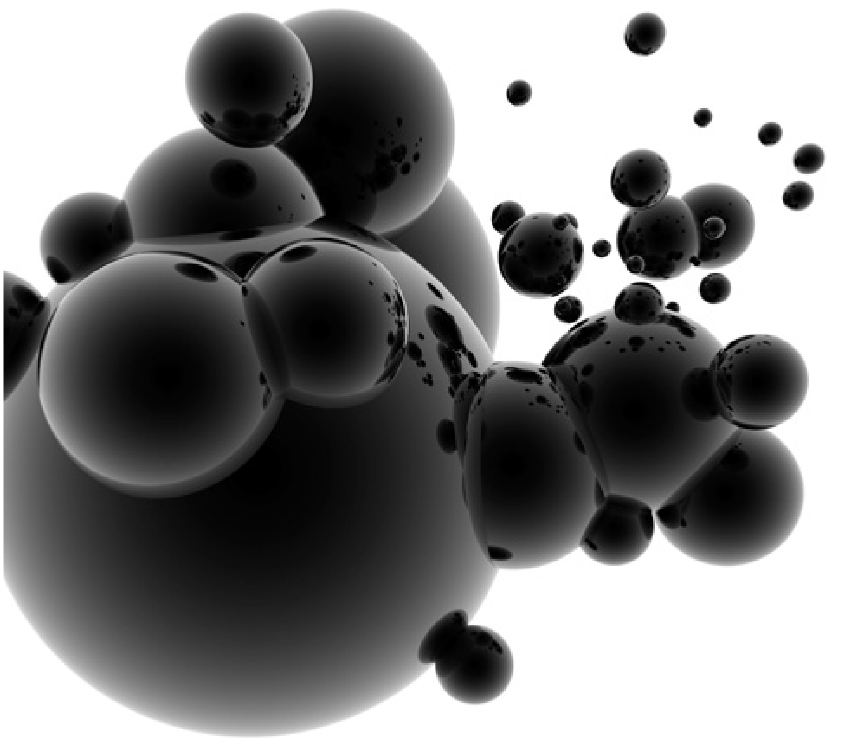
SPECIAL REPORT

New Crudes, New Markets

October, 2012

Price Group / Oil Division



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INTRODUCTION

The US crude oil market is undergoing enormous change. Extensive exploration and production activity in new various crude oil shale plays such as Eagle Ford and Bakken has boosted domestic crude output for these new light sweet crudes. This increased production, which has crossed the 630,000 b/d threshold for Bakken and is estimated to be approximately 600,000 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 weakness 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 and overall Canadian crude production, now above 3 million b/d, 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 reach 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.

Pipeline operators have also responded to this bottleneck of crude supply, with a number of ambitious projects underway. The reversed Seaway pipeline began moving crude from Cushing to the US Gulf Coast on May 19 at a rate of 150,000 b/d. A new grade called "domestic sweet" by some US Gulf Coast refiners began flowing into Freeport, Texas – a Cushing-sourced blend that includes WTI. By the first quarter of 2013, Enterprise and Enbridge's line will begin ramping up to 400,000 b/d – with the new terminus of the line at the Enterprise Houston Crude Oil Terminal. And both companies intend to build a second line for Seaway, expanding the capacity of the project to 850,000 b/d by the middle of 2014.

TransCanada is moving forward with its Gulf Coast Project, one part of the now "on hold" Keystone XL pipeline. The Gulf Coast Project promises to bring nearly 600,000 b/d of landlocked grades such as WTI and Western Canadian Select to the US Gulf Coast – the focal point of refining capacity and waterborne crude imports in the Americas. TransCanada has proposed a new route to Nebraska state regulators for the northern portion of the Keystone XL line, and expects that the cross-border permit will be approved in early 2013.

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 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.

The primary beneficiaries of this change will be inland US and Canadian crude producers who will receive prices in line with the US market, and 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 6.2 million b/d, the highest levels since 1999, according to the EIA. Expected Eagle Ford and Bakken production by 2016 could add as much as 3.4 million b/d of additional domestic crude and condensate production for the US, according to industry forecasts. Some data analysts are forecasting an additional 1.2 million b/d of Bakken production by year-end 2016 to over 1.8 million b/d, and an additional 1 million b/d of Eagle Ford capacity by 2016 to over 1.59 million b/d.

In response to these developments, Platts launched an Eagle Ford Marker crude assessment on October 16. This new assessment aims 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 methodology for this assessment can be found at: http://www.platts.com/IM.Platts.Content/MethodologyReferences/MethodologySpecs/eaglefordmarker.pdf The growth potential for Eagle Ford, as illustrated in this special report, is outstanding.

