricing at a premium at times, as Cushing becomes well connected to the US Gulf Coast. Then the question is how much light sweet crude the US Gulf Coast can take before LLS needs to discount increasingly versus Brent – and versus Maya –

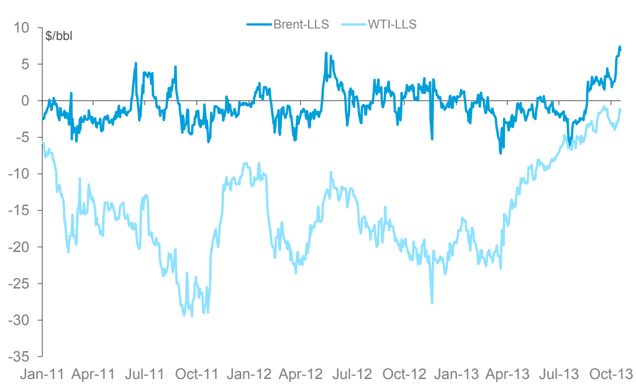
to encourage complex refineries to shift to using light crudes. LLS should need only a relatively small discount to Brent as light sweet imports get all pushed out, and encouraging exports to eastern Canada to push out light sweet imports there too, which are some 100-k b/d on the USGC. Light-heavy blending (at 1:3 to 1:4 ratios) can rise to push out USGC medium crude imports too, which runs at ~900-k b/d, while light sour crude imports run at ~700-k b/d, which could provide further headroom for import substitution too. These offer further absorption for light and heavy availability, with light-heavy blending actually increasing USGC demand for heavy crudes, helping absorb growing arrivals from Canada, keeping LLS-Maya narrower, while pressuring Mars, which itself faces pressure from growing US Gulf of Mexico oil production.

Investments to build capacity to run more light crude on the USGC are also already being incentivized. For instance, Valero has said they are investing $625 million to build pre-flash towers to run an additional 125-k b/d of light crude.

If these avenues are more quickly absorbed than expected, more involved measures may need to be taken. Directly switching a heavy crude slate to running light would need a narrow enough differential between LLS and Maya; an initial assessment, outlined later, suggests LLS-Maya at $6-9 could incentivize a representative heavy refinery to switch to running more light through heavy towers; even with a reduction in throughput and clean product yields, this would be economic with light-heavy spreads at those levels; this may require LLS to discount further against Brent, but Brent-LLS at >$4 and LLS-Maya at $9 might be enough, based on this preliminary analysis. But this remains a major wildcard, and probably needs to be revealed empirically.

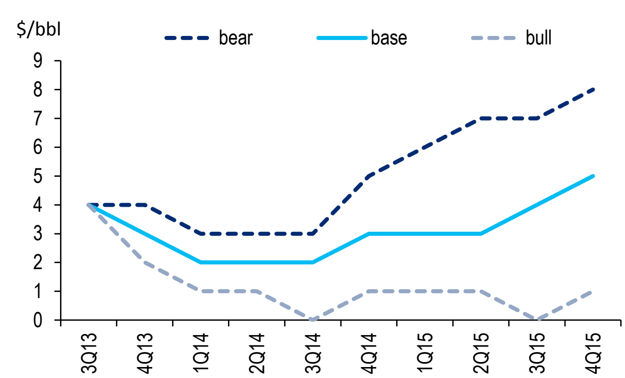
Jones Act tankers might require $3-4/bbl to as much as $5-6, to move volumes to PADD I, which is a ~500-600-k b/d light sweet crude import market. Pushing through all the incremental additions to light sweet availability on the USGC from the Permian Basin, Eagle Ford, lower flows from Cushing after the excess stocks are drawn down, suggests that Jones Act tankers / relaxing of export regulations wouldn't be "needed" until 2015. But the loosening of export regulations is not so unlikely in that time frame; free-trade agreement (FTA) countries like South Korea may be keen to import well-priced, surplus North American crude oil, and US regulations may be amended if export licenses are applied for.

