MIDSTREAM Monitor

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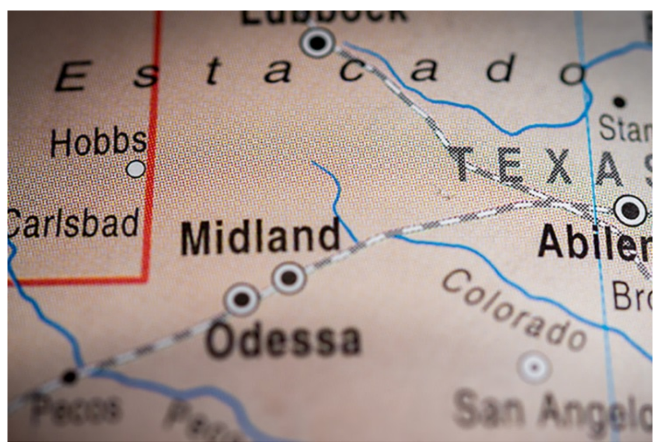
FEATURES

Permian Basin's Growth Threatens Power Overload

By **PAUL HART**, Hart Energy



The oil and gas industry's rapid Permian Basin expansion could push the power transmission and distribution capacity of the region's electric system to its limits by 2020, a new GPA Midstream Association technical committee report cautions.

To forestall potential power service limitations or reliability problems, midstream operators and upstream producers should contact their respective transmission and distribution service providers (TDSP) to discuss projections for future power needs over the next five or more years, James Meier, vice president of Permian gas and power infrastructure for Pioneer Natural Resources Co. and vice-chairman of GPA's technical committee, said.

A critical meeting to consider future West Texas power needs has been set for May 17, he noted. "There's a criticality to the timeline," Meier emphasized in a *Midstream Business* interview. "We know the existing electric system will not be sufficient without significant future upgrades and, if not addressed, will have a significant impact on the future growth and development of the industry."

Meier added that even with the collapse in commodity prices, the Permian Basin remains economic in many areas for producers to continue drilling and, along with midstream operators, use an ever increasing amount of electricity.

(*Continued on page 3*)

Webinar: Appalachian NGL—Monetizing the Opportunity

How much lower for how much longer will prices and margins impact the oil and gas industry? The lower price environment has industry executives searching for new opportunities. Could there be an opportunity for monetizing NGL production from the Appalachian Basin?

"In this lower for longer energy price environment, we have downgraded our NGL production forecasts. Yet, we expect U.S. demand growth and rising offshore exports to remain the key to balancing the U.S. market," Greg Haas, director, integrated energy for Stratas Advisors, said.

With the U.S. exporting about 40% of its produced propane, the question becomes: Which NGL will follow suit and from which regions?

Haas will be joined by David J. Spigelmyer, president of the Marcellus Shale Coalition, to discuss Appalachian NGL opportunities in a webinar on April 27 at 10 a.m. EST.

Participants will hear the two experts on North America's growing NGL markets and will learn:

- How much NGL is forecast to be produced in Appalachia?
- What takeaway options make sense now and in the future? Which new consumption opportunities will make it in today's lower price environment?

For information and to register, **click here.**

(*Continued from page 1*)

He said the current cycle time to approve, build and construct new power transmission projects is three to five years. However, if the TDSP don't have a clear understanding of the future electrical load and its location, planned improvements could be undersized or constructed later than actually needed.

Under Texas law, the Electric Reliability Council of Texas Inc. (ERCOT) is the independent system operator that manages the electrical grid for most of the state, including most of the Permian region, and has a central planning role for transmission upgrades and additions. Meier reviewed the power issue for GPA's board of directors, which met last week at the conclusion of the organization's 95th annual convention in New Orleans.

ERCOT hired a consulting group, Energy Ventures Analysis (EVA), based in Arlington, Va., in the summer of 2015 to assist in a West Texas electrical load study to gather data for ERCOT's Regional Planning Group. Data from the study would be used to identify and potentially justify new transmission projects, starting this year.

However, "response to this survey has been sparse and represents less than one-third of the load in West Texas," Meier told GPA's board. Producers and midstream companies in certain cases already have been required to set up temporary power generation or establish lines of credit to get power connected quickly for new company projects. Both requirements increase project costs significantly, he noted.

ERCOT and its consultant modified the effort to focus on improving the load identification and communication process so that oil and gas operators and TDSPs would have improved understanding about the amount of load to be added, its timing and its location. That way, the TDSPs could identify transmission needs and develop projects in a timely manner to resolve those needs.

An ERCOT presentation prepared last year noted a 40% increase in power demand since 2010 in the organization's Far West zone. The presentation said the bulk of the increase was attributable to "rapid growth of oil and gas exploration and production," and "higher power needs for horizontal drilling." The presentation noted regional utilities spent $299 million in 2014 to expand existing power infrastructure. It projected another $950 million in capital will need to be spent by 2020 to meet already identified demand growth.

An increasing number of midstream companies have opted for electrical service from local utilities rather than using fuel gas or plant-produced power to meet increasingly stringent air emissions standards, according to the GPA Midstream committee report.

