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August 7, 2017

Natural Gas Weekly Spot Prices

Flow Dates: 8/1-8/7

Price Point	$/MMBtu	Chg.	High	Low	Avg. Daily Vol.	Avg. Daily Deals	Aug. Bid Week
GULF COAST							
ANR SE	2.71	-0.14	2.76	2.67	60,057	9	2.87
Col. Gulf - Erath	2.71	-0.14	2.78	2.65	45,629	5	2.87
Col. Gulf - Rayne	2.69	-0.15	2.75	2.64	33,686	5	2.85
Florida Zone 1	—	—	—	—	—	—	—
Florida Zone 2	2.74	-0.16	2.76	2.73	16,891	1	2.93
Florida Zone 3	2.77	-0.12	2.84	2.72	129,668	11	2.93
Henry Hub	2.77	-0.16	2.85	2.74	85,986	10	2.96
NGPL-LA	—	—	—	—	—	—	—
Sonat	2.74	-0.12	2.78	2.68	239,757	29	2.88
Tenn 500 So LA Z1	2.73	-0.12	2.82	2.68	53,449	10	2.89
Tenn 800 So LA Z1	2.68	-0.16	2.73	2.63	13,657	3	2.88
Tetco ELA	2.72	-0.14	2.78	2.68	31,943	6	2.85
Tetco WLA	2.71	-0.17	2.82	2.64	46,743	2	2.85
TGT Zone SL	—	—	—	—	—	—	—
Transco Station 45	2.74	-0.14	2.80	2.69	12,257	5	—
Transco Station 65	2.73	-0.18	2.80	2.71	179,073	16	2.92
Trunkline ELA	—	—	—	—	—	—	—
Trunkline WLA	—	—	—	—	—	—	—
Trunkline Zone 1A	2.69	-0.14	2.76	2.67	58,229	6	2.85
Regional Average	2.73	-0.14	—	—	—	—	2.90
TEXAS (SOUTH/EAST)							
Carthage Hub	2.73	-0.11	2.75	2.70	21,471	3	—
HSC	2.76	-0.14	2.78	2.70	22,129	1	2.91
Katy Hub	2.75	-0.14	2.80	2.73	64,800	4	—
NGPL-South Texas	2.80	-0.07	2.80	2.80	1,714	1	2.90
NGPL-TexOk	2.71	-0.08	2.77	2.62	95,443	8	2.80
Tenn Zone 0	2.68	-0.09	2.69	2.66	2,671	1	2.80
Tetco-East Texas	2.72	-0.12	2.74	2.66	9,386	2	2.84
Tetco-South Texas	2.74	-0.15	2.80	2.69	57,071	4	2.89
TGT Zone 1	2.70	-0.13	2.76	2.67	170,414	12	2.85
Transco Station 30	2.73	-0.12	2.77	2.65	55,414	7	2.88
Regional Average	2.72	-0.14	—	—	—	—	2.85
TEXAS (WEST)							
El Paso Permian	2.51	-0.13	2.69	2.44	506,308	46	2.57
NNG Custer	2.61	-0.09	2.61	2.61	629	1	—
Transwes E of Thoreau	2.54	-0.12	2.66	2.47	72,417	8	2.62
Waha Hub	2.59	-0.10	2.72	2.48	294,944	21	2.59
Regional Average	2.54	-0.13	—	—	—	—	2.58
MIDCONTINENT							
ANR SW	2.51	-0.16	2.60	2.45	76,157	11	2.64
CenterPoint East	2.65	-0.13	2.72	2.48	27,671	3	—
CenterPoint West	—	—	—	—	—	—	—
NGPL-MC	2.53	-0.16	2.63	2.35	72,043	10	2.64
Oneok	2.36	-0.07	2.64	2.15	41,329	7	2.37
Panhandle	2.43	-0.15	2.56	2.37	100,942	16	2.58
Southern Star	2.38	-0.17	2.52	2.36	28,529	4	—
Regional Average	2.47	-0.18	—	—	—	—	2.54
GREAT PLAINS							
Emerson	2.41	-0.20	2.58	2.30	293,777	36	2.61
NB Ventura TP	2.63	-0.08	2.72	2.54	8,805	2	—
NNG Demarc	2.62	-0.12	2.73	2.56	55,200	7	2.72
NNG Ventura	2.67	-0.07	2.72	2.54	8,743	2	2.73
Regional Average	2.45	-0.20	—	—	—	—	2.70

(continued on p2)

Ferc Quorum Restored, But Pipeline Approvals Could Be Weeks Away

Ending six months of regulatory paralysis, the US Senate last week restored a quorum to the Federal Energy Regulatory Commission (Ferc) by confirming two of President Trump's nominees to fill vacant seats.

Once Neil Chatterjee and Robert Powelson are sworn in early this week, they and Acting Chairman Cheryl LaFleur face a daunting backlog of pipeline, LNG and power project applications that have been in limbo since early February.

"Ferc could begin approving projects almost immediately,

(continued on page 15)

Local Permian Sand May Blast Away Some Well Costs for Oil, Gas Industry

The innumerable grains of golden sand that have long chafed West Texas — hiding sunlight, plugging machinery and collecting in the corners of every crevice – may become the rural oil and gas hub's latest valuable natural resource.

In recent years, producers have found that the more sand they pump downhole in a hydraulically fractured well, the more hydrocarbons come to the surface. Consequently, sand use has skyrocketed since the shale boom began.

Nowhere is that more prevalent than in the Permian Ba-

(continued on page 14)

Setback Hits Range's Q2 Gas Output; Antero Touts Technological Advances

Two of the US's largest gas-focused independents concentrated on production growth when reporting their second-quarter results, However, while Range Resources sought to explain why it is reducing full-year 2017 production guidance, Antero Resources touted cutting-edge drilling techniques that enabled it to top expectations.

Range Chief Operating Officer Ray Walker Jr. said the company's Q2 production hit 1.945 billion cubic feet equivalent per day, exceeding company guidance of 1.93 Bcfe/d. However, he raised red flags when he lowered guidance for

(continued on page 7)

Natural Gas Weekly Spot Prices (cont.)

Flow Dates: 8/1-8/7

Price Point	$/MMBtu	Chg.	High	Low	Avg. Daily Vol.	Avg. Daily Deals	Aug. Bid Week
UPPER MIDWEST							
Alliance	2.69	-0.12	2.78	2.66	157,814	11	—
ANR ML7	2.73	-0.17	2.89	2.70	3,881	2	2.90
Chicago Citygate	2.73	-0.06	2.86	2.62	369,639	48	2.83
Consumers	2.76	-0.11	2.85	2.72	213,571	27	2.88
MichCon	2.74	-0.11	2.83	2.70	372,871	39	2.85
Rex Zone 3 Delivered	2.69	-0.11	2.75	2.64	279,957	34	2.82
Regional Average	2.72	-0.10	—	—	—	—	2.85
SOUTHEAST							
Tetco M1	2.74	-0.13	2.79	2.72	17,857	1	—
Transco Zone 4	2.76	-0.13	2.81	2.71	357,775	37	2.92
Transco Zone 5	2.83	-0.11	2.93	2.70	104,035	13	3.01
Regional Average	2.77	-0.12	—	—	—	—	2.94
APPALACHIA							
Col. Gas App. Pool	2.65	-0.16	2.73	2.60	66,505	16	2.78
Dominion North	1.81	0.16	1.99	1.45	13,657	3	1.74
Dominion South	1.57	-0.07	2.02	1.34	198,966	32	1.73
Lebanon Hub	2.69	-0.13	2.76	2.64	58,728	6	2.82
TENN Z4 200-leg	1.90	0.03	2.23	1.65	118,761	18	1.93
TENN Z4 300 leg, receipts	1.77	0.08	1.92	1.57	13,500	2	1.65
TENN Z4 313 pool	1.90	0.08	2.08	1.80	19,050	4	1.87
Transco Leidy Line	1.77	0.03	2.00	1.55	76,814	5	1.72
Regional Average	1.93	0.08	—	—	—	—	1.99
EASTERN CANADA							
Dawn	2.77	-0.09	2.83	2.67	317,400	50	2.89
Iroquois	2.76	0.22	2.90	2.10	25,543	7	2.86
Niagara	—	—	—	—	—	—	—
Regional Average	2.77	-0.08	—	—	—	—	2.89
NORTHEAST / MIDATLANTIC							
Algonquin	2.34	0.31	3.40	1.84	91,110	18	2.45
Dracut	—	—	—	—	—	—	—
Iroquois Zone 2	2.53	0.37	2.99	2.00	18,827	4	2.82
Tenn Gas Zone 6	2.31	0.31	3.35	1.83	103,127	17	2.44
Tetco M3	1.62	-0.09	2.08	1.41	299,847	33	1.80
Transco Z6 - Non-NY	2.25	0.31	2.80	1.65	74,141	11	2.30
Transco Z6 - NY	2.04	0.07	2.72	1.68	55,006	11	2.30
Regional Average	1.97	0.09	—	—	—	—	2.29
ROCKIES							
Cheyenne Hub	2.48	-0.14	2.60	2.42	59,671	8	2.59
CIG	2.46	-0.14	2.57	2.39	42,286	5	2.58
Kern River / Opal	2.49	-0.17	2.70	2.44	572,129	50	2.64
NW Rockies	2.48	-0.17	2.64	2.41	46,714	7	2.59
Questar	2.55	-0.07	2.58	2.45	3,200	1	2.52
White River Hub	2.47	-0.17	2.63	2.43	161,786	12	2.59
Regional Average	2.49	-0.16	—	—	—	—	2.60
SAN JUAN BASIN							
El Paso Bondad	2.52	-0.14	2.63	2.46	58,886	9	—
El Paso San Juan	2.53	-0.11	2.66	2.48	105,650	12	2.61
Transwestern Pipeline, San Juan	2.54	-0.12	2.67	2.47	76,957	10	2.66
Regional Average	2.53	-0.12	—	—	—	—	2.64
PACIFIC NORTHWEST/WESTERN CANADA							
AECO	1.46	0.50	1.72	1.28	782,518	59	1.61
Kingsgate	2.36	—	2.40	2.34	1,186	1	—
Malin	2.57	-0.15	2.73	2.50	167,743	18	2.70
NW Sumas	2.49	-0.12	2.65	2.40	57,886	6	2.48
Stanfield	2.53	-0.08	2.63	2.42	26,586	3	2.59
Westcoast Station 2	0.55	-0.17	0.75	0.12	123,345	15	0.97
Regional Average	1.60	0.09	—	—	—	—	1.63
CALIFORNIA							
Kern - Wheeler Ridge	—	—	—	—	—	—	—
PG&E Citygate	3.21	-0.09	3.28	3.17	132,100	13	3.27
PG&E South	2.62	-0.17	2.89	2.60	183,186	10	—
SoCal Border	2.87	0.08	3.35	2.58	371,572	47	2.85
SoCal Citygate	3.33	0.12	3.58	3.10	159,900	17	3.21
Regional Average	2.96	-0.04	—	—	—	—	3.04
WEEKLY COMPOSITE SPOT PRICES							
Wellhead	2.56	-0.15	—	—	—	—	—
Delivered	2.29	-0.09	—	—	—	—	—

Rebounding Midstream Sector Building New Projects, Boosting Distributions

Midstream players are back with numbers on the positive side of the ledger and growing in all areas – gas, natural gas liquids (NGLs) and crude oil — after several years of struggles. And most important to their investors, quarterly distributions are back on the schedule, if not this year then in 2018.