Figure 39. LLS has weakened substantially in 4Q'13 as syncrude disruptions ended and Louisiana refineries moved into maintenance



Source: Bloomberg, Citi Research

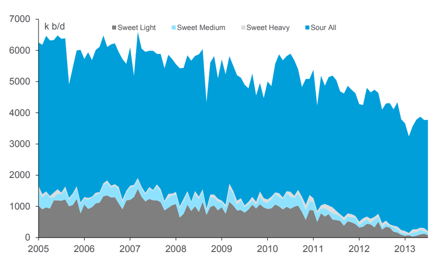
Figure 40. Citi Brent-WTI outlook



Source: Bloomberg, Citi Research

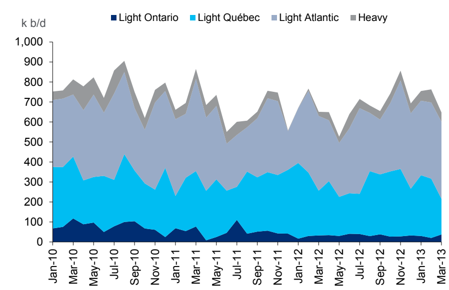
Citi's base case view is for Brent-WTI at $3 on average in 4Q'13 as WTI rallies to parity with the USGC, $2 through 2014 as exports to eastern Canada continue to expand, widening to $3 in 4Q'14 as Permian and Eagle Ford availability continues to increase, and to incentivize USGC refinery switching to absorb this, and widening to $4 through 2015 as inflows into Cushing may be sufficient to allow the Cushing-USGC arb to reopen. US export regulations could well loosen by 2015, but this is not the base case. But spreads should continue to be volatile, reflecting changing conditions including field interruptions, refinery maintenance and utilization[2].

Figure 41. PADD III crude imports by quality



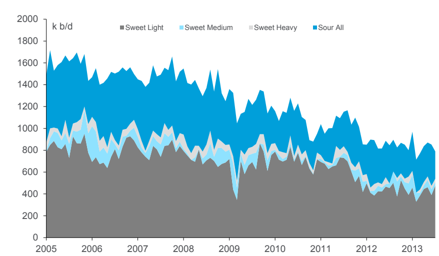
Source: EIA, Citi Research

Figure 42. Eastern Canadian crude imports



Source: NEB, Citi Research

Figure 43. PADD I crude imports by quality



Source: EIA, Citi Research

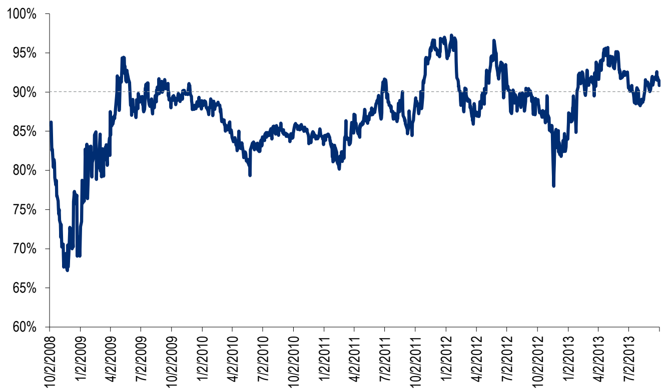
So how big a factor is the refinery switching and light-heavy blending to push out medium crude imports? An initial assessment of various refinery strategies to handle increasing volumes of light and heavy crudes suggests the price range where refiners are indifferent between running light and heavy is at LLS-Maya at ~$6-9. The estimate considers an "average" heavy refinery that looks like Marathon Garyville, Valero Port Arthur, Valero St Charles, which should be fairly representative of PADD III heavy refineries, or some 35% of the 8.6-m b/d of PADD III refinery capacity (~3-m b/d). In theory, a 30% light to 100% light switch – a 70% swing – could mean >2-m b/d of light sweet crude absorption, but this remains an abstracted estimate at this point.

By modeling the changes in gross margin from running different crude slates based on the changes in product yields and performance losses from running light crude in heavy units, it appears that a switch from running 30% light and 70% heavy to 100% light would need to be incentivized by LLS-Maya compressing to ~$7-8 from current levels of $12 (Figure 45); this factors in a 25% reduction in refinery throughput and a 10% reduction in clean product yields. Switching just 10% (30:70 to 40:60 light-heavy) could be incentivized from LLS-Maya at $8-9 (Figure 46).