"The biggest challenge to TDSPs are the large, single-point loads [i.e. processing plants, large compressor stations, pipeline pumping stations] in terms of servicing these large loads in a timely manner and identifying the location of the loads accurately to avoid stranded assets and/or increased costs to rate payers," the report added.

"Unlike oil, product and gas pipelines, paid electric rates do not provide reserved capacity on wires. Generally, reserved capacity on regulated wires does not exist," the committee's report said. "This shared dynamic drives a basin-wide shared responsibility to assist transmission providers and regulators to understand and plan for load growth.

"While TDSPs have an obligation to serve, Permian Basin energy producers have a duty to assist TDSPs in assembling legally-mandated, routine plans to adequately invest in transmission infrastructure to deliver needed service. Failure in rendering this assistance will increase the probability that adequate infrastructure to support Permian Basin growth will be unavailable," it added.

"All producers, midstream companies [including pipelines] and other industrial customers in the Permian Basin need to provide a 5-year electrical load forecast to their individual TDSPs," the committee reported.

These 5-year forecasts are non-bidding estimates that TDSPs use when they develop their own internal planning processes which are used in ERCOT-developed transmission planning models. From year to year, those forecasts could change in response to changes in oil prices, firms' drilling plans, or other factors.

The committee report noted ERCOT has a Regional Planning Group meeting set for May 17 at which EVA will present its findings and recommendations. EVA's final report will be published by the end of June.

Energy firms should make it a priority to discuss their expected power estimates with their TDSPs, Meier told *Midstream Business*. Texas law recognizes the commercially sensitive nature of a firm's electrical needs so it requires the TDSPs to protect confidentiality of the electric customers' commercial information.

The GPA committee noted industrial power users are required to provide their TDSPs with annual power load forecasts by October of each year. "Midstream companies need to work closely with the producers/shippers on their systems to understand volume growth and therefore model required growth of their systems," the report recommended.

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In Post-Sabine World, Midstream Rethinks Contract Strategy

By JOSEPH MARKMAN, Hart Energy

Stunned by a judge's advisory ruling in early March that could put many contracts with upstream partners up for renegotiation, midstream operators warily await a more definitive ruling in the Sabine Oil & Gas bankruptcy case as the realization sets in that a key advantage in putting deals together could be lost.

The ruling by U.S. Bankruptcy Judge Shelley Chapman authorized Sabine to reject gathering and processing contracts with two midstream companies, Nordheim Eagle Ford Gathering LLC and HPIP Gonzales Holdings LLC because the E&P could not meet minimum production requirements and faced substantial financial penalties of up to $35 million.

The argument by the midstream companies that the "covenant running with the land" language in the contracts would preclude rejection by the debtor was put aside for another day, but the judge made it clear in a non-binding ruling that the agreements in question do not "run with the land" in her interpretation of Texas law. "From a practical standpoint, what it says is, all these contracts that rely on acreage dedications are in play," bankruptcy attorney David Ross of Babst Calland told Hart Energy. The hard line that midstream companies had assumed they could take, that the "covenant" language assured them of payment because the agreement was tied to the land and not to the owner, is now open to be challenged.

'Runs with the land'

As Chapman discussed in her ruling, the concept of "covenants running with the land" was created in old English law and tested in court in Spencer's Case in 1583. English courts over time stopped finding that affirmative covenants—those that required a party to do something—run with the land. However, Chapman wrote, U.S. courts still uphold the concept in affirmative cases, though less often in cases involving negative covenants (those that prevent a party from doing something).

Although the case was heard in federal bankruptcy court in the Southern District of New York, federal judges apply state law where it is necessary, Ross said. In this case, Chapman found no applicable binding decision by the Texas Supreme Court on this issue, noting that while the midstream companies were engaged to perform services for Sabine, that do not imply that a real property interest was conveyed to Nordheim and HPIP.

Time to rethink

For operators, it's time to re-examine agreements in place.

"From an industry perspective, the recent ruling on the Sabine deal definitely makes you think hard about the structures that you're willing to do," Brett Wiggs, CEO of Oryx Midstream Services, told Hart Energy. "From our perspective, we felt it was extremely important to be willing to take risk side-by-side with the producer."

However, Oryx does not engage in combination land dedication and minimum volume commitments like those in the Sabine case. Its contracts are pure dedication or pure volume commitments.

Oryx also operates in a sweet spot of the still-thriving Permian. In other less attractive areas, low prices have made similar business structures much more complicated.

“From an E&P operator’s perspective, there’s one less arrow in the quiver about how you actually get midstream service to your wells,” Jay Hammond, an attorney at Babst Calland, told Hart Energy. “You can’t really trade on your land position because the dedications may not be valuable to the midstream operator.”

“From a midstream perspective,” he said, “you are probably going to be much more focused on getting a commitment fee or something like that, than before the ruling, even though that may not be the most cost-effective structure.”

In the end, the key point for E&P operators and midstream providers will likely be physical proximity.

“Assuming existing gathering infrastructure and assuming the gas will be produced at some price, the dynamic between a gatherer on the one hand and a producer on the other is really dictated by where the gatherer’s pipeline is located vis-à-vis the E&P operator’s acreage,” Hammond said. “If you’re the only gatherer in real proximity to a production field, well, the E&P operator is going to have to deal with you, regardless of whether or not the gathering contract can be rejected in bankruptcy.”

