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Too Many North American Proposals And Not Enough South American Demand

By Brian Mothersole, Hart Energy

Grand expectations must reconcile with reality, according to an analyst, especially when new supply from North America interacts with uncertain worldwide demand. South America might provide a home for some of the new capacity, even if nations are more inclined to pipeline natural gas imports and renewables.

A whopping 47 billion cubic feet per day (Bcf/d) of liquefaction capacity has been proposed in the U.S., an amount that dwarfs last year's total worldwide trade of only 35 Bcf/d. Javier Diaz, a manager of energy analysis and consulting at Bentek Energy, expects about a quarter of the proposed U.S. capacity to make it to construction and eventually liquefaction. There simply isn't enough room in the world market to accommodate them all.

By his appraisal, the more realistic estimate includes Cove Point on the U.S. East Coast; the first five trains of Sabine Pass LNG and trains 1 through 3 of Cameron LNG, both in Louisiana; the first three trains of Freeport LNG in Texas; and finally, the first two trains of Corpus Christi LNG. Of the contracts from those projects so far, 4.1 Bcf/d will be dealt to portfolio players, 2.4 Bcf/d will find end-users in Japan and 1.6 Bcf/d will be sold to Spanish companies.

The oil price drop has also affected future U.S. proposals. Before the oil-price drop of this and last year, the average savings for a Henry Hub-linked contract vs. a traditional oil-linked contract to Asian buyers was about $2.24 to $2.74 per million Btu. Now, however, the oil price drop has largely wiped out that price advantage. Moreover, Bentek expects U.S. projects will be competitive with oil-linked projects at a $78 oil price, but when it incorporates the sunk costs on terminals that are currently under construction, oil needs to only be at $54 a barrel to be competitive in 2020.

Canada, like the U.S., is also finding itself adjusting its expectations. Close to 20 projects have been proposed for some time, but it is only recently that one has decided to make the plunge—sort of. Canada was originally well positioned to take advantage of Asian LNG price arbitrage, banking on its available cheaper gas and lower transportation costs. Yet, the opportunity window for British Columbia projects is closing, according to Diaz. The projects there didn't react quickly enough to what Asian buyers were looking for: destination flexibility and diversified price structures with a break from oil links. Moreover, the high infrastructure costs, including monstrous pipelines, added to an already swelling potential bill. In the medium term, this lack of alacrity let Australian projects come in and swoop up the market.

"The room of opportunity is really closing, at least until probably the second half of the next decade," Diaz said about Canadian projects.

Petronas' Pacific NorthWest LNG, which delayed a final investment decision (FID) late last year, has now taken an FID conditional upon regulatory and legislative matters. It is unclear at the moment if other projects will follow and fulfill what British Columbia Premier Christy Clark has promised will be a booming industry for her province.

Potential Imports

Mexican imports look to be outpaced by growing pipeline supplies. The Los Ramones Phase II North Pipeline looks to be completed by the end of the year, and the Los Ramones Phase II South is expected to be finished in June next year, according to Bentek. This pipeline will in part push Texan exports of natural gas to Mexico by 1 Bcf/d next year, and total U.S. exports to Mexico will grow to 4.4 Bcf/d by 2020. This increased reliance on pipeline gas will naturally displace some LNG imports.

As a whole, South America has increased its reliance on natural gas, especially LNG imports. Mainly supplied by a liquefaction facility in Trinidad and Tobago, average South American imports have grown

136% since 2010. Argentina has more than tripled its LNG demand, while Brazil more than doubled and Chile grew at a more modest 30%. The future growth of LNG imports in these countries has potential, but it can stall as countries mull other options.

In Brazil, a multiyear drought of epic proportions has persuaded the country to shift more toward thermal electric generation from fossil fuels and away from its traditional mainstay, hydropower. While the government hopes to continue to use water and wind as its main electricity generators, it has carved out 13% of its 2023 power generation capacity plan for natural gas. As it increases its overall capacity by 7.1 gigawatts (GW) per year, that means that over the next several years Brazil will install 8.3 GW of new natural gas capacity. Of course, it would love to still rely on pipeline imports from Bolivia, as they are the cheaper option; Brazil currently has no long-term LNG import contracts and has been ravaged by the spot market. Further developments in offshore, pre-salt gas present an option for supply as well, but developing it is expensive.

LNG continues to grow in Argentina as well, as the South American nation has had to increase its imports amid declining domestic production. Pipeline imports from Bolivia also appear to be the most attractive option here, too, as they are cheaper.