Switching from 30:70 to 100:0, but with a 25% reduction in clean product yields – in other words, if running light in a heavy tower results in significant performance reductions – could mean a narrower spread LLS-Maya of $5-7 would be required. Worse performance would require even deeper compression of light-heavy, which would imply even weaker LLS relative to Brent, too.

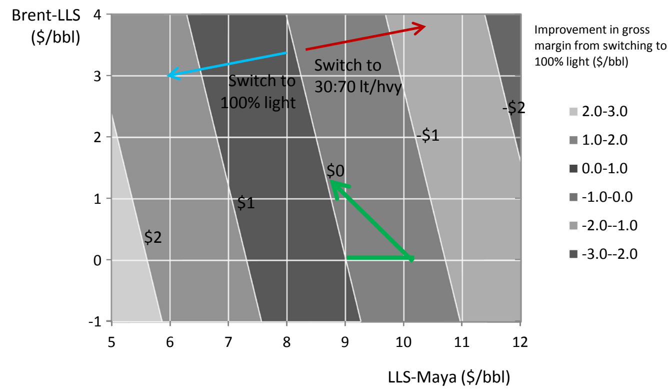
2 "The End of the Beginning" (Eric G. Lee et al, May 2013), "Parity Like It's 1999?" (Eric G. Lee et al, July 2013), "Commodities Super Cycle Sunset: FX Effects – 4Q'13 Commodities Macro Market Update" (Edward L. Morse et al, September 2013).

Figure 44. Historical ratio of Maya to LLS prices (%, 2008-13)



Source: Bloomberg, Citi Research

Figure 45. Estimated gross margin improvement from switching from 30:70 light-heavy to 100% light, as Brent-LLS, LLS-Maya vary

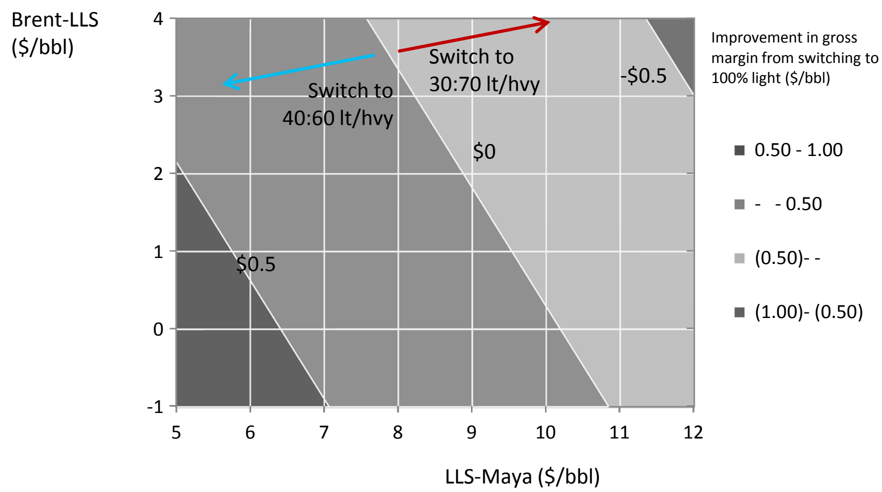


Source: Citi Research

Given 2015 could see fuel oil – and heavy crudes like Maya – falling on the ECA bunker fuel sulfur spec tightening to 0.1%, what is the impact of a fall in Maya on the need for LLS to discount to stay competitive for heavy-to-light switching?

The model suggests that if Maya weakens by $1 versus Brent (a rightwards movement on the surface) LLS would need to discount by $1.1-1.3 versus Brent to stay competitive with Maya (the vertical component of a NW movement to return to the indifference curve, shown by the green arrow above), depending how much refinery throughput and yields suffer from the switch. This implies that the pressure of Canadian heavy crude arrivals on the USGC on Maya could have a more than one-to-one effect on Brent-LLS if refinery switching is a major component of the absorption of light sweet crude.

