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FEATURES

What Midstream Businesses Need To Know About The EPA's Proposed Methane Air Emissions Rules

By George O. Wilkinson Jr. and Corinne Snow, Vinson & Elkins LLP

EPA's recently proposed New Source Performance Standards for methane and volatile organic compound ("VOC") emissions from the oil and gas sector would place time-consuming and expensive new requirements on midstream businesses, including ongoing emissions monitoring and equipment replacement requirements at compressor stations.

Businesses concerned about this proposed rule or interested in participating in EPA's decision-making process have only 60 days after the proposed rule is published in the Federal Register to submit comments to the agency. Submitting comments is the best way to raise concerns about technical issues that are likely to have significant costs to businesses. Because these comments form part of the record that a court reviews when evaluating a regulation, submitting comments is also an important way to preserve these arguments for litigation if businesses later decide to challenge EPA's final rule. The midstream industry can also provide EPA with important insights into the real world implications for some of its proposals, and serve as a counter-balance to environmental advocacy groups that are likely to push for more stringent regulations. EPA is accepting comments on any aspect of the new rule but has specifically requested comments on particular requirements of the proposed rule.

Background

EPA already has established standards for VOC emissions for several select operations in the oil and gas sector through the "Subpart OOOO" regulations which applies to upstream and gas plant operations. Now EPA is proposing to expand the existing VOC standards to cover additional equipment, including from midstream operations, and establish new methane standards for the covered equipment. Under the proposal, the current VOC best system of emission control standards found in Subpart OOOO will apply for both methane and VOC emissions for the expanded list of equipment, including certain equipment at compressor stations. The new rules impose requirements related to fugitive emissions at compressor stations and on the seals used in compressors.

Fugitive Emission Monitoring

Under the proposal, operators of new and modified compressor stations will be required to conduct initial and semi-annual monitoring surveys using optical gas imaging ("OGI") technology or EPA's Method 21. The initial survey must be done 30 days of site startup or a modification. A source is "modified" when one or more compressors is added to a compressor station after the effective date of the final rule, or when a physical change is made to an existing compressor that increases compressor capacity.

If a survey detects leaks, repairs must be completed within 15 days, and then a resurvey of the compressor must be completed within 15 days of the repair. EPA's proposed rule would relax the frequency of subsequent surveys from semiannually to annually if the data shows fugitive emissions from less than one percent of their components. Conversely, the frequency would increase from semiannually to quarterly for sites with fugitive emissions from three percent or more of their components.

EPA has asked for comment on a number of topics related to fugitive emissions including whether this monitoring should be of the compressor or the facility as a whole. EPA also asked for comment on the frequency of surveys. Midstream businesses may also want to comment on whether 15 days is enough time for them to complete repairs.

In addition, midstream businesses may wish to comment on whether OGI or Method 21 should be used for the surveys. Method 21 can be far more time-consuming than the use of OGI cameras. OGI uses a camera type device that is pointed at components or groups of components while the display is monitored to determine whether there is a leak is present. Method 21 requires the operator to slowly move a probe from a hand held instrument in close proximity to the portion of a component that may leak. Studies have shown that OGI can monitor 1875-2100 components per hour, while Method 21 can only monitor about 700 components per day. Method 21 also detects leaks at a much lower level—500 ppm—than OGI, which may not detect fugitive emissions below 10,000 ppm. As a result, using Method 21 is more likely to result in additional equipment replacements and repairs. OGI surveys also present their own problems.

Most midstream companies do not own OGI cameras, and EPA is concerned that there may not be enough contractors to perform the surveys. By contrast, EPA notes that many businesses already own the devices needed to perform surveys using Method 21.

Centrifugal And Reciprocating Compressors

The proposed rule requires wet seal centrifugal compressors to achieve 95% control efficiency by capturing and routing VOC and methane emissions to a combustion control device. Alternatively, the proposed rule will allow centrifugal compressors to use dry seal systems or capture gas from centrifugal compressor seals and route it back to a low pressure fuel gas system. Costs from upgrading these seals can quickly add up, and midstream businesses should consider commenting on the cost and reasonableness of controls.

Conclusion

Midstream businesses can help EPA to make informed decisions about how to regulate methane emissions if they submit comments during the 60-day public comment period. By formulating responses to EPA now, midstream businesses may be able to save compliance costs down the road or be in a better position to challenge EPA's final rule.