“From a midstream perspective, you are probably going to be much more focused on getting a commitment fee or something like that, than before the ruling, even though that may not be the most cost-effective structure.

— Jay Hammond, Babst Calland

The question is then one of who holds the cards—upstream or midstream.

New deal
Figuring out how to restructure deals is the challenge now.

“So what does [the ruling] do?” Ross asked. “It made the alternative that the midstream companies may ask for something different. At the beginning of a contract, they may ask for credit. They may ask for cash. They may ask for a commitment fee. Maybe they ask for liens on the real estate. I think that is a lot different than what the industry has historically seen.”

One exception is Navigator Energy Services LLC, a Permian Basin midstream operator that has maintained strict criteria with its contracts.

“We’ve contracted consistently and responsibly and conservatively,” Matt Vining, the company’s chief commercial officer and co-founder, told Hart Energy. “When crude was at $100, I got laughed at when I asked for credit protection mechanisms from our producers. That doesn’t look so silly now. We feel pretty good.”
Those who don’t feel so good are looking at ways to renegotiate agreements.

"When I say renegotiate, most of the gathering agreements have a minimum quantity, guaranteed payments," Ross said. "But if the producers don't have cash, and they're not producing enough quantities because of the [low] gas price, these guaranteed payments are at risk and the producers are going to say, 'listen, we can't afford to make these payments.'"

In that situation, section 365(a) of the U.S. Bankruptcy Code allows the debtor, in this case Sabine, to accept or reject executory contracts depending on what is known as the "business judgement" test (whether the agreement is good or bad for the business).

Chapman wrote that courts generally accept the debtor's decision unless it is shown that the contract rejections were the "product of bad faith, whim or caprice," which neither midstream company argued was the case.

Expect more of same

Going forward, lingering low commodity prices can be expected to push more producers into bankruptcy court. "Historically, if a producer was having financial issues, the midstream company may not be as open to renegotiating but clearly 'Sabine' has turned the cart upside down," Ross said, referring to the case. "The midstream people were just sitting back and saying, 'hey, covenants run with the land. There's nothing you can do to our agreement. You're stuck with it.'

"What the 'Sabine' case says is, that may not necessarily be the case," he said. "What you're probably going to see is the midstream companies considering renegotiating some of these gathering agreements because the practical answer is, if the producer goes away, is there necessarily anybody else to step in and replace them? A couple of years ago, I'm sure people were standing in line, but I'm not sure that it's the case today."

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Northeast Still Has Midstream Needs

By FRANK NIETO, Hart Energy

The development of the Marcellus and Utica shales caused natural gas production to increase to record levels-- 73 billion cubic feet per day (Bcf/d) in February—as new pipeline infrastructure added demand. However, production has decreased by about 2 Bcf/d in the two months since that additional capacity was brought online.

According to Luke Jackson, project consultant at BENTEK Energy, U.S. gas production should hold firm at 71 Bcf/d through the summer. While pipeline capacity has increased, storage capacity is full and additional demand sources such as electric power generation are similarly maxed out. "We're running out of options and we think the supply side has to be the one side that takes a hit," he said during a conference call hosted by Deutsche Bank Markets Research.

During this year's fourth quarter, production should increase slightly as further infrastructure is brought online in the Northeast; then, production will steadily increase over the next five years before reaching an average of 85 Bcf/d in 2021. Much of this 13 Bcf/d increase in production will be out of the Appalachian Basin.

The rig count in the Northeast is decreasing, but completing inventoried wells in the region will help offset the region's reduced number of rigs and maintain production viability. This inventory figure could possibly be burned through at an accelerated pace if the rig count falls faster than expected, because producers will rely more on this inventory, or if several of these wells are waiting for new infrastructure to be brought online.

"We might need to see a price recovery within the current year or in the first two quarters of 2017 to really spur an increase in rig activity [in the Northeast] to keep production afloat and ongoing in the region," John Hilifiker, energy analyst at BENTEK, said on the call.

Hilfiker added that the dry Utica has been gaining steam as producers focus on the play because of the strong rates of return it is delivering based on the tremendous IP rates of up to 40 MMcf/d, including those drilled by EQT Corp., Antero Resources Corp., and Gulfport Energy Corp.

The dry Utica will require producers to lower well costs and add new infrastructure in the region in order to continue growth.

"You could drill these monster wells, but if you don't have the gathering infrastructure or even a long-haul infrastructure to move that gas to market, it doesn't matter what type of wells you're drilling. You need to bring the well costs down and you need the infrastructure in place to get that gas from those wells to market. But no doubt, the upside is very tremendous there," Jackson said.

A lot of the pipeline takeaway capacity in the Northeast is from long-haul systems with most adding a backhaul project to reverse the flow from the Northeast to the South and Midwest. Hilfiker said that several of these projects have been delayed into 2017, with about 13 Bcf/d announced as coming online in both 2017 and 2018. However, he noted there are challenges for these projects to be developed in time for their in-service dates, since only Williams' Constitution Pipeline is approved at this time. Since this project faced numerous hurdles in obtaining approval, it doesn't bode well for all of these projects moving ahead on schedule. The Northeast still presents a more challenging region for operators in terms of project approval than in many other parts of the country.

