MIDSTREAM Monitor

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Midstream Accelerates In M&A Race; E&Ps Stuck In Neutral

By Joseph Markman, Hart Energy

Midstream continued to roll and upstream continued to wobble in PwC's Oil & Gas M&A analysis of second-quarter transactions.

Midstream accounted for 21 of the 47 oil and gas deals with values greater than $50 million, or 44%, with the value of those transactions adding up to $27.7 billion, or 71% of the $38.8 billion total. The 21 deals followed 22 in the first quarter, the first time the sector has surpassed 20 deals in two consecutive quarters since fourth-quarter 2012. There were 39 total deals worth 34.5 billion in the first quarter.

Upstream companies, however, have been stymied by oil prices that plunged in the latter part of 2014, stabilized, then tumbled another 20% in the past month.

“Companies, as a result of the decline in commodity prices, looked inward and really focused on cost-reduction initiatives,” Doug Meier, PwC’s U.S. energy sector deals leader, told Hart Energy. “That focus took management time and attention, as well as operational time and attention, and we saw a de-emphasis on M&A as a growth vehicle.”

Upstream companies accounted for 18 transactions worth $8.3 billion in the quarter, a decrease of 55% in volume and 67% in value over the same period in 2014. Much E&P activity is related to shale plays, where nine transactions totaled $5.5 billion, a harsh reduction from the same period last year that saw 21 deals worth $11.6 billion. The most active play for M&A in the quarter was the Utica.

“Buyers in the oil and gas industry continue to be opportunistic in shale formations as investors focused on specific resources to further enhance their positions in relevant basins,” said John Brady, a Houston-based partner with PwC’s energy practice, in a statement.

Oil prices drive value and pricing from an M&A perspective, Meier said, and with those pricing levels remaining stubbornly low companies have been forced to contend with a new normal. In the meantime, that pricing uncertainty translates into corporate valuation uncertainty.

“We have seen a fairly significant disparity between what buyers may be willing to pay for an asset and what sellers are willing to sell an asset for,” he said. “So that bid-ask spread, that gap in expectations, has made it more difficult for M&A transactions to get consummated.”

Upstream companies have also been able to access public and capital markets and have instituted hedging programs to supplement cash flow and strengthen balance sheets. Those factors also contributed to the decline in M&A activity among E&P companies in the first half of the year.

On the midstream side, the rise of MLPs has created a larger universe of participants in M&A than existed when the sector was largely composed of units of large integrated companies. MLPs are now positioned to grow through acquisition, thus complementing their organic expansion projects.

“Clearly, from an MLP perspective, the goal is to—on a regular and frequent and predictable basis—increase your distributions,” Meier said. “M&A provides that opportunity for the quicker return projects as opposed to the greenfield projects, which take a significant amount of time for construction, permitting and processing before the returns are generated.”

Twelve of the 21 midstream transactions in the quarter involved MLPs and six of those were dropdowns, a trend similar to the first quarter.

“Looking forward, we think that the dynamics will continue to be there to see significant activity in the M&A space of midstream in the second half of 2015,” Meier said.

PwC projects an uptick in upstream M&A as well, as hedging programs begin to roll off, the ability to raise financing debt lessens for some players and cost-reduction efforts reach the point of diminishing returns.

“We’re starting to see some narrowing of the bid/ask spread, of buyers’ expectations, sellers’ expectations around pricing,” Meier said. “A combination of those factors, we think, will lead to an acceleration of E&P in the second half of the year.”

The report also showed a 40% decrease in oilfield services deals compared to second-quarter 2014, and an 87% decline in downstream deals.

Brent Field Nears Its End

By Paul Hart, Hart Energy

A visitor sees few pumpjacks nodding on the prairie outside Cushing, Okla., nowadays, and the area produces little oil. Still, the town’s name looms large in the world’s oil business.

Thank its extensive storage and pipeline infrastructure dating from the early 20th Century’s northern Oklahoma oil boom for that. Cushing’s midstream legacy provides the trading hub infrastructure today for one of the world’s best-known crude blends: West Texas Intermediate.

In a similar way, the North Sea field that lent its name—Brent—to another, well-known crude type, no longer produces much oil. Three of its four production platforms have gone offline and the last, Brent Charlie, is down to a trickle and is expected to be shut in soon. No firm date has been set, according to the U.K. unit of Shell, which is a partner with ExxonMobil's Esso Exploration and Production U.K. in the field.

But the gathering, processing and transportation infrastructure needed to support the supergiant field helped make other North Sea fields commercial. That infrastructure still moves production from other North Sea fields, in particular Norway's Ekofisk and Oseberg fields and Scotland's Forties Field, which make up Brent blend. The light, sweet crude serves as a benchmark for the world's crude pricing system.

Brent's current flow is in contrast to the 504,000 barrels per day the field averaged in its peak year of 1982. Located 112 miles east of Scotland's Shetland Islands, Brent was a historic find when discovered in 1971. It came along shortly after the 1969 discovery of the Ekofisk Field in Norway's sector of the North Sea and proved supergiant Ekofisk was no fluke—the North Sea held bountiful crude and natural gas reserves. Brent went on production in 1976 and at the time industry analysts expect it to produce for 25 years.

The partners made a further investment in Brent in the 1990s that extended its commercial life, although in recent years most production has been gas. Operating in the rugged North Sea climate for four decades has proved challenging and, despite the partners' efforts, there were accidents and fatalities over the years.