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Decline In Crude By Rail Shipments Continues

By Paul Hart, Hart Energy

The volume of North American crude oil shipped by train continues to fall due to the narrowing spread between West Texas Intermediate (WTI), Bakken and North Sea Brent.

The Association of American Railroads (AAR) reported U.S. petroleum and petroleum product shipments were down 4.7% for the year through the end of August, compared to the first eight months of 2014. For the week ended Aug. 29, shipments were down 15.3%, year over year. However, Canadian crude by rail shipments rose for both periods compared to 2014, according to AAR. This was because of demand created for bargain-priced Canadian oil.

“We note from weekly crude oil import data that heavy crude from Canada has seen decent demand in the U.S. in recent weeks,” Global Hunter Securities said in an Aug. 28 analysis of crude-related rail traffic. “Much of the lift has been catalyzed by exceptionally low prices for Canada crude. Indeed, some quotes were putting Western Canadian Select (WCS) at about $20 per barrel (bbl) just two weeks ago.”
The WTI-Brent price spread has been in the range of $5/bbl recently, compared to as much as $20/bbl two years ago.

The spread in 2015 peaked at $8/bbl in April. That narrowed differential makes more-expensive rail transport uncompetitive with pipelines—if pipeline service is available. Pipeline service is not always in place, particularly in the isolated Williston Basin, and rail transport remains an option for producers in such areas.

That narrowed price spread has led some Atlantic Coast refiners running primarily lighter crudes to move back to imported oils in place of Bakken oil. Irving Oil Ltd. recently confirmed that its 320,000 bbl/d refinery at St. John, New Brunswick—one of the largest refineries on North America’s East Coast—is no longer processing Bakken crude, all of which was shipped by rail.

An Irving spokesman said the move was a global supply-and-demand issue unrelated to rail-safety questions. The runaway train that caused an explosion and fire in Lac-Mégantic, Quebec, in July 2013 was hauling Bakken oil from North Dakota to the St. John plant. A Wall Street Journal article said the plant is now running crudes from Saudi Arabia, western Africa and a small amount of WCS shipped by rail from Alberta.

Irving announced in late August that it would begin a 60-day turnaround Sept. 16.

Another challenge, besides price, to eastbound crude trains could come from new pipeline capacity.

“The Northeast/Quebec crude oil-by-rail story is very likely to be substantially transformed by the eventual completion of TransCanada’s Energy East Pipeline,” Global Hunter said in a recent analysis. “The project is still in the application phase. Assuming the pipeline is approved and proceeds, then it is expected that it will be operational by 2018. The pipeline project would convert and expand upon an existing natural gas pipeline system and convert it for transmission of crude oil within Canada. Projected capacity is indicated at 1.1 MM bbl/d.”

Going west from the Williston Basin, shipments of Bakken crude have remained comparatively stronger as production of Alaskan North Slope crude dwindles—the primary crude used by West Coast refiners. However, those refiners faced an unusual impediment to their supply in late August: forest fires. Fire lines moved within a few hundred feet of BNSF Railway’s main line across Montana, in and around Glacier National Park, for several days at the end of August. That closed the track to all rail traffic, including crude shipments.

Meanwhile, fire fighters used the closed railroad to reach fires that were otherwise inaccessible by highway. Very heavy smoke also grounded fire-fighting aircraft. The fires forced closure of many of Glacier park’s popular attractions. “Wildfires remain a continued concern across the inland Pacific Northwest. There are currently about 100 large fires impacting parts of Idaho, Oregon, Montana, Washington, and California,” BNSF spokesman Gus Melonas said in a late-August press statement.

The drop in what was once a rapidly growing business segment comes at a difficult time for North American railroads, which are also losing traffic in a far-larger product category: coal. The AAR reported as September started that year-to-date coal shipments through August were down 11.1% from 2014. A primary reason has been fuel switching to natural gas—good news for gas transmission systems.

Longer term, there will continue to be a market for crude by rail, primarily for Bakken production, according to railroad analyst Fred Frailey.