And these companies see continued improvement in their operational and financial performance at a time when major expansion projects are needed to serve the upstream and the downstream sectors — both of which also are in growth mode despite restrained commodity prices.

Enterprise Products Partners delivered news of a higher distribution to unitholders and the upcoming startups of a slew of new projects. These include the Midland-to-Echo crude oil pipeline from the Permian Basin to Houston, another NGLs pipeline from the Permian to Enterprise's Mont Belvieu storage and fractionation complex northeast of Houston, a propane dehydrogenation plant at Mont Belvieu and possibly another major gas pipeline.

Activity in the Permian remains strong, the Haynesville Shale has come back and the Eagle Ford Shale has reached an pivotal point that will mark the beginning of its recovery, CEO Jim Teague told analysts on a conference call.

"On the demand side, we believe the US petrochemical industry's demand for low-cost ethane reached the much anticipated inflection point during the first quarter of 2017," he continued. By the end of the year, four new ethane crackers will be completed, the first of which has been commissioned.

The three others will boost demand for ethane by 270,000 barrels per day on top of new record domestic demand of 1.2 million b/d set in May, the Enterprise chief said.

For the quarter, Enterprise saw its earnings climb to $666 million on revenues of $6.6 billion, up from year-ago earnings of $570 million on revenues of $5.6 billion.

Pipeline giant Williams and its master limited partnership affiliate Williams Partners could rank the second quarter as the last reporting period to include petrochemicals, which underperformed in the quarter. Most of the business has been sold to Canada's Nova in a deal set to close in September.

Several new pipeline projects connected to Williams' Transcontinental Gas Pipe Line system have started up recently, and more will go into service later this year, which will add to earnings and revenues.

"We continue to deliver on project execution as planned for 2017. So far this year, we have successfully brought into service three Transco expansion projects including the 1.2 Bcf/d Gulf Trace project, the 800 MMcf/d Hillabee Phase 1 project, and just [last] week, the 400 MMcf/d Dalton Expansion project," said Williams CEO Alan Armstrong.

During the second half of the year, Williams expects to bring three more fully contracted growth projects into service: Virginia Southside II, New York Bay and Garden State Phase 1.

Williams posted net earnings of $81 million in the second quarter, reversing a loss of $ 405 million a year earlier. Williams Partners reported income of $320 million, versus a loss of $90 million a year ago. In the third quarter, Williams Partners will record a $1.1 billion gain from the sale of the petrochemicals unit.

Tulsa-based Oneok was another midstream company to boost its dividend, raising the payment to stockholders by 21% from the first quarter. The higher return also reflects the just completed rollup of the former Oneok Partners with its C-Corp parent.

The company said its results reflected higher revenues from gas and NGL volume growth in the Williston Basin and Stack and Scoop areas of Oklahoma, higher average fee rates in the natural gas gathering and processing segment and higher fee-based transportation services in the gas pipelines segment.

"Producer activity remains strong in the Stack and Scoop and in the core areas of the Permian and Williston basins," CEO Terry Spencer said in a statement. "We continue to expect to benefit from ethane recovery in the second half of 2017 and into 2018 as large petrochemical facilities are completed and increase the demand for ethane."

Oneok had net income of $71.5 million on revenues of $2.7 billion in the second quarter, compared with $85.9 million and $2.1 billion, respectively, a year ago.

Crestwood Equity Partners had its best quarter in recent memory, recording operating earnings and a reduced net loss as new projects in the Bakken, Marcellus Shale and Delaware Basin increased throughput on gas and NGL gathering systems, processing plants and pipes.

The company reported a net loss of $19.5 million on revenues of $603 million, compared to a loss of $51.2 million on revenues of $850 million in the year-ago quarter. Operating earnings were slim but positive at $300,000, up substantially from a negative $37.1 million in the second quarter of 2016.

Crestwood has begun a series of new large-scale expansion projects, including the Bakken Arrow Bear Den pipeline and processing plant and the Orla Express pipeline and processing plant in the Delaware. The Orla projects will fully integrate the company's basin-wide position by ultimately connecting the Northern Delaware assets with the Shell Nautilus system in the southern Delaware.

The company also expects to resume distributions to unitholders in 2018.

Barbara Shook, Houston

Editor's Note: Bidweek Supplement

August bidweek price data and commentary appear in a supplement attached to this issue.

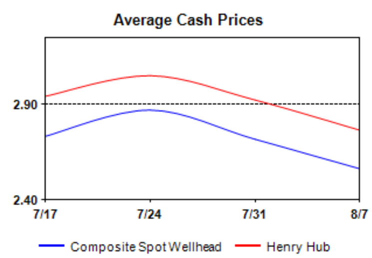
August Gas Slides Nearly 6% Amid Robust Supply, Sluggish Demand

A confluence of bearish fundamentals pulled the September gas futures contract below major support at $2.80 per million Btu on Friday, with a further late-summer price plunge still possible if weather outlooks continue to trend mild.

While the prompt-month contract found some footing in the upper $2.70s, it ended the week down 16.7¢, or 5.7%.

Cooler-than-normal weather expected across a large portion of the Lower 48 through mid-August weighed on the futures market for most of last week, and trading should continue probing five-month lows in the week ahead except during brief short-covering rallies.

However, GMP/FirstEnergy analyst Martin King said gas may yet find solid support north of $2.70 even as weather-driven demand lags.



"Such lower prices should encourage greater use of gas for power generation, despite cooler weather," he said, noting that prices were at similar levels this time last year just before a significant jump by the September 2016 contract occurred despite an bearish storage picture. In addition, the current contract could draw additional strength from growing non-weather related demand and "creeping" production gains.

"In other words, softer prices due to cooler weather make sense, but a further price implosion also seems unlikely," King said.

The US Energy Information Administration (EIA) said in its monthly 914 production report that gas output rose 0.4% to 80.2 billion cubic feet per day in May. That was down 0.9% from a year ago.

The biggest production gain was in West Virginia, which saw a 0.2 Bcf/d or 4.6% rise to a record 4.3 Bcf/d. Texas posted a 0.4 Bcf/d gain to 21.5 Bcf/d. Meanwhile, production in Pennsylvania fell 0.1 Bcf/d to 14.8 Bcf/d and Oklahoma was down 0.1 Bcf/d at 6.7 Bcf/d.

On the storage front, the EIA reported a net injection of 20 Bcf

Intrastate Weekly Spot Prices

Flow Dates: 8/1-8/7

Price Point	$/MMBtu	Chg.	High	Low	Avg. Daily Vol.	Avg. Daily Deals	Aug. Bid Week
Louisiana Intras	—	—	—	—	—	—	—
Oklahoma Intras	2.360	-0.067	2.64	2.15	41,329	7	2.37
South Texas Intras	—	—	—	—	—	—	—
West Texas Intras	—	—	—	—	—	—	—

for the week ended Jul. 28, boosting the volume of working gas in storage to 3,010 Bcf. The build was less than half the 44 Bcf five-year average but well above the 3 Bcf withdrawal seen in the same week last year.

The five-year surplus fell 24 Bcf to 87 Bcf, or 3% above the average; the year-on-year deficit fell 23 Bcf to 279 Bcf, or 8.5% below last year's level. Early injection estimates for the week ending Aug. 4 average 40 Bcf. Last year saw a 24 Bcf build; the five-year average is 54 Bcf.

Last week's unseasonably light storage injection was due mainly to a 17 Bcf net withdrawal in the South-Central region, which includes gas-intensive Texas which experienced unseasonably high temperatures, said independent analyst Stephen Schork. He added that this season's injections have only covered 48% of the gas that was withdrawn last winter, marking the lowest replacement rate since 2000.

Nonetheless, he said, inventories were above 3 trillion cubic feet as of Jul. 28 — only the fourth time that inventories have hit that mark in July — and on track to finish the season at 3.85 Tcf.

September futures lost 2.6¢ Friday to close at $2.774/MMBtu, while September WTI crude rose 55¢ to close at $49.58/bbl, down 13¢ for the week.

Baker Hughes said the number of Lower 48 gas-focused rigs was down by three to 189. Oil-focused rigs were down by one, bringing the total to 765.

The Commodity Futures Trading Commission's Commitments of Traders report for the week ended Aug. 1 showed noncommercials in a 53.7% short futures-only positions.

Lisa Lawson and Tom Haywood, Houston

Lawsuit Over Mountain Valley Pipeline Challenges Eminent Domain Authority

Legal fights over gas pipeline construction are nothing new, but plaintiffs in one Virginia case are taking a novel approach by invoking the US Constitution.

The latest battle involves the 303-mile Mountain Valley Pipeline, which would carry up to 2 billion cubic feet of gas per day through a 42-inch line from northwestern West Virginia to southern Virginia.

Supporters of the $3.5 billion pipeline say it will move Marcellus and Utica Shale gas to Mid- and South Atlantic markets that desperately need it. Opponents argue that land is being taken through eminent domain for a project that will not benefit them or their neighbors — thereby violating the due process clause of the Fifth Amendment.

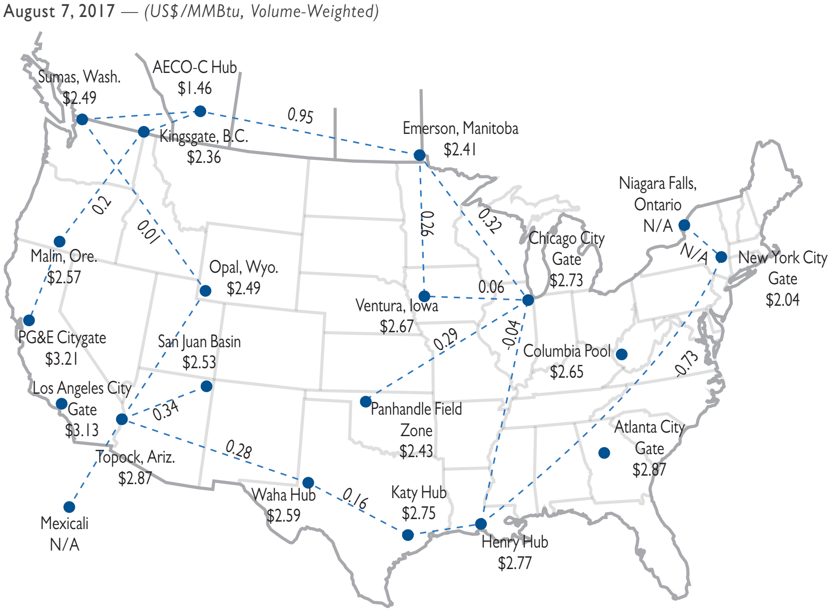
"This is not an anti-energy, political or left vs right issue," plaintiffs' attorney Justin Lugar told *Natural Gas Week*. "It is an issue of constitutional law and individual property rights. The issue of how and when a private entity may invoke eminent domain is one that should concern all Americans, including current and prospective landowners."

