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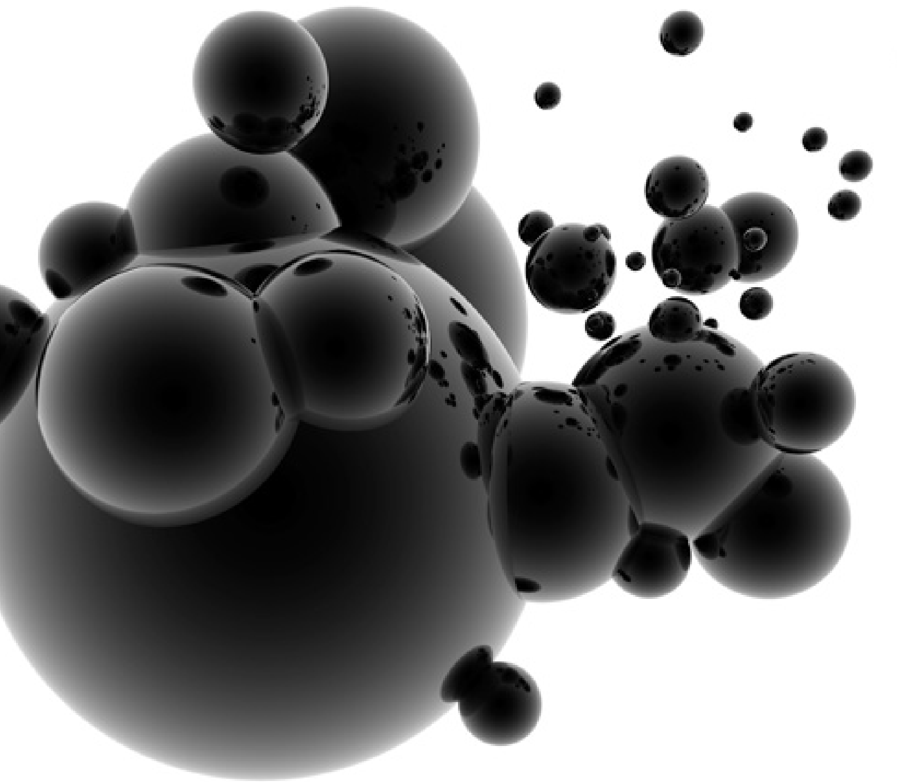
SPECIAL REPORT

New Crudes, New Markets

March, 2013

Price Group / Oil Division



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KEY FINDINGS IN THE NORTH AMERICAN CRUDE OIL MARKET

- The US could produce as much as 11 million b/d of crude in 2020 thanks to shale, according to the International Energy Agency, surpassing Saudi Arabia.

- US crude oil production breaches 7 million b/d, levels not seen since the 1990's.

- Production from key shale plays Eagle Ford and Bakken rises to over 1.6 mn b/d in January, 900,000 b/d above year-ago levels, and could top 3.2 mn b/d combined in 2016.

- Eagle Ford loadings at Corpus Christi jump to 280,000 b/d in November thanks to the completion of pipelines and storage terminals.

- Bakken rail car loadings jump to 500,000 b/d in December as increasing rail loading and offloading capacity provides more flexibility for sellers.

- US crude imports collapse in February to the lowest levels in 12 years at 8 million b/d in response to rising domestic crude production.

- US refiners Valero, Marathon, and Phillips 66 announce shifts to domestic shale crudes at many of their refineries; US Atlantic Coast refiners begin to shift to Bakken and eschew imports.

- Continually wide discounts for WTI relative to Brent spark US Midcontinent to US Gulf Coast pipelines projects to increase total capacity to 1.95 mn b/d by 2014.

- Delays in TransCanada's northern 830,000 b/d Keystone XL line spur alternative delivery options for Canadian heavy.

INTRODUCTION

The US crude oil market is undergoing enormous change with production exceeding forecasted levels. The US is now the second largest liquids producer in the world, and within a hair's breadth of Russian output if one combines crude oil production with natural gas liquids and ethanol output. Light sweet crude imports into the US are vestigial as US refiners switch to the newly found streams pouring into the refining centers. Extensive exploration and production activity in crude oil shale plays such as Eagle Ford and Bakken has boosted domestic crude output for these new light sweet crudes. Hydraulic fracturing has also resurrected drilling activity in established plays such as the Permian Basin, the production center for WTI. This increased production, which has crossed the 800,000 b/d level for Bakken, 1.3 million b/d for Permian and above 800,000 b/d for Eagle Ford, has fundamentally altered wider crude oil dynamics in the US, including a significant impact on benchmark WTI.

The US benchmark entered into a period of unprecedented relative weakness to international benchmarks in 2011, largely due to rising Bakken production and the arrival of additional Canadian crude into Cushing via the 590,000 b/d Keystone system. Furthermore, a lack of exit capacity out of Cushing, Oklahoma – WTI's storage hub – depressed WTI to a record $29.24/b discount to Brent in September 2011.

This production growth from US shale plays, overall Canadian crude production, now at 3.6 million b/d according to Canada's National Energy Board (NEB), and the US Midwest bottleneck have created incentives for producers and midstream companies to find delivery solutions to market. First, Bakken rail takeaway capacity could breach 1 million b/d by the end of 2013. Bakken producers have found willing buyers on both the US Atlantic and West Coasts, albeit at a heavy transportation cost per barrel – estimated to be $12/b to move Bakken from North Dakota to Albany, NY. Still, the destination flexibility of rail is providing producers with a better netback for Bakken than existing pipelines. Bakken and even heavy Canadian crude could travel as far south as Houston, where Kinder Morgan and Mercuria are set to complete a 210,000 b/d rail terminal by early 2014.

Pipeline operators have also responded to this bottleneck of crude supply, with a number of ambitious projects recently completed and underway. A new grade called "domestic sweet" by some US Gulf Coast refiners began flowing into Freeport, Texas last year – a Cushing-sourced blend that includes WTI. Now with the Seaway Pipeline bringing 400,000 b/d of "domestic sweet" and Canadian heavy sour into its new Houston terminus, this "domestic sweet" blend is being consumed by Houston refineries.

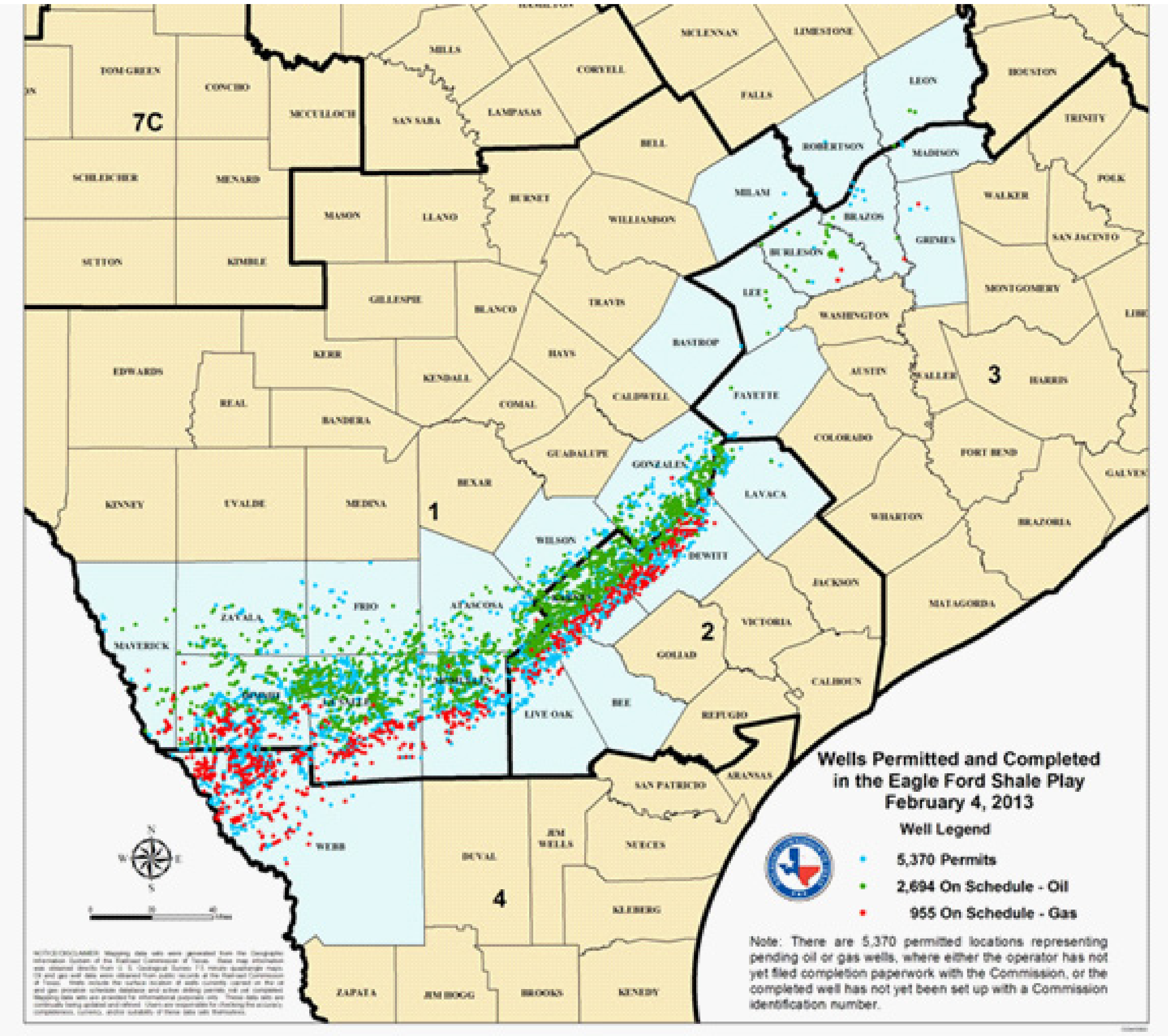
WTI from Midland is beginning to flow into Houston via the 40,000 b/d Kilgore pipeline off Sunoco's West Texas Gulf pipeline. And starting in mid-March, Magellan's Longhorn pipeline will begin bringing light sweet crude from the Permian Basin, and will eventually bring West Texas Sour (WTS) as well once the line reaches its full 225,000 b/d capacity in the third quarter.

The reversed Seaway pipeline expansion added 250,000 b/d capacity and began moving up to 400,000 b/d of crude from Cushing to Enterprise Houston Crude Oil Terminal on January 11. Enterprise and Enbridge also intend to build a second line for Seaway, expanding the capacity of the project to 850,000 b/d by the middle of 2014.

A paradigm shift is already here, with substantial decreases in light sweet crude imports into the US Gulf Coast and an increase in condensate/crude exports by way of condensate splitting and refining into products such as naphtha and distillate.

These structural shifts in the market will likely unseat the dominance of WTI in Cushing, Oklahoma as the singular benchmark for Americas crude in the next two to three years. How benchmark pricing will develop for this region is dependent upon many variables, including shale oil production living up to the lofty expectations, pipeline project approvals, and the growth and expansion of rail as a transportation option, and questions of if and when crude exports from the US Gulf Coast will gain approval. But a change from the status quo in the US, and global crude market, is very likely in the near term.

Eagle Ford Shale Well Activity



Source: Texas Railroad Commission

The primary beneficiaries of this change will be US refiners, who will have access to steady supplies via pipeline, rather than relying heavily on waterborne imports. The US is currently a 17.7 million b/d market in terms of operable refining capacity – current domestic production is 7 million b/d, the highest levels since 1993, according to the US Energy Information Administration (EIA), which expects it to grow to 7.32 million b/d in 2013.