"Bakken oil really can't compete on the Gulf," Frailey said in a recent blog post. "That's kind of a dead market for pipelines. Crude by rail to East Coast and West Coast occurs primarily because there are no pipelines. Rail has a 60-70% share with East Coast refineries. [On the] West Coast they are sending as much as they can but terminal capacity has to go up. Eventually if they get approval for those terminals, you will have more crude going to the west."

Chesapeake Surrenders 50,000 Utica Acres For Pipeline; Cuts Costs

By Darren Barbee, Hart Energy

Chesapeake Energy Corp. (CHK) has turned a deal in the Haynesville and Utica plays that lowers its midstream contract costs in exchange for minimum volumes and dedication of 50,000 net Utica acres to Williams Cos. Inc. (WMB).

The deal will switch Chesapeake to fixed-fee agreements in the shales in January 2016. The company's expects shortfall payments for existing 2016 and 2017 minimum volume commitments (MVC) to be wiped out as a result.
Williams will use the additional land to build more pipelines in the Utica.

"Unexpected and positive news for Chesapeake," said David Kistler, managing director, Simmons & Co. International. The new gathering agreement with Williams Partners "should result in increased cash flow due to improved gas differentials and removal of minimum volume commitments in 2016 and beyond."

In the Utica and Haynesville, Chesapeake will move to fixed-fee agreements that could add $200 million to Chesapeake's EBITDA. Increased earnings will help, though not cure, Chesapeake's debt load. The company's leverage swells in 2017.

The company is targeting a 2015 ending cash balance of about $1.5 billion and a $4 billion undrawn credit facility. Chesapeake's restructured contract will require increased Haynesville production. Chesapeake said in a Sept. 8 presentation that estimated ultimate recoveries (EUR) have increased by more than 25% in the Haynesville.

"The company believes it can meet this commitment with about one rig per year," Kistler said.

Chesapeake plans to bring 140 wells online in the next two years—a commitment that will cost $1.1 billion in gross capex, according to estimates by Tudor, Pickering, Holt & Co.

The net effect will be accelerated gas growth in the Haynesville as Chesapeake reduces operating expense in the Haynesville and Utica by as much as $175 million, Tudor, Pickering, Holt said.

In the Utica, Chesapeake will increase the land dedicated to Williams to 190,000 net acres from 140,000 net acres and will be subject to a new MVC of 250 million cubic feet equivalent per day (cfe/d) beginning in mid-2017, Kistler said.

Williams and Chesapeake executed a long-term, fee-based contract that increases exposure to the dry gas zone of the Utica, where Chesapeake and other operators are targeting production growth, Williams said Sept. 8.

The agreement extends the length of Chesapeake's acreage dedication to 2035 in a strategic area adjacent to Williams' existing assets.

Chesapeake Energy Corp.		
Spending ($MM)		
DCF	Capex	Outspend
$2,189	$3,571	$(1,382)
Leverage: Net Debt/EBITDAX		
2014	2015E	2016E
1.6x	5.1x	7.4x
Source: Wells Fargo Securities LLC		

Williams said it expects to invest more than $600 million over five years to install more than 200 miles of pipeline and related facilities with up to 800 million cubic feet per day (cf/d) of capacity.

"This demonstrates our commitment to working with Chesapeake to align our interests on mutual growth while sustaining the financial support of our investments," said Alan Armstrong, Williams CEO. "These new fee structures are designed to promote production in the best locations across a wider footprint in these great basins, which improves the economics on both the drilling and midstream side."

Tudor, Pickering, Holt saw the deal as a slight negative for Williams, with near-term cash flows reduced. The swap of cost of service agreements to fixed fees suggests "lower revenues today in exchange for higher revenues in the out years as volumes ramp," the firm said.

Doug Lawler, Chesapeake's CEO, said the company has created operating efficiencies across its entire portfolio in the past two years, resulting in lower costs and higher production and recovery rates.

"Our improved performance in the Haynesville is the primary reason that we were able to negotiate new gathering rates," Lawler said. "These agreements will result in lower gathering rates and lower differentials, making these assets even more competitive within our portfolio."

Chesapeake has noted that despite cutting capital spending by $500 million, it will beat original production estimates by about 5%.

Kistler said Chesapeake's Haynesville gas-gathering fees will be reduced by $170 million annually as MVCs are met through consolidation of its Haynesville and Utica gathering contracts and new wells.