Chile has seen more modest growth from its two import terminals, and it is currently considering whether it needs a third. It generated 23% of its power from natural gas in 2013, and it hopes to reduce that share to 19% by 2025.

On the whole, Diaz said there is currently about 7.78 million tonnes of uncontracted South American LNG demand to be met in 2024 and that this presents an opportunity to exporters.

More uncertain Central American and Caribbean imports will be met by challenges including small volumes, lack of financing and high financial risk. Potentially, these nations could overcome these challenges through demand aggregation and container solutions.

On the whole, South and Central America have the potential to soak up some volumes from North America, but certainly not enough to justify building all of the current proposals.

Prepared To Get Back On Track And Rolling Again

By Bryan Sims, Hart Energy

WASHINGTON – The crude-by-rail story–driven by a host of external factors such as weather, congestion, fatal accidents and commodity price volatility–is one that has certainly seen its ups and downs over the years. Yet, Burlington Northern Santa Fe LLC (BNSF) executive chairman Matthew Rose knows his company is poised to tackle whatever the oil industry can throw at it.

While he didn't provide a specific time frame, Rose was adamant in saying that his company is more than prepared to accommodate a potential rebound in oil production.

"Assuming we see some market indicators—and we clearly will see it now with the price of crude—we'll see people uncapping wells and start to frack the next well. We think we're in a much better place to handle that next surge," Rose said at the recent U.S. Energy Information Administration's Energy Conference.

One-third of all domestic crude oil production increases since 2009, according to Rose, have used railroads over pipelines to get product to refineries.

Crude oil production cuts and strong demand from refineries have led prices to rebound to about $60 per barrel (/bbl) currently from a six-year low of less than $44/bbl in March.

DOE Tank Car Rules

Rose commented on a U.S. Department of Transportation's recent ruling that requires a phase-out or retrofit by May 2023 of all legacy DOT-111 rail cars that transport crude oil and ethanol.

The final rule, developed by the Pipeline and Hazardous Materials Safety Administration and the Federal Railroad Administration, was broadened, extended and harmonized with Canada.

"It's good to have certainty over the car design and the phase-out schedules," Rose said.

While he supports the overall scope of what the rule tries to accomplish, Rose takes issue with the requirement to have an electronically controlled pneumatic (ECP) braking system outfitted on a crude oil and ethanol rail car by Jan. 1, 2021.

"It will be difficult to integrated ECP into our fleet of locomotives for crude and ethanol only without substantial risk of impact of network velocity. It will significantly limit how flexible we use these assets, and we certainly realize the importance of the flexibility during our recent service issues. The rule will have to be changed in the future," Rose said.

Evolving Freight Portfolio
Energy products such as crude oil, ethanol, LPG and coal make up nearly 30% of BNSF's freight portfolio; however, crude oil units themselves comprise around 5% of overall total units, according to Rose.

Coal from the Powder River Basin consists about 20% of BNSF traffic, Rose noted, and has traditionally accounted for about 25% of the railroad industry's revenues. However, this is undergoing a massive transition, he said, thanks to cheap natural gas and U.S. Environmental Protection Agency regulations.

Meanwhile, BSNF is the largest shipper of ethanol. It moves about 100,000 units in 2014, which is a year-over-year increase of about 8%. The number of ethanol production facilities sited on the company's network has also grown significantly from its beginning of 17 origins in 2003 to about 54 origins today.

"Today, ethanol demand is relatively stable," Rose said. "We've seen some modest growth as margins have returned due to lower prices for corn, particularly as producers have taken advantage of our unit-train routes."

While BNSF has seen the impact of the shale boom with high-capacity shipments of drilling inputs such as frack sand, pipe, aggregate and cement in recent years, Rose said he expects this freight to come down slightly.

"Every horizontal drilling rig requires about 40 cars of supporting materials, although that number is shrinking because the process has become increasingly more efficient. With no growth, inputs are down appreciably," Rose said.

Eye Toward Investments

In total, Rose said BNSF aims to spend about $6 billion this year alone on rail line expansions, maintenance and renewal of assets, along with locomotive and equipment upgrades.

Maintenance and renewal of assets by far make up the biggest chunk of BNSF's annual investments because the more capacity it adds to haul freight the more it costs to maintain. In 2015, nearly half of its investments ($2.9 billion) will go toward renewal of its assets and maintaining things like replacing rail ties.

"Proper maintenance is about more than safety. It's about utility and leveraging the billions of dollars in new capacity that we've added," Rose said.

In 2014, BNSF spent around $1 billion on network expansions. Rose said BNSF has already surpassed that amount ($1.5 billion) at the mid-way point of 2015.