The EIA outlook for 2014 oil production would mark the highest annual average since 1988, the last year that production topped 8 million b/d. US output peaked at 9.6 million b/d in 1970. Onshore drilling in the Lower-48 states is expected to generate 5.44 million b/d in 2013 and 6.01 million b/d in 2014, EIA said. Central to this projected growth will be ongoing development activity in key onshore basins, including the Williston Basin in North Dakota, Western Gulf Basin in South Texas and Permian Basin in West Texas.

Expected Permian Basin, Eagle Ford and Bakken production by 2016 could add nearly 2 million b/d of additional domestic crude and condensate production for the US, according to industry forecasts. Some data analysts are forecasting an additional 600,000 b/d of Permian production to as high as 1.9 million b/d by the end of 2016, an additional 800,000 b/d of Bakken production by year-end 2016 to 1.6 million b/d, and an additional 800,000 b/d of Eagle Ford capacity by the end of 2016 to 1.6 million b/d.

NEW CRUDES: EAGLE FORD

The Eagle Ford shale play, located in south Texas, is one of the many unconventional oil and gas plays in the US experiencing an unprecedented rate of exploration and production. However, the Eagle Ford play resembles the prolific Bakken play in terms of its ample crude oil and liquids content and striking estimates for production capacity in the next few years with January 2013 estimated crude and condensate production to be between 750,000 and 880,000 b/d. These are substantial increases from a year ago, when Eagle Ford production was estimated to be around 200,000 b/d in early 2012.

The shale formation extends across Texas from the Mexican border to east Texas, roughly 50 miles wide and 400 miles long, according to the Texas Railroad Commission. Recoverable reserve estimates are limited for the formation. In 2010, the US Geological Survey estimated the undiscovered oil reserves in the Eagle Ford shale at a mean of 853 million barrels of oil, which could be on the conservative side given reserve estimates from individual producers in the Eagle Ford. For example, EOG Resources, one of the largest producers in the play, estimated the potential reserves of its assets at 690 million barrels of oil alone.

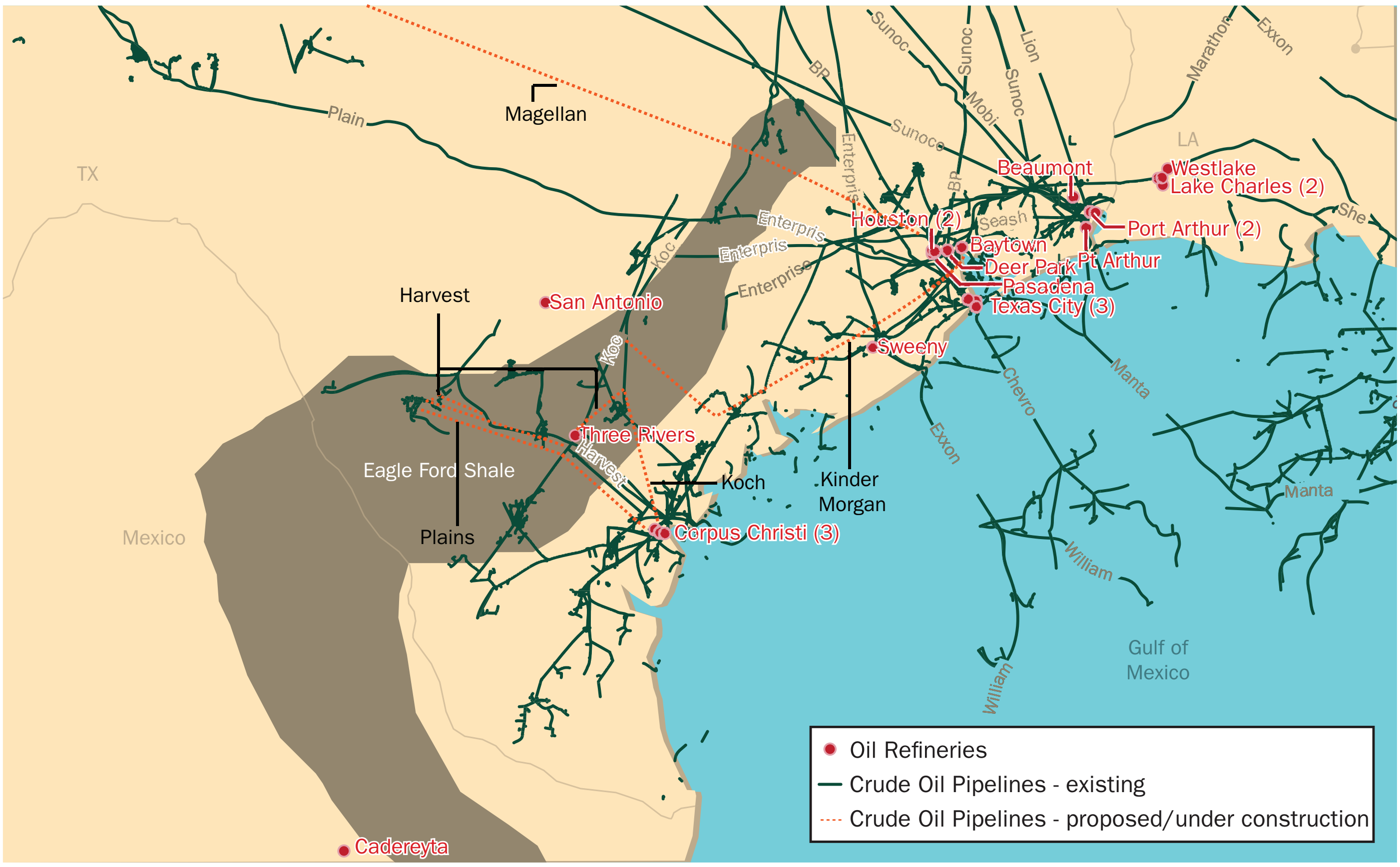
What also sets the Eagle Ford apart from other US shale plays is its location – just 100 miles from the US Gulf Coast refining complex, the center of crude oil demand in the Americas. About half of the total 17.7 million b/d of US refining capacity can be found in the US Gulf Coast, with 4.7 million b/d found in Texas and 3.2 million b/d in Louisiana. This close access to demand and the recent flurry of infrastructure projects to move Eagle Ford production to Texas Gulf Coast refineries has changed the dynamics of the US Gulf Coast crude oil market, with Texas refineries increasing their light crude runs and shunning light crude imports.

Part of the Eagle Ford Shale formation dips into Mexico, but productive wells have not yet been drilled across the border. In February 2011, Mexico state-oil company Pemex announced the results of an Eagle Ford shale exploratory well in Mexico located across the US-Mexico border from Laredo, Texas. This exploratory well, Emergente-1, produced an initial 3 million cubic feet/day of gas and an average of 17,000 b/d of condensate. Pemex said it is now in the process of completing three dry and wet natural gas wells in the states of Coahuila and Hidalgo, with an estimated productive capacity of 27-87 TCF over the life cycle of those wells. Associated crude oil from this portion of the Eagle Ford shale could be relatively low as more crude and condensate-prolific wells are primarily located in the northern part of the formation. President Felipe Calderon said that Eagle Ford production might not make sense for state-owned oil and gas company Pemex, as production of shale gas would have to take second place to higher priced, more profitable oil production.

Bentek estimates that Eagle Ford crude and condensate production crossed the 800,000 b/d in December 2012 and forecasts that production could reach nearly 1.6 million b/d by the end of 2016. Their forecasts reflect all production coming out of the region, including conventional and unconventional production of crude and condensates.

Turner Mason & Company estimates that current Eagle Ford production is around 700,000 b/d, as their estimates do not include

Eagle Ford Shale: Formation, Pipelines, and Refineries



Source: Platts

light condensates. Turner Mason forecasts that Eagle Ford production will also rise to 1.1 million b/d to 1.4 million b/d by 2016.While Eagle Ford may find some competition from light sweet crude out of the Permian Basin in the next few years, Turner Mason expects it would take prices below $50/b to shut-in Eagle Ford wells.

The quality of Eagle Ford production thus far has varied widely, with API gravity levels ranging from 38 to 60 API and higher. While many of the pipelines proposed for Eagle Ford are operational, consistent streams are starting to develop but variability of quality still remains an issue. These common streams have started to emerge at South Texas and Texas Gulf Coast terminals – Eagle Ford condensate (55 API), Eagle Ford crude (45 max API), and more of an intermediate Eagle Ford grade, with an API gravity above the heavier crude and below that of condensate (around 47 API).This condensate blending can, at times, yield Eagle Ford crude that has more light ends yield than desired by refiners. And recently, some Eagle Ford streams are showing high metals content, potentially due to sour crude blending with Eagle Ford steams. The vast condensate production from Eagle Ford is creating opportunities for condensate splitting. BASF and Total Petrochemicals have a 75,000 b/d splitter at the Port Arthur ethylene cracker that is processing Eagle Ford condensate, and additional companies are planning to build condensate splitters.

In late 2011, Enterprise, Sunoco, Plains, and Flint Hills Resources began publishing posted crude oil prices for Eagle Ford grades. All of these companies split out separate streams for Eagle Ford condensate and Eagle Ford crude, with Plains also publishing a separate posted price for Eagle Ford Light (50-60 API, as opposed to 40-45 API for Eagle Ford) and Flint Hills publishing additional postings for Eagle Ford Sour, and for all four grades out of the western portion of the play (Eagle Ford West, Eagle Ford West Condensate, Eagle Ford West Light, and Eagle Ford West Sour). Chevron has also started to publish posted prices for Eagle Ford, in a grade called South Texas Light Sweet.

Eagle Ford's role in the market will be further defined by the outcome of several proposed pipeline projects that will bring additional sweet as well as sour crude to the Gulf Coast – ranging from WTI out of Cushing, WTI and WTS-like crude from the Permian Basin, Bakken Blend unconventional crude, and Canadian heavy sour (*see New Markets section*).

The flurry of drilling rig activity has, in turn, sparked a frenzy of proposed pipeline expansion and construction projects in South Texas, linking inland crude oil and condensate production to Texas Gulf Coast refineries as well as other US Gulf Coast refineries via waterborne access. Many of the Eagle Ford pipeline projects were completed in 2011 and last year, supplanting some of the truck movements from the wellhead to refineries in South Texas.

However, the total capacity for these pipeline projects outpaces expected production for Eagle Ford over the next four years (as much as 1.6 million b/d by 2016) – some 650,000 b/d of proposed and existing capacity into Houston and 1.330 million b/d into Corpus Christi.

The majority of the Houston capacity is now operational. Kinder Morgan started its 300,000 b/d line from Cuero, Texas to the Oiltanking Terminal on June 14, 2012. Kinder Morgan is also in the process of building a condensate splitter and processing facility near the company's Galena Park terminal in the first quarter of 2014.

Phase 1 of Enterprise's South Texas Crude Oil pipeline system came into service in June 2012, a 350,000 b/d line from Wilson County to Sealy, which then connects to the Rancho Pipeline into Houston and the Enterprise Houston Crude Oil (EHCO) terminal. This Sealy to Rancho interconnect was completed in July 2012. Phase 2 of this project, a 200,000 b/d line from Gardendale to Wilson County, is expected to be completed in the second quarter of 2013. The EHCO terminal began accepting crude oil barrels on November 1, 2012 with 750,000 barrels of storage tanks complete.

The pipeline projects slated for Corpus Christi are far more numerous, totaling 1.33 million b/d of proposed capacity, and connect with multiple waterborne terminals as well. Thanks to this influx of pipeline capacity, Corpus Christi has become a waterborne hub for crude oil and condensate as this capacity exceeds the 780,000 b/d of local refining capacity. All of the proposed Corpus Christi pipeline projects have been completed, with the exception of the Double Eagle Pipeline joint venture between Magellan and Copano. That 100,000 b/d line is expected to be partially operational in March, with full operation expected in the third quarter.