"Chesapeake estimates these combined actions will result in a $200 million annual uplift in EBITDA," Kistler said. "While certainly a positive, CHK's leverage still remains a concern."

HollyFrontier Expands Midstream; Squeezes Money From Pipeline, Dropdown Deals

By Darren Barbee, Hart Energy

HollyFrontier Corp.'s (HFC) aim is simple: get higher values at the bottom of the barrel.

A pair of deals is the latest step in incrementally upping the company's take home pay.

Affiliate Holly Energy Partners LP (HEP) said Sept. 3 it has acquired a 50% interest in Frontier Pipeline Co., owner of the Frontier Pipeline of Wyoming, from an affiliate of Enbridge Inc. (ENB).

HollyFrontier also executed a dropdown to Holly Energy that gives it a stake in a refinery locked in with Cushing, Okla.

The Frontier Pipeline Co. will continue to be operated by an affiliate of MLP Plains All American Pipeline LP (PAA), which owns the remaining 50% interest.

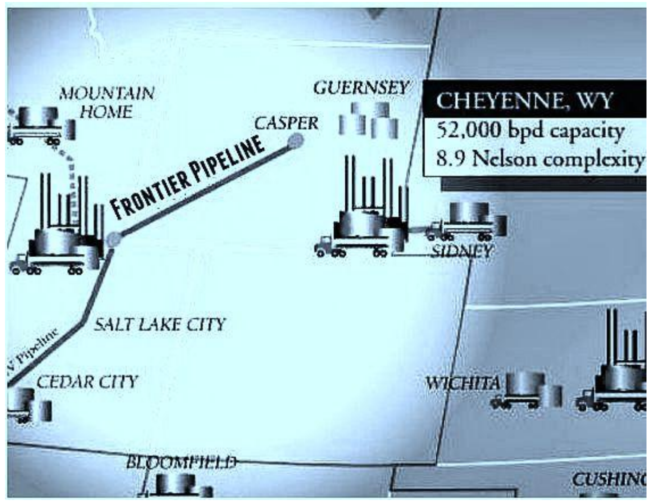
The 296-mile crude oil line runs from Casper, Wyo., to Frontier Station, Utah. It has a 72,000 barrel per day (bbl/d) capacity. The line supplies Canadian and Rocky Mountain crudes to Salt Lake City area refiners through a connection to the SLC Pipeline. Holly owns 25% of the SLC Pipeline.

The purchase price was not disclosed. Documents filed with the Federal Energy Regulatory Commission (FERC) on Sept. 3, which use Plains All American's corporate address, list the value of its carrier property interests at $79.8 million before depreciation and other expenses.

FERC documents show the pipeline received 5.1 MMbbl of oil as of September and delivered 4.4 MMbbl, leaving 709 Mbbl of oil terminated on trunk lines. Sources to the line include the Express, Big Horn and local crude gathering.

Holly Energy's parent company, Dallas-based HollyFrontier Corp. (HFC)**,** expects the non-operating interest to eventually generate $6- to $7 million in EBITDA for Holly. The deal has an effective date of Aug. 31.

In 2001, Enbridge acquired an additional 34% interest in the Frontier Pipeline Co. for US$28.9 million, or $38.9 million when adjusted for inflation. That increased Enbridge's interest to 77.8%. It's unclear when Plains was able to gain 50% of Frontier.



In a separate transaction, Holly Energy Partners and HollyFrontier said Holly Energy would purchase a newly constructed naphtha fractionation and hydrogen generator units at HollyFrontier's El Dorado refinery in Kansas.

The refinery is one of the largest in the plains states and the Rocky Mountain region with crude oil capacity of 135,000 bbl/d. More importantly, the refinery has the capability to process several types of crude oil because of its direct access to the Cushing hub, which is connected by pipelines to Canada.

The HollyFrontier dropdown to Holly Energy is expected to close during the fourth quarter of 2015.

Holly Energy and HollyFrontier are expected to enter into 15-year tolling agreements, said Mark Reichman, director of research covering MLPs for Simmons & Co. International. HollyFrontier expects the tolling agreements to generate $6.9 million in 2016 EBITDA.

The transaction is expected to be immediately accretive to Holly Energy distributable cash flow, he said.