"If you look historically, the Millennium Pipeline had its own challenges. It took just under a decade to get that pipeline fully approved and built. Constitution may be the next really similar pipeline project to Millennium," Hilfiker said. He noted that there is also the possibility for delays to the Mountain Valley Pipeline, which is majority-owned by EQT Midstream Partners, and Dominion's Atlantic Coast Pipeline, due to their scope. The Mountain Valley Pipeline is facing pushback on right-of-way issues through the Appalachian Mountains. According to Hilfiker, the Atlantic Coast Pipeline is more secure at moving forward as it has signed up a lot of local distribution companies and power generators as subscribers.

Kinder Morgan's Northeast Energy Direct Pipeline might also face an in-service date risk due to opposition in New England, Pennsylvania and New York. Additionally, only half of the project's proposed capacity has been subscribed.

There are also challenges with pipeline projects in the Midwest-- Spectra Energy's NEXUS project is also about 50% subscribed and will need to be 80% to 90% subscribed in order to be pushed through, according to Hilfiker. This higher subscriber rate is because of Energy Transfer's Rover Pipeline, which overlaps with the NEXUS Pipeline in many ways.

"It's getting tough with the in-service dates on a lot of these projects; they're starting to become moving targets as we hit critical deadlines based on their proposed project timelines," Hilfiker said while adding that should they hit their proposed deadlines, they would relieve a great deal of regional supply basis in the Northeast by the beginning of 2018.

Jackson said that with so much of the production out of the Northeast being moved down to the Gulf Coast, Henry Hub prices are negatively impacted. The longer this situation continues, the longer it will take for gas markets to recover.

BENTEK's forecast is more bullish as the firm anticipates gas prices to average $4 per million British thermal units (Btu) over the next five years. "We're going to start losing a substantial amount of associated gas because of the slowdown in oil- and NGL-directed drilling. A lot of demand is also expected to increase in the coming years. We think that will help drive the price recovery," Jackson said.

The largest driver of demand for natural gas over the past two years has been gas-fired power generation, which has increased by about 6 Bcf/d since 2013, according to Jackson. Fuel switching from coal to gas has been driven both by lower gas prices and coal plant retirements. In 2015 15,000 megawatts of coal plants were taken offline and another 8,000 megawatts of coal plants are scheduled to go offline in 2016. There will also be new demand from exports to Mexico and exported U.S. LNG.

Though New England and New York will continue providing the highest prices for gas in the U.S., the price spikes aren't expected to be as extreme or as consistent moving forward because more supplies are finding their way to these markets. Incremental LNG volumes are being sent into Boston, and Williams' Leidy Southeast project is online in New York; this is resulting in some volumes flowing south from the area due to the moderate winter temperatures and limited heating demand.

Midstream Connect Series:
What Will Incentivize Infrastructure Investment?

What will it take to get NGL infrastructure construction projects rolling again? Peter Fasullo, principal, EnVantage Inc., says a restart will rely on the confidence of producers in prices and whether they'll be willing to enter in long-term deals again.

To view the video, please visit Midstream Business.com

Interview: A Private Equity Viewpoint

By **PAUL HART** , Hart Energy

Editor's Note: The following is an excerpt. **Read the full interview**.

James P. Benson, Founding Partner, Energy Spectrum Capital

James P. Benson is a founding partner of Dallas-based Energy Spectrum Capital, a major midstream private-equity provider that that makes direct investments in companies that acquire, develop and operate midstream energy assets.

Since its start in 1996, Energy Spectrum has raised more than $3.5 billion of equity capital from corporate and public pension funds, insurance companies, endowments, banks and other institutional investors. Benson has 30 years of private equity, investment banking, financial advisory and commercial banking experience in the energy industry.

Prior to co-founding Energy Spectrum with Thomas O. Whitener Jr., Leland White and Jim Spann, Benson was a managing director at R. Reid Investments Inc. for 10 years. He began his career at InterFirst Bank Dallas, where he served for four years and was responsible for various energy financings and financial recapitalizations. He holds a bachelor's degree from the University of Kansas and a master's of business administration degree from Texas Christian University.

He visited with *Midstream Business* to give his views on financing the midstream space during an important time of transition.

MIDSTREAM BUSINESS: **Suppose I am part of a small team of experienced midstream executives. We know of a small gathering and processing system we'd like to buy and operate. But we're engineers; we don't know much about this financial stuff. Where and how do we get the money?**

BENSON: There are multiple private-equity partners out there looking for deals. Energy Spectrum is interested in reviewing all midstream opportunities that are identified and evaluated by an experienced midstream management team. Usually, in the described situation, the management team, with its operational and commercial expertise, will have determined that the opportunity has merit and can be a platform for future activity and growth.

The "financial stuff" is working on structure and compensation for the management team, which can be quickly explained. Also, I would encourage the team to talk to existing management teams who are utilizing private equity to understand their thoughts with regard to structure and incentive. If the new venture gets off the ground and is funded, the team may need to add a financial member to round out the team and handle the financial reporting function, banking and other capital market opportunities going forward.