NEW CRUDES: EAGLE FORD

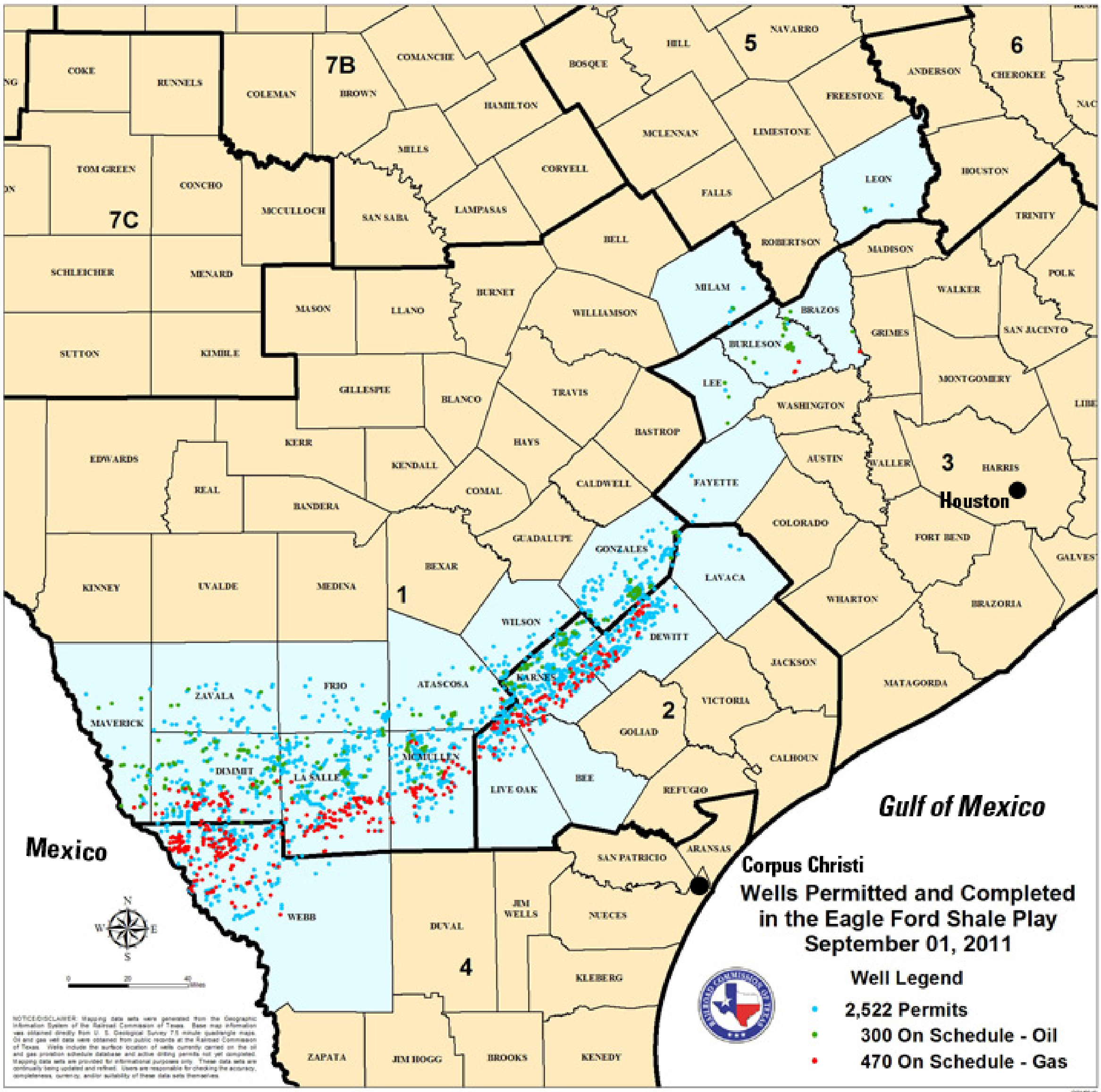
The Eagle Ford shale play, located in south Texas, is one of the many unconventional oil and gas plays in the US experiencing an unprecedented rate of exploration and production. However, the Eagle Ford play resembles the prolific Bakken play in terms of its ample crude oil and liquids content and striking estimates for production capacity in the next few years with September 2012 estimated crude and condensate production to be between 500,000 b/d and 700,000 b/d.

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

Eagle Ford Shale Well Activity



Source: Texas Railroad Commission

Coast, with 4.7 million b/d found in Texas and 3.2 million b/d in Louisiana. The multitude of proposed projects to connect Eagle Ford production to Texas Gulf Coast refineries and waterborne access could change the face of the US Gulf Coast crude oil market in coming years. The Eagle Ford shale formation is highly versatile, allowing producers to exploit the region for a mix of condensate, crude oil, natural gas liquids, and natural gas.

Eagle Ford drilling activity has increased dramatically since 2010, with more than 200 new well starts in the shale play a month for oil and gas, up four times more than the new well starts seen per month in the first quarter 2010, according to data analysis provider Bentek, a unit of Platts. Rigs in the Eagle Ford Shale play hit their peak in May and June, and have since come off, according to Bentek. However, this is not translating in reduced production as the start time for well starts has decreased, Bentek said.

Analysts Tudor, Pickering & Holt have estimated break-even costs for Eagle Ford wells around $48-$80/b, and EIG Global Energy Partners have estimated production costs for Eagle Ford wells at $60-$70/barrel. This is higher than the estimated $40-$65/b range for wells in the Bakken. This compares with the deepwater offshore oil production, where Brazil's estimated production is $18/barrel.