FRAC SPREAD

Bargain Shopping

By Frank Nieto, Hart Energy

Though a sizable portion of refineries are undergoing planned turnarounds in anticipation of the winter season, lower prices of butane and isobutane are encouraging refiners to acquire supplies earlier. This is similar to the situation taking place in the propane market as farmers and suppliers stock up ahead of the crop-drying and winter-heating seasons.

This helps explain why those three products had the largest price increases in the theoretical NGL bbl for the week of Sept. 2. The improved propane prices, which rose 14% at Conway and 11% at Mont Belvieu, were especially impressive considering that storage is still at record levels.

Prices are likely to dip until the heating season arrives, but the improvements experienced this week should help to shorten the shoulder season. As it currently stands, propane prices at both hubs were at their highest level since mid-May.

Another reason for improved propane prices is the product's increasingly closer relationship to crude prices as the bulk of NGL production has been through associated production in the last few years. West Texas Intermediate (WTI) prices have been trading in the mid-$40/bbl range for the past few weeks after falling below $40/bbl. WTI prices may struggle to approach $60+/bbl through the end of the year but low prices have caused an increase in gasoline demand, which should help create a bottom for crude prices barring a geopolitical event.

CURRENT FRAC SPREAD (CENTS/GAL)				
September 11, 2015	**Conway**	**Change from Start of Week**	**Mont Belvieu**	**Last Week**
Ethane	15.87		17.90	
Shrink	17.37		17.57	
Margin	-1.50	50.08%	0.33	-45.02%
Propane	40.60		43.17	
Shrink	24.00		24.27	
Margin	16.60	47.24%	18.90	30.11%
Normal Butane	49.83		55.57	
Shrink	27.17		27.48	
Margin	22.66	18.79%	28.09	15.54%
Isobutane	59.17		56.30	
Shrink	26.10		26.39	
Margin	33.07	14.03%	29.91	11.64%
Pentane+	99.17		97.73	
Shrink	29.06		29.39	
Margin	70.11	9.96%	68.34	11.69%
NGL $/Bbl	18.37	8.63%	18.95	6.94%
Shrink	9.57		9.68	
Margin	8.79	22.33%	9.27	16.36%
Gas ($/mmBtu)	2.62	-1.50%	2.65	-0.75%
Gross Bbl Margin (in cents/gal)	19.35	24.49%	20.90	17.20%
NGL Value in $/mmBtu (Basket Value)				
Ethane	0.87	8.48%	0.99	-0.17%
Propane	1.41	13.92%	1.50	10.75%
Normal Butane	0.54	6.79%	0.60	6.87%
Isobutane	0.37	6.61%	0.35	5.47%
Pentane+	1.28	6.34%	1.26	7.63%
Total Barrel Value in $/mmbtu	4.47	9.13%	4.69	6.58%
Margin	1.85	28.84%	2.04	17.86%

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.

RESIN PRICES – MARKET UPDATE – SEPTEMBER 11, 2015					
TOTAL OFFERS: 16,113,416 lbs		**SPOT**		**CONTRACT**	
Resin	**Total lbs**	**Low**	**High**	**Bid**	**Offer**
HDPE - Inj	4,290,556	0.54	0.62	0.53	0.57
LDPE - Film	3,727,888	0.51	0.695	0.55	0.59
LLDPE - Film	2,231,864	0.54	0.63	0.52	0.56
HDPE - Blow Mold	2,200,416	0.56	0.585	0.52	0.56
PP Copolymer - Inj	1,099,104	0.59	0.725	0.59	0.63
HMWPE - Film	1,058,208	0.575	0.61	0.54	0.58
PP Homopolymer - Inj	600,460	0.625	0.65	0.57	0.61
LLDPE - Inj	542,736	0.49	0.62	0.56	0.6
LDPE - Inj	362,184	0.5	0.64	0.58	0.62