MIDSTREAM BUSINESS: **Is there still investor interest right now in midstream deals?**

BENSON: Absolutely. There is a significant amount of capital available for North American midstream opportunities. The challenges are acquiring or developing a project in an economic basin and working with a credible and well-funded producer.

Today, counterparty risk is critical in the success or failure of a deal, as well as the fundamental reserve base that supports the midstream activity. Midstream deals follow more of a throughput model, but if the producers behind the system are simply not drilling, or drilling has slowed to a snail's pace, then a declining throughput could derail the project.

Overall, midstream deals can be extremely attractive for a private-equity investor; but a production profile—existing or to be developed—modeled to provide an adequate return would need to be established before the midstream group gets a green light to move forward. This is one of the principal challenges today in this difficult price environment.

MIDSTREAM BUSINESS: **What's different, from an equity perspective, about midstream operators vs. upstream producers?**

BENSON: First, upstream producers are the customers for the midstream operator, and both need to fully understand the reserves behind the system and the opportunity for growth and enhanced drilling activity or upside. Second, both need to have quality management teams with operational and commercial skills to buy, build and develop the reserves and the associated midstream assets needed to support the reserves.

MIDSTREAM BUSINESS: **What do you look for when you consider a deal?**

BENSON: We always look to the management team first, and quickly determine if they have similar philosophical beliefs on how to manage their business. They must have an entrepreneurial spirit.
We then look to the basin and reserves, and we determine if the midstream deal is viable in the long run. We also want to believe that our capital can be invested to achieve a quality rate of return commensurate with the perceived risks. Very few deals look alike.

MIDSTREAM BUSINESS: **What is your sweet spot, in size, for a project?**

BENSON: Our most recent fund, Energy Spectrum Partners VII, is $1.225 billion. We would like to invest approximately $50 million to $200 million of equity with each portfolio company. We may start off smaller and build up to this level by closing multiple deals, and we can also use conventional leverage to enhance everyone's cost of capital. If there are larger projects that interest us, we would utilize our existing limited partners to co-invest in a project, or we would bring in another private-equity group as a partner.

MIDSTREAM BUSINESS: **There has been a lot of greenfield development in the unconventional plays. But what about brownfield projects that repurpose existing assets in mature areas, such as the Permian and Scoop? Is there a market for them?**

BENSON: There is a lot of repurposing of existing assets in the Permian, Scoop and other prolific areas. But in many cases, the need to develop new infrastructure exists as well. With the technological advances in drilling and completion methods, most of the new wells are being produced at higher pressures and higher rates. In some cases, the existing infrastructure is not sufficient to handle the new activity, which means new pipe in the ground. There will always be a market for quality assets in these prolific areas.

FRAC SPREAD

Frac Spread: Signs Of Supplies Tightening Supporting Market

By **FRANK NIETO**, Hart Energy

The failure of OPEC and several key non-OPEC producers to come to an agreement to freeze crude oil output saw crude prices tumble below $40 per barrel (/bbl) before they climbed back above that price threshold due to supply disruptions in Nigeria, Iraq and Kuwait.

Natural gas prices also experienced significant gains as the forward curve is improving with the expectation that supply and demand will tighten as drilling decreases and export demand increases. According to an April 19 research note from Barclays Capital, the U.S. will be the third-largest LNG exporter by 2020 with as much as 8.2 billion cubic feet per day (Bcf/d) being shipped around the globe. This is likely to create a cap on how prices can get in the next few years as the price spread between the U.S. and Europe will close. It is unlikely prices will approach their 2007 highs anytime soon, but they could double in value, on average, in the next 12-18 months.

NGL PRICES

Mont Belvieu	Eth	Pro	Norm	Iso	Pen+	NGL Bbl
April 13 - 19, '16	20.00	45.22	54.70	56.82	92.12	**$19.10**
April 6 - 12, '16	17.99	44.04	53.58	55.60	89.44	**$18.38**
March 30 - April 5, '16	17.33	43.38	51.40	53.78	88.74	**$17.99**
March 23 - 29, '16	18.78	44.38	52.50	54.38	90.83	**$18.55**
March '16	17.68	45.26	53.27	55.05	86.68	**$18.26**
February '16	14.83	37.42	53.83	53.80	69.04	**$15.68**
1st Qtr '16	15.90	39.03	52.22	52.84	76.84	**$16.46**
4th Qtr '15	17.50	42.15	60.09	60.57	97.59	**$19.11**
3rd Qtr '15	18.26	40.99	54.16	55.19	100.10	**$18.80**
2nd Qtr '15	17.93	46.30	58.11	59.66	126.14	**$21.48**
April 15 - 21, '15	17.03	56.70	65.66	68.16	134.28	**$23.76**
Conway, Group 140	**Eth**	**Pro**	**Norm**	**Iso**	**Pen+**	**NGL Bbl**
April 13 - 19, '16	16.43	42.78	53.24	64.58	92.42	**$18.58**
April 6 - 12, '16	14.70	40.78	51.16	63.20	91.06	**$17.82**
March 30 - April 5, '16	12.56	38.92	47.62	57.76	87.46	**$16.67**
March 23 - 29, '16	12.75	39.75	48.20	56.33	87.50	**$16.80**
March '16	13.18	40.87	49.35	57.65	85.03	**$16.93**
February '16	13.09	33.72	48.44	60.06	69.16	**$15.00**
1st Qtr '16	13.45	35.23	48.14	57.05	76.01	**$15.61**
4th Qtr '15	14.90	38.06	57.31	64.04	95.84	**$18.20**
3rd Qtr '15	15.47	36.28	48.59	54.34	99.10	**$17.59**
2nd Qtr '15	15.50	40.55	52.40	56.80	121.50	**$19.89**
April 15 - 21, '15	15.15	49.56	60.26	64.42	123.60	**$21.66**