Recently, Enterprise announced a joint venture with Plains to combine some of their existing pipeline projects from the Eagle Ford to Corpus Christi and Houston. This joint venture included the 350,000 b/d system proposed by Plains to take crude from Plains' Gardendale terminal to a marine terminal in Corpus Christi. That pipeline is expected to be operational in the first half of this year. In addition, Enterprise and Plains will connect Three Rivers to Enterprise's existing South Texas Crude Oil system via its Lyssy, Texas station.

Corpus Christi is the first Eagle Ford waterborne hub, connecting the Eagle Ford play with demand outlets on the US Gulf Coast and US Atlantic Coast. If US export permits are granted, Corpus Christi is also poised to be the hub for waterborne exports. The reason for this development is that Corpus Christi is relatively close to the shale play, and the potential demand for sweet crude there among the three area refineries -- Flint Hills, Valero, and Citgo --- comes far below the 1.33 million b/d pipeline capacity into the port. As such, several companies have built infrastructure to allow for waterborne crude loadings, and many are looking to expand that infrastructure given the flurry of loading activity.

Flint Hills upgraded its Ingleside terminal near Corpus Christi to ship up to 200,000 b/d of waterborne crude in the summer of 2012. Martin Midstream completed its 300,000 barrel crude terminal with waterborne loading capability in December 2011 and has begun construction of new terminal at the Port of Corpus Christi, Texas, to receive crude from the Eagle Ford Shale. The new facility will have an initial storage capacity of 600,000 barrels, with the ability to expand up to 900,000 barrels.

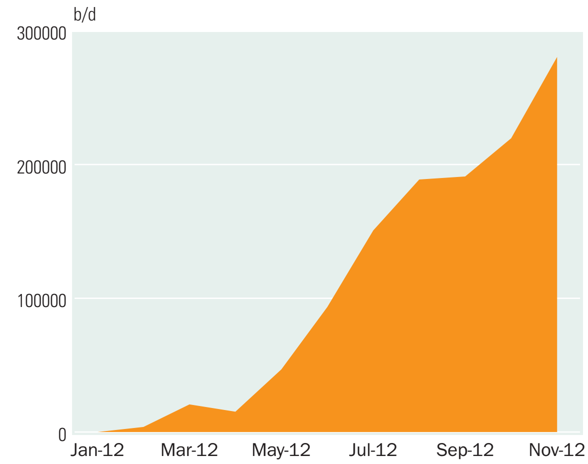
Magellan Midstream is expanding its 3 million barrel Corpus Christi storage terminal by 500,000 barrels of condensate/crude oil storage and the addition of a dedicated dock delivery pipeline by the end of the first quarter 2013. And NuStar is adding a new ship dock to its 2 million barrel North Beach storage terminal by the first quarter of 2014.

In addition, Trafigura, a commodity trading company, acquired a 600,000 barrel terminal in Corpus Christi from Texas Docks & Rail in January 2012, and this terminal can be expanded up to 2-million barrels. In May 2012, Trafigura began rail off-loadings of Eagle Ford crude at this terminal.

Waterborne loadings of Eagle Ford crude are occurring with regularity out of Corpus Christi, with ocean-going barges loading for delivery along the Texas Gulf Coast or Louisiana. In addition, several US-flagged Panamax (50,000 mt) and MR2 (30,000 mt) tankers have loaded out of Corpus Christi to move Eagle Ford crude to the US Atlantic Coast market. In 2012, Corpus Christi saw crude waterborne loadings (barges and cargoes) climb from negligible levels to over 280,000 b/d by November (*see graph*). This number is expected to rise as Eagle Ford crude production continues to grow and marine terminals continue to build additional storage and loading docks. Analysts RBN Energy said that a bottleneck is forming at Corpus Christi, as increasing Eagle Ford crude production and pipeline flows to the port are overwhelming existing docks and rendering marine transport equipment scarce.

Despite expensive rates for US-flagged tankers, some Eagle Ford crude is moving on Jones Act vessels. In September 2012, both Phillips and the Carlyle Group moved US-flagged vessels of Eagle Ford crude to their respective US Atlantic Coast refineries in New Jersey and Pennsylvania. These movements represent a growing trend among US Atlantic Coast refiners to eschew Brent-related crudes and run US shale crudes such as Bakken Blend and Eagle Ford (*see Bakken Blend for additional details*).

Corpus Christi Waterborne Crude Loadings



Source: Port of Corpus Christi

NEW CRUDES: BAKKEN BLEND

Bakken Blend crude oil represents the light sweet crude produced from the Bakken Shale Formation in the North Dakota/Montana/Saskatchewan/Manitoba region. Production from the US side of the Williston Basin, the sedimentary basin that contains the productive Bakken Shale Formation, crossed the 800,000 b/d mark in September according to the North Dakota Pipeline Authority. Estimates for 2016 production vary, but are as high as 1.6 million b/d for the Bakken Formation, spurring a flurry of pipeline expansion and rail projects in progress. With this buoyant production, Bakken is finding its way to the three US coasts and is now being delivered in blends against CME Group's NYMEX crude futures contract.

Take-away capacity is the most critical issue for those exploiting the Bakken shale formation, given its distant location away from most of the US refining capacity in the northern Rockies. Several rail expansion projects are set to start up this year to meet the exit capacity needs of Bakken producers. Rail is a more expensive shipping option than pipeline for crude oil on paper, but it gives fast-growing areas takeaway capacity and it provides flexibility on where the crude is shipped. This flexibility is becoming more critical -- on the US Gulf Coast, the ultimate destination of most pipeline projects, Bakken faces additional competition from rising production of Eagle Ford and Permian grades (WTI, domestic sweet, etc).

By year-end 2012, rail takeaway capacity from the Bakken Formation totaled 730,000 b/d. According to the North Dakota Pipeline Authority, rail exports from the Bakken hit 500,000 b/d in November. By the end of this year, this rail capacity number could come in just north of 1.1 million b/d (see table)

Rail capacity at St. James, Louisiana to accept Bakken crude is growing, with US Development's (now Plains All-American Pipeline) planned expansion at their St. James rail terminal in 2011 to a total 130,000 b/d, or two unit trains. Bakken Blend has found its way into the Light Louisiana Sweet stream along with some Eagle Ford crude, increasing the overall supply of LLS and placing some pressure on LLS values relative to Brent.

Bakken could make its way to Houston as early as 2014 thanks to a proposed rail terminal on the Houston Ship Channel. Kinder Morgan has entered a long-term agreement with Mercuria to build a 210,000 b/d crude by rail receiving terminal. This could even give Bakken access to the water, as the terminal will have 100,000 b/d of barge loading capacity.

However, the increasing production of Eagle Ford and Permian crude could make St. James and potentially Houston a less attractive destination for Bakken in the next few years. By 2014, Turner Mason expects that the US Gulf Coast market will only be opportunistic for Bakken producers and marketers as rising supplies of Texas light crude could potentially overwhelm Bakken demand.

That upcoming shift in the US Gulf Coast market is one of the primary reasons for the recent boom in rail capacity and interest from both shippers and refiners in the US Atlantic and West Coasts to move Bakken in either direction.

Bakken Crude Rail Terminals

Terminal Company	Location	Year-End 2010 (b/d)	Year-End 2011 (b/d)	Year-End 2012 (b/d)	Year-End 2013 (b/d)
Exit Capacity					
Musket	Dore, ND	0	0	60,000	60,000
Hess (up to 120,000 b/d)	Tioga, ND	0	0	60,000	60,000
Eighty-Eight Oil	Guernsey, WY	0	0	0	80,000
Enbridge	Berthold, ND	0	0	10,000	80,000
Bakken Oil Express	Dickinson, ND	0	100,000	100,000	100,000
Global Partners (bought from Basin Transload)	Columbus, ND Beulah, ND	0	0	0	100,000 60,000
Rangeland (COLT)	Williams County, ND	0	0	120,000	120,000
EOG Resources (up to 90,000 b/d)	Stanley, ND	65,000	65,000	65,000	65,000
Dakota Plains	New Town, ND	20,000	40,000	40,000	40,000
Savage Services	Trenton, ND	0	0	90,000	90,000
Plains	Ross, ND		20,000	20,000	65,000
Sites in Minot, Dore, Stampede, Donnybrook, and Gascoyne	ND	30,000	30,000	30,000	30,000
Great Northern Midstream	Fryburg, ND	0	0	60,000	60,000
US Development Group	New Town, ND	0		35,000	70,000
Basin Transload	Zap, ND	0	20,000	40,000	40,000
	Total	**115,000**	**275,000**	**730,000**	**1,120,000**

Source: Platts, North Dakota Pipeline Authority

Rail deliveries of Bakken Blend to the US Atlantic Coast were 72,000 b/d at the end of 2012, according to Bentek. Turner Mason expects this number to average as much as 150,000 b/d by the end of 2013, and Bentek says it could be as much as 235,000 b/d. Some of these shipments, in a departure from standard practices for domestic crudes, have been sold on a Brent-related basis, as these barrels are competing with Brent-related imports.

Several area refineries are ramping up their use of Bakken in a region with around 1 million b/d of operable refining capacity, according to the EIA (see Demand for New Crudes section for further analysis). The 330,000 b/d Philadelphia refinery, now owned Carlyle Group and Sunoco joint venture called Philadelphia Energy Solutions, is shifting to US crudes and away from North Sea and African grades. The partners also said in June they will build a rail facility to take in greater volumes of domestic crudes, most likely Bakken from North Dakota given its expansive rail export capacity.

Monroe Energy, Delta Air Lines' refining unit, said in January that it will receive its first railroad shipment of Bakken in the first quarter at its 185,000 b/d Trainer, Pennsylvania refiner. Once this test run of Bakken is completed, Monroe will have a better idea as to how to develop its crude sourcing options from the Bakken, the company said.

As well, Phillips 66 announced a five-year contract to move 50,000 b/d of Bakken to its 238,000 b/d Bayway, New Jersey refinery with Global Partners. Global had supplied the Bayway refinery with Bakken crude since December 2011, but not on a term basis. Global owns a 160,000 b/d rail offloading terminal in Albany, New York that handles Bakken crude and ethanol.

PBF Energy, the company that acquired both the 190,000 b/d Delaware City, Delaware and the 180,000 b/d Paulsboro, New Jersey refinery from Valero in 2010, announced this month that it had completed its second rail offloading facility at Delaware City to receive Bakken and heavy Canadian crude. With this new facility, the refinery's rail terminal capacity increased to 110,000 b/d.Now, Delaware City will be able to receive 40,000 b/d of Canadian heavy crude, like Western Canadian Select, and 70,000 b/d of light crude such as Bakken.

In response to this interest, Enbridge announced it would complete a unit train facility with pipeline infrastructure in the Philadelphia area. Thie Eddystone Project, part of a joint venture with Canopy Prospecting (25%), should be able to handle 80,000 b/d of crude by rail in the third quarter, and will be expanded to 160,000 b/d of capacity for rail and barge offloadings as early as mid-2014. As well, Plains All American will complete construction of a 130,000 b/d crude rail receiving terminal in the first half of 2013.

US West Coast buyers are beginning to seek out Bakken as a potential option. Alon USA plans to bring in Midcontinent crude by rail to resell into the Los Angeles market rather than use for its own 68,000 b/d idled refinery in Bakersfield, California, according to a source close to operations. Alon is eight to 10 months away from receiving shipments of Midcontinent crude by rail. When received, those supplies will likely be shipped by pipeline into the Los Angeles market.