"We can expand the network to take more volume for a long time to come. Our model is to build the railroad for growth, grow the business and reinvest those revenues back in the network where it's needed, when it's needed. Sounds straight-forward, but it's not without risk," Rose said.

After Rejecting Bid, M&A Future Uncertain For Williams

By Caryn Livingston, Hart Energy

After a May announcement that Williams Cos. Inc. (WMB) would fold its MLP Williams Partners LP into the C corp, the Williams story took a new twist June 21 after the company rejected an unsolicited $53.1 billion bid from Energy Transfer Equity LP (ETE).

The company has spurned ETE's overtures for months. The all-equity takeover would have consisted of $48 billion for WMB's common stock and $5.1 billion for assumption of liabilities. The offer was also dependent on the cancelation of Williams' pending merger with Williams Partners LP (WPZ).

Despite a 32% premium to Williams' last closing price, the $64 per share offer was deemed too low.

Williams said in a press release that its evaluation of the offer "determined that it significantly undervalues Williams and would not deliver value commensurate with what Williams expects to achieve on a standalone basis and through other growth initiatives."

ETE has been courting Williams for about six months, but felt compelled to send a letter to the company after the May 13 announcement that Williams and Williams Partners would merge, the company said in a June 22 press release. It followed up with letters in June, one to Williams' board.

"ETE is disappointed that, despite the best of intentions and its efforts to reach a friendly, negotiated combination, it is forced into a position to publicly confirm its offer for Williams," the company said.

Until its announcement June 21, Williams' management had ignored ETE's efforts to engage in a discussion, ETE said

While Williams' announcement stated that it would not accept the offer, ETE may not be out of the game just yet. Williams stated it would continue to evaluate potential transactions.

“Given Energy Transfer’s interest in the Marcellus/Utica, they may not give up easily,” Simmons & Co. International analyst Mark Reichman said in the investment bank’s “Morning Energy Note” for June 22.

“After all, Williams has an enviable portfolio of assets and commercial relationships in the region and a long-tailed backlog of development projects.”

Acquiring Williams' assets in the Northeast as well as the Transco Pipeline system offers expansion opportunities to ETE that are not available elsewhere, according to a June 22 note from Tudor, Pickering, Holt & Co.

“Transco ownership would allow [ETE] to integrate the Rover Pipeline and further end-market expansions as system continues transition to East Coast supply header vs. historical long-haul,” the note said.

Additionally, securing Northeast gathering and processing assets would allow ETE to direct liquids to Sunoco Logistics Partners LP’s Mariner System and complete the commercial value chain.

If ETE were to acquire WMB, it could re-shuffle its current assets with assets held by WMB to optimize asset value, Reichman said.

“ETE could choose to operate Williams Partners as a stand-alone entity,” as it would acquire the 60% ownership interest in the partnership that WMB currently holds, he said.

Williams Partners unit holders could benefit since “distribution growth and the potential for future M&A activity is uncertain.”

Tudor Pickering agreed it will be necessary to address the “converging LP/GP growth rates and persistent coverage issues” Williams Partners is experiencing.

ETE “would clearly need to support growth in the near-term by selling assets” to the partnership, the note said.

If the transaction goes through, ETE could support the partnership’s growth by selling Energy Transfer Partners LP’s (ETP) interstate pipelines to Williams Partners as a complement to the Transco Pipeline. It could also structure the MLPs geographically—“for example making one the ‘Northeast midstream co.,’” the note said.

Price Forecasts

Analysts took differing viewpoints as to how Williams’ rejection of the offer, and its exploration of alternative transactions, should impact share and unit prices.

Darren Horowitz, analyst, Raymond James Energy, wrote in an update he expected shares and units of the Williams family to trade up on the news.

“This is a strong statement from management regarding its perception of the family’s current market valuation with additional upside from a more favorable strategic alternative still a possibility,” he said.

Reichman was less enthusiastic. He expects Williams shares will likely continue strong but Williams Partners units could take a hit after rejecting the offer.

“Clearly, ETE’s unsolicited offer will complicate matters,” he said.

“Regardless of whether a higher bid emerges, Williams shareholders will need to be convinced that existing management will be able to deliver equal or greater shareholder value,” Reichman said.

While holders of Williams Partners units have enjoyed a boost in unit prices after the announcement that WMB would roll the MLP up into the C corp, “the disclosure of ETE’s unsolicited bid for WMB creates uncertainty,” Reichman said.

“We would not be surprised if WMB shares enjoy a boost following the announcement based on the potential for a higher offer to materialize but [Williams Partners] units could be pressured due to the uncertainty of future outcomes for unit holders.”