The improvements in oil and gas prices is helping support modest gains for NGL prices as they rose across the board at both the Mont Belvieu, Texas, and Conway, KS, hubs. The largest gain at both was for ethane, which experienced an 11% gain at Mont Belvieu and a 12% at Conway. The Texas price rose to 20 cents per gallon (/gal), its highest price since mid-October 2015, and the Kansas price improved to 16 cents/gal, its highest price since late October 2015.

These price increases occurred even as a number of ethane crackers are undergoing turnarounds and is a reflection of the improved balance in the ethane market. In fact, it is likely that ethane is moving closer to the other two ethylene feedstocks - propane and butane. In turn this is moving ethane further from gas prices and closer to crude prices. Though crude prices are struggling, this is a very good sign for ethane on a long-term basis.

On the flip side of the light NGL bbl, propane's momentum has slowed the last two months as exports have fallen short of expectations and created larger inventory builds than were anticipated. Should this

CURRENT FRAC SPREAD (CENTS/GAL)				
APRIL 22, 2016	**Conway**	**Change from Start of Week**	**Mont Belvieu**	**Last Week**
Ethane	16.43		20.00	
Shrink	12.27		13.26	
Margin	4.16	21.45%	6.74	11.29%
Propane	42.78		45.22	
Shrink	16.95		18.32	
Margin	25.83	2.48%	26.90	-2.37%
Normal Butane	53.24		54.70	
Shrink	19.18		20.74	
Margin	34.06	1.56%	33.96	-2.73%
Isobutane	64.58		56.82	
Shrink	18.43		19.92	
Margin	46.15	-0.25%	36.90	-2.05%
Pentane+	92.42		92.12	
Shrink	20.52		22.18	
Margin	71.90	-0.42%	69.94	0.66%
NGL $/Bbl	18.58	4.26%	19.10	3.94%
Shrink	6.76		7.31	
Margin	11.82	1.82%	11.80	-0.06%
Gas ($/mmBtu)	1.85	8.82%	2.00	11.11%
Gross Bbl Margin (in cents/gal)	26.69	1.81%	27.11	-0.17%
NGL Value in $/mmBtu (Basket Value)				
Ethane	0.90	11.77%	1.10	11.17%
Propane	1.49	4.90%	1.57	2.68%
Normal Butane	0.58	4.07%	0.59	2.09%
Isobutane	0.40	2.18%	0.35	2.19%
Pentane+	1.19	1.49%	1.19	3.00%
Total Barrel Value in $/mmbtu	4.56	4.91%	4.80	4.48%
Margin	2.71	2.39%	2.80	0.21%

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.

continue, the propane market won't be as strong heading into the fall and winter as originally expected. Propane prices did improve this week as exports were in line with forecasts and if expectations can continue to be met then the market should be solid come the fall.

Growth was more muted for heavy NGL prices as refiners have switched to making summer-grade gasoline, which uses less butane and C5+ in the mix than winter-grade fuel. Overall, the theoretical NGL bbl improved 4% at both hubs with the Conway price hitting $18.58/bbl with a 2% gain in margin to $11.82/bbl. The Mont Belvieu price rose to $19.10/bbl with the margin remaining flat at $11.80/bbl.

RESIN PRICES – MARKET UPDATE – APRIL 22, 2016					
TOTAL OFFERS: 9,152,364 lbs		SPOT		CONTRACT	
Resin	Total lbs	Low	High	Bid	Offer
LDPE - Film	1,899,588	0.58	0.68	0.58	0.62
HDPE - Blow Mold	1,715,404	0.55	0.62	0.5	0.54
HDPE - Inj	1,322,760	0.56	0.575	0.505	0.545
PP Copolymer - Inj	1,270,828	0.58	0.65	0.58	0.62
PP Homopolymer - Inj	708,196	0.54	0.63	0.56	0.6
LLDPE - Film	656,644	0.55	0.63	0.52	0.56
HMWPE - Film	573,196	0.55	0.59	0.51	0.55
LLDPE - Inj	527,012	0.61	0.65	0.57	0.61
LDPE - Inj	478,736	0.535	0.63	0.58	0.62

Source: Plastics Exchange – www.theplasticsexchange.com

The most profitable NGL to make at both hubs was C5+ at 72 cents/gal at Conway and 70 cents/gal at Mont Belvieu. This was followed, in order, by isobutane at 46 cents/gal at Conway and 37 cents/gal at Mont Belvieu; butane at 34 cents/gal at both hubs; propane at 26 cents/gal at Conway and 27 cents/gal at Mont Belvieu; and ethane at 4 cents/gal at Conway and 7 cents/gal at Mont Belvieu.