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

Proposed Pipeline Projects/Expansions for Eagle Ford

	New Capacity	Completion date	Total Proposed Capacity	Destination	Status
Enterprise	**550,000**		**550,000**		Near Completion
Phase 1 (Wilson County to Sealy/ Rancho Pipeline)	350,000	2Q 2012	350,000	Houston	Operational
Phase 2 (Gardendale to Wilson County)	200,000	2Q 2013	200,000	Phase 1 Line Terminus	Near Completion
Koch Industries	**250,000**		**250,000**		
Pettus to Corpus Christi Line	250,000	Summer 2012	250,000	Corpus Christi	Under Construction
Harvest Pipeline	**355,000**		**420,000**		
Pearsall to Corpus Christi	15,000	Dec-11	80,000	Corpus Christi	Operational
Gardendale to Corpus Christi	250,000*	Jul-12	250,000*	Corpus Christi	Under Construction
Arrowhead Expansion/ New Line to Three Rivers	90,000	Dec-11	90,000	Three Rivers	Operational
Magellan	**100,000**		**100,000**		**Under Construction**
Double Eagle Pipeline (Copano JV)	100,000	1Q 2013	100,000	Corpus Christi	Proposed
NuStar/Koch/TexStar/ Valero Agreements	**150,000**	2012	**300,000**		
NuStar Corpus Line (Reversal)	100,000	2Q/3Q 2012	200,000	Corpus Christi	Existing and additional capacity
Odem Line Reversal (Valero)	0	Sep-11	50,000	Corpus Christi	Operational
NuStar Pettus Line (Koch)	50,000	Jun-11	50,000	Corpus Christi	Operational
Kinder Morgan	**300,000**	**2Q 2012**	**300,000**	**Houston**	**Operational**
Plains/Enterprise Pipeline	**350,000**	**4Q 2012**	**350,000**	**Corpus Christi**	**Under Construction**
Proposed Capacity to Houston			**650,000**		
Proposed Capacity to Corpus Christi			**1,330,000**		

*Initial capacity of this line will be 150,000 b/d.

Source: Platts

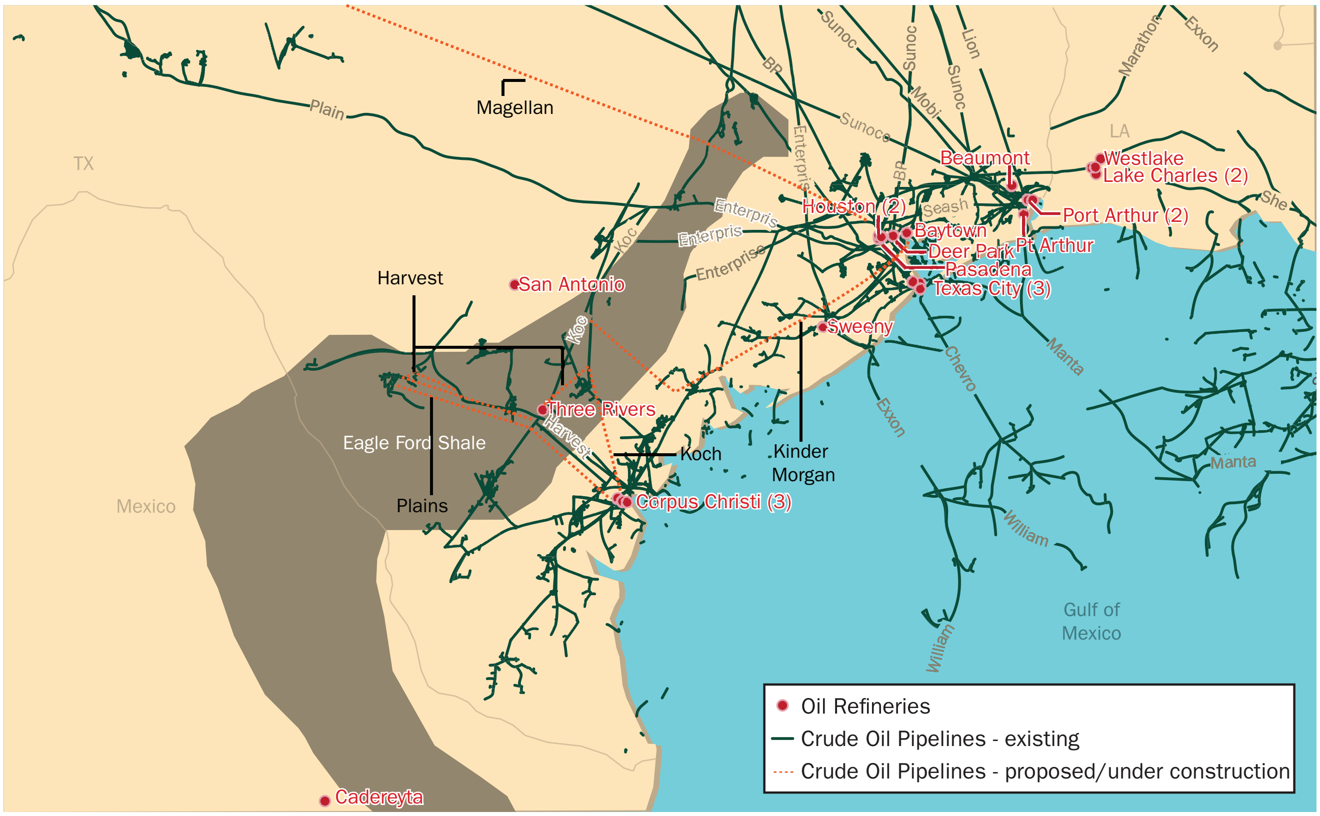
results of an Eagle Ford shale exploratory well in Mexico located across the US-Mexico border from Laredo, Texas. This exploratory well, Emergente-1, produced an initial 3 million cubic feet/day of gas and an average of 17,000 b/d of condensate. Pemex said it is now in the process of completing three 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 700,000 b/d in September 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 500,000 b/d. Turner Mason forecasts that Eagle Ford production will also rise to 700,000 b/d by 2016.The slowing rate of production growth is due to infrastructure constraints around Eagle Ford such as labor, logistical, and manpower constraints, in addition to the fact that supply is expected to overwhelm local demand for light, sweet crude, according to Turner Mason.