"To date, the field has produced about 4 billion bbl. of oil equivalent, which is almost 10% of all the oil and gas produced in the U.K. sector of the North Sea," according to a Shell U.K. publication. Handling that much crude required a massive investment in gathering and processing infrastructure. The four platforms, 64 miles of pipelines and 64 oil storage cells beneath the platforms' topsides served 140 wells.

Decommissioning and removal of that infrastructure will take years, according to Shell U.K. The Brent Delta platform ended production in 2011 and the Alpha and Bravo platforms ceased production in fourth-quarter 2014. The decommissioning process may extend until 2040, the company added.

A fifth structure, the Brent Spar oil storage and tanker loading buoy, became an international environmental cause in 1995 following completion of a pipeline to the Sullom Voe terminal in the Shetlands. Shell U.K. had proposed to sink the buoy at sea but following protests moved the buoy to Stavanger, Norway, where it is used in the harbor following refitting.

Santos: Countdown To GLNG Is Like Landing A Jumbo Jet

By Lauren Barrett, Hart Energy

The Santos-operated GLNG project is set to be the second project to commercialize CSG to LNG in Queensland, behind the BG Group-led QCLNG project.

BRISBANE, AUSTRALIA—While 2015 is shaping up to be a tough year for the oil and gas business, the slump in market conditions isn't expected to take the shine away from Australia's next big industry development, with Santos revealing its massive US$18.5 billion GLNG project is a mere two months away from first gas.

Addressing attendees at the DUG Australia event on July 29, Santos vice president for Queensland Trevor Brown used his keynote address to laud the progress and achievements of the state's $80 billion CSG-LNG sector and provided an update on the imminent start-up of GLNG.

The Santos-operated GLNG project, which counts Petronas, Total and Kogas as joint venture partners, is tipped to be the second project to commercialize CSG to LNG in Queensland, behind the BG Group-led QCLNG project.

Brown, a geologist by trade, said no one should underestimate the large scale nature of the developments and the amount of time and investment that has been committed.

"These projects are the culmination of a lot of ambition, a lot of strategic thinking, a lot of bold risk taking decisions, a lot of careful planning and an extraordinary amount of hard work by an extraordinary number of people," he said.

A bullish Brown didn’t ignore the elephant in the room, telling a 250-strong crowd that low oil prices were nothing new for him and would not impact GLNG over the long-term.

“I’ve been in this industry 30 years and it’s about the sixth time there has been an oil price shock or big price correction,” he said. “My view is that it’s [low oil price] really good for the industry. It forces us to focus on the fundamentals and it’s really good for the long term sustainability of our business.

“Regardless of the fact that the oil price is miserably low in recent terms, we stand here on something that we should look decades ahead on when we’re assessing the significance of [CSG-LNG] projects,” he continued. “For decades to come, there will be revenue streams coming through to these projects.”

Brown said the years of investment-heavy construction, development and commissioning were culminating to a big crescendo for Queensland’s CSG industry, with as little as eight weeks left on the timetable before all three CSG-LNG developments are up and running.

Brown then went on to address speculation and industry chatter about supposed competition between the start-up dates of GLNG and the APLNG joint venture, led by Origin Energy and ConocoPhillips.

“Let me state that this is not a race,” he said. “It matters not to me who comes first, second and third in terms of getting first cargo. What’s really important to me is that we maintain and operate a safe, reliable and efficient business and as a nation develop a clear reputation as a safe and reliable supplier of LNG to global markets.”

With the construction and commissioning phase of GLNG, located on Queensland’s Curtis Island, drawing to a close, Brown said the final stage of the project would be like landing a jumbo jet.

“We are roughly two months away on our project from our first LNG being produced and we’re on final approach, our wheels are down, and there’s very little we can do at this point apart from hang on and hope that the landing is smooth,” Brown said.

“It will be a very proud moment for our company to be involved in such a world scale project when we get the first cargo out.”

While some assume first gas will mark the completion of the project, Brown said the operational phase, which will include operating the CSG fields in the most efficient and optimal way, would bring with it new challenges.

Challenges do come with rewards, and for Santos, GLNG will have many. Brown highlighted the fact that Santos will be delivering 11% of Korea’s gas needs in the 20 years, and 9% of Malaysia’s, once GLNG hits full production.

While there is much to look forward to, it’s clear the last few years have left its mark on Brown.

“I think this has been one of the most challenging, stimulating and interesting periods of my career,” he said.

Analysts Turn Bearish On Buildout

By Caryn Livingston, Hart Energy

Plains All American Pipeline LP's (PAA) shares fell about 10% following its second-quarter earnings call on Aug. 5 where it indicated distributions might remain flat until 2017.

Additionally, Plains commented that midstream infrastructure may be at an overbuilt point. This "may have set off an alarm bell with investors that extends beyond PAA and PAGP [Plains GP Holdings] units, and beyond this week," said Jeff Birnbaum, a senior analyst at Wunderlich Securities, in a research note.

After the comment, the midstream energy market sold off broadly, indicating the insight "could be troubling for go-forward MLP performance broadly," Birnbaum said.

The takeaway from both Plains' comments and the market reaction is that ongoing low oil prices could have a wider-ranging effect on the sector than originally anticipated, said Bernard Colson, senior analyst for MLP at Oppenheimer, in an "Equity Research" note.