Examining The Value Gap Between Crude, NGL and Natural Gas Prices

By Caryn Livingston, Hart Energy

HOUSTON--When it comes to the current low price environment for gas and NGL, a great deal of optimism exists when looking to the future of LNG exports and ethane cracking. However, Suzanne Minter, manager of energy analysis at Bentek Energy, told an audience at Platts' Benposium that she is less optimistic.

"This collapsing value gap [between crude oil, NGL and natural gas prices], in my mind, potentially threatens all of this export that we're looking for," she said.

Minter came to this conclusion after years of falling prices across the energy sector led to decreased targeted production, first of natural gas then of NGL, with high crude oil prices instead driving production of associated gas and NGL. When oil prices finally collapsed during the past winter, Minter said two questions were raised: "Is there enough value left at the high end of that value gap for producers to want to produce the crude that will give us the associated natural gas and NGLs, and secondly, is the value gap wide enough to incentivize further midstream infrastructure buildout, to allow the transfer of Btus that we were all looking for?"

This concern is warranted, Minter said, because major investments such as the decision to build ethane crackers occurred around 2010 to 2012, when there was a wide value gap to incentivize infrastructure buildout.

"Ethane was supposed to replace naphtha as the feedstock of choice," she said. "We're going to burn LNG, supposedly, because it's the lowest-cost per Btu, and it can replace more costly fuels such as fuel oil … [and]—ultralow sulfur diesel—these sorts of things that historically set high on the value gap. But now that that value gap's collapsed, I argue that this is demand-destructive for natural gas, ultimately."

The other significant challenge ahead, Minter said, revolves around North America's projected future as a major exporter of LNG and olefins. With oversupply on the continent driving down domestic prices, producers are depending on global markets purchasing those products. The problem with this plan, according to Minter, is that most of the products are in competition with each other.

Looking at the NGL barrel, Minter said current forecasts predict that by 2020 North America will need to export about 33% of the refined NGL products it produces. However, all of those same products are competing for the same end-use, as petrochemical feedstocks.

This problem is compounded by the type of crude oil produced in North America—a mix of condensate and light crude that, when cracked, produce naphtha.

"So I don't care if we split all the condensate here in North America, or if we send it out to global markets to crack–we're going to create naphtha," she said. "The more and more light-end crude we produce will give us more and more naphtha," which will quickly become competitive with NGL as a petrochemical feedstock as the abundance of naphtha drives the price down. Naphtha is also becoming competitive with condensate and natural gas as a diluent for crude from the Canadian oil sands, Minter said.

"Naphtha, condensate and natural gasoline are effectively like Coke vs. Pepsi," she explained. "You have a preference, you might like a Coke over a Pepsi, but if you're buying a whole bunch, you're going to buy the least cost."

"They become interchangeable as more and more molecules come to bear on the market, and the consumer gets to set the price," she said. "I believe that we see continual price pressure on these commodities as they compete for market share."

The major risk in current projections of NGL and natural gas prices is expecting global demand to boost prices, though there is a "real risk" that may not be the case, Minter said.

"If that happens, this value gap should continue to stay under pressure and collapse, and if so it comes back to this LNG question of we're all banking on LNG exports of anywhere from 8 [Bcf] to 12 Bcf a day out of North America," she said. "If that value gap's not wide enough, am I really going to invest, or continue to invest, to take that LNG, if I can take fuel oil, or diesel or something like that, that happens [to be] at a much lower price at this point?

"I think ultimately it could potentially be really damaging to the overall demand story," Minter concluded. "And what these collapsed prices are signaling to us is we just have too much."

Frac Spread: Decoupling Returns

By Frank Nieto, Hart Energy

It appears as though any recoupling that took place between crude and NGL prices in the past year was a coincidence more than a return to the old form of normalcy given the decoupling between the two produces that has taken place in the past month.

While West Texas Intermediate (WTI) crude has been trading at an average of $60 per barrel (/bbl) for the past month, NGL prices have lost nearly 10% in value at Conway and Mont Belvieu. Interestingly, there is more evidence to suggest that prices should recouple on the downward cycle more than a further widening of the delta between the two markets.

NGL prices are expected to continue to face headwinds throughout the rest of the summer with the possible exception of ethane, which may begin to see improvements. The biggest headwind facing the NGL market is the large storage build for most liquids with ethane being the only product that can reasonably anticipate a tightening of volumes in the near term. This situation has caused most NGL prices to hit their lowest level in nearly a decade.