Tesoro is taking 40,000 b/d in Bakken via rail to its 120,000 b/d refinery in Anacortes, Washington, and will increase this to 50,000 b/d in February. Valero, who has been moving Bakken to its Memphis, Tennessee refinery via rail cars offloading in St. James then moving up the Capline Pipeline, could also consider moving Bakken to its California refineries, according to sources close to the company.

Midstream companies are also looking to expand rail receiving terminal capacity for Bakken. Plains All American Pipeline in December 2012 acquired multiple crude rail terminals from US Development Group, including a project to construct a crude oil unloading terminal near Bakersfield, California. Equity analyst firm Dahlman Rose says the US West Coast, particularly California, is about 18 months to 2 years behind the US Atlantic Coast in terms of infrastructure, as rail offloading terminals must go through a permitting process.

While rail capacity appears to be expanding faster than Williston Basin production, several large pipeline projects could add additional

Williston Basin Pipelines

Source: Platts

exit capacity for Bakken crude to reach potential buyers. Enbridge is expanding its North Dakota pipeline system by an additional 145,000 b/d by the first quarter of 2013, and this Bakken Expansion Project is readily expandable to as much as 325,000 b/d by the end of 2014, according to Enbridge.

In addition, Enbridge has proposed the 325,000 to 350,000 b/d Sandpiper pipeline from Beaver Lodge, North Dakota to Superior, Wisconsin, connecting back to the Enbridge mainline system into Chicago. This would provide Williston Basin producers with another option to move Bakken crude out of the region via pipeline and onto the Enbridge Lakehead system. As well, Enbridge will expand the 230,000 b/d Neche, North Dakota to Superior, Wisconin Lakehead system pipeline to 585,000 b/d by 2015. The overall Lakehead system has a combined capacity of 2.5 million b/d, moving crude from Alberta to the US Midwest. This Sandpiper project would shift the interconnection point from the Bakken to the Enbridge mainline system to Superior, Wisconsin, away from the current Clearbrook, Minnesota hub.

This Sandpiper project fits into the company's Eastern Canadian Refinery Access Initiative, where Enbridge is looking to reverse Line 9 between Sarnia, Ontario and Montreal, Quebec in two phases. The complete project, expected to be completed by the second quarter of 2014, would enable Bakken to move along with Canadian synthetic grades to Canadian refineries (see Keystone XL and Alternatives for Canadian Producers).

TransCanada's Bakken MarketLink project could link Williston Basin producers to potential buyers in Oklahoma and the US Gulf Coast, a proposed 100,000 b/d on-ramp that would link it to the proposed 1.5 million b/d Keystone XL pipeline system. However, this line's status is still up in the air as TransCanada still awaits approval of its cross-border permit for the Keystone XL project from the US State Department. (see New Markets section for more information on Keystone XL and impact).

While there is no connection from the Williston Basin to TransCanada's main 590,000 b/d Keystone line currently, the Keystone line's start-up initially freed up space on Kinder Morgan's 170,000 b/d Platte system to move Bakken from Guernsey, Wyoming to Wood River, Illinois.

Beyond Keystone XL, TransCanada is considering converting an underutilized natural gas line from Western Canada to Ontario and Quebec to carry Bakken as well as light and heavy Canadian synthetic crudes. An announcement is expected in early 2013 as to the status of this project.

Kinder Morgan Pony Express (KMPE) and Hiland Crude in December 2012 received regulatory permission for a project that would ship crude from the Bakken formation to Oklahoma. The companies would ship the crude from Montana to Oklahoma using three pipeline segments. The Pony Express mainline and Cushing extension would together provide about 230,000 b/d of light petroleum pipeline export capacity from Wyoming to Oklahoma. Hiland Crude and KMPE would offer joint transportation services once the project starts operation, which is slated for third quarter 2014.

Several new pipeline projects emerged last year to bring Bakken crude to market, but failed. One such project was the Bakken Crude Express Pipeline that OneOK Partners announced --a 200,000 b/d pipeline from the Williston Basin to Cushing in April, with a projected completion date of mid-2015. This plan was dropped due to a lack of "sufficient" demand from prospective clients, OneOK said on November 27.

High Prairie Pipeline, LLC had proposed a 150,000 b/d pipeline from Alexander, North Dakota in the Williston Basin to potentially connect with the Enbridge Lakehead pipeline system at Clearbrook, Minnesota. Clearbrook is the most active spot pipeline market hub for Bakken Blend, and is one of the two locations for which Platts publishes Bakken Blend assessments. The pipeline was expected to be operational by the fourth quarter of 2013, but Enbridge refused an interconnection with High Prairie following several months of negotiations. This prompted the company to file a formal complaint with the US Federal Energy Regulatory Commission (FERC) in September 2012.

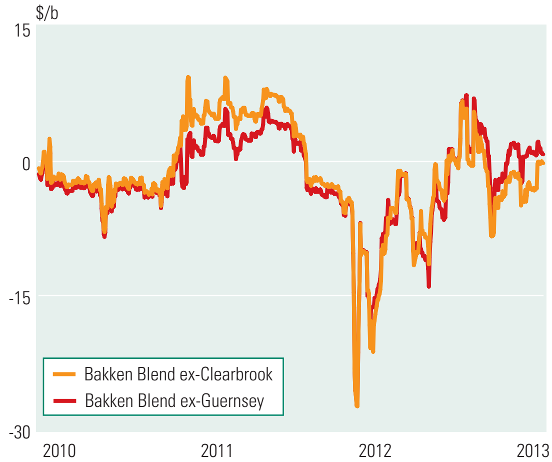
High Prairie filed a second complaint with the FERC against Enbridge in November 2012. This was in response to Enrbidge's Sandpiper project that would shift the receipt point for Bakken crude on the mainline system from Clearbrook, Minnesota to Superior, Wisconsin, hundreds of miles east. High Prairie is claiming that this "appears to be a coordinated effort by Enbridge to limit shipper's transportation options and control access to pipeline infrastructure critical to the continued growth and development of the Bakken."

In the past year, several of these pipeline startups, expansions, and the opening of rail terminals have exposed Bakken Blend crude production to new sources of demand, allowing differentials for this light, sweet grade to firm relative to other US reference prices. Bakken Blend crude has a sulfur level of around 0.2% and API gravity of 38-40.

However, there has been volatility due to logistical bottlenecks. A year ago, a combination of rising production out of the Williston Basin and western Canada forced values for Bakken Blend differentials to record lows in January and February 2012, as Bakken producers had to compete with Canadian producers for limited pipeline space and a finite group of buyers. Bakken Blend differentials ex-Guernsey, Wyoming hit lows of $23.85/b below Calendar Month WTI on February 3, and ex-Clearbrook, Minnesota differentials fell to $24/b below CMA WTI on the same day, the lowest level assessed by Platts since launching Bakken Blend assessments in May 2010. This steep drop showed the vulnerability of the play to pipeline bottlenecks, and has encouraged many to look to rail as an exit option for Bakken Blend.

Since then, Bakken Blend differentials have mounted a significant recovery, now trading at premiums to slight discounts to CMA WTI for ex-Guernsey and ex-Clearbrook, as the Brent/WTI spread

Bakken Blend vs Calendar Month Average WTI



Source: Platts

continues to be at a $21/barrel premium for Brent. Bakken Blend, via rail options, can access markets that compete with Brent-related grades on the international market such as the US Gulf Coast and the US Atlantic Coast. Now, those rail markets are yielding better netbacks for Bakken sellers than shipping the crude via pipeline to Guernsey or Clearbrook.

If TransCanada's Keystone XL project, and by association the Bakken Marketlink project, is approved, Bakken Blend crude, along with Canadian crude and West Texas grades in Cushing such as WTI, will eventually compete with foreign grades on the US Gulf Coast. Since this pipeline project has seen delays in the past few years, the void has been filled by rail, and rail enables Bakken to reach markets beyond the US Gulf Coast – a region which is already dealing with a surplus of light crude from Eagle Ford and more recently, WTI.

The outlook for Bakken crude production over the next few years is promising, and many of the government reserve estimates could be understating the potential of the Bakken and Three Forks formations. Producers do face unique challenges in the way of infrastructure constraints, and the industry is working expediently to make sure enough exit capacity is in place to get this high quality, unconventional crude to market.

NEW AND OLD CRUDES: NIOBRARA AND PERMIAN BASIN

Eagle Ford and Bakken represent the most new infrastructure-intensive shale oil plays in the US, but other plays such as Niobrara near the US Rocky Mountains and the Permian Basin in west Texas, will add extensively to the burgeoning domestic crude production from the two shale plays discussed above.

The Niobrara play is a shale rock formation located in northeastern Colorado, northwest Kansas, southwest Nebraska, and southeast Wyoming. Current production in the Bentek estimates that year-end 2011 production broached 100,000 b/d, and is forecasting that Niobrara production could come close to 400,000 b/d by the end of 2016. Currently, most Niobrara production is being consumed by local refineries.

The Permian Basin in west Texas and eastern New Mexico has been the hot-bed of domestic onshore conventional oil production for years, and is the source basin for the WTI crude stream. Strong crude prices and the developments in horizontal drilling have opened the door to unconventional production in the Permian Basin.

Turner Mason estimates that current Permian Basin production is 1.3 million b/d. By 2016, Permian conventional and unconventional oil production could rise as much as 600,000 b/d at the high end of Turner Mason's forecasted range of 1.7 million to 1.9 million b/d. Most of the unconventional production from the Permian is going into the WTI stream, and the strong forecast, Turner Mason said, is due to the fact that WTI is a more marketable crude than Eagle Ford for US Gulf Coast refiners. The infrastructure is being built to support that kind of production growth, Turner Mason said.

Bentek estimates that the 2012 production in the Permian Basin was just above 1.2 million b/d for both conventional and unconventional crude, and forecasting a 480,000 b/d rise to 1.68 million b/d by year-end 2016. Bentek cited that the majority of the growth in the Permian will come from unconventional wells while conventional wells will continue to decline.

This rise in Permian Basin production prompted several producers and midstream companies to propose pipelines that would bring this unconventional crude to the US Gulf Coast. In total, midstream companies have proposed 975,000 b/d of incremental capacity (see table). In addition, Kinder Morgan is looking to convert existing natural gas pipelines between Texas and the US West Coast into a crude pipeline that would move Permian grades from west Texas to Southern California refiners. The project is named Freedom Pipeline, and has the potential to move 250,000 to 400,000 b/d of crude. Kinder Morgan is in discussions with shippers now to ascertain interest, but says it would take one to two years to complete the pipeline reversals pending regulatory approval.

Magellan Midstream is in the process of reversing its existing Longhorn products pipeline to crude service from Crane, TX to Magellan's East Houston terminal. The partnership is expecting to begin filling the reversed pipeline with crude oil in mid-March 2013 and beginning partial operations at an estimated 75,000 b/d in mid-April, increasing to its full 225,000-b/d capacity in the third quarter of 2013. The project was initially proposed as serving the Eagle Ford Shale, but its close proximity to the Permian Basin makes it ideal to carry Permian production to Houston.

The BridgeTex project, a joint venture between Occidental Petroleum and Magellan, is proposed to carry 300,000 b/d of crude from the Permian Basin to Houston by the middle for 2014. This project is currently in a developmental phase right now.

Magellan is looking to expand its connectivity to Houston and Texas City refineries to compliment this new inbound capacity from the Permian Basin. In January, Magellan Midstream Partners launched an open season for firm commitments to ship crude originating from its 12.495 million barrel Galena Park terminal near Houston. The open season which closed January 21 is the latest step in the partnership's plans for the construction of new pipeline infrastructure stretching out from the Galena Park terminal to Magellan's Houston Gulf Coast crude distribution system for deliveries to Houston and Texas City area refineries. The five refineries in the Houston area and three in Texas City have a combined refining capacity of 2.23 million b/d.