"Lower oil prices signify lower demand and result in lower production volumes," Colson said. "Our concern is that a low cost of capital and high crude prices in prior years have led to overcapacity. Persistent weakness in demand lessens the need for additional infrastructure."

Additionally, the market's reaction to the news indicated that "that the market has not fully appreciated the effects of this low crude oil price environment on liquids-focused MLP unit prices," Colson said. "As other MLPs evaluate 2016 prospects, we believe they, too, will have to come clean about what 2016 looks like barring a significant crude oil price recovery."

Before the reaction to Plains, it was thought that “this outlook was largely baked into stock prices,” Colson said, adding, “PAA’s disclosure and subsequent beating prove us wrong. We will be re-evaluating our ratings/price targets as second-quarter 2015 reporting season continues.”

Plains’ comment echoed earlier sentiment from Robert W. Baird & Co. Inc.

In a late-June sector update on MLPs, analysts Ethan Bellamy and Fischer Van Handel said, “We are increasingly bearish on mid- to long-term infrastructure investment opportunities as production slows, commercial participants saturate opportunities in larger projects and flush PE/public entities chase a dwindling opportunity set.”

In other words, “onshore transportation is headed toward built-out if not overbuilt,” with certain exceptions, including “Northeast connections, steering gas volumes to LNG exports and Appalachian reversals.”

According to the sector update and a Baird research note following Plains’ earnings call, the outlook hasn’t changed much due to Plains’ comments.

“We have previously highlighted our bearish bias on MLPs through Halloween as seasonal headwinds on both MLPs and crude oil persist,” the note said, while adding that “the generally negative turn on energy sentiment has come harder and faster than we had anticipated.”

Bright Spot

Though the market has reacted negatively to the comments and to Plains’ cuts in distribution growth, the news isn’t a death knell.

“We see the outlook from Plains as indicative of deferred rather than eliminated growth, and a prudent course of action by management to reduce distribution increases in favor of DCF coverage,” Baird said.

Additionally, though the infrastructure outlook has pulled back, “we are more bullish, accordingly, on M&A prospects as small/mid-cap MLPs hit capex roadblocks and may seek value through consolidation,” Baird said.

“We expect bidding wars to emerge led by Energy Transfer and Kinder Morgan. Ultimately, micro and small cap players have a good put option backstopping valuation in the form of bids from the empire-builders,” Baird added.

Frac Spread: Waiting Is The Hardest Part

By Frank Nieto, Hart Energy

West Texas Intermediate (WTI) crude prices continued to fall the first full week of August as refiners are preparing to switch to winter-grade gasoline production. During this time multiple refineries will be down for maintenance to prepare for the switch. As a result, the price for the week fell below $45 per barrel (/bbl), its lowest level since 2009.

Global crude remains oversupplied but demand growth is most being impacted by a macroeconomics, especially a worrying outlook for the Chinese economy as Asia represents the largest growth driver for crude demand.

"There are more risks to the forecast lift in global economic growth in the second-half of 2015. So far market sentiment has deteriorated more than oil balances. The back of the market has led prices lower as speculators are no longer convinced higher oil prices are required to balance future oil supply and demand," PIRA Energy Group said in its Aug. 2 Weekly Oil Market Recap. The group noted it disagreed with this sentiment, but stated that prices will remain lower than previously forecast until the market sees balances begin to tighten.

"It is PIRA's belief that crude oil and product prices are set simultaneously in both the physical and paper markets. Commercial entities that have physical positions, which they hedge in the futures markets, are the connective tissue between these two markets. Post 2003, fears that the world would be running out of crude led speculators to increase their paper length, which raised deferred futures prices enough to allow physical players to find and develop higher cost crude. What is different this time is the role of prime move has shifted from speculators to commercials. This time commercials have become increasingly short, encouraging through lower prices speculators to enter the long side of the market," PIRA said.

It is likely that crude prices will improve once the refinery maintenance season is over in the fall, but until that time WTI prices could decrease further. This will create another headwind for NGL prices, which will need to wait until winter for both refinery blending and heating demand to begin to see any sustained price uptick.

Indeed, heavy NGL prices were down across the board at both Conway and Mont Belvieu with C_{5+} hitting its lowest levels at each location since January.

There is an equally negative short-term outlook for the light NGL market as propane awaits heating demand to begin to work off its overhang, which is expected to far exceed the five-year average by the time winter begins. Margins remain positive, but are getting thinner, especially at Conway.