The lawsuit representing 17 homeowners who own 10 parcels along the pipeline's current route maintains that the Federal Energy Regulatory Commission (Ferc) should not be allowed to grant the power of eminent domain to a private company for its pursuit of "private pecuniary gain." The case is being heard in US District Court in Roanoke, Virginia.

The suit claims Ferc's process for determining whether a pipeline will actually benefit the public is deeply flawed and violates the Constitution. It also argues that when the Natural Gas Act of

Prices And Differentials For Major Hubs And Selected City Gates

August 7, 2017 — *(US$/MMBtu, Volume-Weighted)*



Selected Daily Differentials

Differential	7/31	8/1	8/2	8/3	8/4
HH-NY	-0.16	-0.05	-0.16	-0.90	-1.02
HH-Chicago	-0.05	-0.02	+0.02	-0.00	-0.07
AECO-CHIC	+1.41	+1.26	+1.28	+1.26	+1.25
AECO-PG&E	+1.87	+1.73	+1.74	+1.75	+1.74

1938 was amended by Congress in 1947, it gave Ferc's predecessor the authority to grant eminent domain — but did so without enough guidance.

"Without boundaries from Congress, Ferc has run wild in the years since and has unconstitutionally sub-delegated the power of eminent domain to private parties seeking private properties," the suit reads.

The complaint also alleges that Mountain Valley survey teams have entered private property without landowners' permission, an act he said represents an unconstitutional "taking" of private property without compensation. Lugar said the surveyors are leaving with valuable information such as soil and water samples for analysis, as well as data on the potential historical or archeological sites.

"They are excluding the landowner from this data and they are not paying," Lugar said.

A Ferc representative told NGW the agency does not comment on pending litigation. A spokesman for Mountain Valley said the company is "aware of the complaint and will, of course, review. As this is pending litigation, however, we are unable to provide additional information at this time."

The suit names as defendants Ferc, acting Commission Chairman Cheryl LaFleur and Mountain Valley Pipeline. Lugar said no hearing date has been set.

Mountain Valley is being built by a joint venture of EQT Midstream Partners; NextEra US Gas Assets; Con Edison Transmission; WGL Midstream; and RGC Midstream. EQT Midstream will operate the pipeline and own a significant interest in the joint venture.

Mountain Valley began the voluntary pre-filing process with Ferc in October 2014. The company said it is hoping to clear these legal hurdles and get the necessary state and federal permits and begin construction before the end of the year, with an estimated in-service date during the fourth quarter of 2018.

John A. Sullivan, Houston

EIA Overestimating Gas Production Growth, Consultancy Kayrros Says

The federal government is overstating how much gas will be produced later this year, according to a French consultancy that employs proprietary modeling to forecast supply and demand trends.

Kayrros projects that domestic output will average 73.7 billion cubic feet per day in October, far lower than the US Energy Information Administration's (EIA) prediction of 76.9 Bcf/d.

EIA data has shown a steady rise in projected shale gas volumes since last fall, led by the Marcellus Shale and augmented by a resurgence of drilling in the Haynesville Shale and growing volumes of associated gas from the tight oil plays in the Permian Basin.

Kayrros sees similar strength in production figures for the Marcellus, where the EIA has forecast production to grow to 19.75 Bcf/d in August after it troughed last October at 17.42 Bcf/d.

But company researchers see greater weakness than the EIA in Texas, the largest producing state, where output declined significantly at the start of the commodity price downturn and has not recovered to date, Kayrros President Antoine Rostand told *Natural Gas Week*.

"Texas currently accounts for 25% of onshore Lower 48 gas production," he said. "Since the price crash of 2014, gas production in Texas took a harder hit than oil and even as oil production started to stabilize in mid-2016, gas continued to drop."

Some of the continued decline in gas production is due to operators shift from the Eagle Ford to the Permian, where wells produce less gas than in the Eagle Ford. And though those Permian wells still have a significant gas component, Kayrros researchers believe the Permian will underperform EIA production estimates for both oil and gas due to bottlenecks in the hydraulic fracturing sector.

Paris-based Kayrros was founded with backing from former Schlumberger CEO Andrew Gould and is seeking to apply some of the same big data and machine learning techniques that have caught

North American Weekly Gas Storage

(Billion Cubic Feet)

Region	Week Ending Jul. 28	Week Ending Jul. 21	% Full	1 Week Chg.	Year Ago	1 Yr Chg.	5 Yr Avg.	5 Yr Chg.
US								
East	651	626	60.9	25	727	(76)	678	(27)
Midwest	754	744	61.4	10	824	(70)	724	30
Mountain	200	197	42.9	3	213	(13)	175	25
Pacific	293	294	70.8	(1)	315	(22)	327	(34)
South Central	1,112	1,129	70.7	(17)	1,211	(99)	1,019	93
Total Lower 48	3,010	2,990	63.3	20	3,289	(279)	2,923	87
Canada								
East	181	175	64.3	6	207	(25)	162	19
West	418	413	85.6	6	457	(38)	377	41
Total Canada	600	588	77.8	12	663	(64)	541	58
Total North America	3,610	3,578	65.3	32	3,952	(342)	3,465	145

Sources: US-EIA. Canada-Enerdata. Values in Bcf unless otherwise noted.

the attention of the industry to make better production forecasts.

The company believes it is able to reach more accurate conclusions about the trajectory of supply and demand, Rostand said, in part by stripping out the underlying biases that could cloud more human-based modeling scenarios. “The model is not bearish or bullish,” he said. “The model sees numbers and then replicates the future based on what we have learned from the past.”

On the oil side, EIA sees US onshore production eclipsing 7.4 million barrels per day by October, while Kayrros said its models show US production at less than 7.1 million b/d by October. “The main theory that we have is that there is more inertia in the ramping-up of the fracking sector,” Rostand said. “We see, obviously, production growth, but probably slower than what most analysts are projecting.”

However, while the operational inertia coming out of the downturn could cause US production to surprise to the downside in the coming months, Rostand warned that the same effect could cause production to surprise to the upside if the rig count steadies or even declines through the second half of the year and into 2018.

“Clearly it takes time for the fracking activity to ramp up,” he said. “At same time, if the number of rigs goes down, production will keep increasing.”

Noah Brenner, Houston

Chesapeake Dialing Back on Drilling; Marcellus Well Produces 61 MMcf/d

While many of its peers are returning rigs to operation, Chesapeake Energy plans to throttle back drilling this year even as it maintains or slightly grows US oil and gas production.

The nation’s second largest gas producer plans to have 14 rigs operating at year’s end, down from 18 currently, and bring on 20 fewer wells than originally planned as the debt-strapped company reins in spending, executives said on a conference call last week.

“We are actively managing our 2017 capital program to the highest return on investments in our portfolio, or reducing spending in certain areas altogether,” CEO Doug Lawler said.

Still, Chesapeake said longer laterals and more efficient completion techniques — particularly in the Marcellus, Utica and Eagle Ford Shales — may allow output to tick up in the second half of the year.

The company is maintaining its previous full-year guidance of 541,000-562,000 barrels of oil equivalent per day on spending of $2.1 billion-$2.5 billion, including 2.38 billion to 2.47 billion cubic feet per day of gas. Chesapeake produced roughly 2.3 Bcf/d of gas in the second quarter.

While turning a profit for the second straight quarter after years of losses, Chesapeake continues to battle a hefty debt load accumulated during the early part of this decade under former CEO Aubrey McClendon (NGW Dec.12’16). The company said it carried $9.7 billion as of Jun. 30, down from $10 billion as of Dec. 31.

The company continues to aggressively divest noncore assets to shave down debt. Year-to-date, Chesapeake has sold or agreed to sell producing properties to various private buyers for around $360 million, not including proceeds from the company’s Haynesville Shale divestitures that closed earlier this year.

On the conference call, Lawler repeatedly touted what may be the company’s biggest accomplishment during the second quarter: its giant McGavin E WYO 6H well in the Marcellus. The well produced at a peak of more than 61 million cubic feet per day, a company record, from a 10,429-foot lateral.

Given those results, Chesapeake expects to place up to 40 Marcellus wells into production in the second half of 2017, up from 11 in the first half.

Lawler said the well cost $8.5 million, but “we believe we can get that cost down as we go forward.”

Mark Davidson, Washington

Natural Gas Futures

Trading Dates: July 31-August 4

New York Mercantile Exchange (NYMEX) Henry Hub

	– Monday –		– Tuesday –		– Wednesday –		– Thursday –		– Friday –		Week’s	Open
	Jul 31	Volume	Aug 1	Volume	Aug 2	Volume	Aug 3	Volume	Aug 4	Volume	Low-High	Interest
Sep 2017	2.794	176,226	2.819	151,158	2.811	111,069	2.800	125,787	2.774	—	2.753-2.900	344,291
Oct 2017	2.834	72,136	2.855	63,742	2.851	44,443	2.844	55,621	2.817	—	2.799-2.932	189,665
Nov 2017	2.920	29,376	2.936	32,171	2.936	22,376	2.933	25,022	2.906	—	2.886-3.019	92,852
Dec 2017	3.079	26,283	3.093	26,465	3.094	19,433	3.092	15,150	3.065	—	3.050-3.168	77,123
Jan 2018	3.173	39,097	3.182	28,420	3.184	26,520	3.183	28,267	3.158	—	3.143-3.267	124,717
Feb 2018	3.164	14,630	3.171	9,842	3.175	9,804	3.172	9,699	3.149	—	3.132-3.255	55,027
Mar 2018	3.119	28,939	3.127	17,040	3.132	16,421	3.130	14,952	3.109	—	3.093-3.192	82,136
Apr 2018	2.795	25,301	2.806	15,976	2.826	14,990	2.835	13,197	2.822	—	2.782-2.849	104,623
May 2018	2.769	6,538	2.780	8,524	2.802	12,874	2.813	8,128	2.802	—	2.755-2.823	42,649
Jun 2018	2.795	4,023	2.804	1,845	2.827	5,809	2.838	2,265	2.829	—	2.782-2.842	26,666
Jul 2018	2.821	3,030	2.828	3,239	2.852	6,402	2.863	1,684	2.856	—	2.806-2.869	26,059
Aug 2018	2.826	2,120	2.833	1,857	2.857	4,258	2.868	1,523	2.861	—	2.811-2.873	23,325
Sep 2018	2.806	1,237	2.814	1,114	2.838	2,155	2.849	565	2.841	—	2.790-2.856	19,623
12-Mth Strip	**2.924**	**—**	**2.936**	**—**	**2.946**	**—**	**2.948**	**—**	**2.929**	**—**	**—**	**—**
2017 Strip	3.097	—	3.103	—	3.102	—	3.101	—	3.092	—	—	—
2018 Strip	2.915	—	2.924	—	2.942	—	2.950	—	2.938	—	—	—
Total Volume	—	**436,912**	—	**369,688**	—	**302,098**	—	**306,821**	—	—	—	—

Antero ...
(continued from page 7)

annual growth to 30%, below the company's previous guidance of 33% to 35%.