Sunoco Logistics is proceeding with two projects that will increase the capacity of its West Texas system by 450,000 b/d. The Permian Express system will be completed in two phases – the first phase will take crude from the region to Wichita Falls, where it will connect through its Central Texas Pipeline with its reversed West Texas Gulf pipeline. Initial capacity of phase I is 150,000 b/d by the second half of 2013. Phase II will add an additional 200,000 b/d to this system and will extend lines as far west as St. James, Louisiana, and the expected startup of this phase is the middle of 2014. Sunoco is also expanding the West Texas Gulf line from the Permian to Beaumont (Nederland) by an additional 100,000 b/d to be operational in the first quarter of 2013.

In addition, rail cars of Permian crudes from both Midland and Cushing could reach the Houston market and access to water as early as the first quarter of 2014, thanks to the Kinder Morgan/Mercuria 210,000 b/d rail terminal project on the Houston Ship Channel.

Pipeline projects for Permian Basin to US Gulf Coast

	Completion date	New/Expanded Capacity	Total Capacity	Destination	Status
Magellan Longhorn Segment Reversal	1Q 2013	225,000	225,000	Houston	Near Completion
BridgeTex (50/50 Oxy & Magellan)	Mid-2014	300,000	300,000	Houston	Developmental Stage
Permian Express (Sunoco Logistics)	2H 2014	350,000	350,000	Beaumont	Phase 1 Construction
Phase I	2H 2013		150,000	Beaumont	
Phase II	2H 2014		200,000		
Sunoco West Texas Gulf	1Q 2013	100,000	140,000	Beaumont	Construction
	Total	**975,000**			

Source: Platts

This 975,000 b/d of Permian capacity will mean additional sweet crude supplies headed to the Texas Gulf Coast, as the majority of crude on these lines will be WTI-like crude out of Midland with some West Texas Sour (WTS) as well. Unlike Eagle Ford, this could present a more stable quality of light sweet crude to Texas and even Louisiana refiners, thanks to Shell's proposed Houma to Houston pipeline reversal project (see Cushing to USGC section).

Both of these shale oil plays could bring as much as 900,000 b/d of incremental crude to the US market in the next four years.

DEMAND FOR NEW CRUDES

The rapid increase in domestic US crude production has transformed crude slates across the country while replacing imports of light foreign crude on the US Gulf Coast and, more recently, the US Atlantic Coast. Increasing US refinery consumption of competitive, domestically produced crude has slashed total US crude imports to the lowest level since 2000 at just under 8 million b/d (see graph). According to the EIA, the US has imported an average of 2.8 million b/d from Canada, and roughly 2.2 mn b/d of this is pipeline crude from Canada. At current US import levels, that implies that US waterborne imports equate to about 5.8 million b/d.

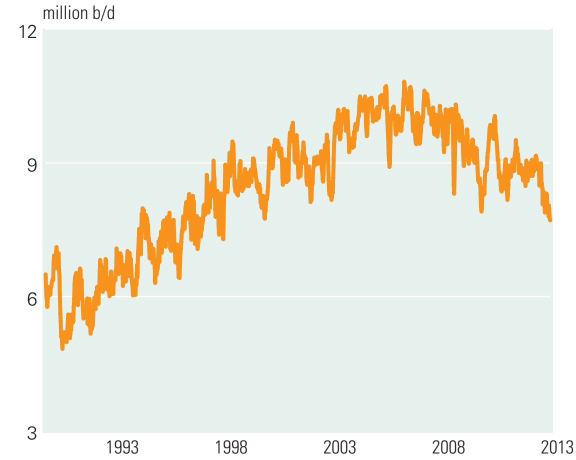
Canadian imports via pipeline are expected to rise to over 4 million b/d by 2016, according to Bentek. However, waterborne imports are clearly feeling the brunt of the shale crude boom impact and will continue to decline as US domestic production increases. Bentek estimates that US waterborne imports could fall to just 3.4 million b/d by 2016, a decline of 2.4 million b/d from current levels. While overall US crude imports will decline slightly according to these forecasts, waterborne imports will suffer the most.

Recent announcements by US refineries underpin the massive switch to domestic crude. Major US refiner Valero Energy replaced all its foreign light oil imports with domestic crude at its Gulf Coast and Memphis, Tennessee, plants during the fourth quarter of 2012. The company's Gulf Coast refineries typically imported light sweet crude from Brazil, Nigeria and North Africa, but are now using crudes from Eagle Ford, Bakken and Louisiana fields.

Likewise, Phillips 66 is no longer taking light sweet crude imports at its three US Gulf Coast refineries. The company has backed out all light sweet crude imports into the Gulf Coast as it has met its sweet demand along the Gulf Coast with more profitable domestic sweets, including Eagle Ford and Bakken. Phillips 66 can run 350,000 b/d of light sweet crude on the Gulf Coast, and has considered running all sweet crude at its Sweeney plant versus the 60,000 b/d now run there.

In addition, Marathon Petroleum in January disclosed plans to boost profits by displacing foreign crude oil imports at its Gulf Coast refineries, ship more Bakken and Canadian crude to its Midwest plants, and outfit its Ohio and Kentucky facilities to process more Utica shale oil and condensate. Production from US shale prospects, such as the Eagle Ford in south Texas, is expected to displace expensive foreign crude oil imports into the Gulf Coast this year. This

Total US Imports of Crude Oil



Source: EIA

is a boon for refiners like Marathon, which operates the 490,000 b/d Garyville refinery in Louisiana and will complete its $2.5 billion purchase of BP's Texas City, Texas refinery in February.

And midstream companies are looking to supply US Gulf Coast refineries with multiple options. Genesis Energy plans to spend about $125 million on new rail and pipeline infrastructure to connect ExxonMobil's Baton Rouge, Louisiana, refinery to more than 500,000 b/d of new crude supply. The project's construction will begin early in 2013, and the terminal upgrades and new pipeline should be completed by the end of the year. Completion of the rail facility is scheduled for the second quarter of 2014. This project will increase the ability of the refinery to access a wider slate of crude oil grades, potentially Bakken Shale crude from North Dakota, Eagle Ford Shale crude from South Texas and heavy crude from Canada.

Nearly every refinery on the US Atlantic Coast is receiving Bakken crude via rail car, or is mulling the idea (see New Crudes: Bakken Blend section). In addition, several refineries, including PBF Energy's Delaware City refinery, are also looking to receive heavy Canadian crude via rail to take advantage of those steep discounts.

US refiner Phillips 66 plans to boost the volume of domestic crude it refines to more than 200,000 b/d this year, an increase from the 2012 average of 112,000 b/d. In January, Phillips 66 entered into a five-year transportation and logistics contract with Global Partners to move approximately 90 million barrels of Bakken crude to the Bayway refinery. In addition, the first of two chartered Jones Act vessels was delivered in January, with the second expected to be delivered during the second quarter of 2013. Both vessels will transport Eagle Ford crude to the company's Gulf and East Coast refineries.

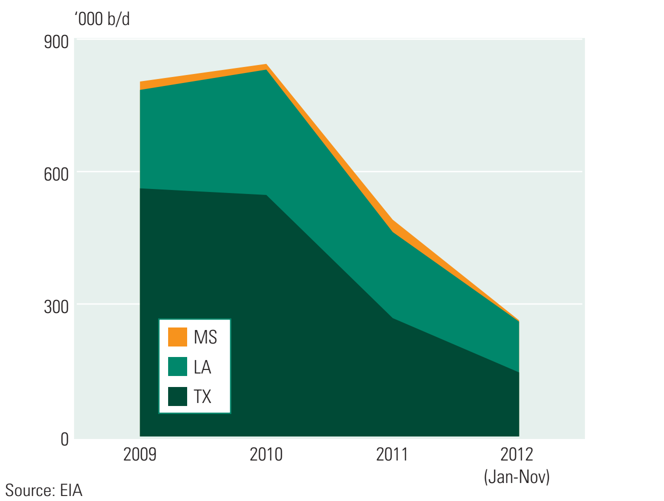
Several Texas refineries began accepting Eagle Ford crude oil and condensate deliveries via truck to their refinery gate in 2011, and thanks to improved infrastructure, Eagle Ford crude is being processed by Louisiana refineries and even refineries on the US Atlantic Coast. Barges and tankers of Eagle Ford are loading out of Corpus Christi at at an ever increasing rate, and hit 280,000 b/d in November 2012 (see New Crudes: Eagle Ford section). Additional docks and marine transportation vessels may be needed to relieve the bottleneck already developing at Corpus Christi.

In 2013, crudes from the Permian Basin will begin arriving on the US Gulf Coast via the Magellan Longhorn Pipeline, Sunoco Permian Express, and potential the Seaway line. The West Texas to US Gulf Coast projects will mostly bring WTI and some WTS. This will add additional light crude supply to an already burgeoning market for light crude.

With as many refineries shifting to domestic light crudes across the US, it begs the question as to when we will hit the light crude demand "wall." That "wall" appears to be the replacement of all light crude imports into the US Gulf Coast, and based on EIA data, we already appear to be nearing that point.

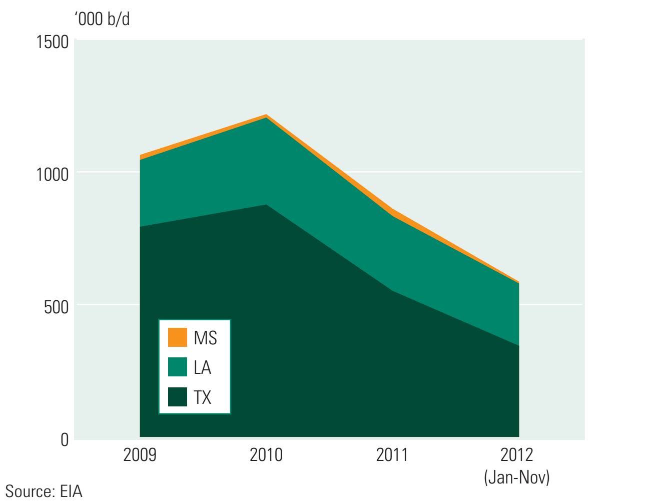
Light sweet crude imports (crudes with an API greater than 35 degrees and less than 0.5% sulfur) have declined by 65% from 844,000 b /d in 2010 into PADD III (Texas, Louisiana, and Mississippi)

US Gulf Coast Light Sweet Crude Imports



Source: EIA

US Gulf Coast Light Crude Imports



Source: EIA

to just 288,000 b/d for 2012 (January through November). Texas has seen the steepest declines in light sweet crude imports, with 2012 levels at just above 150,000 b/d, compared to 550,000 b/d in 2010. This shows the immediate impact of Eagle Ford on Texas refinery demand, and will likely carry over to Louisiana following the reversal of Shell's Houma to Houston line from Houston to St. James.

The next potential replacement for light crudes like Eagle Ford, Bakken, and Permian in the Gulf Coast would be light grades overall, as these domestic crudes would likely still be competitively priced against foreign grades with high APIs and sulfur levels above 0.5%. And substantial declines have also been seen in this data, with PADD III light imports falling by 47% from 1.21 million b/d in 2010 to 640,000 b/d in 2012. Again, the largest declines are in Texas, as light crude imports fell to 375,000 b/d in 2012, a 57% decline from 2010 levels of 877,000 b/d.

Nigerian and Algerian imports into the US Gulf Coast have contracted the most of any countries of origin, while Saudi Arabian light imports have increased slightly. Imports of crude from the United Kingdom, or North Sea crude grades, fell to zero in 2012. This is a likely outcome of a deeply inverted Brent/WTI spread and a lack of demand opportunities for these typically spot cargoes.