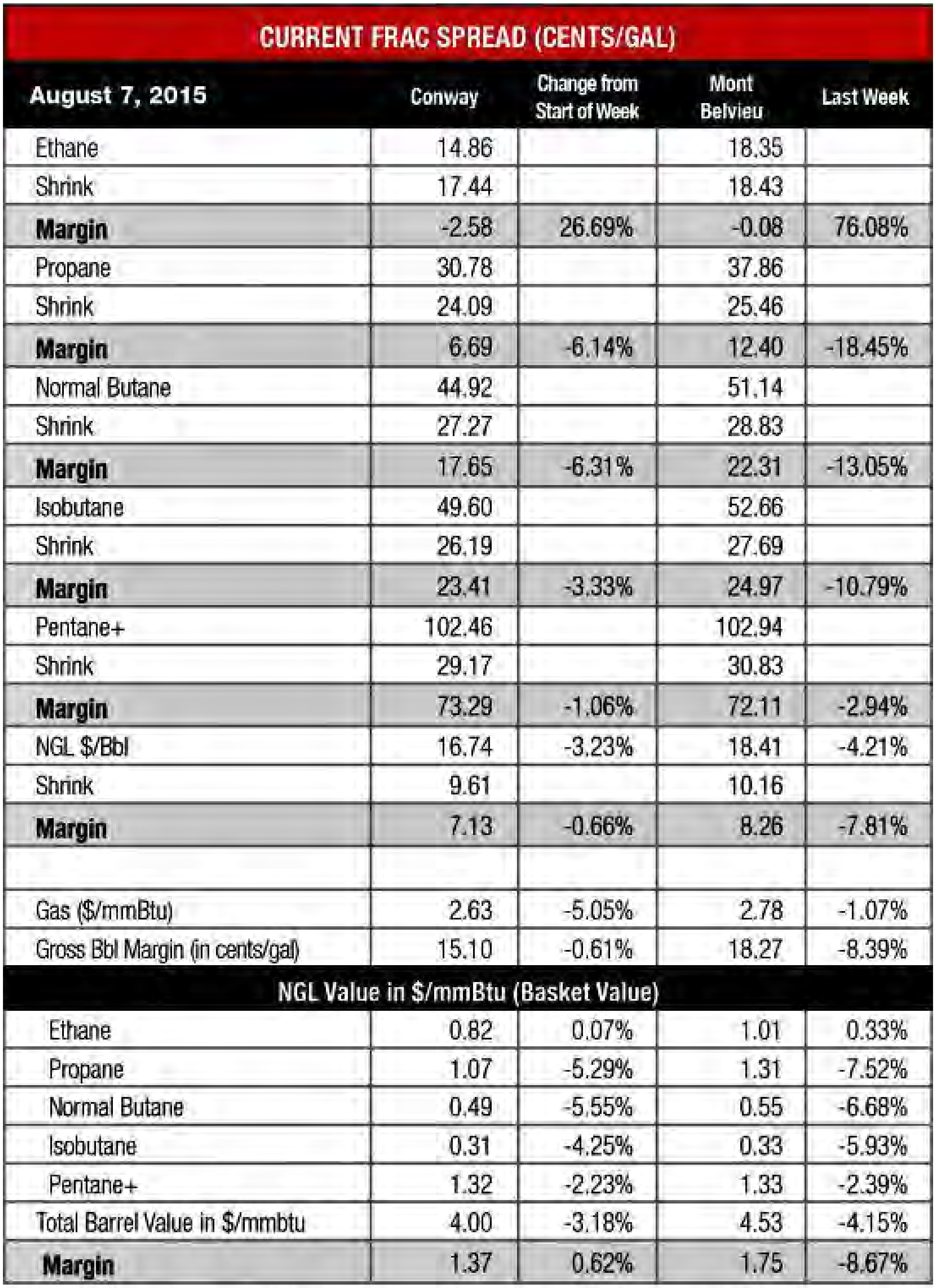
Ethane storage levels have been improving, but received some unwanted news as the U.S. Energy Information Administration (EIA) reported that storage declined by 649,000 bbl in May. This put storage levels below their five-year average, but was well off the 1.2 million bbl decline forecast by En*Vantage.

"Reviewing our ethane stock projections for the last few months compared to actual EIA numbers revealed that we were forecasting lesser builds and higher declines than what the EIA was reporting. It occurred to us that there is a new source of ethane reaching the market and this source is the amount of ethane that is de-ethanized from fuel grade propane to make refrigerated propane for exports. With the recent new refrigerated propane export expansions by Enterprise, Targa and Sunoco Logistics the amount of de-ethanized ethane could be as much as 15,000 to 20,000 bbl/d," the company said in its Aug. 6 *Weekly Energy Report*. The company anticipates ethane balances tightening through November with prices trading between 18 cents per gallon (/gal) and 22 cents/gal.

Natural gas prices also lost value at both hubs with the Conway price falling 5% to $2.63 per million Btu (/MMBtu) while the Mont Belvieu price dropped 1% to $2.78/MMBtu. High storage levels that are expected to reach 4 trillion cubic feet (Tcf) when heating season begins in the fall are the primary downward pressure on natural gas.

EIA reported that gas in storage grew by 32 billion cubic feet to 2.912 Tcf the week of July 31 from 2.88 Tcf the previous week. This was 23% greater than the 2.377 Tcf posted last year at the same time and 2% above the five-year average of 2.848 Tcf.