Figure 46. Estimated gross margin improvement from switching from 30:70 light-heavy to 40:60 light-heavy, as Brent-LLS and LLS-Maya vary



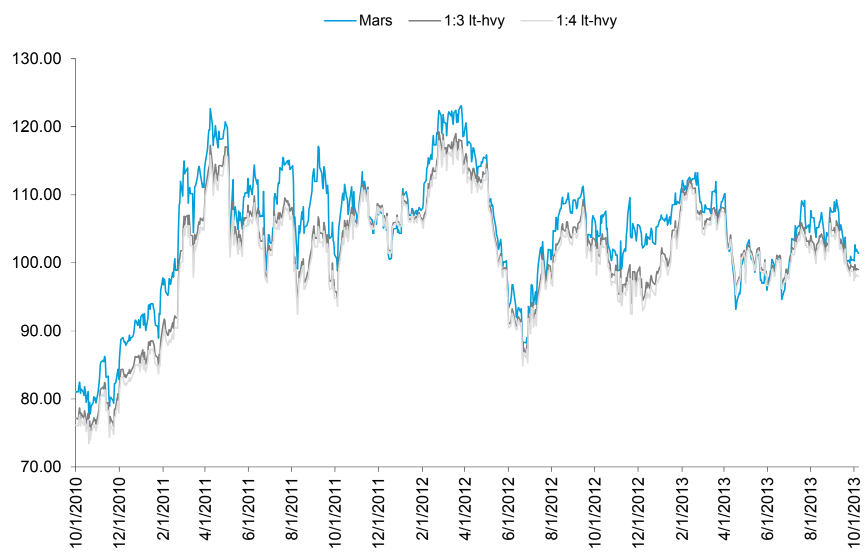
Source: Citi Research

Model sensitivities to keep in mind include the following. First, a 25% reduction in total crude throughput and a 10% reduction of light and middle distillate yields are built in for when running light crude through a heavy crude tower. Second, VGO and residual fuel oil prices affect the picture, and buying feedstock on the open market

to run through downstream units can be competitive to keep up product yields; refineries have been assumed to be price-takers here, but if this switching drives up prices in the aggregate, this could worsen switching economics.

If the product yields from running light crude in a heavy tower are worse than the 90% assumed for the basic model, LLS-Maya needs to compress further to make economic sense for heavy-to-light switching. If light and middle distillate yields worsen to a lower 75% of what they would be when run through a light crude tower, LLS-Maya looks to need to be in the $5-7 range to incentivize switching. At 60%, LLS-Maya needs to be in the $3-5 range.

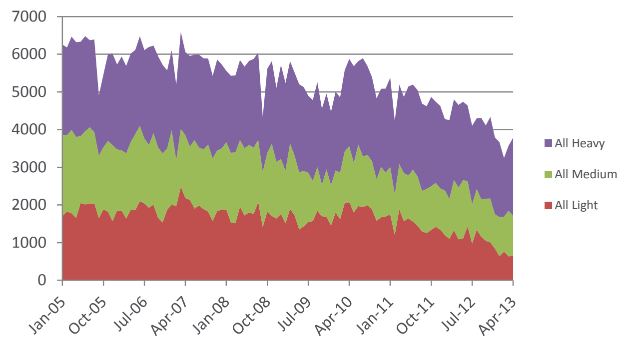
Figure 47. Mars prices and 15:85 and 25:75 light-heavy weighted average prices ($/bbl, 2010-13)