Walker cited two main drivers behind the change, but chiefly the underperformance of its Terryville wells in North Louisiana.

"Using round numbers, the underperformance of these wells and the corresponding frack hits to offset production accounts for the loss of approximately $75 million a day for the year. By itself, this would explain a 5% difference in growth for 2017," Walker said.

"Despite the early North Louisiana setback, we were still expecting to hit our full-year guidance of 33% to 35% growth, as our Marcellus Shale wells have continued to perform well, in many cases, significantly above our average type curves. However, we've been hampered by delays in obtaining the necessary permits."

That regulatory setback caused 32 Marcellus wells to be delayed an average of 25 days, Walker explained.

"This represents 800 combined sales days and approximately $75 million a day of production for the year, coincidentally very similar to the underperformance from North Louisiana.

So, we could have withstood some underperformance in the early North Louisiana production or we could have withstood some delays in Pennsylvania permitting, but the cumulative effect of both results in a reduction to our annual guidance."

But Range is back on track in the Marcellus, where the permitting issue has been resolved, he said. "And we anticipate significantly better well results in North Louisiana for the second half of the year."

Seaport Global Securities noted that the "disappointing" Terryville results stemmed from Range changing its completion design so it used 40% less fluid per foot while not backing off on the amount of proppant. It had hoped to lessen the frack impact on offset wells drilled by a previous operator. nearby.

The remaining 23 Terryville wells to be completed in the second half of this year will use the original completion design, Seaport said. "Range Resources also noted the option to shift capital back to the Marcellus if [second-half] results disappoint."

As for Antero, the company is raising its 2017 net production guidance by 3% from a range of 2.16 Bcf/d to 2.25 Bcfe/d to a band of 2.25 Bcf/d to 2.3 Bcfe/d. Antero attributes the increase primarily to advanced completion techniques that are significantly improving the estimated ultimate recovery (EUR) per well.

Antero reported its completions have used an average of 2,045 pounds of proppant per foot so far this year, yielding "encouraging results with initial wellhead EURs ranging from 1.9 [Bcf] to 2.7 Bcf per thousand feet of lateral as compared to the company's historical 1.7 Bcf per thousand feet type curve."

Antero brought 29 Marcellus wells and five Utica Shale wells on line during the second quarter with an average lateral length of 9,380 feet and 11,222 feet, respectively. That includes a 17,380-foot super lateral in the Utica that was drilled in 12 days and should enter sales in the third quarter.

Antero is operating four drilling rigs and three completion crews in the Marcellus and two drilling rigs and two completion crews in the Utica.

Raymond James analysts said Antero's incorporating "leading-edge completion designs" to increase production is no surprise. "With a consistent track record of beat and raise quarters, Antero inevitably remains a high expectation story, particularly as it continues to deliver well results above corporate type curves," they said.

Antero also reports strides in reducing average per-well drilling days in the Marcellus from 15 in 2016 to 12 in the second quarter of this year, despite drilling longer laterals. Antero's pad sizes have also grown and it is now developing a 12-well pad, as well as a 14-well pad in the Marcellus.

As a result of efficiencies, the company is maintaining a $1.3 billion capital expenditure budget even as it raises production guidance.

"Our ability to grow production 25% year-over-year while essentially holding capital spending flat speaks to our material gains in capital efficiency, especially in the face of the commodity down cycle," said Antero President and Chief Financial Officer Glen Warren.

"These gains are driven by a combination of drilling efficiencies which we have continued to achieve and the operational momentum we have been able to sustain ... due to our ability to lock in volumes and pricing through our hedge book and firm transportation portfolio."

Warren said the company expects 20% to 22% production growth in 2018 while keeping its drilling and completion budget at or below 2017 levels.

Nonetheless, second-quarter earnings were still in the red, though much improved year-on-year. Antero reported a net loss $5 million, or 2¢ per share, compared to a net loss of $596 million, or $2.12/share, in the 2016 second quarter. Antero earnings continued to suffer from to takeaway capacity restraints in the Northeast, a condition expected to dramatically improve by this time next year (NGW Jul.31'17).

Antero's average gas price before hedging increased to $3.15 per thousand cubic feet, a 63% rise from the 2016 second quarter. However, its realized gas price after hedging was $3.53/Mcf, an 18% decrease from 2016.

Tom Haywood, Houston

Financing, Offtake Contracts Remain Elusive for US LNG Export Projects

A second wave of US LNG export projects has been making steady progress lining up regulatory approvals and engineering contracts. However, key endgame components — including financing and offtake agreements — generally remain elusive in a world that is awash in LNG.

Adding to the uncertainty, US LNG suppliers were not expecting Qatar's recent announcement of a 30 million ton per year (4 billion cubic feet per day) expansion of its liquefaction capacity in an effort to defend its share of the global market (NGW Jul.10'17).

The US currently has three LNG liquefaction trains with a combined capacity of 13.5 million tons per year (1.9 Bcf/d) up and running — all of them at Cheniere Energy's Sabine Pass facility in Louisiana. The first wave of US LNG export projects also includes another 12 trains that have been approved and are already under construction. These will increase US liquefaction capacity to about 67 million tons/yr (9.5 Bcf/d) by 2020.

The second wave is led by several projects that have not yet proceeded to construction but have received full approval from the Federal Energy Regulatory Commission (Ferc) and the US Department of Energy. These include a further expansion at Sabine Pass as well as expansions at Corpus Christi and Cameron.

They also include the Magnolia LNG project in Louisiana — backed by Australia's LNG Ltd. — and the last two planned conversions of brownfield LNG import plants: Lake Charles LNG in Louisiana and Golden Pass LNG in Texas. Delfin LNG — a proposed floating liquefaction project — has also received the necessary regulatory approvals. Altogether, these projects represent an additional 69 million tons/yr (9.8 Bcf/d) of liquefaction capacity.

Within this second wave of projects, the expansions of existing plants are expected to be the first to go to a final investment decision (FID). These are likely to be the lowest-cost projects because they require only additional liquefaction equipment and almost none of the other expenses associated with greenfield projects (NGW Mar.13'17).

However, public disclosures by Cheniere indicate that over the last two years it has made little progress in marketing the production from a proposed sixth train at Sabine Pass and a proposed third train at Corpus Christi.

Sempra is in a similar position with its plans for two additional trains at the Cameron plant: no offtake contracts have been announced in the year since permitting was finalized. As for expansions that have not yet been permitted, a proposed fourth train for the Freeport project is currently in the pre-filing phase at Ferc, as are a planned fourth and fifth train at Corpus Christi.

The Lake Charles and Golden Pass LNG projects are also fully permitted. Like Sabine Pass, they were originally conceived as LNG import facilities before the shale boom turned a gas shortage in the US into a surplus. They were also among the first LNG export projects to be proposed, but this has not hastened progress toward FIDs.

Both projects have powerful backers, but it is unclear how committed they are to pushing them forward. Lake Charles LNG is backed by Energy Transfer and Royal Dutch Shell, while South Korea's Kogas has also recently expressed an interest in participating.

However, Shell already has significant exposure to US LNG and appears wary about adding more. It already has commitments to use liquefaction capacity at Sabine Pass and take LNG from Elba Island.

Golden Pass LNG — owned by Qatar Petroleum (70%) and Exxon (30%) — received its export permit in April and has said it is targeting an FID by 2021. But it is unclear how Qatar's pending expansion of its domestic liquefaction capacity will impact plans for Golden Pass.

Magnolia LNG is a fully permitted project with a planned capacity of 8 million tons/yr (1.1 Bcf/d). It recently lined up a $1.5 billion financing commitment from Stonepeak Infrastructure Partners and extended an engineering, procurement and construction contract for the project through Dec. 31. However, it has also said that it still needs to finalize offtake agreements.

In a regularly scheduled monthly status report submitted to Ferc, Magnolia said no construction work was planned for August. "Current global energy market conditions have extended the time necessary to obtain binding LNG offtake agreements required to underpin the construction program for the Magnolia LNG liquefaction project," the company said. "Consequently, Magnolia LNG will not commence any construction activities until it achieves a final investment decision."

Michael Sultan, Washington

A version of this article originally ran in NGW sister publication EI Finance.

Comparative Fuel Prices

(Cash Market)

Augusat 7, 2017

Natural Gas	$/MMBtu	Comparative Fuel	Fuel Price	MMBtu equivalent
Appalachia				
App Pool Dvld Util	$2.01	Central Appalachian Coal	$55.00/ton	$2.29
East Coast				
NY City Gate	$1.91	Heating Oil No. 2*	154.16¢/gal	$11.12
		Residual 0.30%	$52.93/bbl	$8.42
		Residual 1.00%	$47.93/bbl	$7.62
Gulf Coast				
TX Onshore Dlvd	$2.88	Heating Oil No. 2*	144.50¢/gal	$10.42
		Residual 0.70%	$47.72/bbl	$7.59
Louisiana Onshore	$2.83	Residual 3.00%	$46.16/bbl	$7.34
		WTI Cushing	$49.52/bbl	$8.54

Notes: (1) Residual=Residual Fuel Oil, priced exclusive of taxes; (2) WTI=West Texas Intermediate crude oil; (3) % = % of sulfur content. *Average sulfur content = 0.2%-0.5%.

Sources: Gas: Natural Gas Week; all prices volume-weighted. Oil: The weekly average of The Oil Daily's cash price postings.

With Cheap Gas Prevalent, Utilities Pull Plug on S.C. Nuclear Reactors

The decision by two South Carolina utilities to cancel construction of a pair of reactors at the V.C. Summer plant is bad news for the nuclear industry and casts doubt on the future of the only other US nuclear newbuilds in the past 30 years: the two-unit Vogtle project in neighboring Georgia.

It also raises questions about state and federal subsidies that allowed both projects to proceed and that now permit one of the Summer plant owners, regulated Scana subsidiary SCE&G, to continue collecting billions from ratepayers over the next 60 years to cover abandonment costs.

When the two 1,117-megawatt units were cleared for construction, nuclear power seemed to be undergoing a renaissance in the US, with about a dozen projects being proposed. But almost all of them were sidelined by cheap and abundant supplies of shale gas, leaving just Georgia Power's Vogtle site in northern Georgia and South Carolina Electric & Gas' V.C. Summer site in South Carolina.

Together they could have displaced as much as 750 million cubic feet per day of gas demand. That's now down to 375 MMcf/d — and even that is in doubt (NGW Mar.6'17).