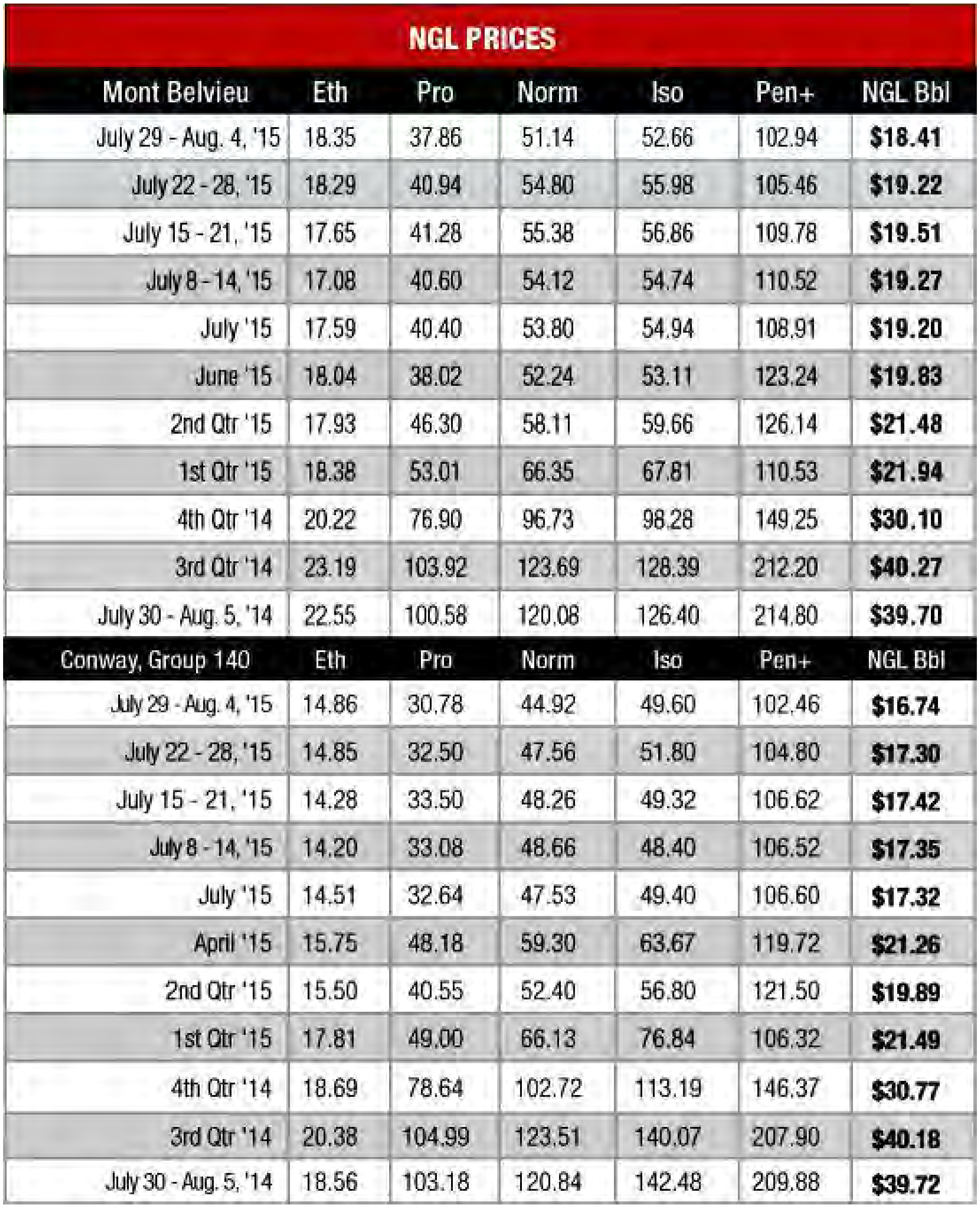
Cooling demand is expected to remain mixed the week of Aug. 12 as the National Weather Service's forecast anticipates cooler-than-normal temperatures in the Northeast and much of the Midwest. This will be countered by warmer-than-normal temperatures along the Gulf Coast, much of the West Coast and the Rockies.



CURRENT FRAC SPREAD (CENTS/GAL)