The U.S. Energy Information Administration reported that natural gas storage levels rose very slightly the week of April 15 with a 7 Bcf increase to 2.484 trillion cubic feet (Tcf) from the previous week. This was 55% greater than the 1.603 Tcf posted last year at the same time and 49% greater than the five-year average of 1.673 Tcf.

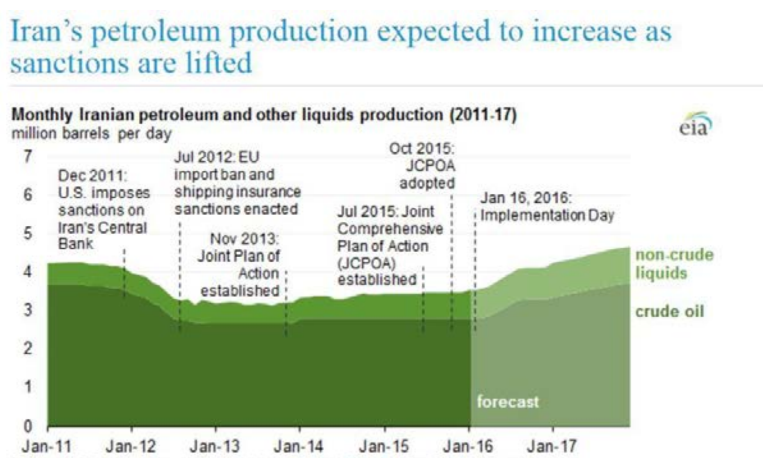
MORE TOP STORIES

OPEC Unglued: Saudi Arabia Won't Freeze Oil Growth Unless Iran Has To

By **DARREN BARBEE**, Hart Energy

No Iran, no deal.

The much ballyhooed Doha, Qatar, meetings to freeze production among some OPEC and non-OPEC members, such as Russia, ended without agreement April 17.



The stumbling block: Saudi Arabia's unwillingness to go forward on holding production steady without cooperation from Iran. After sanctions related to development of nuclear capabilities were lifted in January, Iran has been trying to ramp up volumes. The country's ability to sell oil on the global market had been hobbled since 2011.

On April 17, OPEC's de facto leader Saudi Arabia said it wanted all members of OPEC to take part in the freeze, including Iran, which was absent from the talks, Reuters reported.

On April 16, the kingdom's Deputy Crown Prince, Prince Mohammed bin Salman, brandished the country's production capacity ahead of the talks. The prince said Saudi Arabia could increase volumes to 12.5 million barrels per day (MMbbl/d) from 11.5 MMbbl/d "if we wanted to," according to a report by Bloomberg. Tehran declined to attend the meetings as it attempts to restore production to pre-sanction levels.
Reuters reported that after five hours of fierce debate about the wording of a communique—including between Saudi Arabia and Russia—delegates and ministers announced no deal had been reached.

But David Elmes, a professor at Warwick Business School in the U.K. and head of the Global Energy Research Network, said that the meeting occurred at all was telling for the cartel.

"No deal in Doha is not a very surprising outcome, but a significant group of OPEC and non-OPEC oil producing countries meeting at all might indicate a new realization of the role that oil and gas play in the global economy," Elmes said. "While a lack of agreement between Saudi Arabia and Iran looks to have blocked any deal this time, the question is what do all the major producers see as the long-term picture for oil and gas?"
In the short-term, crude prices could be driven down by 10-20%, back to the low-to-mid $30 per barrel range, said Vikas Dwivedi, an analyst at Macquarie Research.

A tough environment awaits, Dwivedi said, that with other factors will drive crude lower before supply and demand balanced near year-end.

Dwivedi said that, of note:

- Iran's loadings are significantly ahead of schedule and he estimates Iran is now loading 550 Mbbl/d greater than the beginning of 2016;
- Saudi Arabia KSA could add up to 1 MMbbl/d to global crude supply immediately if the country desired; and
- Saudi's insistence on maintaining growth optionality as long as others join in "may be driven by positioning for future OPEC discussions [but] pure rivalry vs. Iran can't be dismissed."

Brian Singer, analyst with Goldman Sachs Equity Research, said the firm's forecast of second quarter 2016 WTI prices at $35 per barrel were more likely since the freeze talks produced no results.
"We maintain our fourth-quarter 2016 forecast of $45 per barrel and fiscal year 2017 average WTI forecast of $58 per barrel," Singer said.

However, demand appears to be holding strong. Singer noted that the International Energy Agency revised its fourth-quarter 2015 demand up by 500 Mbbl/d largely in countries outside of the U.S., Canada, Germany and the U.K., collectively known as the Convention on the Organization for Economic Co-operation and Development (OECD).

In first-quarter 2016, oil demand was 300 Mbbl/d greater than expected.

"Product demand data has been mixed—we see rising diesel inventories as a risk, although we note recent green shoots in China," Singer said, which could offset declines.

Singer said OPEC oil production is likely to increase to 33 MMbbl/d by 2017 from current levels of 32.6 MMbbl/d.

I Squared Quickly Sells Stake In San Juan Gathering System To GE

By **DARREN BARBEE**, Hart Energy

Fresh off buying WPX Energy's (NYSE: WPX) San Juan Basin gathering system, buyer I Squared Capital said April 14 it sold a 28% stake in the oil, gas and water gathering system to GE.