Source: Bloomberg, Citi Research

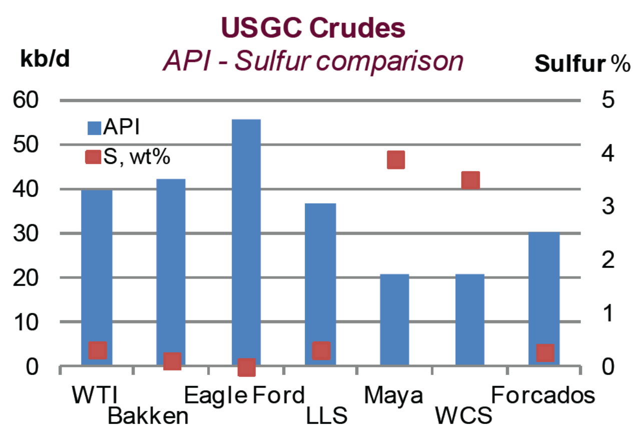
What about light-heavy blending to replace medium crude imports? Before heavy-to-light switching comes into play, USGC refiners are blending light and heavy to match medium crudes; to match product yields with medium crudes, not much light crude is required, only some 1:3 to 1:4 of Bakken and WCS could do it, without significant penalties to distillate yields. LLS and Maya prices have generally traded where blending to make a medium crude like Mars makes sense; the graph above shows weighted average prices of blends of LLS and Maya versus Mars prices. Given that there needs to be little change to current price levels to make this look economic, this could provide a way to use both more light *and* heavy crude – with more emphasis on heavy crude – which could weaken Mars and strengthen Maya relative to LLS. This would also help narrow light-heavy differentials and stimulate more heavy-to-light switching as discussed earlier; every barrel of light would be blended with two or three barrels of heavy, to back out three or four barrels of medium. Given the USGC still imports ~900-k b/d of medium (here, 25-32 API gravity), this seems like it would be a theoretical cushion of 300-k b/d light and 600-k b/d heavy, but only some of this should be substitutable. Light sour imports of ~700-k b/d could be another buffer. This could thus be supportive for Maya and WCS on the USGC, while pressuring Mars until medium crude prices fall below the weighted average price of blends with one part LLS and two or three parts Maya.

Figure 48. US Gulf Coast crude imports by API gravity (light >32, heavy <25)