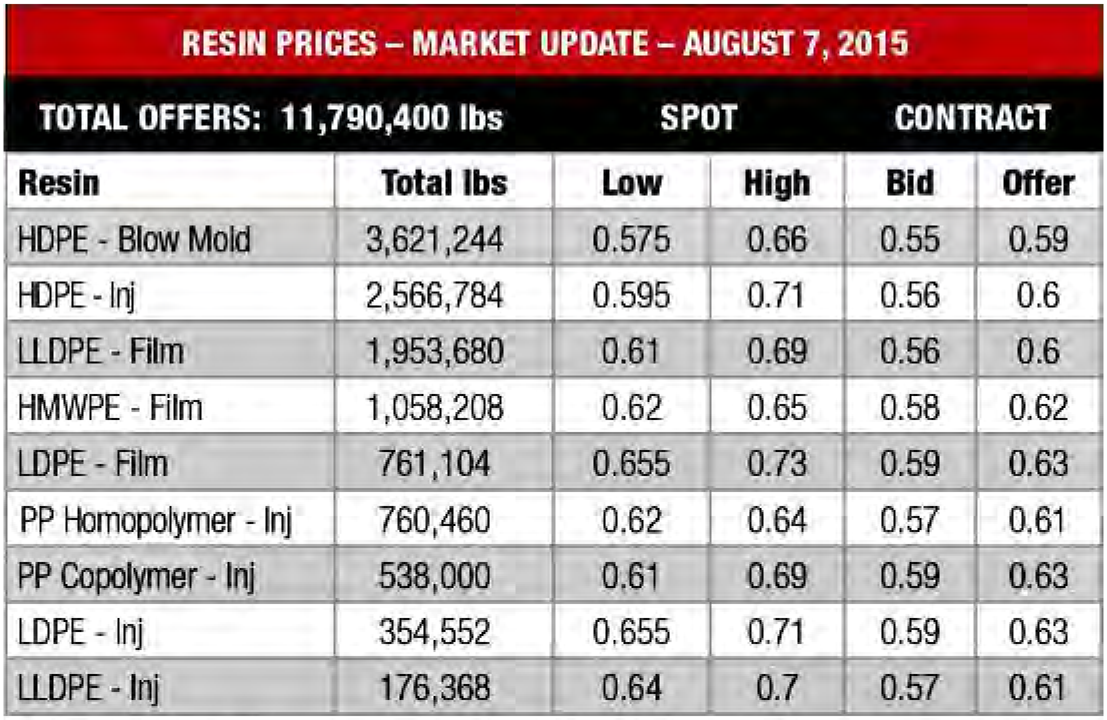
August 7, 2015	Conway	Change from Start of Week	Mont Belvieu	Last Week
Ethane	14.86		18.35	
Shrink	17.44		18.43	
Margin	-2.58	26.69%	-0.08	76.08%
Propane	30.78		37.86	
Shrink	24.09		25.46	
Margin	6.69	-6.14%	12.40	-18.45%
Normal Butane	44.92		51.14	
Shrink	27.27		28.83	
Margin	17.65	-6.31%	22.31	-13.05%
Isobutane	49.60		52.66	
Shrink	26.19		27.69	
Margin	23.41	-3.33%	24.97	-10.79%
Pentane+	102.46		102.94	
Shrink	29.17		30.83	
Margin	73.29	-1.06%	72.11	-2.94%
NGL $/Bbl	16.74	-3.23%	18.41	-4.21%
Shrink	9.61		10.16	
Margin	7.13	-0.66%	8.26	-7.81%
Gas ($/mmBtu)	2.63	-5.05%	2.78	-1.07%
Gross Bbl Margin (in cents/gal)	15.10	-0.61%	18.27	-8.39%
NGL Value in $/mmBtu (Basket Value)				
Ethane	0.82	0.07%	1.01	0.33%
Propane	1.07	-5.29%	1.31	-7.52%
Normal Butane	0.49	-5.55%	0.55	-6.68%
Isobutane	0.31	-4.25%	0.33	-5.93%
Pentane+	1.32	-2.23%	1.33	-2.39%
Total Barrel Value in $/mmbtu	4.00	-3.18%	4.53	-4.15%
Margin	1.37	0.62%	1.75	-8.67%

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
July 29 - Aug. 4, '15	18.35	37.86	51.14	52.66	102.94	**$18.41**
July 22 - 28, '15	18.29	40.94	54.80	55.98	105.46	**$19.22**
July 15 - 21, '15	17.65	41.28	55.38	56.86	109.78	**$19.51**
July 8 - 14, '15	17.08	40.60	54.12	54.74	110.52	**$19.27**
July '15	17.59	40.40	53.80	54.94	108.91	**$19.20**
June '15	18.04	38.02	52.24	53.11	123.24	**$19.83**
2nd Qtr '15	17.93	46.30	58.11	59.66	126.14	**$21.48**
1st Qtr '15	18.38	53.01	66.35	67.81	110.53	**$21.94**
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**
July 30 - Aug. 5, '14	22.55	100.58	120.08	126.40	214.80	**$39.70**
Conway, Group 140	Eth	Pro	Norm	Iso	Pen+	NGL Bbl
July 29 - Aug. 4, '15	14.86	30.78	44.92	49.60	102.46	**$16.74**
July 22 - 28, '15	14.85	32.50	47.56	51.80	104.80	**$17.30**
July 15 - 21, '15	14.28	33.50	48.26	49.32	106.62	**$17.42**
July 8 - 14, '15	14.20	33.08	48.66	48.40	106.52	**$17.35**
July '15	14.51	32.64	47.53	49.40	106.60	**$17.32**
April '15	15.75	48.18	59.30	63.67	119.72	**$21.26**
2nd Qtr '15	15.50	40.55	52.40	56.80	121.50	**$19.89**
1st Qtr '15	17.81	49.00	66.13	76.84	106.32	**$21.49**
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**
July 30 - Aug. 5, '14	18.56	103.18	120.84	142.48	209.88	**$39.72**



RESIN PRICES – MARKET UPDATE – AUGUST 7, 2015					
TOTAL OFFERS: 11,790,400 lbs		SPOT		CONTRACT	
Resin	Total lbs	Low	High	Bid	Offer
HDPE - Blow Mold	3,621,244	0.575	0.66	0.55	0.59
HDPE - Inj	2,566,784	0.595	0.71	0.56	0.6
LLDPE - Film	1,953,680	0.61	0.69	0.56	0.6
HMWPE - Film	1,058,208	0.62	0.65	0.58	0.62
LDPE - Film	761,104	0.655	0.73	0.59	0.63
PP Homopolymer - Inj	760,460	0.62	0.64	0.57	0.61
PP Copolymer - Inj	538,000	0.61	0.69	0.59	0.63
LDPE - Inj	354,552	0.655	0.71	0.59	0.63
LLDPE - Inj	176,368	0.64	0.7	0.57	0.61

Source: Plastics Exchange – www.theplasticsexchange.com

Azure Begins Holly Gas Gathering System Expansion

Dallas-based Azure Midstream Energy LLC began the growth expansion project in the core Holly Gas Gathering System, the company said Aug. 4.