From this analysis, there is still is some room for light crudes in the US Gulf Coast refining slate, but the window of opportunity is shrinking rapidly. Moreover, the API gravity of the Eagle Ford production is generally considered to be extra light in the 45-50 API range, and while these barrels could supplant light imports, US Gulf Coast refiners may need to balance Eagle Ford with increased medium sour and heavy sour grades in their crude slates. This could mean increased medium or heavy imports until Keystone XL is completed and increased volumes of WCS are able to reach the US Gulf Coast.

This appears to be happening to a small degree already in Texas with medium grades. In 2012, medium sour (25-35 API) imports into Texas refineries increased to 788,000 b/d, a 14% increase from 2010 levels of 671,000 b/d. In general, refiners on the US Gulf Coast are swapping expensive distillate-rich imports like Nigerian grades for distillate-poor Eagle Ford crude, and there is a need to make up for this loss in distillate yields by consuming medium grades in crude slates.

The influx of domestic crude is also having a significant impact on the US Atlantic Coast market, and there appears to be additional room for growth. In 2012, PADD I refiners imported an average of 345,000 b/d of light sweet crude, a 24% decline from average 2011 levels of 455,000 b/d. In November 2012, light sweet imports dipped to just 200,000 b/d. Bakken will continue to supplant these imported crudes as long as they remain competitive on a rail basis into the US Atlantic Coast. Waterborne movements of Eagle Ford from the US Gulf Coast have also provided an alternative for USAC refiners to imported crude.

Domestic light sweets could also find additional demand on the US West Coast, as the infrastructure to receive Bakken in California is beginning to emerge. Already, Tesoro is receiving Bakken at its Anacortes, Washington refinery, and Alon USA is building infrastructure to receive Bakken and US midcontinent crudes at its idled 89,000 b/d Bakersfield refinery. The Alon Bakersfield facility could then be a rail offloading hub for Bakken to move to Los Angeles. In addition, Kinder Morgan's proposed Freedom Pipeline project, if pursued, could mean up to 400,000 b/d of Permian crude flowing from Texas to Southern California. While light sweet crude imports were 275,000 b/d into PADD V at its peak in 2012, domestic sweet crudes would likely be a cheaper alternative to heavier grades from Asia and the Middle East.

Most of the light sweet crude infrastructure is moving crude into the US Gulf Coast, a region where refiners have a preference for heavier crude. That is evident in the data on their prevailing run rates. According to the US Energy Information Administration, US PADD III (Gulf Coast) refineries ran crudes with an average monthly API of between 28 degrees and 30 degrees with average monthly sulfur content ranging from 1.58-2.01% between 2001 and November 2012. Prior to 2001, Gulf Coast refiners ran crudes with an average monthly API ranging from 31 to 35 degrees and average monthly sulfur content ranging from 0.77% to 1.68%. The shift occurred as new coking units and other heavy oil treatment facilities were brought on line, designed specifically for a world crude market that was projected to get heavier.

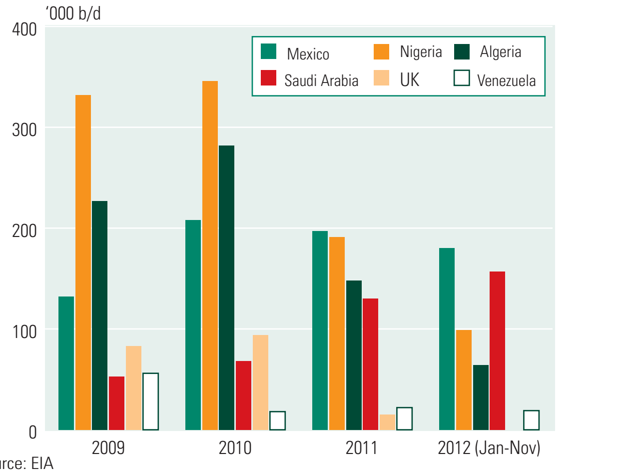
Given the preponderance of this coking capacity and sour crude slates on the US Gulf Coast, some industry players in the Eagle Ford market have applied to the US Federal Trade Commission for export licenses, given the proposed marine terminal expansions in Corpus Christi and Houston. Valero Energy received in November 2012 a one-year permit from the US government to export any crude of domestic origin to Eastern Canada where it operates a 230,000 b/d refinery in Quebec City, Quebec. Valero is expected to replace some of its North Sea, Mediterranean and West African imports with waterborne Eagle Ford crude and Bakken crude via rail cars.

Beyond this Valero permit, US exports are restricted to crude oil from Alaska's Cook Inlet and North Slope, certain domestically produced crude oil destined for Canada, shipments to US territories and the potential export of Californian crude oil to Pacific Rim countries.

Industry players could also petition the government for a waiver of the Jones Act, a maritime act in place since the 1930's that calls for US-flagged only vessels to transport goods between US ports. Such a waiver would allow for domestic sweet crude to move economically to the US Atlantic Coast, displacing foreign sweet imports there while still maintaining the crude oil export moratorium for US (except Alaska).

The Obama administration suspended the Jones Act temporarily in November 2012 to allow foreign tankers to carry fuel and petroleum feedstocks from the Gulf Coast to the Northeast after Hurricane Sandy disrupted supplies. It also waived the Jones Act following the 30 million barrel release of oil from the Strategic Petroleum Reserve in June 2012, which could set a precedent for another waiver of the act vis-a-vis US energy policy, industry sources said.

US Gulf Coast - Top Five Foreign Suppliers (Light grades >35 API)

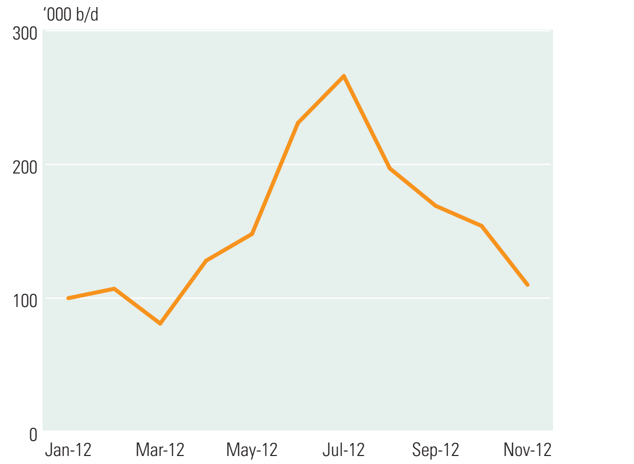


Source: EIA

US Atlantic Coast Light Sweet Crude Imports

Source: EIA

US West Coast Light Sweet Crude Imports



* Excludes Alaska and Hawaii
Source: Platts

If a Jones Act waiver cannot be granted, the economics are already working on US-flagged vessels, specifically Panamax and MR2 tankers, as mentioned above. However, the majority of US-flagged tankers are dedicated solely to Alaska-California moves of Alaska North Slope (ANS) crude. This is already changing as ANS production continues to decline and the need to transport domestic crudes such as Eagle Ford via tanker increases.

NEW MARKETS

This boom in domestic onshore crude production in the US, combined with a shift in pipeline flows from the US Midwest to the US Gulf Coast, are seismic market forces that have already started to shift consumption patterns among US refineries, to reverse global crude flows to and from the US, and to reshape pricing structures.

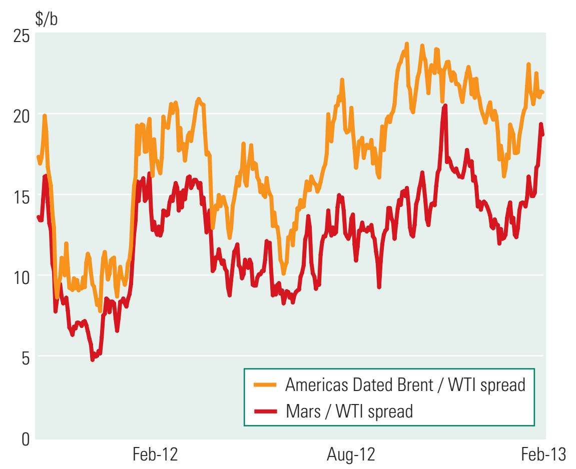
The critical pieces in this paradigm shift are the Cushing to US Gulf Coast pipeline projects, some 1.95 million b/d of pipeline capacity that is changing the face of the US and even the global crude market.

For several years now, the deviations seen in WTI from the global crude market and from other US domestic grades have signaled that infrastructure was out of sync with the changing supply/demand balance. The disconnect of US benchmark WTI from the global crude market and even the US Gulf Coast crude market has persisted since 2009, and entered into sustained weakness in 2011 through 2012 due to rising Bakken production and the arrival of additional Canadian crude into Cushing via the 590,000 b/d Keystone system.

With no "relief valve" in place for this crude save local refinery demand in PADD II, the Brent/WTI spread (Platts Americas Dated Brent versus front-month WTI Cushing assessments) widened to a record $29.24/b on and Mars, a heavier, sour grade, widened to a record $28/barrel premium over front-month WTI in September 2011 (see graphs). The Seaway pipeline reversal announcement narrowed the Brent/WTI spread below $10/barrel in November 2011.

Rising North American production and flows into the US Midcontinent depressed WTI's value relative to Brent prior to the May startup of

Americas Dated Brent, Mars vs WTI Cushing



Source: EIA

the Seaway Pipeline, while Brent prices were supported by increased exports of North Sea grades to Asia – this allowed the Americas Dated Brent to WTI spread to widen out to $21.43/b on April 3, 2012, the widest premium for Brent relative to WTI assessed by Platts since November 7, 2011 (when the Seaway reversal was announced).

Following the start-up of the Seaway line, the Brent/WTI spread narrowed to $10.09/b on June 21, 2012. But this narrowing did not continue, and Brent has remained at large premiums to WTI from late June through early October, jumping as high as $22.10/b on August 25, 2012. The spread narrowed since the startup of the Seaway pipeline expansion to a January average of $18.47/b, but has widened back out again to as much as $22/b in mid-February.

WTI's former premium to Brent had a fundamental premise as the US is a net importer of crude, and therefore prices in the US Gulf Coast have traditionally reflected the international cost of crude oil plus the cost of transportation. Between 2000 and 2006, WTI on average traded at around $1.65/b above Brent, but with increasing frequency and persistence, this differential has slipped into negative territory – thanks to burgeoning supplies in PADD II and limited local demand.

Due to this US inland production boom and upcoming pipeline projects, CME announced in December 2011 that it is considering launching a new Gulf Coast crude contract with physical delivery at the Enterprise Houston Crude Oil (EHCO), the destination of Enterprise's Eagle Ford Crude pipeline and the reversed Seaway pipeline. CME Group will discuss the new contract with oil market participants. The announcement of this contract proposal is an acknowledgement by the CME that the US crude market is changing. As of January 2013, CME Group is still evaluating a potential futures contract at this location that would complement its light, sweet crude futures contract in Cushing.

Canada's development of its huge oil sands resources in Alberta and the subsequent rise in exports to the US led to it overtaking Saudi Arabia as the main supplier of crude oil to the US in 2004. In 2010, around 60%, or 1.2 million b/d, of Canada's crude imports to the US were into the US Midwest where the imported volumes equated to around one third of the operable refining capacity. And total Canadian crude oil production, both conventional and synthetic, is expected to be 3.3 million b/d in 2012, and this is expected to rise to 4.7 million b/d by 2020, according to the Canadian Association of Petroleum Producers. Combined with Bakken Blend production now over 800,000 b/d, PADD II is saturated with crude – crude that could move to the US Gulf Coast and compete directly with foreign grades as the infrastructure continues to be built.