In February, Toshiba's now bankrupt Westinghouse unit, which was in charge of constructing the AP1000 reactors at Vogtle until last week and had been at V.C. Summer, took a $6.1 billion nuclear-related impairment because of ballooning costs. This underscored the difficulty of financially justifying what was left of the US nuclear newbuild, when natural gas plants could be constructed and run at less than half the levelized cost for the life of the project, according to data compiled by NGW sister publication *EI New Energy.*

While V.C. Summer is dead, ratepayers could remain on the hook thanks to the state's Base Load Review Act (BLRA), under which SCE&G is allowed to collect billions in reactor construction financing costs with a guaranteed rate of return that started at 11% and has since gradually declined to 10.25%.

Crucially, the move also allows the utility to recoup abandonment costs estimated at $4.9 billion at the same rate of return — effectively earning income for decades for its costly mistake.

Scana Chief Financial Officer Jimmy Addison told analysts in a call last week the utility will write off abandonment costs over six decades, eventually netting out some $2.2 billion once SCE&G receives its $1.1 billion share of the Toshiba contract guarantee and realizes tax deductions.

While former Nuclear Regulatory Commissioner Peter Bradford said this amounts to ratepayers having to pay "a profit in the hundreds of millions for utility mistakes," Addison portrayed the amortization strategy as partly aimed at softening the blow to present-day residential ratepayers who have seen rates climb 18% since 2012 because of the Summer project.

Making this even more frustrating to regulators and ratepayers alike, the power V.C. Summer would have produced wasn't even needed given a "slowed" load forecast, efficiency gains and plummeting natural gas prices.

Santee Cooper, SCE&G's 45% project partner, had already lost at least one major wholesale customer to a utility offering lower rates, and its own rates were slowly climbing thanks in part to the Summer project. Meanwhile, SCE&G estimated a $9.9 billion total cost for completing the two units and $8.2 billion for completing one unit and abandoning the other.

Its projected in-service dates — December 2022 for Unit 2 and March 2024 for Unit 3 — were earlier than Santee's but still well past the current end-2020 deadline for securing its portion of $2.2 billion in federal production tax credits over eight years.

Scana CEO Kevin Marsh claimed that completing one reactor and "supplementing our remaining generation needs with a natural gas-fired facility resulted in a combined cost that was less than the fixed-price option for the two new nuclear units," although he conceded it would be "subject to significant challenges."

This was hypothetical, though, since it had long been clear that the state didn't need an additional 2.2 gigawatts of new nuclear capacity. When SCE&G realized the project wouldn't be completed as originally promised before 2020, it secured a gas supply contract, but for only 300 MW, and that was enough to keep its available capacity at the high end of its 14%-20% margin range through the end of 2019, when the contract ends.

There is no obvious rush to replace either the abandoned nuclear capacity or even look for new supplies until after 2019, when it could move forward on adding new gas-fired capacity with a two- to three-year timeline for the project, Marsh told analysts.

"The flexibility of adding a gas unit is we could add it when we need it without going over the reserve margin," he said. "I don't think it's important to go in immediately in 2020, it might come on in 2021."

Stephanie Cooke, Washington, and Tom Haywood, Houston

Spot Electricity Trading

Trading Dates: July 31-August 4, 2017

POINT	Avg. Price This Week	Avg. Price Last Week	Change	Year Ago	Month Ago
COB	$89.60	$41.00	$48.60	$37.00	$32.50
ERCOT	34.60	41.20	-6.60	56.67	30.25
Mid-Columbia	81.00	37.20	43.80	35.33	23.50
NEPOOL	34.20	26.20	8.00	58.33	35.25
Palo Verde	77.20	32.60	44.60	35.00	37.00
PJM-West	33.20	30.40	2.80	47.67	38.75

Notes: (1) Prices in $/MWh. (2) Prices are for next day peak delivery. *Sources: Energy Intelligence and wire reports.*

DTE Applies to Construct 1,100-MW Gas-Fired Power Plant in Michigan

DTE Energy has applied to the Michigan Public Service Commission (MPSC) to build a 1,100 megawatt gas-fired power plant in East China Township. The project will cost $1 billion, with DTE expecting to begin operation by 2022. The new gas-fired plant, which could burn up to 185 million cubic feet of gas per day, will fill some of the gap created when three of the company's Michigan coal-fired power plants – River Rouge, St. Clair and Trenton Channel – are removed from service in the 2020-23 timeframe.

Trevor Lauer, president of subsidiary DTE Electric, said the project represents one of many steps DTE is taking to achieve its goal of reducing carbon emissions by 30% by the early 2020s and more than 80% by 2050. DTE said it will achieve these reductions by adding 4,000 MW of renewable energy from wind and solar farms, transitioning its 24/7 power sources from coal to gas, and continuing to operate its zero-emission Fermi 2 nuclear power plant. Long-term, DTE plans to produce over three-quarters of its power from renewable energy and efficient gas-fired facilities.

The MPSC has 270 days to review DTE's request. If approved, the new plant would be the most efficient in Michigan, the company said. DTE selected the East China Township site because it already has in place electric, gas and other infrastructure.

The Oklahoma Corporation Commission (OCC) and the Oklahoma Geological Survey (OGS) are investigating an earthquake swarm last week near the town of Edmond that included one tremor registering a magnitude 4.2. An OCC spokesman said the quakes "have been clustered close together in an area where there is a known fault. There are no Arbuckle disposal wells at or very close to the location." Restrictions were placed on several wastewater disposal wells near Edmond that were pumping into the Arbuckle formation. State officials have said they have received no reports of damage to oil or gas infrastructure in the area. The US Geological Survey and the OGS said that since Aug. 2, seven earthquakes of magnitude 3.0 to 3.5 were felt in the same area as the 4.2 tremor, about four miles east-northeast of Edmond.

A ruptured gas line is believed responsible for an explosion and fire last week that ripped through a private Christian school in Minneapolis that left two people dead and nine hurt. Local, state and federal regulators were on the scene late last week trying to determine the events that led up to the explosion Aug. 2 at the Minnehaha Academy. School officials said contractors had been working on a gas line and a metering station leading into the school before the blast.

Legal & Legislative:

The Republican-controlled Pennsylvania Senate has passed a bill that would help cover the state's budget shortfall by imposing new taxes on natural gas producers and consumers, as well as the electricity and telecommunications industries. The plan must still be approved by the state's GOP-ruled House of Representatives.

The bill would set a severance tax of 2¢ per thousand cubic feet on gas production, which supporters said would generate $80 million this year. In addition, it calls for levying a 5.7% gross receipts tax on home heating bills that supporters said would raise $400 million for state coffers. The tax hikes put Pennsylvania at a competitive disadvantage with other gas-producing states seeking capital investment, according to Daniel J. Weaver, executive director of the Pennsylvania Independent Oil & Gas Association. "Picking on an individual segment of our economy to balance the budget should offend every Pennsylvanian, but singling out one having financial troubles is mind-boggling."

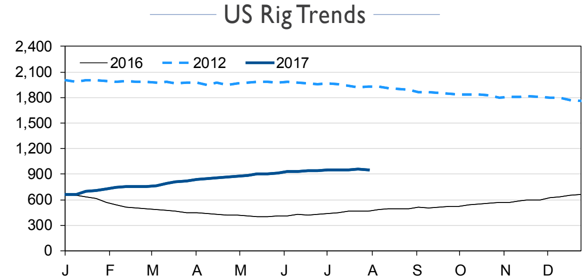
The North Dakota Public Service Commission (PSC) has approved a siting permit for the Wild Basin Gas Plant in McKenzie County. The PSC said Oasis Midstream Services applied for the permit to expand the capacity of its existing Wild Basin plant and crude handling facility that has a current daily capacity of processing 80 million cubic feet of gas and stabilizing up to 60,000 barrels of crude. Oasis plans to increase the capacity of the plant to process up to 345 MMcf/d, stabilize

Baker Hughes Rig Count

Week Ended August 4, 2017

Region	Current Week	Previous Week	Year Ago
Total US	**954**	**958**	**464**
Land	937	934	443
Inland Waters	0	0	4
Offshore	17	24	17
Gulf of Mexico	16	23	17
Total Canada	**217**	**220**	**122**
US Rigs Exploring for			
Oil	765	766	381
Gas	189	192	81
Unspecified	0	0	2
Drilling Direction			
Directional	74	77	44
Horizontal	807	810	362
Vertical	73	71	58
US Rigs by State			
California	13	13	6
Colorado	37	37	20
Louisiana	51	49	26
New Mexico	60	61	30
North Dakota	53	54	28
Ohio	28	28	13
Oklahoma	132	134	61
Pennsylvania	34	34	15
Texas	466	462	216
Wyoming	26	26	8
Major Oil Basins			
Cana Woodford	60	63	29
DJ Niobrara	30	29	18
Eagle Ford	78	76	37
Permian	379	379	177
Williston (Bakken)	53	54	28
Major Gas Basins			
Marcellus	46	46	21
Haynesville	45	45	15

US Rig Trends



up to 80,000 barrels/d and add 150,000 barrels of crude storage to accommodate the increased production.

Industry News:

The Culberson County [Texas] Groundwater Conservation District has approved a plan to allow a company to drill into a desert aquifer near Van Horn, build a 60-mile pipeline and ship up to 5.4 million gallons of water per day for use in hydraulic fracturing operations in the Permian Basin. Texas oilman Dan Allen Hughes is developing the project, which is known as Agua Grande.

Fracking operations need millions of gallons of water per well, and supporters have said this pipeline will cut down on heavy truck traffic as the water is usually trucked to oil and gas well sites. But a coalition of greens, ranchers, farmers and residents have said the project will take water from the Capitan Reef aquifer and away from cattle and crops and could damage a spring-fed pool at the nearby Balmorhea State Park. Although no suits have been filed, several groups have threatened to seek injunctions to stop the project.

Hughes' venture is one of three that have recently announced plans to develop water resources for use in the Permian Basin. Wolfcamp Water Partners has leased 31,000 acres in the Davis Mountains and drilled into the Capitan Reef aquifer, the same one Agua Grande is using. Wolfcamp Water Partners is planning to pump about 8 million gallons/day and expects to begin drilling its wells and building a 65-mile pipeline and catch basins by the end of the year.

The third company is The Woodlands, Texas-based Layne Christensen. The company has completed a high-capacity, 20-mile, 22-inch water pipeline and infrastructure system serving energy producers in the Delaware Basin. The system is anchored by nearly 1,000 acres of company-owned, highly-productive water-producing land near Pecos, Texas. The system has a delivery capacity of 100,000 barrels per day of non-potable water.

Energy Transfer Partners is selling a 32.44% stake in a firm associated with the Rover gas pipeline project to Blackstone funds for about $1.57 billion. Blackstone Energy Partners and Blackstone Capital Partners will buy a 49.9% interest in ET Rover Pipeline, or HoldCo, which owns a 65% interest in Rover. Energy Transfer and HoldCo are constructing the pipeline and will operate it once it goes into service, possibly by late summer. The 700-mile Rover system is designed to transport 3.25 billion cubic feet per day of Marcellus and Utica Shale gas to markets across the eastern US and into Canada. But the project has run into a host of problems: West Virginia's Department of Environmental Protection has ordered the project to stop some work, citing environmental concerns; Ohio regulators have filed sanctions for violations of environmental rules; and federal officials have ordered a moratorium on new horizontal drilling activity until the cause of major spills during construction can be determined.