Construction began on the Holly production optimization project, which will extend the core Holly footprint and reduce line pressures across Holly, maximizing the system's 2.1 billion cubic feet per day (Bcf/d) capacity. Reducing pressure to 500 pounds per cubic inch from more than 1,200 pounds per cubic inch will enhance volume deliverability. It will also attract additional volumes across the service area, Azure said.

Also, nine miles of 12-inch diameter gathering pipeline will be added, connecting existing dedicated production on Holly's northwest side to several prospective undeveloped sections from existing anchor producers. The lateral's initial throughput will be about 40MMcf/d, and more supply could be added in 2016, the company said.

About 15,000 horsepower (hp) of compression will be added, and ultimate capacity will be 600MMcf/d. Holly is scheduled to be in service by October. The project's total cost will be about $24 million, Azure said.

Holly serves Haynesville and Bossier producers in DeSoto, Red River and Caddo parishes, La., and also serves the liquids-rich Cotton Valley Formation.

On June 30, Holly had about 335 miles of high- and low-pressure pipeline with about 69,000 dedicated gross acres. There are also four amine treating plants with combined capacity of 920MMcf/d and two 1,340-hp compressors connecting to eight downstream access points.

Open Season Begins For Delaware Basin Crude Gathering Pipeline

Business Wire

ETP Crude LLC, an affiliate of Energy Transfer Partners LP (ETP), will begin binding open season for the new Delaware Basin Crude Gathering Pipeline, ETP said Aug. 5.

Delaware Pipeline will handle about 120,000 barrels per day (Mbbl/d) of crude oil. The oil will be transported from receipt points in Reeves County, Texas, and Lea County, N.M., to delivery points in Loving County, Texas, and Lea County.

The pipeline is scheduled to be in service in the first half of 2016. The open season will end on Sept. 4.

Interstate service on the Delaware Pipeline is subject to Federal Energy Regulatory Commission jurisdiction, ETP added.

There will be three separate gathering systems on about 130 miles of pipe. The gathering systems will deliver crude oil into Sunoco Logistics Partners LP's Delaware Basin Extension.

Caliber Midstream Scraps Sale Plans

Reuters

Pipeline operator Caliber Midstream Partners LP scrapped plans to sell itself after it failed to attract a high-enough offer, Bloomberg reported, citing sources familiar with the matter.

The company, owned by private equity firm First Reserve Corp and oil and gas exploration and production company Triangle Petroleum Corporation, was exploring a sale for as much as $1 billion, including debt, Reuters had reported in April.

Caliber was working with Credit Suisse Group AG to find a buyer, Bloomberg reported, adding that the sale had entered the final bidding stage when Caliber's advisers told bidders last week that it was ending the auction.

The deal fell through partly because the potential buyers were nervous about the production outlook for Triangle Petroleum, Caliber's main customer, Bloomberg said.

Triangle Petroleum and First Reserve officials were not immediately available for comment.

Based in Denver, Colorado, Caliber has more than 250 miles (400 km) of pipelines in McKenzie County, North Dakota. It offers transport and storage to oil and gas producers in the Bakken and Three Forks shale formations.

First Reserve and Triangle formed Caliber in 2012 with an initial investment of $100 million. Since then, they have committed an additional $114 million to the joint venture.

Triangle, which has a market capitalization of $266 million, has a 28.3 percent stake in Caliber, while First Reserve owns the rest.

Brent Crude At $50 Signals Long, Deep Price Crisis

Reuters

After slashing spending by $180 billion to deal with one of the worst industry downturns in decades, oil companies are still bleeding cash and slipping further into debt to maintain dividends to shareholders.

Depressed crude prices - at below $50 a barrel Brent crude is half what it was a year ago - mean even more cuts are needed at new projects and existing operations. Companies trying to dispose of oilfields to raise cash could be forced to sell quickly and for less than they hoped.

There is little sign that the oil price will come to the rescue as the Organization of the Petroleum Exporting Countries (OPEC) continues to pump hard into an oversupplied crude market in response to explosive growth in U.S. shale oil.

Brent is expected to average $60.60 in 2015 and $69 in 2017, according to a Reuters poll of analysts. The International Energy Agency said in February it saw it recovering to $73 in 2020 as the supply glut slowly eases.

Analysts at investment bank Jefferies say international oil companies lowered their break-even points by $10 a barrel after the latest round of spending cuts, but will still need a price of $82 a barrel in 2016 to cover spending and dividends, which have been the main investment attraction for the sector for decades.

"In order to cover the shortfall, the sector will increase its borrowing. While leverage remains manageable within the sector, this is not a practice that can continue in perpetuity," Jefferies said in a note on Aug. 5.

Oil majors such as Royal Dutch Shell, Chevron and Total are helped by profitable refining operations. Most are increasing oil and gas output, squeezing as much revenue as they can from past investments but exacerbating the oversupply.

Spending next year is expected to decline by a further 5 to 15 percent depending on the oil price, according to Oslo-based consultancy Rystad Energy. The world's top oil companies used second-quarter results to show they were ready for deeper, more painful measures.

"The tone has changed. Maybe we didn't quite create the right impression of urgency back in January," said Shell Chief Executive Officer Ben van Beurden.

BP Chief Executive Bob Dudley said "oil prices will be lower for longer".

Part of the problem for the oil majors is that large national oil companies and shale producers have increased their share of global production gradually for years, leaving the majors victims of forces largely beyond their control.

Their heavy investment cuts are expected to lower global production capacity by 2 million barrels per day by 2020, according to Rystad Energy. But OPEC producers will only move in to make up the shortfall.