Source: Plastics Exchange – www.theplasticsexchange.com

NGL PRICES						
Mont Belvieu	Eth	Pro	Norm	Iso	Pen+	NGL Bbl
Sept. 2 - 8, '15	17.90	43.17	55.57	56.30	97.73	**$0.00**
Aug. 26 - Sept. 1, '15	17.93	38.98	52.00	53.38	90.80	**$17.72**
Aug. 19 - 25, '15	18.31	37.02	49.58	50.96	89.64	**$17.27**
Aug. 12 - 18, '15	18.97	37.68	51.42	52.54	98.56	**$18.20**
August '15	18.55	37.35	50.57	51.80	94.58	**$0.00**
July '15	17.59	40.40	53.80	54.94	108.91	**$19.20**
2nd Qtr '15	17.93	46.30	58.11	59.66	126.14	**$0.00**
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**
Sept. 3 - 9, '14	22.46	105.18	125.22	128.04	212.88	**$0.00**
Conway, Group 140	Eth	Pro	Norm	Iso	Pen+	NGL Bbl
Sept. 2 - 8, '15	15.87	40.60	49.83	59.17	99.17	**$0.00**
Aug. 26 - Sept. 1, '15	14.63	35.64	46.66	55.50	93.26	**$16.91**
Aug. 19 - 25, '15	15.78	33.44	44.18	51.92	88.12	**$16.26**
Aug. 12 - 18, '15	16.35	34.46	45.88	51.96	95.76	**$17.08**
August '15	15.71	33.52	44.88	51.94	93.63	**$0.00**
July '15	14.51	32.64	47.53	49.40	106.60	**$17.32**
2nd Qtr '15	15.50	40.55	52.40	56.80	121.50	**$0.00**
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**
Sept. 3 - 9, '14	22.23	105.04	124.64	138.84	208.28	**$0.00**

Ethane prices remain a mixed bag as the Conway price rose 8% to 16 cents per gallon (/gal), its highest price in a month; however, the Mont Belvieu price remained flat for the third straight week at 18 cents/gal. In fact, the Mont Belvieu price has traded in this range for the past two months.

Complicating matters for the ethane price outlook is that natural gas prices have also been stagnant. Ethane's close relationship with gas has also helped keep Mont Belvieu prices steady. Unfortunately, the $2.60 per million Btu level gas has been trading at both hubs is resulting in negative margins for ethane.

The one positive to take from ethane prices is that they are the closest to a recovery back to their 2014 levels. Of course, last year ethane margins were negative so there is still a lot of work to do for ethane to return to a balanced market.

It is likely that ethane won't become fully balanced for several more years, but storage levels have decreased this summer and should see rejection levels dial back in the fall. This will help prices return to their highest levels in years. As it stands, margins are on the cusp of positivity at both hubs, but are still not attractive.

Similarly the theoretical NGL bbl may be positive, but prices are also not as striking as the market would like. The Mont Belvieu bbl rose 7% to $18.95/bbl with a 16% gain in margin to $9.27/bbl. The Conway price improved 9% to $18.37/bbl with a 22% gain in margin to $8.79/bbl.

The most profitable NGL to make at both hubs was C5+ at 70 cents/gal at Conway and 68 cents/gal at Mont Belvieu. This was followed, in order, by isobutane at 33 cents/gal at Conway and 30 cents/gal at Mont Belvieu; butane at 23 cents/gal at Conway and 28 cents/gal at Mont Belvieu; propane at 17 cents/gal at Conway and 19 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 a gas storage injection of 68 billion cubic feet (Bcf) for the week of Sept. 4. This was about 20 Bcf lower than analysts had been predicting as cooling demand was up along the East Coast.

Overall the storage level rose to 3.261 trillion cubic feet (Tcf) from 3.193 Tcf, which was 17% higher than the 2.788 Tcf reported last year at the same time and 4% greater than the five-year average of 3.134 Tcf.

The National Weather Service’s forecast for the week of Sept. 16 anticipates warmer-than-normal temperatures to continue throughout the East Coast through the Gulf Coast and into the Midwest. This should further reduce storage injection levels and help mitigate any fears of the industry hitting storage capacity before heating season.

MORE TOP STORIES

Centennial Pipeline's Conversion To Transport NGL Could Take Two Years

Marathon Petroleum Corp's joint-venture Centennial Pipeline could be converted to move natural gas liquids to Texas and its flow reversed southward from Illinois within two years, Enterprise Products Partners said in an investor presentation on Sept. 8.

The 795-mile (1,279 km) Texas-to-Illinois refined products pipeline can move up to 210,000 barrels per day, but has been largely empty since mid-2011. Marathon operates the line and Enterprise is its 50 percent partner. Enterprise stopped moving products in the line last year.