Samson Resources is selling almost all of its gas assets in East Texas and North Louisiana to an affiliate of Rockcliff Energy for $525 million. The assets consist of 210,000 net acres currently producing about 90 million cubic feet per day. Samson Resources II is the latest incarnation of Samson Resources Corp., which filed for Chapter 11 bankruptcy protection in 2015.

Gas Price Trends

($/MMBtu)

	CALIFORNIA		ROCKY MTNS	NEW MEXICO	TEXAS			MID-CONT.	LOUISIANA			MID-WEST	APPA-LACHIA	SOUTH-EAST	NEW ENGLAND
	South	North			Gulf Coast Offshore	Central Onshore	West		Gulf Coast Offshore	Gulf Coast Onshore	Northern Louisiana				
Aug 07, 2017															
Inter (Well)	—	—	2.37	2.36	2.66	2.65	2.47	2.38	2.64	2.65	2.63	—	1.82	2.61	—
Intra (Well)	2.85	—	2.34	—	2.67	2.67	2.47	2.36	2.64	2.65	2.62	—	—	—	—
Dlvd (Pipe)	2.87	2.85	2.49	2.53	2.73	2.73	2.54	2.48	2.71	2.72	2.70	2.71	1.93	2.76	1.91
Dlvd (Util)	2.87	2.85	2.82	2.68	—	2.88	2.62	2.73	—	2.83	2.84	2.73	2.01	3.21	2.33
July 2017															
Inter (Well)	—	—	2.44	2.43	2.80	2.81	2.53	2.52	2.78	2.81	2.78	—	2.06	2.78	—
Intra (Well)	2.77	—	2.41	—	2.81	2.83	2.53	2.50	2.78	2.81	2.77	—	—	—	—
Dlvd (Pipe)	2.79	2.81	2.56	2.60	2.87	2.89	2.60	2.62	2.85	2.88	2.85	2.76	2.17	2.93	2.35
Dlvd (Util)	2.79	2.82	2.89	2.75	—	3.04	2.68	2.87	—	2.99	2.99	2.79	2.25	3.33	2.58
Second Quarter 2017															
Inter (Well)	—	—	2.56	2.50	2.89	2.92	2.61	2.67	2.90	2.91	2.87	—	2.43	2.86	—
Intra (Well)	2.80	—	2.53	—	2.90	2.94	2.61	2.65	2.90	2.91	2.86	—	—	—	—
Dlvd (Pipe)	2.82	3.02	2.68	2.67	2.96	3.00	2.68	2.77	2.97	2.98	2.94	2.91	2.54	3.01	2.72
Dlvd (Util)	2.82	2.97	3.01	2.82	—	3.15	2.76	3.02	—	3.09	3.08	2.93	2.62	3.45	2.92
First Quarter 2017															
Inter (Well)	—	—	2.72	2.61	2.83	2.82	2.68	2.71	2.79	2.86	2.83	—	2.60	2.81	—
Intra (Well)	3.03	—	2.69	—	2.84	2.84	2.68	2.69	2.79	2.86	2.82	—	—	—	—
Dlvd (Pipe)	3.05	3.08	2.84	2.78	2.90	2.90	2.75	2.81	2.86	2.93	2.90	2.90	2.71	2.96	3.56
Dlvd (Util)	3.05	3.06	3.17	2.93	—	3.05	2.83	3.06	—	3.04	3.04	2.92	2.79	3.36	4.42
2016 Average															
Inter (Well)	—	—	2.20	2.07	2.30	2.32	2.24	2.22	2.32	2.34	2.26	—	1.77	2.29	—
Intra (Well)	2.53	—	2.17	—	2.31	2.34	2.24	2.20	2.32	2.34	2.25	—	—	—	—
Dlvd (Pipe)	2.55	2.50	2.32	2.24	2.37	2.40	2.31	2.32	2.39	2.41	2.33	2.41	1.88	2.44	2.45
Dlvd (Util)	2.55	2.51	2.65	2.39	—	2.55	2.39	2.57	—	2.52	2.47	2.43	1.96	2.89	3.03
August 2016															
Inter (Well)	—	—	2.46	2.43	2.63	2.61	2.52	2.49	2.62	2.66	2.62	—	1.69	2.59	—
Intra (Well)	2.80	—	2.43	—	2.64	2.63	2.52	2.47	2.62	2.66	2.61	—	—	—	—
Dlvd (Pipe)	2.82	2.96	2.58	2.60	2.70	2.69	2.59	2.59	2.69	2.73	2.69	2.72	1.80	2.74	2.40
Dlvd (Util)	2.82	2.94	2.91	2.75	—	2.84	2.67	2.84	—	2.84	2.83	2.73	1.88	3.19	3.02

Notes: (1) This table presents historical data from the Gas Price Report. (2) All prices are volume-weighted. (3) The price points that made up the "Texas Central" and "Texas Gulf Coast, Onshore" composites in the Gas Price Trends table have been incorporated into the new "Texas Central Onshore" composite. The "Texas Central" composite will be eliminated.

LNG Woes Not Stopping TransCanada From its Aggressive Expansion Plans

The recent cancellation of the Pacific NorthWest LNG (PNW LNG) project in British Columbia won't hinder TransCanada's aggressive pipeline expansion plans, company executives told analysts and investors last week, as growing domestic demand will justify the new capacity.

The Calgary-based pipeline giant intends to expand its gas network across North America as well as continue with several major oil systems, executives said in discussing second-quarter financial results (NGW Jul.31'17). The company announced 400 million cubic feet per day of new long-term contracts into its Gas Transmission Northwest (GTN) system and a 2 billion cubic feet per day expansion on its NGTL system in Alberta.

TransCanada's near-term capital program totals C$24 billion (US$19 billion), much of which will be funded through internally generated cash flow, said Don Marchand, chief financial officer. Most of the funds are slated for gas projects in Canada, but the largest single venture is the C$7 billion Keystone XL oil pipeline from Hardisty, Alberta, to Steele City, Nebraska.

Even without PNW LNG, TransCanada has plenty of work in the Western Canadian Sedimentary Basin (WCSB), the nation's primary source of gas. Ten other shippers have signed long-term agreements to gain access to the NGTL system, officials said. The Montney unconventional play along the Alberta-British Columbia border has ample gas that can flow south into the US Pacific Northwest and then California via GTN, or to the east through NGTL across Alberta. From there it can flow into the US Midwest on Northern Border Pipeline or to eastern Canada on the TransCanada Mainline.

On the other side of the continent, some pipeline companies have faced challenges expanding from the Marcellus Shale into the underserved New England market. But TransCanada doesn't anticipate such obstacles, said Karl Johannson, president of the company's Canadian and Mexican gas operations.

That is in part because TransCanada plans to use existing rights of way along its Iroquois Pipeline and Portland Natural Gas System that are connected to its Canadian Mainline for expansion in the New York and New England regions, Johannson told analysts. The company already has relationships with local governmental agencies, which should ease the permitting process.

On the Portland system, for example, "we don't have anything signed up to announce right now, but we don't think it's been a secret that we've been in that area talking to customers there. So, we're quite optimistic."

Capacity on the Portland system can be increased with the addition of compression rather than building new pipe. Marcellus gas can move through TransCanada's US affiliates such as Columbia Gas Transmission and ANR Pipeline to Dawn, Ontario, for transportation through the Canadian Mainline to an interconnect with Portland at the US border in New England.

TransCanada will use the same strategy on the Iroquois system, though it is not as well developed, Johannson said. The pipeline will use similar techniques in Canada as it continues to interconnect and expand its systems between the US and Canada.

Company executives stressed that the NGTL system expansion wasn't contingent on construction of any LNG projects in British Columbia, although TransCanada could have served as many as three. Besides PNW LNG, the company has a contract to deliver feedstock and fuel gas to the Royal Dutch Shell-led LNG Canada project at Kitimat, B.C.

As part of its agreement with Progress Energy, the Canadian affiliate of Malaysia's Petronas, TransCanada will be reimbursed for the full costs and carrying charges incurred to advance the PNW LNG project. TransCanada continues to work with Shell and LNG Canada and will continue to be compensated while the project partners determine their future course of action.

"As a result, we expect to receive approximately C$80 million in September, followed by quarterly payments of approximately C$7 million," CEO Russ Girling said. "But just to be perfectly clear, this project continues to advance, and we continue to work with LNG Canada and others toward a final investment decision."

The Exxon Mobil/Imperial Oil WCC LNG venture at Prince Rupert is still in the early stages of evaluation and does not have an arrangement with a pipeline company. Meanwhile, drilling activity in the WCSB has proved far beyond expectations in the past five years, Girling said. "It appears that there's a lot more gas than anybody ever anticipated that can be recovered at an ever-decreasing cost."

TransCanada reported significantly higher earnings for the second quarter of C$881 million on revenues of C$3.2 billion, compared with earnings of C$365 million on revenues of C$2.8 billion a year earlier.

Rig count: There were 203 rigs drilling for natural gas and oil in Western Canada as of Jul. 31, three rigs more than last reported by the Canadian Association of Oilwell Drilling Contractors (CAODC). During the same period a year ago, CAODC reported 105 rigs were drilling in the region. A total of 634 rigs were available in the region, unchanged from CAODC's previous report.

Working gas in all Canadian storage was reported to be 77.8% of capacity as of Jul. 28, with an 11.6 Bcf increase from the week before, according to the most recent Canadian Enerdata gas storage survey. A total of 599.5 Bcf of gas was in storage last week; capacity is 770.4 Bcf. Stores were 86.2% full a year ago.

Working gas levels in facilities west of the Manitoba-Saskatchewan border rose to 418.4 Bcf, up from 412.8 Bcf the week before; capacity is 488.6 Bcf. Working gas levels east of the border rose to 181.1 Bcf, up from 175 Bcf the week before; capacity is 281.8 Bcf.

The composite spot import price this week is US$2.37MMBtu for gas leaving Canada and entering the US through six border-crossing points. *Natural Gas Week*'s Aug. 8, 2016, average for Canadian exports was US$2.65/MMBtu.

Barbara Shook, Houston

In Victory for Ineos, UK Court Cracks Down on Anti-Fracking Protesters

Anti-fracking protesters in the UK could be fined or imprisoned if found to be unlawfully interfering with shale gas sites owned by chemical group Ineos after the company won a ruling to protect its exploration and production activities.

Ineos said it obtained a series of injunctions from the High Court on Jul. 31, stating that any obstruction of Ineos' shale business units would be considered as a contempt of court, extending to any business or persons across Ineos' supply chain. The injunctions are an interim measure until a return hearing to be held in September.

The preliminary ruling is stronger than any existing legal protections for onshore oil and gas explorers against protesters, who have been intensifying their demonstrations against fracking sites. Last month, a shale gas drilling rig owned by UK explorer Cuadrilla, intended to be used at the company's Preston New Road site, was seriously vandalized. Located in northwestern England, the site has seen a constant stream of protests.