The quality of Eagle Ford production thus far has varied widely, with API gravity levels reported by consumers ranging from 42 to 60 API and higher. While many of the pipelines proposed for Eagle Ford are operational, consistent streams have yet to develop. Some producers have said they expect to see the refinery-grade Eagle Ford come in around 45 max API, with heavier Eagle Ford crude

Eagle Ford Shale: Formation, Pipelines, and Refineries



Source: Platts

streams blended with condensate. Consensus is growing that several grades of Eagle Ford crude may emerge once production is co-mingled into common streams 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. The northern counties in the Eagle Ford Shale play tend to carry the heavier crude, while farther south and east, condensate is more dominant in this gas-rich area. These common streams will likely emerge once pipelines to these terminals are completed, many of which are projected to be in service by the second quarter of 2012.

Late last year, 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 posted prices for Eagle Ford, a grade called South Texas Light Sweet.

Turner Mason expects that once these streams develop, a commercially viable grade of Eagle Ford crude will emerge that is close in quality to Bakken Blend – around 0.2%S and 40 and higher API.

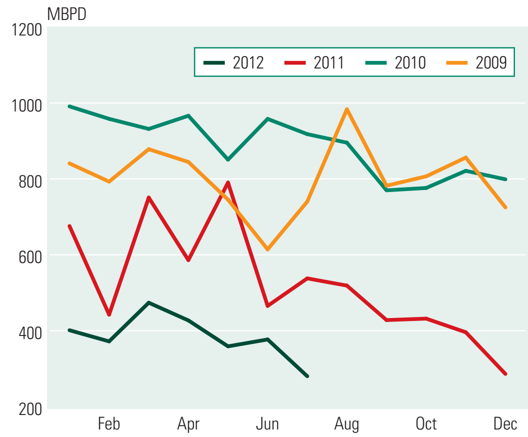
INFRASTRUCTURE

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 this year, supplanting some of the truck movements already taking place 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 1.33 million b/d into Corpus Christi (*see table on page 4*). One would expect that those pipelines that have already secured firm commitments from shippers will likely survive this flurry of infrastructure projects. Since October of last year, many of these projects have moved from the proposal phase to the construction phase.

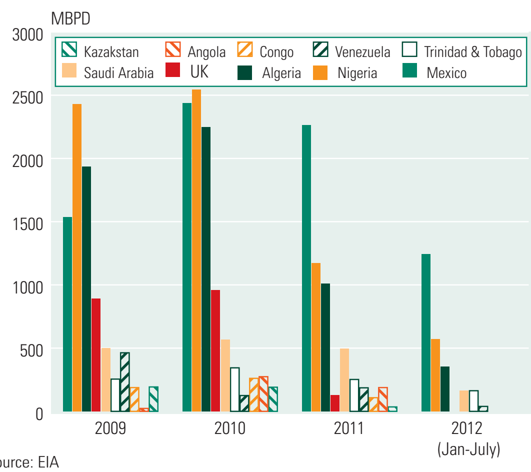
The majority of the Houston capacity is now operational. Kinder Morgan started its 300,000 b/d line from Cuero, Texas to the Oiltanking Terminal on June 14. Kinder Morgan is also in the process

Texas Light Sweet Crude Imports



Source: EIA

Top Ten Texas Light Sweet Imports' Country of Origin



Source: EIA

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. 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 will be ready to accept crude oil barrels in "a few weeks", Enterprise said in early October, with 750,000 barrels of storage tanks complete.

The pipeline projects slated for Corpus Christi are far more numerous, totaling 1.330 million b/d of proposed capacity, and connect with multiple waterborne terminals as well. Depending on how these projects develop, Corpus Christi will likely become a waterborne hub for crude oil and condensate as pipeline delivery capacity into the port is set to exceed the 780,000 b/d of local refining capacity. Please see the table above for details on these projects.

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. In addition, Enterprise and Plains will connect Three Rivers to Enterprise's existing South Texas Crude Oil system via its Lyssy, Texas station.

Gardendale, an unincorporated town on Interstate 35 in south Texas, may emerge as a critical hub for Eagle Ford Shale crude and condensate, with several proposed pipelines running through or connecting to the south Texas town's proposed storage facilities. Several pipelines are connected to the Plains' Gardendale terminal in addition to 100,000 b/d line to Three Rivers under an agreement with NuStar, including Harvest Pipeline's 250,000 b/d Gardendale Pipeline, and Plains/Enterprise's 350,000 b/d Corpus Christi Pipeline.

Additionally, these pipelines will have connections to the US Development Group's Gardendale terminal. This terminal, located 80 miles south of San Antonio near Gardendale, started loading crude and condensates to rail cars last summer. The facility currently has truck-to-rail loading capability of 40,000 b/d, and initial rail destinations will include USDG's crude terminal in St. James, Louisiana. USDG is in the process of upgrading the terminal to include inbound pipeline-to-tank capacity then onto rail, and truck off-loading to tank capacity then onto rail as well as high rate loading of rail cars via a loading rack. This will increase the rail loading capacity of the terminal to 60,000 b/d. The Plains, Enterprise, and Harvest Pipeline systems will each have origin tank and pump stations in additional to the rail facility.

In addition to pipelines, Corpus Christi is poised to be the first Eagle Ford hub with the potential for waterborne exports. 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 proposed into the port (see demand section for a refinery breakdown). As such, three companies are poised to expand or construct infrastructure to allow for waterborne crude loadings.