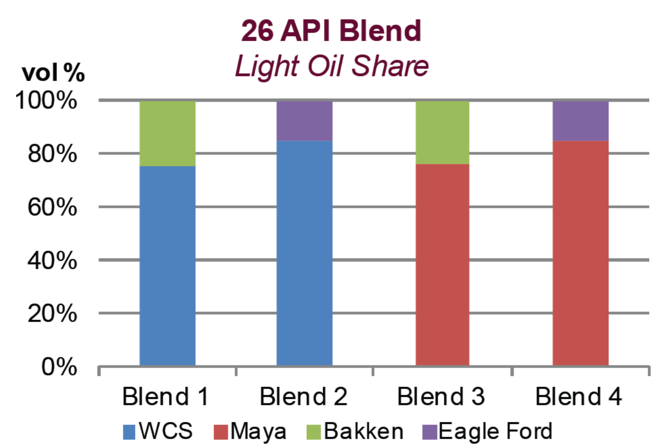
Source: EIA, Citi Research

Figure 49. Specifications of key USGC crudes



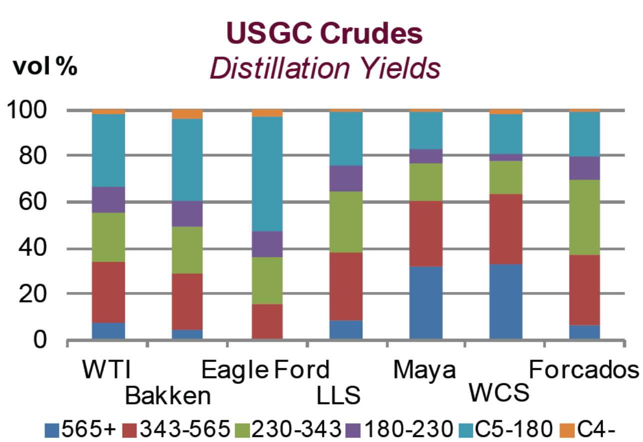
Source: IEA

Figure 50. Selected blends of light and heavy crudes on the USGC



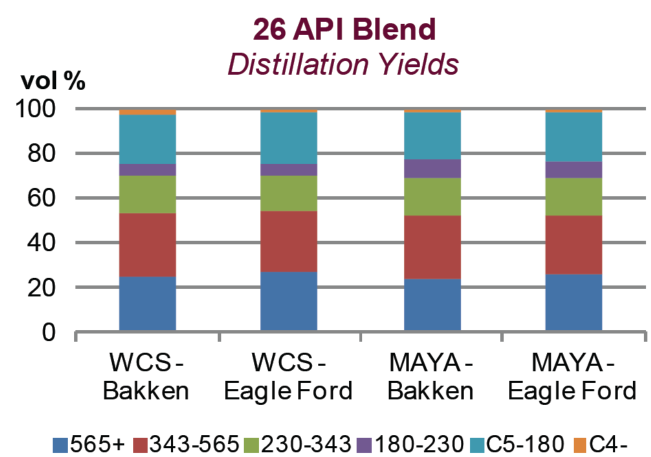
Source: IEA

Figure 51. Distillation yields of key USGC crudes



Source: IEA

Figure 52. Distillation yields of selected light-heavy blends



Source: IEA

Risks to the outlook

The outlook for North American crude price differentials has a lot of moving parts, and this report attempts to address the major ones. Of the moving parts that could present particularly salient risks to the outlook, here are several, addressed briefly.

Firstly, it is clear that the Energy East pipeline is a major pipeline that debottlenecks western Canadian production for a good number of years, even without Keystone XL. But its absence would keep western Canada stranded for longer. What are the risks to its approval, construction and completion? At this stage, the $12 billion project sees 300km of gas pipeline between Alberta and Ontario converted to oil service, and another 1,400km of new pipe through Quebec and New Brunswick. The end point, around the Irving St John refinery in NB, sees an affiliated export terminal project in the Bay of Fundy, a deep, ice-free harbor.

So far, Energy East has seen enthusiastic support from NB, which is facing 11% unemployment and keen to see the boost that this pipeline could bring to the province; Ontario and Quebec have been lukewarm but not actively opposing it. Ontario may question the benefits of being a transit province, and imports well under 100-k b/d of light crude oil, which could be pushed out. Quebec, however, imports over 250-k b/d of light and heavy crudes, and the benefits of import substitution with better priced crude would be a positive. On the crude transportation, Quebec is still reeling from the crude oil railcar explosion that leveled part of a small town at Lac Megantic (though the railcars were carrying Bakken shale oil, not oil sands-derived crude), and while this may increase opposition to any form of crude oil transit through Quebec, also makes crude-by-rail transport seem less palatable versus safer pipeline transportation of crude. The argument that insufficient pipeline takeaway capacity out of Alberta would likely mean increased volumes of crude-by-rail movements could mean less opposition or greater support for the Energy East pipeline, given the alternative. So, there seems to be little active opposition to Energy East in ON and QC, and a supporter in NB. This is in contrast to British Columbia, where Premier Christy Clark has been much more pro-natural gas than supportive of approving oil pipelines to the western coast of Canada; for BC, the concerns are multiple, with calls for a “fair share” of the economic benefits, as well as recognition of environmental and First Nation concerns. Despite recent willingness to discuss these, it seems the westward pipelines – Northern Gateway, and the expansion of Kinder Morgan Trans Mountain – remain less likely to make it to service by 2018, if at all.

Ultimately, the Energy East approval application needs to be filed with the National Energy Board of Canada, after which it goes to the federal Cabinet for a final decision; the decision does not reside with the provinces, though they can apply political pressure. This is unlike Keystone XL, where the crossing of an international border has meant that approvals are also needed on the US side, where it can be focused on lobbying against a US Presidential approval, where the final decision resides. And Prime Minister Harper has endorsed the project. Separately, given the complexity of the field and environmental work, TransCanada announced that it had delayed its goal of filing the application by the end of 2013; it is now likely to be filed in 2014. This is a reminder that pipeline projects are more often delayed than early, for approvals as well as construction itself. In the analysis in this report, the pipeline is seen to start in 2H’17, but there are risks to it being pushed into 1H’18. The analysis of price differentials would still stand, but the shift to narrower western Canadian crude price discounts would be delayed a little longer.

Relatedly, there could also be new opposition to the full reversal of the Line 9 pipeline, which would allow an incremental 300-k b/d of pipeline capacity to take light crudes further east to Montreal and then further to Portland, Maine. This would have a nearer-term effect of limiting inland flows out to serve eastern Canada's light sweet crude market, which could then remain a larger market for USGC light crude exports in the 2014-15 timeframe.