"At Ineos we will not stand for intimidation, threats or risks to safety. Today's High Court injunctions will protect our sites, our people, our suppliers and the public from the militant activists who try to game the system and cause maximum disruption," Ineos Shale Operations Director Tom Pickering said in a statement.

The injunctions detail a number of unlawful activities that would qualify as being in contempt of court, including trespassing on Ineos shale sites and offices, and blocking the highway around the sites. Actions such as "lock-ons" and "slow-walking" would also be classified as interference, harassment or conspiring to injure people and business operations.

Breaching the injunction could lead to imprisonment, fines or seizure of assets, with the company also being able to recover damages from any individual being in contempt of court.

The UK Onshore Oil & Gas (UKOOG) industry group welcomed the ruling, adding that a small minority of protesters was putting people at risk at shale sites. "Everyone, correctly so, has the right to protest peacefully, and the injunction served today only reinforces rules already in place, namely that criminal action does not constitute lawful protest," UKOOG CEO Ken Cronin said.

Environmental activists have expressed concern over the implications of the legal proceedings for the right to protest, particularly as Ineos has become more litigious. "Following six years without fracking in the UK, this latest move smacks of desperation," Friends of the Earth campaigner Guy Shrubsole told NGW sister publication *International Oil Daily*. "The fracking industry is in crisis, and they're growing more extreme in their tactics."

Jaime Concha, Copenhagen

Canadian Price Report

($US/MMBtu and $Can/MMBtu)

	British Columbia			Alberta		Manitoba	Ontario	
	Total Province	NW Sumas Border	Kingsgate Border	AECO Hub	Empress Border	Emerson Border	Dawn Hub	Niagara
August 7, 2017								
Wellhead U.S. $	2.28	—	—	—	—	—	—	—
Canadian $	2.90	—	—	—	—	—	—	—
Delivered to Pipe U.S.$	2.42	2.49	2.36	1.46	1.51	2.41	2.77	—
Canadian $	3.04	3.12	2.97	1.83	1.89	3.02	3.48	—
July 2017 Average								
Wellhead U.S. $	1.98	—	—	—	—	—	—	—
Canadian $	2.56	—	—	—	—	—	—	—
Delivered to Pipe U.S.$	2.12	2.18	2.06	1.43	2.01	2.67	2.90	—
Canadian $	2.70	2.77	2.62	1.81	2.55	3.39	3.68	—
2nd Quarter 2017 Average								
Wellhead U.S. $	2.29	—	—	—	—	—	—	—
Canadian $	3.13	—	—	—	—	—	—	—
Delivered to Pipe U.S.$	2.43	2.46	2.40	2.01	2.01	2.72	3.11	3.19
Canadian $	3.27	3.32	3.23	2.70	2.70	3.66	4.18	4.29
1st Quarter 2017 Average								
Wellhead U.S. $	2.62	—	—	—	—	—	—	—
Canadian $	3.52	—	—	—	—	—	—	—
Delivered to Pipe U.S.$	2.76	3.04	2.49	1.96	1.98	2.80	3.18	3.39
Canadian $	3.66	4.02	3.29	2.60	2.62	3.71	4.21	4.49
2016 Average								
Wellhead U.S. $	1.99	—	—	—	—	—	—	—
Canadian $	2.68	—	—	—	—	—	—	—
Delivered to Pipe U.S.$	2.13	2.29	1.97	1.53	1.73	2.37	2.48	1.70
Canadian $	2.82	3.03	2.60	2.03	2.29	3.13	3.28	2.25
August 2016 Average								
Wellhead U.S. $	2.35	—	—	—	—	—	—	—
Canadian $	3.10	—	—	—	—	—	—	—
Delivered to Pipe U.S.$	2.49	2.50	2.49	1.57	2.06	2.59	2.75	—
Canadian $	3.24	3.24	3.23	2.04	2.68	3.36	3.58	—

Note: Monetary conversions are done weekly. All prices represent volume-weighted averages for the most recent Monday-Sunday trading week.

Permian …
(continued from page 1)

sin, where fracking reinvigorated the hunt for hydrocarbons. By the end of 2016, the Midland Basin increased the use of sand as a proppant by 73%; in the Delaware, 215%; and the total Permian, 120%.

Beyond the Permian, sand demand has increased in the gassier Bakken Shale by 25%, according to data from Tudor Pickering Holt. And in less than eight years, producers will escalate their usage of sand to extract gas and oil by 264%, according to a recent McKinsey Energy Insights report.

Mined in Wisconsin, Northern White sand is the industry standard and sets the price, which has doubled to $40 per ton since the beginning of the year in some areas, Fitch Rating found. And based on current market conditions, Tudor Pickering analysts forecast sand prices near $53/ton in 2018 before deflating to $45/ton in 2019.

Meanwhile, wells in the Permian are located at the farthest end from Wisconsin's sand mines, and transportation expenses exacerbate the cost of production in the prolific play. Consequently, oilfield service companies and their E&P clients have the incentive to find closer alternatives.

Last year, it was widely believed Texas and Oklahoma producers would source up to 65% of their sand needs from Wisconsin. But things are rapidly shifting.

At least a dozen companies are scrambling to capitalize on the sand dunes in the tiny town of Kermit, Texas, population 5,708. The biggest city in Winkler County has a bull's eye on its sand resources (NGW Jul.31'17). Not all the mines are in Kermit, which is a total 2.5 square miles; some may be scattered across the sparsely populated county.

Winkler County Judge Charles Wolf told *Natural Gas Week* that the burgeoning sand mining industry will be an economic boom for the county, adding at least 1,000 jobs and much-needed tax revenue. Several of the companies looking for mining opportunities are weighing their contributions to the community, too.

Three have pledged more than $3 million for infrastructure upgrades, including roads that will likely buckle under the weight of thousands of trucks, carrying millions of pounds of sand.

"They're trying to be part of the community … But with the good, there usually comes some bad," he said, noting a 10% population surge may bring with it additional crime, drugs and noise.

Fairmount Santrol recently said it will build a sand mining complex in Winkler County on the Texas-New Mexico border and in the heart of the Permian. Beginning in the second quarter of 2018, Fairmount Santrol said the facility will have the capacity to produce up to 3 million tons per year of sand.

As much as 34 million tons/yr capacity could be brought on line within the next 18 months and another 11 million tons/yr is speculative. Credit Suisse sees 32 million tons/yr hitting the marketplace by year-end 2018.

"We have looked for water for 100-plus years. We only just started looking for sand in earnest," said James Wicklund, Credit Suisse managing director for equity research. "The Permian, Eagle Ford and the Scoop/Stack look to achieve regional self-sufficiency much more quickly than has been expected."

Still, not every Texas mining permit will turn into profit. Some won't manage to access necessary capital, and others may struggle with access to water, an ingredient as crucial as sand in fracking fluid.

Flowing water deposits sand in horizontal wells, propping open cracks in the earth that free oil and gas beneath the surface. But unlike sand, water is a precious commodity, especially in arid West Texas, where the energy industry must compete for it with major industries such as agriculture and ranching.

What's more, it remains unclear if operators in the southern Delaware will use the local proppant, West Texas 40/70, which has a lower crush resistance than Northern White, Credit Suisse analysts said.

Diamondback Energy, a spunky Permian pure-play E&P, has no such qualms. The company recently signed a local sand deal that will save around 5% on current well costs and secure an economic proppant supply for several years, said Michael Hollis, Diamondback's chief operating officer, during a second-quarter earnings call Aug. 2.

Once the mine begins producing in early 2018, Diamondback will use the product in the Midland and perhaps some of the shallow zones in the Delaware. All signs indicate the West Texas grains will provide high-quality cost savings, said Travis Stice, Diamondback's CEO.

"We've done a significant amount of third-party testing and all indications point towards this being a sand that's capable of being run in anything in the Midland Basin and everything shallow in the Delaware," he said.

But some companies still might hesitant to make the switch, said James Wicklund, managing director for equity research at Credit Suisse. "Commentary from operators varies, with some saying they will pump regional 40/70 all day while others will tell you they're not convinced that material will work in the southern Delaware. The reality is at this point nobody really knows."

Deon Daugherty, Houston

Ferc ...

(continued from page 1)

although we see several weeks as more likely," analyst Benjamin Salisbury of FBR Capital Markets said in a report Friday. "This is the first time a majority of the commissioners will be brand-new; it is reasonable to expect a period of acclimation and deliberation to show that controversial issues are being considered carefully."

Pipeline industry officials estimate that up to $52 billion worth of vital infrastructure is being held in abeyance because of Ferc's inability to act.

The five-member Ferc, which requires three sitting commissioners to take significant action on energy project approvals, has lacked a quorum since then-Chairman Norman Bay abruptly resigned weeks after President Trump took office (NGW Jan.30'17). Commissioner Colette Honorable then left after her term ended Jun. 30, leaving just LaFleur.

The gas industry breathed a collective sigh of relief after Thursday evening's vote, as many officials were increasingly convinced the Senate would leave for its summer recess without confirming the pair.

"The commission now can get back to work thoroughly reviewing the many energy infrastructure projects of national importance that have been sidelined in recent months," said Don Santa, CEO of the Interstate Natural Gas Association of America.

"Returning Ferc to full strength will allow LNG developers to move forward with confidence that the required permits and permissions to build projects will be considered quickly and efficiently," said Charlie Riedl, director of the Center for LNG.

Consternation grew among industry officials, first because Trump took months to put forth nominations and then because Senate confirmation of those candidates took a backseat to other major policy initiatives and controversies.

The impasse has already led to Nexus Gas Transmission pushing back its in-service date from November to sometime in 2018 due to the lack of a Ferc quorum (NGW Jul.31'17). The 1.5 billion cubic feet per day capacity line will run 255 miles from eastern Ohio to southeastern Michigan, where it will interconnect with the Vector Pipeline to provide access to markets in Ontario.

FBR cited several other major pipelines requiring quick Ferc action. The Mountain Valley Pipeline in Virginia and West Virginia being built by EQT, NextEra and others (related) needs approval by September to meet its late-2018 in-service date, the companies have said.

Others in the queue are the Atlantic Coast Pipeline, PennEast Pipeline and Mountaineer Xpress.

Chatterjee is a longtime aide to Senate Majority Leader Mitch McConnell (R-Kentucky); Powelson is president of the National Association of Regulatory Utility Commissioners. Both were confirmed by unanimous consent, meaning there was no Senate debate.

The Senate still must act on Trump's other two nominees – Republican Kevin McIntyre of law firm Jones Day and Richard Glick, Democratic counsel for the Senate Energy and Natural Resources Committee. But that process is expected to last well into the fall as they first must be approved by the energy committee. A hearing is scheduled for Sep. 7.

"We believe that pairing the Democrat with the Republican expected to serve as chairman will help smooth confirmation," FBR's Salisbury said. "But given the Senate's heavy workload in the fall, it will likely be several months before the commission is at full strength and primed to tackle some of the larger issues lurking, such as state support for variable resources."