Oil pipeline capacity from Canada to the US is still undergoing much development but currently stands at an estimated 3.9 million b/d. A further 150,000 b/d of pipeline capacity able to feed crude imports from Canada into Cushing began operating February 2011 as part of TransCanada's Keystone project, which also consists of adding 500,000 b/d pipeline capacity out to the Gulf Coast via the Keystone XL expansion. However, continued delays in this expansion raise questions as to the growth potential for Canadian oil production and if there are alternatives to the US Gulf Coast.

Proposed projects for US Midcontinent to US Gulf Coast			
	New capacity (b/d)	**Completion date**	**Status**
Enterprise Seaway Pipeline	850,000	Q2 2014	Phase 1 Completed
TransCanada Gulf Coast Project	700,000	4Q 2013	Under Construction
Energy Partners Trunkline	400,000	2Q 2014	Regulatory Review
US Midcontinent to US Gulf Coast	**1,950,000**		

Source: Platts

Western Canadian crude is primarily heavy, and is a natural fit for a demand center with extensive coking capacity – the US Gulf Coast. But Asian refiners, particularly in China, also have the coking capacity to run this heavy crude. The infrastructure for Western Canadian crude is already constrained, and without a relief valve to the US, such as Keystone XL, some of this ideal crude for US Gulf Coast refiners may move east rather than south.

CUSHING TO USGC – AND BEYOND

Several companies are proposing to build the infrastructure to move landlocked Western Canadian crude, domestic light sweet from Cushing, and Bakken to the US Gulf Coast, with a total of 1.95 million b/d of pipeline capacity proposed (see table). As explained above, the spreads between US Midcontinent crudes and those on the US Gulf Coast are enough to justify additional capacity – and with the Seaway pipeline reversal set to take place this year, existing pipelines are already seeing the impact of promised US Midcontinent exit capacity.

Enterprise on November 16, 2011 agreed to buy ConocoPhillips' 50% stake in the Seaway crude pipeline system, an under-utilized pipeline routed to bring crude into Cushing, Oklahoma from Freeport, Texas. Enbridge and Enterprise, in a 50:50 joint venture, reversed the direction of the pipeline to bring crude to the US Gulf Coast, and 150,000 b/d of the total 400,000 b/d capacity came online into Freeport, Texas on May 23. In January 2013, the reversed Seaway system begun running at rates up to 380,000 b/d of the full 400,000 b/d capacity.

Enterprise and Enbridge are also planning to build an 85 mile pipeline from the EHCO terminal to the Port Arthur Beaumont area to be in service by early 2014. The Seaway Pipeline System will be expanded to 850,000 b/d by mid-2014, after receiving commitments that supported construction of a parallel line along the existing Seaway route.

The ECHO terminal currently has two storage tanks in service and a third is expected to be available mid-February and an additional 900,000 barrels of capacity and will be up and running in early 2014. Eventually, this terminal will receive barrels not only from Cushing, but from the Permian Basin and the Eagle Ford.

The newest US Midcontinent to US Gulf Coast proposal comes from Energy Transfer Partners, as the company is planning to convert its 770-mile Trunkline system from natural gas to crude and then reverse the flow. The company will spend an estimated $1.5 billion and expects the line to be in service by mid-2014. Once the pipeline is reversed, crude will flow to the US Gulf Coast from the Upper Midwest. According to a transcript of the company's third-quarter earnings call in January, President Marshall McCrea said that based on "early conversations," the converted crude pipeline's capacity will likely start at near 400,000 to 420,000 b/d. The line could be expanded up to 600,000 b/d.

Shell Pipeline's Houma to Houston crude pipeline reversal project promises connect Louisiana to all of this inbound crude from the Permian Basin, Eagle Ford, Cushing, and Canada. A segment of the Ho-Ho line opened for shippers in January with 200,000 b/d capacity. That Houston to Nederland, Texas, segment is the first phase of the Ho-Ho pipeline reversal project, a 325,000 b/d line that currently moves crude from offshore production and the Louisiana Offshore Oil Port (LOOP) from Louisiana to Texas. The reversed line would connect Louisiana with Eagle Ford production as well as crude coming off of the proposed lines from Cushing to the US Gulf Coast. The US FERC approved the rates and service plan for the HoHo line in June 2012, and the reversed line is expected to begin operations in early 2013. Shell issued another open season for the line in January 2013.

Shell also has proposed the construction of new line from St. James, Louisiana to Nederland/Port Arthur, Texas called Westward Ho. The 300,000 b/d Westward Ho is projected to be in service in the third quarter 2015, and received US FERC approval for its proposed rate structure and service plan on October 5, 2012. This line would enhance access for Texas refiners to domestic offshore crudes via the St. James, Louisiana hub.

The most controversial of these projects is TransCanada's Keystone XL project – part of which is a 700,000 b/d line connecting Cushing to the US Gulf Coast, called the Gulf Coast Project. This portion of the Keystone XL project was approved last summer by the US Army Corps of Engineers, while the 830,000 b/d portion of the line connecting Hardisty, Alberta to Cushing, Oklahoma is still pending US State Department approval (see Keystone XL and Alternatives for Canadian Producers section).

The Gulf Coast Project is currently under construction as of August 2012, and is expected to be operational in the fourth quarter of this year. TransCanada announced in February that the Cushing to Nederland, Texas line was 45% complete. The line has faced challenges from lawsuits from Texas land owners on the pipeline's "eminent" domain and from protesters seeking to inhibit construction progress, but TransCanada still expects completion by the end of this year and expects to raise the capacity to 830,000 b/d in 2015. In addition, TransCanada will also build a 175,000 b/d Houston Lateral line that would connect the Gulf Coast Project line to Houston-area refineries.

KEYSTONE XL AND ALTERNATIVES FOR CANADIAN PRODUCERS

While the Gulf Coast Project is progressing, the fate of the remainder of the 1.5 million b/d Keystone XL project is uncertain and could have a profound impact on Canadian crude producers. The Alberta oil sands are vast in reserves and yield a very competitively priced crude, Western Canadian Select, that would fit well in US Gulf Coast refining slates. Bentek estimates that current oil sands production in Alberta was 2.1 million b/d in January. At current production rates, oil sands production by 2016 could grow another 500,000 b/d to 2.6 million b/d, according to Bentek.

Given this, the continued delays in approval of the 830,000 b/d Keystone XL line from Alberta to Oklahoma have spurred producers and midstream companies to consider options for WCS beyond the Gulf Coast.

The initial Keystone XL project was proposed as a Hardisty, Alberta to Nederland, Texas project, and was rejected at the state and US government level in early 2012. Following a review by the US State Department, President Barack Obama rejected TransCanada's original application to build the 1,700-mile pipeline on January 18, 2012 saying the decision rested not on the project's merits, but rather a 60-day deadline Congress imposed on the process. One of the critical points raised in the rejection of the Keystone XL application at the state and federal level was protection of the Nebraska Sand Hills, dunes that form a thin layer above the Ogallala aquifer, a massive waterway that underlies 27% of the irrigated land in the US.

TransCanada applied for the pipeline in two segments and has received regulatory approval for the Gulf Coast Project, formerly known as Cushing Marketlink. The Nebraska governor approved the new route for the 830,000 b/d XL line through the state on January 22.

The XL line also has to gain US State Department approval for a cross-border permit, and a presidential permit. US Secretary of State John Kerry said that in February that he will ensure a decision on the line is taken in the "near-term." Sources close to the White House had told the press in late January that the Obama administration would likely not make a decision until June. TransCanada expects the Keystone XL line to be completed in 2015.

While many expect that Keystone XL will eventually be approved, Canadian oil sands producers are seeking other options to get Canadian heavy unconventional crude to market. The options bypass the US Gulf Coast and would bring Canadian crudes to either the US West Coast or Canadian/US Atlantic Coast for local consumption and export to Asia.

Enbridge's Eastern Canadian Refinery Access Initiative aims to take additional Canadian crudes off its mainline system to eastern Canadian and US Atlantic Coast refiners. To move crude east from the Bakken, Enbridge is seeking permission to reverse its 399-mile Line 9B that runs from Westover, Ontario to Montreal, and to increase the line's capacity from 60,000 b/d to 300,000 b/d. Enbridge expects this project to be completed by the second quarter of 2014. This would enable Canadian light and heavy synthetic crudes and Bakken to reach Canadian refineries on the US Atlantic Coast via pipeline. Enbridge is in the process of removing Line 9A, the portion of Line 9 that runs between Sarnia, Ontario and Westover – this 200,000 b/d portion of the line is expected to be in service by the fall of 2013.

In response to the needs to move Canadian crude to market, Enbridge and Energy Transfer Partners have s announced a joint venture to build another 660,000 pipeline from Flanagan, Illinois to Cushing,

Western Canadian Outbound Pipeline Projects

Projects	Route	Existing Capacity	New Capacity	Total Capacity	Completion Date	Stage
Enbridge Line 9 Reversal	Ontario to Quebec (2 segments)	240,000 b/d	60,000 b/d	300,000 b/d		
Line 9A Segment	Sarnia, Ontario to Westover, Ontario	200,000 b/d	-	200,000 b/d	Fall 2013	Under Construction
Line 9B Segment	Westover, Ontario to Montreal, Quebec	240,000 b/d	60,000 b/d	300,000 b/d	2Q 2014	Regulatory Review
TransCanada Keystone XL	Hardisty, Alberta to Steele City, Nebraska	-	830,000 b/d	830,000 b/d	2015	Regulatory Review
TransCanada Natural Gas Pipeline Conversion	W. Canada to Ontario & Quebec	N/A			N/A	Proposed
Kinder Morgan TransMountain Expansion	Alberta to Vancouver	350,000 b/d	540,000 b/d	890,000 b/d	2017	Proposed
Enbridge Northern Gateway	Edmonton, Alberta to Kitimat, British Columbia	------	525,000 b/d	525,000 b/d	2017	Proposed

Source: Platts

Oklahoma, parallel to Enbridge's existing 190,000 b/d Spearhead line. The two companies expect the line to be in service by early 2015 and are awaiting regulatory approval from the US Federal Energy Regulatory Commission (FERC).

As mentioned previously, TransCanada is considering converting an underutilized natural gas line from Western Canada to Ontario and Quebec to carry Bakken as well as light and heavy Canadian synthetic crudes. An announcement is expected in early 2013 as to the status of this project.

Moving Canadian crude west is also an option for oil sands producers to market their production, as loading crude out of British Columbia would provide a shorter shipping route to China, the largest possible consumer of these heavy crudes outside of North America. However, like Keystone XL, some of the projects are facing similar legal and regulatory approval challenges amid environmental impact concerns. And the expansions would not arrive for another four years at least, limiting near-term transportation options for producers.

For over a decade, Canadian heavy synthetic crude has been exported out of Vancouver, British Colombia at the end of Kinder Morgan's TransMountain system. Kinder Morgan announced in January that it would expand the TransMountain system to 890,000 b/d based on customer interest. This is a 140,000 b/d increase from the initial 750,000 b/d expansion announced last April. The expansion would include increased storage and additional loading berths at the Westridge Marine Terminal near Vancouver, which would increase the maximum number of tanker loadings from the current 5 per month to 34 per month. Kinder Morgan expects the project to be completed in 2017, following regulatory approval sometime next year.

Enbridge has proposed a 525,000 b/d oil-sands crude line from Edmonton, Alberta to Kitimat, British Columbia called Northern Gateway. The line would be new construction and has prompted growing opposition from communities, First Nations and environmentalists. Enbridge expects completion of the project by 2017 subject to regulatory approval this year. A Canadian federal review panel is reviewing the Northern Gateway project, hearing testimony from both sides of the debate.