Flint Hills is upgraded its Ingleside terminal near Corpus Christi to ship up to 200,000 b/d of waterborne crude in the summer. Martin Midstream completed its 300,000 barrel crude terminal with waterborne loading capability in December. 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 has a land lease option approved by the Port of Corpus Christi authority to possibly develop 15 acres of land adjacent to its 2 million barrel North Beach storage terminal. In addition, Trafigura, a global commodity trading company, acquired a 600,000 barrel terminal in Corpus Christi from Texas Docks & Rail in January, and this terminal can be expanded up to 2-million barrels. In May, 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 September, 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).

DEMAND

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.

Current local refinery demand of Eagle Ford Shale crude totals at least 340,000 b/d. Flint Hills' 300,000 b/d Corpus Christi refinery is running nearly half of its capacity of Eagle Ford crude, according to a source close to refinery operations. Valero has confirmed the following crude run rates of Eagle Ford: the 315,000 b/d Corpus Christi refinery is reportedly running 35,000 b/d, the 100,000 b/d Three Rivers refinery is running 75,000 b/d, and the 160,000 b/d Houston refinery is running 35,000 b/d. Citgo's 165,000 b/d Corpus Christi refinery is running 30,000 b/d, said a source close to the company. NuStar's 15,000 b/d San Antonio, Texas refinery is also running Eagle Ford crude, though exact figures on the amount of Eagle Ford crude could not be confirmed.

Levels of consumption has begun to rise in Houston as Eagle Ford barrels have started to reach the area via pipeline, truck, and barge from Corpus Christi. Corpus Christi, which has numerous terminals dedicated to Eagle Ford waterborne loadings, has become a key hub for shipments of barges, larger ocean-going barges, and tankers such as MR2s and Panamaxes. This has allowed Eagle Ford crude and condensate to find markets beyond that of Corpus Christi and Houston, as far as the US Atlantic Coast where Eagle Ford is now competing with Brent-priced crudes from Europe and Africa.

Already, waterborne domestic exports out of Corpus Christi have allowed Eagle Ford crude to compete with light, sweet crude imports for buyers on the US Gulf Coast and the US Atlantic Coast. The question remains, how much of these imports can and will Eagle Ford crude supplant? In 2012, according to EIA Company Level Imports data, Texas refineries imported an average of 384,000 b/d of light sweet crude (35 API or greater and 1.1% maximum sulfur). Compared to previous years, Texas imports of light, sweet crude are markedly lower thanks to the Eagle Ford impact.

The source of this crude varied from Mexico, Algeria, Nigeria, Saudi Arabia, and Venezuela. Over 54% of these imports are from Mexico, Venezuela, and Saudi Arabia, which are strictly sold on a contractual basis. However, the other 46 %, or roughly 177,000 b/d represent incremental sweet imports that could potentially compete with Eagle Ford crude grades. Over 136,000 b/d of those incremental imports are comparable in quality to Eagle Ford crude, with sulfur lower than 0.5% and API above 38 degrees. With Eagle Ford production now approximately 600,000 b/d, supply has likely already approached the upper limits of local demand and will need to seek new markets.

The marine delivery access currently proposed to export Eagle Ford crude from Corpus Christi and possibly Houston could open Eagle Ford to markets in Louisiana. Rail cars of Eagle Ford Shale crude are moving into the Light Louisiana Sweet blending pool at St. James, Louisiana. While additional rail capacity is being planned via US Development's proposed Gardendale terminal, barges of Eagle Ford destined for Louisiana refineries are already loading out of Corpus Christi and Houston.

According to EIA data, light sweet crude imports into Louisiana this year are proportionally lower than Texas. While Texas refineries, totaling almost 4 million b/d of refining capacity, imported over 384,000 b/d from January to July 2012, Louisiana refineries with a total capacity of 2.8 million b/d imported almost 173,000 b/d, less than half of the imports to Texas buyers.

However, US Gulf Coast refiners, in general, have a preference for sour crude. "Light crudes are not preferred by Gulf Coast refiners because they have invested heavily in secondary units and by running light or very light crudes, they would be under-utilizing their secondary units and this affects their margins," said Tom Hogan of Turner Mason consultants.

Light crudes tend to produce more light ends (naphtha, gasoline) and distillates (diesel and jet fuel) with little residual fuel oil. But Gulf Coast refiners with coking capacity are designed to take that residual fuel and turn it into transportation fuels. "The lack of larger quantities of residual oil in Eagle Ford Shale is why Gulf Coast refiners may not run this crude in large volumes," noted Hogan. "If they did run Eagle Ford Shale it would be to blend down a very heavy sour crude." And to run more light, sweet crude would require rebuilding standard refinery units with entirely different metallurgy and sizes. The size of this capital expenditure and downed production time may not offset the potential cost benefits from running additional Eagle Ford crude.

That Gulf Coast refiners like heavier crudes, and are built to process them, 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 29 degrees and 30 degrees with average monthly sulfur content ranging from 1.48-1.75% between 2001 and November 2011. 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.

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
Enbridge	Berthold, ND	0	0	10,000	80,000
Bakken Oil Express	Dickinson, ND	0	100,000	100,000	100,000
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
Basic Transload	Zap, ND	0	20,000	40,000	40,000
	Total	**115,000**	**275,000**	**730,000**	**880,000**

Source: Platts, North Dakota Pipeline Authority

Given the preponderance of this coking capacity and sour crude slates on the US Gulf Coast, speculation has also surfaced that industry players in the Eagle Ford market will apply to the US Federal Trade Commission for export licenses, given the proposed marine terminal expansions in Corpus Christi and Houston.