Interestingly, the global crude market is also oversupplied, but prices have been improving. According to Barclays Capital prices may reverse as the market reacts to the large storage levels for crude. "The market has benefitted from several one-off and seasonal factors over the past six months," the investment firm said in a June 26 research note.

"In Q1, winter weather added to price-dependent demand and a precipitous decline in drilling activity. Remarkably, over three-quarters of Europe's oil demand growth in January and February came from weather-related gasoil demand. In Q2, one-off refining outages kept non-OECD (Organization for Economic Co-operation and Development) throughputs in check, amid strong gasoline demand, which created strong margins and high demand for crude. The conflict in Yemen erupted and is likely not going away anytime soon. The winter was severe, Saudi-Yemeni conflicts continue, refining outages have been acute, OPEC and non-OPEC unplanned outages are at record levels, and the Chinese have continued their opportunistic crude buying. So OPEC managed to squeak by the shoulder season without too steep of a price decline. Put in the context of the past several years, these events are exceptional and almost all bullish in nature. What if the next group of factors is the opposite of this?" the report said.

Further, Barclays Capital noted that the oil glut hasn't sufficiently cleared and instead only shifted geography. Additionally, North American balances have been supported by very high refining runs, declining output from the Bakken, wildfires in Canada, and synthetic crude oil maintenance. It is unlikely that crude prices will reach their lows from earlier in this year, but it wouldn't be surprising if it holds firm.

The story is starker for NGL prices, especially for propane, which hit 14-year lows at both Mont Belvieu and Conway at 35 cents per gallon (/gal) and 30 cents/gal, respectively. While margins remain positive, the Midcontinent frac spread is very thin. There is a silver lining though and that's the fact that storage builds have been lower than expected the past few weeks as LPG exports grow.

Ethane margins are negative at both hubs, but balances are tight due to rejection of approximately 540,000 bbl/d. According to En*Vantage, next month frac spread margins will need to rise to economically dispatch rejected volumes in areas with the lowest transportation costs to Mont Belvieu.

The theoretical NGL bbl price had a 6% decline at both hubs with the Mont Belvieu price down to $18.89/bbl with an 11% drop in margin to $8.84/bbl and the Conway price dropped to $17.69/bbl with a 10% drop in margin to $7.97/bbl.

The most profitable NGL to make at both hubs was C5+ at 91 cents/gal at Conway and 90 cents/gal at Mont Belvieu. This was followed, in order, by isobutane at 17 cents/gal at Conway and 21 cents/gal at Mont Belvieu; butane at 15 cents/gal at Conway and 19 cents/gal at Mont Belvieu; propane at 6 cents/gal at Conway and 10 cents/gal at Mont Belvieu; and ethane at negative 2 cents/gal at Conway and nil at Mont Belvieu.

The U.S. Energy Information Administration reported that natural gas storage injection was down to 75 billion cubic feet the week of June 19 due to increased cooling demand. This increased the storage level to 2.508 trillion cubic feet (Tcf) from 2.433 Tcf. This was 38% higher than the 1.813 Tcf posted last year at the same time and 1% greater than the five-year average of 2.473 Tcf.

Cooling demand should remain high on both the East and West coasts according to the National Weather Service's forecast for the week of July 1, which anticipates warmer-than-normal temperatures. However, demand from the Midwest will be less as it expects cooler-than-normal temperatures.

CURRENT FRAC SPREAD (CENTS/GAL)				
June 26, 2015	Conway	Change from Start of Week	Mont Belvieu	Last Week
Ethane	15.66		17.99	
Shrink	17.64		18.23	
Margin	-1.98	-5.81%	-0.24	53.72%
Propane	30.16		35.10	
Shrink	24.37		25.19	
Margin	5.79	-28.96%	9.91	-25.11%
Normal Butane	42.52		47.32	
Shrink	27.58		28.52	
Margin	14.94	-17.83%	18.80	-21.08%
Isobutane	43.02		47.88	
Shrink	26.49		27.39	
Margin	16.53	-17.65%	20.49	-18.73%
Pentane+	120.00		120.44	
Shrink	29.50		30.50	
Margin	90.50	-4.48%	89.94	-5.49%
NGL $/Bbl	17.69	-5.55%	18.89	-6.34%
Shrink	9.72		10.05	
Margin	7.97	-9.70%	8.84	-11.03%
Gas ($/mmBtu)	2.66	-1.85%	2.75	-1.79%
Gross Bbl Margin (in cents/gal)	16.76	-10.57%	19.30	-11.69%
NGL Value in $/mmBtu (Basket Value)				
Ethane	0.86	-2.73%	0.99	-0.28%
Propane	1.05	-8.55%	1.22	-9.72%
Normal Butane	0.46	-8.12%	0.51	-10.48%
Isobutane	0.27	-8.58%	0.30	-9.83%
Pentane+	1.55	-3.85%	1.55	-4.58%
Total Barrel Value in $/mmbtu	4.18	-5.63%	4.57	-6.17%
Margin	1.52	-11.59%	1.82	-12.11%