Enterprise said both companies own pipelines that could be repurposed to connect Centennial to Utica and Marcellus NGL output. The line could move 100,000 bpd to Texas once pump stations are reversed and possibly more are added. The project would take up to two years to complete, Enterprise said. Neither company disclosed a potential cost.

Marathon Chief Executive Gary Heminger said in July that Centennial could become a southbound NGL line with the necessary connection to Utica and Marcellus to maintain substantial throughput. **- REUTERS**

New Mexico Rail Terminal Will Serve Delaware Basin Oil Producers

CIG Logistics opened a new rail terminal in Jal, N.M., to reduce transportation, transloading and storage costs for Delaware Basin oil producers, the oil and natural gas logistics provider said Sept. 8.

Michael Collins, vice president of business development, said the terminal will help companies reduce their frack sand transportation and storage costs.

As the sixth terminal in CIG’s network, the large-scale Jal terminal includes more than 550 rail car spots and 12,000 tons of silo storage capacity. The facility is designed and located to help producers decrease distance from rail terminal to wellhead, improve efficiencies and decrease total operational costs.

The terminal, in Lea County, receives and handles manifest and unit trains. There are 21 employees including railroad engineers and conductors. To meet growing demand, a Phase Two expansion of 160 additional rail car spots and 6,000 tons of silo storage is already being planned for early 2016, the company said.

CIG now has six transloading and storage facilities. The Fort Worth, Texas-based company operates across Texas.

Nexen Allowed To Reopen Some Long Lake Pipelines

Alberta's energy regulator said late on Sept. 6 it will allow Nexen Energy, the Canadian subsidiary of China's CNOOC Ltd, to reopen some pipelines ordered closed following a major spill.

The Alberta Energy Regulator said it would allow a restart of 40 of 95 pipelines closed at Nexen's Long Lake oil sands operations after reviewing maintenance and monitoring documentation.

"The remaining 55 pipelines affected by the order, which contain several products, including crude oil, natural gas, salt water, fresh water and emulsion, continue to be suspended," the regulator said in a statement.
"These pipelines ... will not return to service until Nexen can demonstrate that the pipelines can be operated safely and within all requirements."

The provincial regulator last month ordered Nexen to shut in the pipelines at the Long Lake facility as part of an investigation into one of the largest-ever oil-related pipeline spills on North American soil, discovered in July.

House Subcommittee Passes Bill To Repeal Export Ban

A U.S. House of Representatives subcommittee passed a bill on Sept. 10 to repeal the U.S. ban on oil exports, providing momentum in the chamber for overturning the 40-year old trade restriction.

The House Energy and Power subcommittee passed the bill, sponsored by Republican Representative Joe Barton of Texas. It is expected to be voted on by the full Energy and Commerce committee next week.

A similar bill passed the Senate energy panel this summer, but no Democrats voted for the legislation in the committee. **- REUTERS**

ARM Midstream Will Develop Gas Gathering System In Stack Play

ARM Midstream and Highbridge Principal Strategies LLC will build a cryogenic processing plant, natural gas gathering system and crude oil gathering system in Oklahoma's Stack play, ARM said Sept. 8. ARM Midstream is a wholly owned subsidiary of Asset Risk Management (ARM).

The Kingfisher Midstream project will provide producers in Kingfisher, Blaine, Logan, Garfield, and Canadian counties, Okla., with infrastructure and takeaway capacity. There will be more than 100 miles of low- and high-pressure gas gathering pipelines and more than 15,000 horsepower of compression.

The cryogenic processing facility's initial capacity will be 60 million cubic feet per day (MMcf/d) of natural gas. There will be additional plant expansions, a high-pressure gathering backbone and centralized low pressure delivery points.

ARM Midstream also said there will be a crude oil gathering system connecting in-field production to Cushing, Okla. There will also be truck loading facilities and storage for 50,000 barrels of oil.

The Kingfisher Midstream Project is scheduled to begin gathering operations in fourth-quarter 2015, and the processing plant will be in service by the first quarter of 2016.

A long-term commitment of about 100,000 gross acres underpins the project, the company said.
Taylor Tipton, president of ARM Midstream and ARM Energy Management, said that as the Stack develops, the takeaway capacity will give producers an edge in the market.

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