Currently, 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. Shell applied for an export license to move Bakken crude to Canada, the company confirmed in October.

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 Eagle Ford 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 waived the Jones Act following the 30 million barrel release of oil from the Strategic Petroleum Reserve in June, which could set a precedent for another waiver of the act vis-a-vis US energy policy, industry sources said.

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 could change as ANS production continues to decline and the need to transport Eagle Ford via tanker increases.

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, Bakken Blend unconventional crude, and Canadian heavy sour (see New Markets section).

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 600,000 b/d mark this summer and is approaching 700,000 b/d as of late September, according to the North Dakota Pipeline Authority. Estimates for 2015 production vary, but are as high as 1.3 million b/d for the US portion of the Bakken Formation, spurring a flurry of pipeline expansion and rail projects in progress.

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, but it gives fast-growing areas takeaway capacity and it provides flexibility on where the crude is shipped. By year-end 2012, rail takeaway capacity from the Bakken Formation will total 730,000 b/d. Analyst Lipow Oil & Associates expects rail takeaway capacity to hit 1 million b/d by year-end 2013, while the North Dakota Pipeline Authority expects this rail capacity number to come in just north of 900,000 b/d.

Rail capacity at St. James, Louisiana to accept Bakken crude is growing, with US Development's 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. Rail has also opened up markets for Bakken producers in California and Washington. Rail deliveries of Bakken Blend to the US Atlantic Coast are estimated to be as much as 100,000 b/d. Some of these shipments, in a departure from standard practices, have been sold on a Brent-related basis as opposed to WTI.

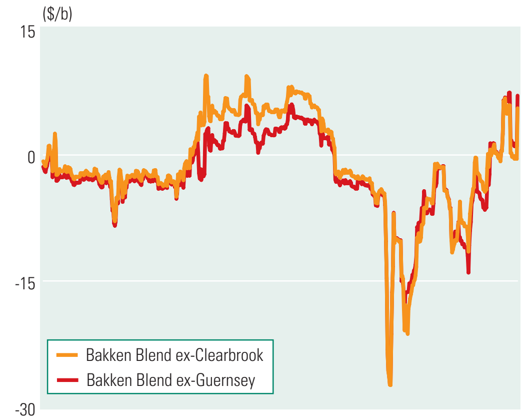
The 300,000 b/d Philadelphia refinery, soon to be owned by a Carlyle Group and Sunoco joint venture called Philadelphia Energy Solutions, is shifting to US crudes and away from North Sea and African grades. The partners also said in June they will build a rail facility to take in greater volumes of domestic crudes, most likely Bakken from North Dakota given its expansive rail export capacity. Statoil is shipping some of its Bakken crude production to Irving Oil's 300,000 b/d Saint John refinery in New Brunswick, Canada.

While rail will serve the immediate needs of Bakken producers to get crude to market, several large pipeline projects such as Enbridge Bakken Expansion Project (145,000 b/d by 2013, potential for 325,000 b/d by 2014) and TransCanada's Keystone XL Project (700,000 b/d of new capacity for a total of 1.3 million b/d), when completed, will add cheaper, more efficient exit capacity for Bakken crude to reach potential buyers. However, if Bakken production meets or exceeds projections in the next four years, rail capacity will still play a much needed role. 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 a 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 and onto the Enbridge Lakehead system.

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, pushing ex-Guernsey differentials to as high as $4.38/barrel over the NYMEX front-month calendar month average on May 16, a new record high, according to Platts data (see graph).

Bakken Blend vs Calendar Month Average WTI



Source: Platts

Williston Basin Pipelines

Source: Platts

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 1.3 million b/d Keystone XL pipeline system. However, the US State Department's rejection of TransCanada's cross-border permit for the Keystone XL project has pushed out the expected completion of the project to late 2014, if approved once TransCanada reapplies (see New Markets section for more information on Keystone XL and impact).

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	Awaiting Regulatory Approval
BridgeTex (50/50 Oxy & Magellan)	Mid-2014	278,000	278,000	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	Houston	Construction
	Total	**953,000**			

Source: Platts

Several new pipeline projects have emerged in 2012 to bring Bakken crude to market. OneOK Partners announced its plan to build a 200,000 b/d pipeline from the Williston Basin to Cushing in April, with a projected completion date of mid-2015. The capacity of the Bakken Crude Express Pipeline could be increased if the company receives supply commitments to support it prior to construction, OneOK said, which is expected to commence in early 2014. OneOk announced an open season to begin September 21 and end November 20 for long-term transportation contracts.

High Prairie Pipeline, LLC has 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 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.

In the past year, several of these pipeline startups, expansions, and the opening of rail terminals has 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.

Earlier this year, 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 (*see graph on page 9*).

Since then, Bakken Blend differentials have mounted a significant recovery, now trading at premiums to CMA WTI for ex-Guernsey and ex-Clearbrook, as the Brent/WTI spread has widened out to a $20/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.

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. These pipeline expansions stand to threaten current rail export activity from North Dakota to US demand centers on paper, but most industry players and analysts believe that rail will continue to play a key role in transportation for Bakken Blend crude to US refineries.

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 CRUDES: OTHER SHALE PLAYS

Eagle Ford and Bakken represent the most 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. Thanks to the rising production in both the Permian and Eagle Ford, Texas production in July 2012 hit 1.925 million b/d, the highest levels since 1989, according to the EIA.