Price, Shrink of 42-gal NGL barrel based on following: Ethane, 36.5%; Propane, 31.8%; Normal Butane, 11.2%; Isobutane, 6.2%; Pentane+, 14.3%, Fuel, frac, transport costs not included. Conway gas based on NGPL Midcontinent zone, Mont Belvieu based on Houston Ship Channel.

NGL PRICES						
Mont Belvieu	Eth	Pro	Norm	Iso	Pen+	NGL Bbl
June 17 - 23, '15	17.99	35.10	47.32	47.88	120.44	**$18.89**
June 10 - 16, '15	18.04	38.88	52.86	53.10	126.22	**$20.17**
June 3 - 9, '15	17.57	36.98	52.38	53.76	124.18	**$19.73**
May 27 - June 2, '15	17.87	40.40	54.42	56.28	122.72	**$20.25**
May '15	18.69	46.42	58.02	59.80	127.69	**$21.72**
April '15	17.06	54.84	64.36	66.38	127.64	**$22.97**
4th Qtr '14	20.22	76.90	96.73	98.28	149.25	**$30.10**
3rd Qtr '14	23.19	103.92	123.69	128.39	212.20	**$40.27**
2nd Qtr '14	29.26	106.55	124.12	130.23	222.81	**$42.31**
1st Qtr '14	34.50	129.51	137.62	141.49	212.60	**$46.16**
June 18 - 24, '14	28.83	107.70	128.70	137.12	226.10	**$43.02**
Conway, Group 140	Eth	Pro	Norm	Iso	Pen+	NGL Bbl
June 17 - 23, '15	15.66	30.16	42.52	43.02	120.00	**$17.69**
June 10 - 16, '15	16.10	32.98	46.28	47.06	124.80	**$18.73**
June 3 - 9, '15	15.23	31.70	46.22	49.92	121.50	**$18.28**
May 27 - June 2, '15	15.43	37.16	49.26	54.80	119.62	**$19.13**
May '15	15.15	40.99	51.78	58.32	122.34	**$19.95**
April '15	15.75	48.18	59.30	63.67	119.72	**$21.26**
4th Qtr '14	18.69	78.64	102.72	113.19	146.37	**$30.77**
3rd Qtr '14	20.38	104.99	123.51	140.07	207.90	**$40.18**
2nd Qtr '14	26.26	105.44	121.26	163.00	221.62	**$42.62**
1st Qtr '14	25.46	169.48	132.08	147.10	216.86	**$49.93**
June 18 - 24, '14	25.88	108.04	126.82	142.30	223.90	**$42.76**

RESIN PRICES – MARKET UPDATE – JUNE 26, 2015					
TOTAL OFFERS: 19,744,152 lbs		SPOT		CONTRACT	
Resin	Total lbs	Low	High	Bid	Offer
LLDPE - Film	4,710,980	0.63	0.75	0.625	0.665
HDPE - Blow Mold	4,050,072	0.61	0.72	0.605	0.645
HDPE - Inj	3,790,256	0.64	0.74	0.615	0.655
LDPE - Film	1,714,116	0.69	0.76	0.645	0.685
HMWPE - Film	1,438,208	0.64	0.76	0.635	0.675
PP Homopolymer - Inj	1,183,104	0.63	0.73	0.62	0.66
LDPE - Inj	1,085,472	0.6	0.77	0.645	0.685
LLDPE - Inj	1,058,208	0.71	0.76	0.625	0.665
PP Copolymer - Inj	713,736	0.65	0.73	0.64	0.68

Source: Plastics Exchange – www.theplasticsexchange.com

Total In Talks To Sell Frigg Pipeline To ArcLight

Bloomberg

Total SA, Europe's second-biggest oil company, is in exclusive talks to sell its gas pipeline in the U.K.'s North Sea to ArcLight Capital Partners, according to two people familiar with the matter, Bloomberg said June 25.

The French company's Frigg network may be sold to the energy-focused U.S. buyout firm for an enterprise value of as much as $1 billion, the people said, asking not to be identified as the information is private. While discussions are at an advanced stage, a final agreement is yet to be reached and talks may still fall apart, the people said. ArcLight may make the investment through its affiliate, North Sea Midstream Partners, one of the people said.