"This has been really a tough time for the industry from Aberdeen to Angola to Houston ... It does feel like 1986," BP CEO Dudley said last week after a near two-thirds drop in quarterly profit.

In late 1985, oil prices slumped to $10 from around $30 over eight months as OPEC raised output to regain market share following an increase in non-OPEC production. The industry responded by cutting spending by nearly a quarter and slashing its workforce by a third, according to Morgan Stanley. Prices gradually recovered over the next decade as global demand rose.

But today's supply overhang could last much longer. "If oil prices follow the path suggested by the forward curve ... this downturn would be more severe than that in 1986," Morgan Stanley said in a note.

The $180 billion of cuts this year represent roughly a 20 percent drop from 2014, according to Rystad. Oil companies have deferred up to $200 billion worth of projects including complex, expensive ventures that hold huge resources, such as Canadian oil sands and deepwater projects in Africa, Southeast Asia and the Arctic.

Production lags investments by a minimum of six months for onshore drilling, but up to ten years for complex deepwater fields, liquefied natural gas projects or Canadian oil sands mega projects.

Some observers say the industry needed an efficiency drive with or without the oil price slump, after operating costs tripled over the past five years.

BP found it easier to adapt to the halving of oil prices because it had already sold $45 billion of assets and lowered costs to cover the huge clean-up and fines from the 2010 Gulf of Mexico spill.

"BP is probably the most advanced among these companies in actually achieving the cost savings," said Jefferies analyst Jason Gammel, who holds a "buy" rating on BP and Chevron.

For now, the oil majors can cover the shortfall by higher borrowing, which currently averages around 15 percent of their market value - still relatively low compared with other industries.

Smaller exploration and production companies that lack big refining operations such as Premier Oil and Tullow Oil have been forced to abandon dividends this year.

Tullow executives said the company had "reset the business" to be competitive at an oil price around $50. Like its peers, the Africa-focused company has slashed spending on new projects and shifted away from complex wells to focus on onshore and simpler offshore plays.

Tullow arranged financing before the oil price drop and that means it can weather the downturn for now, say analysts at Morningstar. But they said Tullow's cash flow burn means it must eventually sell assets which, with oil where it is today, would probably fetch a depressed price.

Tullow's interests in major oil discoveries being developed "will require far more capital than any company of its size can possibly generate from its operations," Morningstar said.

Rangeland Energy III Receives $300 Million In Equity

Rangeland Energy secured $300 million in equity from private-equity firm EnCap Flatrock Midstream to support Rangeland Energy III LLC, which will support North American midstream opportunities, Rangeland said Aug. 4. Rangeland's management also contributed to the commitment, the company added.

This is the third commitment EnCap has made to a Rangeland company, bringing the total to more than $600 million since Rangeland's formation in late 2009.

"We are excited to expand our ability to serve the oil and gas industry by broadening our longstanding relationship with EnCap Flatrock Midstream and expanding our management team. We look forward to building on the success we have had in the Bakken Shale and the Delaware Basin as we continue developing midstream infrastructure that services the needs of oil and gas producers, marketers and refiners," said Chris Keene, president and CEO of Rangeland II and Rangeland III.

Currently, Rangeland Energy II LLC operates in the Delaware Basin portion of the Permian Basin. It will continue constructing, operating and expanding its RIO System, which provides midstream and logistics services to New Mexico and West Texas crude oil and condensate producers. Rangeland II was formed in early 2013 with an initial $200 million equity commitment from EnCap and Rangeland's founders.

Construction at the RIO Hub began in July. The 300-acre rail facility near Loving, N.M., is in the center of the basin's drilling and production. The terminal serves outbound crude oil and condensate and inbound frack sand, the company added. Unit train loading, silo storage and truck loading are available. To date, 14 unit trains and additional rail cars have been received, and about 175,000 tonnes of frack sand have been distributed.

In July, there were 26,000 tonnes of silo storage capacity. The company said volumes will increase in the coming months, and so it plans to expand the hub to handle more than 1 million tonnes/year of frack sand. Truck unloading facilities installation, tankage and storage services and rail and pipeline connectivity are being worked on, the company added.

RIO Pipeline is now being built. It begins at the RIO State Line Terminal near Mentone, Texas. It will end at the RIO Midland Terminal, which will connect to terminals and interstate pipelines serving Cushing, Okla., and Gulf Coast markets.

Contracts have been drawn up with four shippers. The pipeline and terminals are scheduled to be in service in May 2016. The pipeline's capacity will handle more than 85,000 barrels per day.

Rangeland Energy is based in Sugar Land, Texas.

EnCap Flatrock Midstream is based in San Antonio.

Contact Information:

CARYN LIVINGSTON Associate Editor
clivingston@hartenergy.com

Contributing Editors: Velda Addison, Darren Barbee, Nissa Darbonne, Rhonda Duey, Dale Granger, Leslie Haines, Mary Hogan, Paul Hart, Susan Klann, Mike Madere, Joseph Markman, Richard Mason, Emily Moser, Brian Mothersole, Frank Nieto, Erin Pedigo, Larry Prado, Jennifer Presley, Chris Sheehan, Bryan Sims, Kristie Sotolongo, Steve Toon, Theresa Ward, Scott Weeden, Peggy Williams

Graphic Designer: Felicia Hammons

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