Adil Rahmathulla, Partner at I Squared Capital, told Hart Energy that was the plan all along — to sell a stake to a financial partner that could continue to grow the company and inject capital as the system expands.

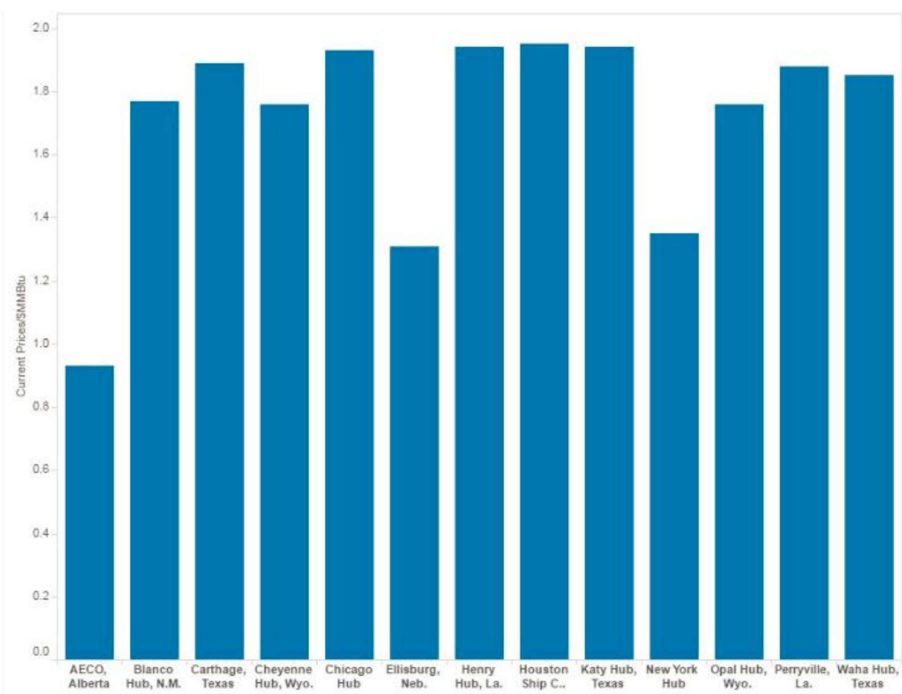
I Squared's new company, Cube Midstream, will operate and manage the new 220-mile system in New Mexico. The global infrastructure fund closed its deal WPX on March 9 to acquire the system for $285 million.

Rahmathulla, who led the deal, said that GE's 28% stake was purchased on the same terms and conditions as I Squared's, putting GE's acquisition at roughly $80 million.

In addition to making the investment in Cube and subsidiary Whiptail Midstream, GE will collaborate with I Squared Capital to invest in other near-term opportunities for oil and gas infrastructure in the basin.

Key North American Gas Hub Prices

(As of April 21, 2016)



Keep up to date on daily changes in North American gas hub prices at MidstreamBusiness.com

Carthage, Texas: 1.89
Katy Hub, Texas: 1.94
Waha Hub, Texas: 1.85
Henry Hub, La.: 1.94
Perryville, La.: 1.88
Houston Ship Channel: 1.95
Opal Hub, Wyo.: 1.76
Blanco Hub, N.M.:1.77
Cheyenne Hub: 1.76
Ellisburg Neb. Hub: 1.31
New York Hub: 1.35
AECO, Alberta: 0.93

Bayou Bridge Pipeline Begins Operations To Lake Charles, La.

Bayou Bridge Pipeline LLC said April 21 it has started commercial operations on the 30-inch segment of the pipeline from Nederland, Texas, to Lake Charles, La.

Bayou Bridge is jointly owned by subsidiaries of Phillips 66 Partners LP, Energy Transfer Partners LP and Sunoco Logistics Partners LP.

In addition, the joint venture completed a successful binding expansion open season to assess additional interest in transportation service from Nederland, Texas, to refining markets east of Lake Charles on the Bayou Bridge Pipeline. Based on shipper commitments, the Louisiana segment of the pipeline from Lake Charles to St. James will be 24 inches in diameter.

At Lake Charles, Bayou Bridge has agreed to connect to Phillips 66 Partners' Clifton Ridge terminal and Citgo's Lake Charles refinery. At St. James, Bayou Bridge has agreed to connections to Plains Marketing LP's and NuStar Energy LP's crude oil terminals.

Bayou Bridge also is in discussions with additional parties to connect to the extensive existing crude oil terminalling infrastructure in the region.

Bayou Bridge remains on schedule with respect to the 24-inch segment to St. James, and commercial operations for this segment are expected to begin in the second half of 2017, according to the release.

--BUSINESS WIRE

LNG Tanker Heads To Portugal From Sabine Pass

The *Creole Spirit* LNG tanker is destined for Portugal from Cheniere Energy Inc.'s Sabine Pass Liquefaction terminal project, two trade sources said.

Creole Spirit is the sixth cargo to be exported by Cheniere Energy's project and the first to come to Europe. The cargo was purchased by Portugal's Galp Energia, one source said.

--REUTERS

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