Total unveiled a plan earlier this year to cut spending and sell assets following a plunge in the price of crude. It aims to sell $10 billion of assets through 2017, including $5 billion this year.

Boston-based ArcLight focuses mainly on investments in North American energy infrastructure assets. Since its establishment in 2001, the company has invested about $13 billion in 90 power, midstream and production assets, according to its website.

The Frigg U.K. System, which covers about 362 kilometers (225 miles), transports natural gas from fields across the North Sea to St. Fergus in Scotland. Completed in 1977, Frigg is 100 percent owned by Total's E&P UK Ltd. unit.

Representatives for Total declined to comment. A spokeswoman for ArcLight didn't respond to requests for comment.

Quebec Opposes Pipeline Projects On Environmental Concerns

Bloomberg

Across Quebec, cardboard signs are popping up on lawns depicting a broken pipe gushing black crude. "Don't flow near us," they warn in French, Bloomberg said June 25.

That sums up Benoit Pigeon's feelings about TransCanada Corp.'s proposed C$12 billion ($9.7 billion) pipeline that would traverse the province on its way to connect Alberta oil-sands fields with the Atlantic Coast. In addition to his yard sign, Pigeon has marched with street protesters and helped rally opposition to the project on Facebook.

"This investment should be in renewable energy instead," Pigeon, 51, said in an interview at his home.

For a resource-rich nation eager to expand crude exports from the oil sands, Canada has been striking out lately. TransCanada's Energy East marks the fourth time this decade an oil-sands pipeline has been mired in environmental opposition. Keystone XL, which would bring oil to the Gulf Coast, remains bogged down in U.S. politics for a seventh year.

And protests and lawsuits are hobbling two lines that would carry crude to the Pacific Coast.

Quebec has frustrated the fossil fuel industry before, imposing a ban on shale drilling in 2012. Now resistance is building in the province where the majority of the construction on the 4,600-kilometer (2,900-mile) pipeline would take place.

Energy East was supposed to be easier. It largely involves converting an existing natural gas line to oil, with a route that doesn't cross an international border. Quebec, which currently ships imported oil up the St. Lawrence River to two refineries, would gain access to new supplies -- and the possibility of becoming, along with neighboring New Brunswick, an export hub.

‘Nation Building’

“We look at it as a nation-building initiative,” said Donald Arseneault, New Brunswick’s energy and mines minister, who’s trying to persuade his Quebec counterpart of the project’s merit. “Quebeckers are people that, probably more than anyone else in the country, are concerned about their environment.”

The environmental movement is strong in the French-speaking province, which relies on hydropower for more than 95 percent of its electricity. Quebec Premier Philippe Couillard has said he looks favorably on the line. But he has set seven conditions for the province’s support and given no deadline for a decision.

In a poll conducted by researchers at the Universite de Montreal last November, 50 percent of Quebeckers opposed the project and 33 percent voiced support -- the exact opposite of national results.

‘Uphill Battle’

“It’s clearly an uphill battle for TransCanada in Quebec,” said Erick Lachapelle, an assistant professor of political science who worked on the survey.

Energy East backers in the province, including business and labor groups, want its refineries to benefit from access to cheaper crude from Western Canada.

The mayor of Cacouna, 200 kilometers down river from Quebec City, laments the loss of about 50 potential jobs tied to a marine terminal TransCanada had planned as part of the project. Faced with concerns the facility might threaten an endangered population of local Beluga whales, TransCanada scrapped plans to build in Cacouna in April.

Wildlife Preserve

The St. Lawrence River, traversed as far back as the 1500s by French explorers, has emerged as a focal point of dissent. The pipeline would pass through a wildlife preserve of mud flats along the migration route of 200 species of birds, a spot where 17 unique species of flowers grow. It would then tunnel below the river near a drinking water intake for Quebec City.

“It’s almost the worst place to put a pipeline,” said Jacques Anctil, the president of a nonprofit organization that owns the preserve.

In meetings with residents, TransCanada has emphasized local jobs and community payments that would come with the project. Oil spills are rare and TransCanada said it would clean up and compensate in a worst-case scenario. “Once we get the facts into people’s hands, the communities then become supportive,” Chief Executive Officer Russ Girling said.

There’s no financial compensation that would make Lanoraie farmers Gaetan Roy, Sophie Belisle and Rejean Beauparlant support the line, they said in interviews. The agricultural town is among more than 50 Quebec communities that have issued resolutions opposing the project, according to environmental group Equiterre.