The TransMountain project may have an easier route to approval due to the fact that this would be an expansion of an existing line. However, despite the challenges that Northern Gateway is facing, the recent approvals from the Canadian National Energy Board to allow LNG exports out of Kitimat show that such environmental sensitive projects can be approved in British Columbia, data analyst Bentek said. The concerns raised at the initial hearings, though, for the Northern Gateway review are focused on concerns around diluted bitumen as damaging to the environment if spilled.

If Northern Gateway, Transmountain and the Keystone XL system are all approved, that could be an additional 2 million b/d of capacity for move unconventional crude out of Alberta, and this capacity could, in turn, improve margins for oil sands producers and incentivize additional production. But this capacity would not be fully available until 2017, and approvals for these western Canadian pipeline projects are facing challenges similar to those seen with the Keystone XL project that could potentially push their in-service dates past 2017.

If Keystone XL does not move forward, and some of these east or west Canadian projects are delayed, what will happen to Canadian production? Bentek expects that it may slow down that 500,000 b/d Canadian crude production growth in expected by 2016 somewhat, but it would not negate growth. Rail is an option for Canadian heavy crude as well, and can be more economically viable than pipelines at times since diluent is not required for rail movements. Even with rail costs at $15/barrel to move WCS from Canada to the US Atlantic Coast, it still makes economic sense to do so given cheap differentials for WCS at Hardisty, Bentek said. And the proposed Kinder Morgan Houston rail terminal could provide an outlet for heavy Canadian crude on the US Gulf Coast ahead of any possible Keystone XL completion.

In addition, demand for Canadian heavy crude is growing in the US midcontinent. BP's recent conversion of the 405,000 b/d Whiting refinery to run more heavy crude is an example of increasing Canadian heavy demand in the US midcontinent, according to analyst firm Muse Stancil and Company. In their view, this should displace light crudes such as WTI from the Midwest and force them to the US Gulf Coast.

SHIFTING GROUND

The 1.95 million b/d of proposed capacity to move crude from Cushing to the US Gulf Coast, along with the Bakken, Eagle Ford and Permian Basin crude boom, promises to change crude slates of nearby refineries while shifting traditional crude flows and price relationships between the US and the global market.

Questions linger as to how the dust will settle in terms of US exports and shifting price relationships. The expected influx of pipeline crude, both sweet and sour, to the US Gulf Coast could have two immediate knock-on effects in the next two years: first, a sharp narrowing of the USGC to WTI premiums. US Gulf Coast offshore grades would compete directly with these "new" crudes, forcing relative values lower. A reversal of the current pipeline flows to where crude moves out from PADD II to PADD III means that naturally, US Midwest grades should be cheaper than those on the coast. However, these spreads would now be tied to pipeline transportation costs and local supply/demand factors rather than the stark difference between Brent and WTI.

The second knock-on effect would be a narrowing of the Brent/WTI spread. Reduced US imports mean spare capacity to move elsewhere, tempering European and even Asian premiums to the US benchmark as the pool of potential buyers for incremental Brent-related grades shrinks. This narrowing could extend further if either the US waives the Jones Act for shipping crude from the US Gulf Coast to the US Atlantic Coast, displacing additional Brent-related crude imports, or if industry players are granted export licenses to export crude. The likelihood of these two scenarios taking place, however, is uncertain due to their highly politicized nature.

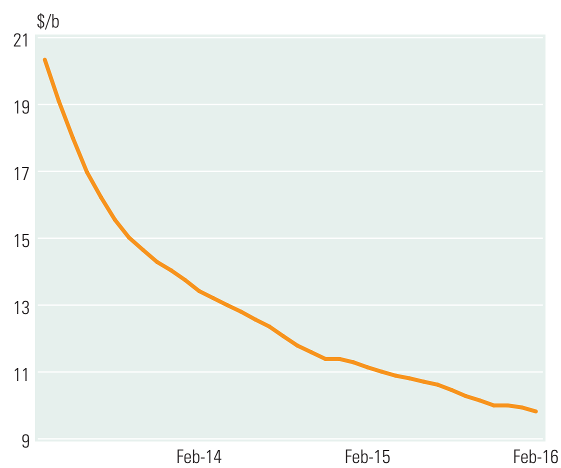
However, the Seaway Reversal and the additional projects to move Canadian and US midcontinent crude have not impacted the current Brent/WTI forward curve as expected. Even as far out as 2016, Brent still retains a nearly $10 premium to WTI, compared to $5-$6/b for 2016 back in October and near parity a year ago. This has led to suggestions that even more capacity needed to relieve the bottleneck. However, this could also be an acknowledgement that expectations for growing US crude production, rather than logistical constraints at Cushing, could keep US crude prices below Brent and Dubai.

Despite the possibility that WTI's logistical dislocation from the coastal US and global markets could still normalize in the long term, its future role as a dominant regional benchmark is still questionable. For some time, the market has sought a sour crude benchmark to compliment the preponderance of US Gulf Coast sour crude demand, both from domestic and imported sources. The limited production of offshore grades such as Mars, Poseidon, and Southern Green Canyon, as well as their vulnerability to hurricane activity, has limited their impact as potential pricing bases.

As of December 2012, Mars production was just below 260,000 b/d, up 6,000 b/d from year-ago levels. Poseidon production in December 2012 was just below 189,500 b/d. SGC production averaged 82,281 b/d in 2012, lower than the 96,536 b/d average in 2011.

Western Canadian Select is poised to compete with US offshore grades as a potential US sour benchmark, especially if the remainder of the Keystone XL project is approved. Western Canadian Select is a blend of conventional heavy production and bitumen from the Alberta oil sands. Western Canadian oil sands crude production averaged 1.6 million b/d in 2011, according to the Canadian Association of Petroleum Producers (CAPP). By 2015, CAPP expects oil sands production to rise by 700,000 b/d, or 43.75%, to 2.3 million b/d. With points into the US Gulf Coast at Houston and Nederland (to feed Louisiana) via proposed lines, WCS could be a prolific sour crude grade that competes directly with sour imports at multiple locations with size behind it.

Brent vs WTI frontline swap, February 22 2013



Source: Platts

On the sweet side of crude, Bakken Blend and Eagle Ford crude production by 2016 could exceed as much as 3.2 million b/d combined, nearly double the current levels of around 1.6 million b/d total for both plays, though some analysts question if the recent strong gains in production can be maintained given logistical challenges in both plays. While some Bakken and Eagle Ford crude is blending into the Light Louisiana Sweet stream currently, it is unknown whether this will increase once established pipelines can bring the two grades direct to refineries.

If more Bakken and Eagle Ford find their way into the LLS stream, LLS at St. James, Louisiana could develop as a standalone sweet benchmark for the US Gulf Coast. However, LLS is on the Louisiana Gulf Coast, and is not nearly a demand center like Houston in the Texas Gulf Coast, and the market may be looking for other options that provide a greater confluence of inputs. In addition, the expanding marine delivery capacity for crude oil in both Corpus Christi and Houston has resulted in waterborne markets developing for Eagle Ford crude, but the wide variability of quality will likely render the crude as a reference price rather than a regional benchmark.

The other critical market to watch will be Houston, where a confluence of Eagle Ford, Permian, and Cushing lines and crude by rail could result in the development of a new domestic sweet grade – one that is not as condensate-rich as Eagle Ford and reflects the value of crude at the largest refining hub in the US. While Eagle Ford pipeline capacity for Kinder Morgan and Enterprise is already operational, the completion of Phase I of the Seaway line reversal in January equates to 400,000 b/d of crude coming in from Cushing, with a potential for 850,000 b/d by 2013. And 975,000 b/d of lines from Permian Basin to the US Gulf Coast carrying light, sweet unconventional crude add to a growing pool of light sweet crude that could evolve into a potential benchmark. The upside to the Permian Basin, with as much as 600,000 b/d expected incremental supply to 1.9 million b/d by 2016, is exceptional.

The potential for a shift from St. James as the home of a regional sweet benchmark to Houston is reflective of the dramatic changes in the US crude market. A decade ago, St. James, Louisiana was a logical choice for a benchmark hub as it was the entry point for domestic offshore production and imports via the Louisiana Offshore Oil Port facility. In the next few years, Houston will become the interconnection point for key domestic crude pipeline "highways" from Eagle Ford, Permian Basin, western Canada, and the US Midcontinent.

There is some skepticism over Houston as a benchmark hub that could one day replace Cushing, Oklahoma. As evidenced by the recent cutback in Seaway pipeline throughput due to a bottleneck at the Jones Creek junction in Houston, the Houston pipeline distribution network between refineries and pipelines needs to be expanded, according to RBN Energy. In addition, storage must be expanded further for it to be a key benchmark hub like Houston, as the proposed 6 million barrels at the EHCO terminal, for example, falls far short of the 50 million barrels of storage at Cushing, RBN Energy said.

There is also the potential for a medium benchmark to emerge as well – with the potential blending of WCS and light crudes such as Eagle Ford. Given the limitations of US Gulf Coast refiners for light runs, blending more light ends into an extra heavy sour like WCS could yield a crude that would meet US Gulf Coast refiners' configurations and provide a competitive distillation curve that would not idle coking units.

CONCLUSION

The US crude market is changing, where refiners will become more reliant on inland pipelines for supply, and less dependent on waterborne imports. The new shale crude developments, Eagle Ford, Bakken, and other emerging plays will boost domestic US crude production to levels not seen since the peak of Alaska North Slope production, and could potentially yield over 5 million b/d by 2016 just between the Permian Basin, Eagle Ford and the Bakken. This boom in US crude production comes at a time when domestic consumption of refined products, particularly gasoline, has decline from the peak of gasoline demand seen in 2007, according to EIA data. In 2007, summer gasoline demand broached the 9.6 million b/d level. In 2012, summer gasoline demand barely broached 9 million b/d for a couple of weeks.

The pipeline capacity projects for Eagle Ford far exceed the production forecasts at a total of 2.0 million b/d connecting producing areas to Houston and Corpus Christi, but this plethora of proposed infrastructure guarantees that Eagle Ford crude and condensate production will find potential buyers on the US Gulf Coast. Another 975,000 b/d of Permian Basin pipeline capacity to the US Gulf Coast could further establish a light benchmark at the demand center of North America, and even a Texas to California throughway for Permian crude is possible. Additional pipeline and rail capacity out of the prolific Bakken Shale Formation is connecting Bakken producers to additional buyers and new markets.

Light crude imports are already being supplanted on the US Gulf Coast and the US Atlantic Coast. This extensive growth in US crude production thanks to shale and the completion of key pipeline projects such as Seaway and eventually Keystone XL, if approved, will mean that medium crude imports and possibly heavy imports into the US Gulf Coast could also be supplanted.

These important structural changes in supply, demand, and crude oil pricing are unprecedented, and Platts has closely monitored the developments and will closely align its methodology development to this shifting ground, be it new assessments for WCS, Bakken Blend, and Eagle Ford in the US Gulf Coast, or a shift in Americas pricing basis to any of these new benchmarks.

In response to these developments, Platts launched Eagle Ford crude assessments on October 16, 2012. These new assessments aim to represent the value of crude produced out of the prolific Eagle Ford shale play, and follow in the tradition of the Bakken Blend assessments launched in 2010. The growth potential for Eagle Ford, as illustrated in this special report, is outstanding. Platts is also considering additional Eagle Ford assessments addressing lighter and heavier gravities as well as several other other US Gulf Coast crude assessments to reflect the dynamic changes in these markets thanks to the domestic production boom and shifts in infrastructure. To learn more about these new assessments, please visit (http://www.platts.com/IM.Platts.Content/MethodologyReferences/MethodologySpecs/eaglefordmarker.pdf).

For any questions, suggestions, or comments, please contact Americas_crude@platts.com, and pricegroup@platts.com.

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