Turner Mason estimates that by year-end, Permian production will cross 1.2 million b/d. By 2016, Permian conventional and unconventional oil production could rise 250,000 b/d to 1.454 million b/d. Most of the unconventional production from the Permian is going into the WTI stream. Turner Mason noted that the limited production growth in this forecast was due to potential issues in logistics, manpower, materials, regulatory and other obstacles and shortages. If those obstacles can be overcome in the Permian, Turner Mason said, and the recently strong growth seen in production continues, then production could potentially exceed these levels.

Bentek estimates that September 2012 production in the Permian Basin was just below 1.3 million b/d for both conventional and unconventional crude, and forecasting a 500,000 b/d rise to 1.8 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.

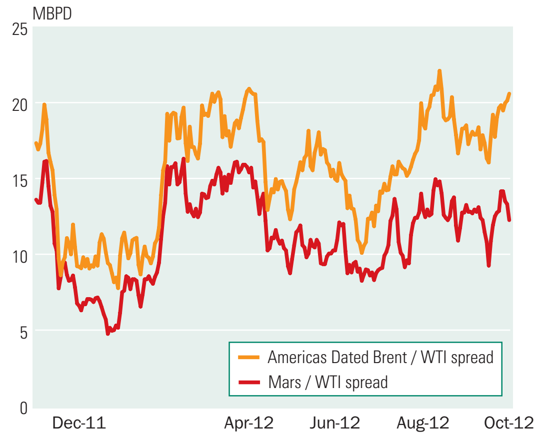
This rise in Permian Basin production has prompted several producers and midstream companies to propose pipelines that would bring this unconventional crude to the US Gulf Coast. In total, midstream companies have proposed 953,000 b/d of incremental capacity (*see table on page 10*).

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 project is expected to be completed by the middle of 2013, and will have an initial capacity of 135,000 b/d expandable to 225,000 b/d. 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 278,000 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,

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 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 Houston by an additional 100,000 b/d to be operational in the first quarter of 2013.

Americas Dated Brent, Mars vs WTI cushing



Source: EIA

Both of these shale oil plays could bring as much as 800,000 b/d of incremental crude to the US market in the next four years.

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 1.59 million b/d of pipeline capacity that could change 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 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 September 6 and Mars, a heavier, sour grade, widened to a record $28/barrel premium over front-month WTI on September 7 (*see graph*). 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 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.

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.

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 October 2012, 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, was 3 million b/d in 2011, and is expected to rise to 4.7 million b/d by 2019, according to the Canadian Association of Petroleum Producers.

Oil pipeline capacity from Canada to the US is still undergoing much development but currently stands at an estimated 3.6 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.

Combined with Bakken Blend production now over 600,000 b/d, PADD II is saturated with crude – crude that could move to the US Gulf Coast and compete directly with foreign grades if the infrastructure could be built.

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.

In response to the needs to move Canadian crude to market, Enbridge has announced it will build another 585,000 pipeline from Flanagan, Illinois to Cushing, Oklahoma, parallel to its existing 190,000 b/d Spearhead line. Enbridge expects the line to be in service by the middle of 2014, and is expandable to 800,000 b/d

CUSHING TO USGC – AND BEYOND

Several companies are proposing to build the infrastructure to move landlocked Western Canadian crude and Bakken to the US Gulf Coast, with a total of 1.59 million b/d of pipeline capacity proposed (see table). The most controversial of these projects is TransCanada's Keystone XL project – part of which is a 591,000 b/d line connecting Cushing to the US Gulf Coast, called the Gulf Coast Project.

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, 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 has now applied for the pipeline in two segments and has received regulatory approval for the Gulf Coast Project, formerly known as Cushing Marketlink. The company expects that the Presidential Permit will receive approval for the northern portion of the project, which crosses the Canada/US border, in the first quarter of 2013. In September, TransCanada sent Nebraska regulators a

Proposed pipeline projects for Cushing to US Gulf Coast

	New capacity (b/d)	Completion date	Status
Enterprise Seaway Pipeline	850,000	Q2 2014	Phase 1 Completed
TransCanada Keystone XL	591,000*	4Q 2013	Under Construction
Energy Partners Trunkline	150,000	TBD	Regulatory Review
Cushing to USGC Capacity	**1,591,000**		

*This portion of the expansion reflects Cushing Marketlink, not the entire 700,000 b/d XL expansion.

Source: Platts

new route for the XL line that avoids the Sandhills region and other environmentally-sensitive areas in the state.

TransCanada started construction of the 485-mile Gulf Coast Project line in August after receiving permit approval from the US Army Corps of Engineers, and expects the line will be completed in mid to late 2013. Once fully completed, the initial 700,000 b/d capacity XL line from Hardisty, Alberta to Cushing, Oklahoma will bring the total Keystone system capacity to 1.3 million b/d. The XL line from Hardisty to Cushing is expandable to 830,000 b/d. 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.

While questions linger as to whether or not Keystone XL will be approved, the firm commitments received for the line are supportive for eventual government approval. The Keystone XL line has received firm commitments for over 500,000 b/d of capacity for the entire Hardisty to Port Arthur system, according to TransCanada. Those firm commitments, particularly for the Cushing to USGC portion of the line, were expected to have tempered interest in other pipeline projects.