Secondly, much of the debottlenecking from 2H'14 to 1H'16 comes before Keystone XL, and are downstream of Chicago. Upstream of Chicago – that is, pipelines from Alberta to Superior, WI and onwards to the Chicago area (and also Sarnia, ON and further east) – could see periodic bottlenecks. As discussed in the section, "The weakest link(s)?", the Superior to Flanagan, IL sections of pipe could present problems, and mean that the actual pipeline capacity for the Mainline could be at times restricted due to these downstream sections of pipe; these sections of pipe are expanded over 2H'14 (+160-k b/d) and over 2H'15 (+640-k b/d), after which these concerns should ease.

Thirdly, growing bitumen production requires corresponding growth in diluent needs. For dilbit blends, this would be some 0.39 bbls per one barrel of bitumen, though for railbit, this would be a lower 0.24 bbl requirement per barrel of bitumen. Taking a high case and assuming all bitumen requires diluent to make dilbit, western Canada may need almost 800-k b/d of diluent by 2020, to blend with 2-m b/d of bitumen, up from current levels of ~400-k b/d of diluent to blend with ~1-m b/d of bitumen production. Canada's domestic condensate production is seen as flat to declining by CAPP, although it is possible that growing shale oil production could lead to growth in this area. But with local condensate production at ~150-k b/d, which could decline to 100-k b/d by end-2020 (as is CAPP's outlook), Canada would need to import some 650-k b/d of diluent, up from imports of over 250-k b/d today. Pipeline imports today are from Flanagan to Edmonton, AB, up the Southern Lights pipeline, with 180-k b/d of capacity. This is planned to expand by another 95-k b/d. Other proposed diluent pipelines are the Kinder Morgan Cochin conversion project (95-k b/d, 3Q'14, from Illinois to Alberta), which would bring Eagle Ford condensate up from the USGC via the Explorer pipeline; TransCanada Grand Rapids (330-k b/d, from Heartland, AB to Fort McMurray, AB, proposed for 2017); and the Northern Gateway, (193-k b/d, from Kitimat, BC to Alberta, likely 2018). Rail brought an estimated 50-k b/d of diluent to Alberta in 2010, and this could grow, with backhaul potential from the USGC on dual-use bitumen/condensate railcars. But of the proposed pipelines, these add an incremental ~700-k b/d of capacity, with only 380-k b/d from outside the province, and the Northern Gateway project in question. This means growing diluent needs might need to be met by using railcars, or using syncrude to blend with bitumen at a 50:50 ratio to make synbit, or through further pipelines, likely from the US, where fortuitously for diluent needs, condensate/NGLs production is growing fast from the shale revolution.

Fourthly, east coast refineries may yet be at risk, with the Trainer, Philadelphia and Delaware City refineries potentially under pressure without access to more competitively priced North American crude coming by rail or otherwise, including from the US Gulf Coast. Refiners on the east coast of Canada have some advantages due to a range of options that are opening up for crude access – rail, Line 9, Energy East, and US crude exports from the US East and Gulf Coasts – but could be at risk too. This could reduce the local markets available to absorb USGC and North American light crude, bolstering the need for exports, competing for growing yet limited pipeline space. This could add some bias to North American crude prices to the downside versus waterborne grades.

Finally, the outlook in this report sees Brent-Maya at $10-12 levels up to 2016. This is at the wider end of the recent historical average levels, but Maya prices could see further risks to the downside, through increased arrivals of Canadian heavy crude on the USGC from 2H'14, as well as the 2015 ECA 0.1% sulfur limit for bunker fuel, and growing production in Mexico, Colombia, perhaps Venezuela. Other than the bunker fuel sulfur spec, which would hit heavy crudes globally if enacted, growing local availability in the US Gulf of Mexico from Canada, Mexico and Colombia could mean Maya needs to price lower to move to Asian refineries. This could pressure WCS, as well as widen the light-heavy differential, curtailing higher levels of heavy-to-light switching in USGC refineries, pressuring light crudes too.

Appendix A-1

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