As with the Keystone debate, protesters are linking the project to climate change, saying use of oil-sands crude will contribute to higher greenhouse-gas emissions. About 25,000 protesters showed up for a climate march in Quebec City on April 11, double what organizers expected. “‘Yes’ to climate equals ‘No’ to tar sands,” was the message on banners.

“Every time we move, the activists that want to keep the oil in the ground get out there in front of us,” Girling said. “There’s just a lot of misinformation out there.”

Blue Racer Commissions Second Cryogenic Plant In Ohio

Blue Racer Midstream LLC commissioned a second cryogenic processing plant at its Berne natural gas processing complex in Monroe County, Ohio, the company said June 24.

The Berne II facility has 200 million cubic feet per day (MMcf/d) of nameplate capacity, bringing total processing capacity in the Utica and Marcellus shales to 800MMcf/d. At the complex, two 200MMcf/d plants are now in service, and two additional 200MMcf/d plants are in service at the Natrium natural gas processing and fractionation complex in in Marshall County, W.Va., Blue Racer said.

A 30-mile, y-grade pipeline connects Berne to Natrium. Natrium’s fractionation capacity was expanded to 123Mbbl/d, enough to serve at least six 200 MMcf/d cryogenic plants.

The company plans to install a fifth processing plant in first-half 2016 to meet growing customer demand. In 2014, Blue Racer’s processed volumes more than tripled to 650MMcf/d. Total gathered volumes, including lean gas, are at more than 825MMcf/d, having more than doubled, the company said.

Blue Racer has long-term service agreements with 14 natural gas producers in the Utica and Marcellus. About 200,000 acres are dedicated to the company’s Super system, and there are about 380MMcf/d in total volumetric commitments.

The gathering network in the Utica has more than 650 miles of gathering pipeline across 13 Ohio counties. The system also extends into Wetzel County, W.Va., the company added.

An additional 200 miles of gathering lines are under construction.

The company recently expanded into Washington County, Ohio, in the southern Utica, with the Washington County Connector. This 20-inch, 17-mile pipeline takes about 400MMcf/d of gas to the Berne facility.

Dallas-based Blue Racer Midstream LLC is a joint venture between Caiman Energy II LLC and Dominion.

Plains All American Begins Open Season For Two Pipelines

Business Wire

Plains All American Pipeline LP began an open season for a proposed new pipeline that would carry crude oil from Cushing, Okla., to Longview, Texas, the company said June 23. The open season began that day and is scheduled to end on July 23.

The pipeline would carry about 120,000 barrels per day (Mbbl/d) of light sweet crude from Plains' Cushing terminal to Longview.

Bidders can enter long-term throughput and deficiency agreement for capacity by submitting a binding proposal.

Also, Plains and Delek Logistics Partners LP said an open season began June 23 for Caddo Pipeline LLC, a 50:50 joint venture between the companies.

The new pipeline will take about 80Mbbl/d of light sweet crude from the Longview terminal to refineries in Shreveport, La., and to Delek's pipeline system that supports the El Dorado, Ark., refinery owned by Delek US Holdings.

The Caddo open season also ends July 23.

Plains All American Pipeline LP is an MLP based in Houston.

Howard Energy Partners Proposes Texas-Mexico Gas Pipeline

Business Wire

Howard Midstream Energy Partners LLC, doing business as Howard Energy Partners, plans to build the Nueva Era Pipeline connecting its hub in Texas to Mexico's national pipeline, the company said June 23.

The Webb County Hub is in Webb County, Texas. Mexican National Pipeline System (Sistema Nacional de Gasoductos) is in Monterrey, Mexico. Nueva Era would also link to Escobedo, Nuevo Leon, Mexico.

Nonbinding interest indications for hub and transportation services on the Nueva Era system are now being accepted until July 17.

Nueva Era Pipeline is scheduled to be in service in July 2017, and will be developed with Howard's Mexican partner. It will carry 600,000,000 cubic feet per day of gas to Escobedo, connecting South Texas producers to Mexican end users. The pipeline will run about 200 miles and will be 30 inches in diameter.

Previously, Howard had a solicitation period for interest in transporting and exporting natural gas to Mexico.

Transportation service rates will range from 13 cents to 20 cents per thousand cubic feet, subject to shippers' specifications. Rates will also be subject to Mexican legal requirements including a Comisión Reguladora de Energía transportation permit.

Mike Howard, chairman and CEO, said the company could provide industrial centers in northern Mexico with access to the most competitively priced gas in the U.S. "This proposed pipeline is a testament to our great partnerships in Mexico and the deep relationships we have developed there. Our philosophy is that what is good for Mexico is good for South Texas."

Howard Midstream Energy Partners LLC is based in San Antonio.

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