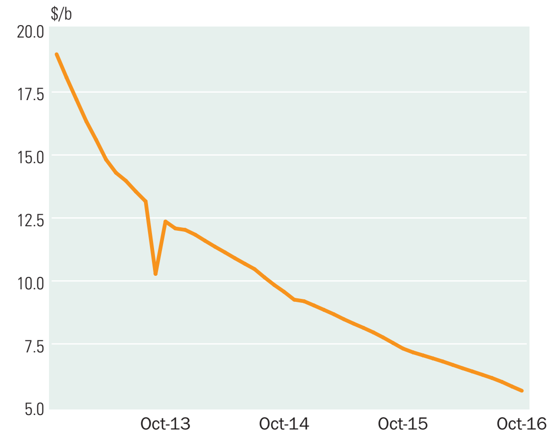
However, the spreads between US Midcontinent crudes and those on the US Gulf Coast are enough to justify additional capacity – and with the Seaway pipeline reversal set to take place this year, existing pipelines are already seeing the impact of promised US Midcontinent exit capacity.

Enterprise on November 16 agreed to buy ConocoPhillips' 50% stake in the Seaway crude pipeline system, an under-utilized pipeline currently 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. By early 2013, the reversed Seaway system would run at the full 400,000 b/d capacity.

Enterprise and Enbridge also plan to build a 45-mile line to connect Seaway to Enterprise's EHCO terminal near the Houston Ship Channel, where crude could reach Houston and Texas City area refineries. And the two companies 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 EHCO terminal is "a few weeks away" from receiving its first crude barrels, Enterprise said on October 4, with 750,000 barrels of the proposed 6 million barrels of capacity completed. Eventually, this terminal will receive barrels not only from Cushing, but from the Permian Basin and the Eagle Ford.

Following the Seaway reversal announcement last year, Enterprise and Enbridge canceled their proposed 800,000 b/d Wrangler Pipeline project from Cushing to the US Gulf Coast. Enterprise had earlier in the year planned to build a 450,000 b/d line from its Cushing terminal to Houston in a partnership with Energy Transfer Partners, a project called Double E, but the proposal was dropped after failing to solicit sufficient support from shippers.

Brent vs WTI frontline swap, October 2 2012



Source: Platts

The newest Cushing to US Gulf Coast proposal comes from Energy Transfer Partners, and the company is proposing to convert its 770-mile Trunkline system from natural gas to crude and then reverse the flow. But the company has yet to publicly announce this project, and its comments are limited to a regulatory docket at the US Federal Energy Regulatory Commission. Analysts expect this line could carry anywhere from 150,000 b/d to 400,000 b/d once the project is completed, but first, Energy Transfer must convince the FERC that ending natural gas supplies on Trunkline would not leave US midcontinent customers stranded.

These Cushing to USGC lines, existing and proposed, are just the foundation for additional interconnections for Canadian and US Rockies production all the way to US Gulf Coast refineries.

Kinder Morgan is also proposing to convert its existing Pony Express gas line back to carrying crude oil by 2014, connecting the Bakken and the nascent Niobrara Shale in Colorado to Cushing, and then other pipelines to the US Gulf Coast. The existing pipeline runs from Guernsey, Wyoming to Missouri, crossing Colorado and Kansas. Kinder Morgan is proposing a north-south extension of the Pony Express line that would connect it to Cushing, OK, and from there to the US Gulf Coast via the various Cushing to USGC proposed lines. The line could carry up to 210,000 b/d into Cushing, Kinder Morgan said.

In addition, Shell Pipeline has proposed reversing its Houma-to-Houston (Ho-Ho) pipeline, 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 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. This line would enhance access for Texas refiners to domestic offshore crudes via the St. James, Louisiana hub.

SHIFTING GROUND

The 1.59 million b/d of proposed capacity to move crude from Cushing to the US Gulf Coast, along with the Eagle Ford and Permian Basin crude boom, promises to change crude slates of local refineries while shifting traditional crude flows and finding 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: 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 $5-$6/b premium to WTI (*see graph on page 13*). Back in January, a similar forward curve was showing the two benchmarks at near parity. This has led to suggestions that even more capacity needed to relieve the bottleneck.

Despite the possibility that WTI's disconnection from the larger market 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 August, Mars production was just above 230,000 b/d, down 154,000 b/d from year-ago levels. Poseidon production in August was over 183,000 b/d. SGC production was just 84,000 b/d in August, above year-ago levels of 59,000 b/d amid August 2011 maintenance.

Western Canadian Select is poised to compete with US offshore grades as a potential US sour benchmark. Western Canadian Select is a blend of conventional heavy production and bitumen from the Alberta oil sands. Current Western Canadian oil sands crude production averaged 1.6million 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 as well as 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.

On the sweet side of crude, Bakken Blend and Eagle Ford crude production by 2016 could exceed as much as 3.4 million b/d combined, 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 could develop as a standalone sweet benchmark for the US Gulf Coast. 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.

The other critical market to watch will be Houston, where a confluence of Eagle Ford, Permian, and Cushing lines 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 complete reversal of the Seaway line in 2013 means 400,000 b/d of crude coming in from Cushing, with a potential for 850,000 b/d by 2014. And 903,000 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.

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 3.4 million b/d by 2016 just between the Eagle Ford and Bakken plays. 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. Additional pipeline and rail capacity out of the prolific Bakken Shale Formation will connect Bakken producers to additional buyers and new market.

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 light sweet crude imports and possible heavy sour imports into the US Gulf Coast could 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. As a result, Platts has launched Eagle Ford crude assessments on October 16. The Eagle Ford Marker assessment reflects the yield value of a 47 API Eagle Ford crude barrel based on Platts product assessments and then adjusted for spot crude values. In addition, Platts has launched a daily average of four Eagle Ford company postings as a basis of comparison. 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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