Mark Davidson, Washington

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Campaign to Shutter Aliso Canyon Could Have Far-Reaching Implications

The Aliso Canyon saga in Southern California might finally seem resolved after injections resumed last week at the massive gas storage facility. But "resolved" is an adjective that may never apply to Aliso Canyon until the final nail is pounded into its coffin, which should have been yesterday if its most vehement critics had their way or a decade from now as suggested by some Los Angeles area politicians and regulators (NGW Jul.24'17).

Southern California Gas is surely vexed that a well blowout in October 2015 would threaten its carefully balanced gas supply grid through the end of the 2020s and beyond. Make no mistake: California, for all its anti-fossil fuel bluster, is getting more dependent on gas as it embarks on a renewables spree. In a 2015 article published about three months before the Aliso Canyon accident, *Forbes* contributor Jude Clemente outlined why gas is increasingly vital to the Golden State's power grid.

As California ratchets up its Renewable Portfolio Standards, he explained, it raises the bar for needing reliable back-up capacity. That is "mostly determined by the 'capacity credit,' which indicates how much conventional electricity can be avoided or replaced by renewables," he wrote.

"At 2% to 20%, wind and solar have low capacity credits because of variability, compared to a very high 90% of a [combined cycle gas turbine]. Although difficult to accept for some, this energy market reality of intermittency means that new wind and solar capacity typically increases, not decreases, the need for more natural gas capacity."

This observation is especially noteworthy in the Los Angeles Basin, which despite the rise of renewables is still powered mainly by gas-fired plants. Aliso Canyon is uniquely situated to keep gas supply balanced during peak demand periods or in the event of inbound pipeline disruptions — 95% of the 2.3 trillion cubic feet of gas annually consumed in California comes from out of state. So having adequate, well-positioned in-state storage is critical.

But that need is understandably offset by safety concerns given that the 2015 accident was no ordinary blowout. It spewed 5 billion cubic feet of gas into the air over five months to the detriment of nearby residents in Porter Ranch, an affluent neighborhood in northwest Los Angeles, drawing international news coverage. More than 8,300 homes were evacuated for the duration of the emergency, which no doubt left a lasting legacy of antipathy.

And while some of the charges being levied against Aliso Canyon may have merit, they could apply to any storage facility in the state.

For instance, the danger posed by earthquakes is not confined to Aliso Canyon, which shares the region with three smaller storage fields with a combined capacity of about 40 Bcf — about half Aliso Canyon's. Not that Aliso Canyon will ever contain that amount of gas again, as capacity has been capped at about 24 Bcf, and none of that gas can be touched until storage is exhausted at the other fields.

Gas Price Report

($/MMBtu—Spot)

August 7, 2017

	Interstate Wellhead		Intrastate Wellhead		Delivered To Pipeline		Delivered To Utility	
	This Week	Bid Week for Aug	This Week	Bid Week for Aug	This Week	Bid Week for Aug	This Week	Bid Week for Aug
CALIFORNIA								
South	—	—	2.85	2.83	2.87	2.85	2.87	2.85
North	—	—	—	—	2.85	2.93	2.85	2.93
ROCKY MOUNTAINS	**2.37**	**2.48**	**2.34**	**2.45**	**2.49**	**2.60**	**2.82**	**2.93**
NEW MEXICO	**2.36**	**2.44**	—	—	**2.53**	**2.61**	**2.68**	**2.76**
TEXAS								
Gulf Coast, Offshore	2.66	2.81	2.67	2.82	2.73	2.88	—	—
Central, Onshore	2.65	2.75	2.67	2.77	2.73	2.83	2.88	2.98
Central	—	—	—	—	—	—	—	—
West	2.47	2.51	2.47	2.51	2.54	2.58	2.62	2.66
MID-CONTINENT	**2.38**	**2.48**	**2.36**	**2.46**	**2.48**	**2.58**	**2.73**	**2.69**
LOUISIANA								
Gulf Coast, Offshore	2.64	2.78	2.64	2.78	2.71	2.85	—	—
Gulf Coast, Onshore	2.65	2.83	2.65	2.83	2.72	2.90	2.83	3.05
North	2.63	2.78	2.62	2.77	2.70	2.85	2.84	2.99
MIDWEST	—	—	—	—	**2.71**	**2.77**	**2.73**	**2.83**
APPALACHIA	**1.82**	**1.88**	—	—	**1.93**	**1.99**	**2.01**	**2.08**
SOUTHEAST	**2.61**	**2.78**	—	—	**2.76**	**2.93**	**3.21**	**3.37**
NEW ENGLAND	—	—	—	—	**1.91**	**2.27**	**2.33**	**2.45**

	Composite Wellhead	Delivered to Pipeline	12-Month Strip Nymex
August 7, 2017	2.56	2.29	2.93
2017 Outlook	2.91	2.98	—

The price points that made up the "Texas Central" and "Texas Gulf Coast, Onshore" composites in the Gas Price Report table have been incorporated into the new "Texas Central Onshore" composite. The "Texas Central" composite will be eliminated.

That last nugget is clear evidence that Aliso Canyon has a target on its back due to its past sins. But, it could be argued that the facility is now the model of safety considering what SoCalGas had to do before the California Public Utilities Commission allowed it to restart injections after a nearly two-year hiatus.

The utility went through a meticulous safety review and upgrade to its aging wells so they now meet and often exceed the highest operational standards. As the state Division of Oil, Gas and Geothermal Resources noted, the field has likely undergone more safety and regulatory scrutiny than any US storage facility, and certainly more than any of the state's 13 others.

This should give pause, because if a campaign to shutter Aliso Canyon on safety concerns succeeds, where is the logic to keep any gas storage capacity open in the Golden State?

The *Natural Gas Week* composite spot wellhead price this week is \$2.56/MMBtu, 16¢ less than last week and 8¢ less than the Aug. 8, 2016, average. The spot delivered-to-pipeline price this week is \$2.29/MMBtu, 9¢ less than last week and 22¢ less than last year's corresponding average.

Tom Haywood, Houston

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NATURAL GAS WEEK®

MONTHLY BIDWEEK SUPPLEMENT

Vol. 33, No. 32 August 7, 2017

Natural Gas Bidweek Prices

Flow Dates: 8/1-8/31

Price Point	August Avg. $/MMBtu	Chg. from Prev.	High	Low	Vol.	Deals	Prev. Bid-Week
GULF COAST							
ANR SE	2.87	-0.09	2.87	2.87	10,000	1	2.96
Col. Gulf - Erath	2.87	-0.10	2.87	2.87	80,510	8	2.98
Col. Gulf - Rayne	2.85	-0.10	2.85	2.85	60,000	6	2.95
Florida Zone 1	—	—	—	—	—	—	—
Florida Zone 2	2.93	-0.11	2.96	2.90	43,662	10	3.03
Florida Zone 3	2.93	-0.09	2.95	2.93	76,052	13	3.03
Henry Hub	2.96	-0.10	2.97	2.96	52,500	4	3.06
NGPL-LA	—	—	—	—	—	—	—
Sonat	2.88	-0.11	2.91	2.84	37,153	15	2.99
Tenn 500 So LA Z1	2.89	-0.08	2.89	2.89	865	2	2.96
Tenn 800 So LA Z1	2.88	-0.10	2.88	2.88	5,000	1	2.97
Tetco ELA	2.85	-0.11	2.85	2.85	20,000	1	2.96
Tetco WLA	2.85	-0.12	2.85	2.85	15,000	1	2.97
TGT Zone SL	—	—	—	—	—	—	2.97
Transco Station 45	—	—	—	—	—	—	—
Transco Station 65	2.92	-0.09	2.93	2.85	40,594	6	3.00
Trunkline ELA	—	—	—	—	—	—	—
Trunkline WLA	—	—	—	—	—	—	—
Trunkline Zone 1A	2.85	—	2.85	2.84	25,400	3	—
Regional Average	2.90	-0.09	—	—	—	—	2.99
TEXAS (SOUTH/EAST)							
Carthage Hub	—	—	—	—	—	—	2.96
HSC	2.91	-0.27	2.91	2.91	10,000	2	3.18
Katy Hub	—	—	—	—	—	—	—
NGPL-South Texas	2.90	-0.10	2.91	2.89	30,000	3	3.00
NGPL-TexOk	2.80	-0.10	2.84	2.78	11,290	3	2.90
Tenn Zone 0	2.80	-0.09	2.80	2.79	42,500	7	2.89
Tetco-East Texas	2.84	-0.12	2.84	2.84	20,000	1	2.96
Tetco-South Texas	2.89	-0.18	2.89	2.89	10,000	2	3.07
TGT Zone 1	2.85	—	2.85	2.85	35,800	5	—
Transco Station 30	2.88	-0.10	2.88	2.87	11,300	2	2.98
Regional Average	2.85	-0.10	—	—	—	—	2.95
TEXAS (WEST)							
El Paso Permian	2.57	-0.09	2.63	2.52	123,000	22	2.65
NNG Custer	—	—	—	—	—	—	—
Transwes E of Thoreau	2.62	—	2.62	2.62	20,000	4	—
Waha Hub	2.59	-0.09	2.61	2.58	25,000	4	2.69
Regional Average	2.58	-0.09	—	—	—	—	2.67
MIDCONTINENT							
ANR SW	2.64	-0.09	2.64	2.64	41,900	9	2.73
CenterPoint East	—	—	—	—	—	—	2.88
CenterPoint West	—	—	—	—	—	—	2.86
NGPL-MC	2.64	—	2.64	2.63	32,293	3	—
Oneok	2.37	-0.24	2.40	2.32	70,000	10	2.60
Panhandle	2.58	-0.11	2.62	2.57	121,347	9	2.69
Southern Star	—	—	—	—	—	—	2.65
Regional Average	2.54	-0.18	—	—	—	—	2.72
GREAT PLAINS							
Emerson	2.61	-0.08	2.69	2.60	27,105	7	2.69
NB Ventura TP	—	—	—	—	—	—	—
NNG Demarc	2.72	-0.05	2.75	2.68	38,110	12	2.77
NNG Ventura	2.73	-0.04	2.75	2.68	68,900	23	2.76
Regional Average	2.70	-0.05	—	—	—	—	2.76

(continued on p2)

August Bidweek Prices Down from July; Constraints Keep Station 2 Below $1

Bidweek spot prices for August were down almost across the board from a month ago, according to *Natural Gas Week data,* as the overall market comes under increasing pressure from ample storage stocks, rising production and outlooks for lighter-than-usual late summer power loads.

However, in hindsight, the monthly cash indices might seem stronger than expected as futures prices have plunged since the August contract rolled off the board Jul. 27 at $2.969 per million Btu. The three-day Nymex average was $2.945, reflecting a mooted rally into settlement.

The August expiration trailed July's by 9.8¢ but was the highest August contract finale since the pre-downturn peaks of 2014. But downward momentum in futures kicked in the following day and continued early last week, with a possible test of lows in the $2.50s on the horizon.

Monthly spot prices reflected trends in the day-ahead market. For instance, the benchmark Henry Hub index came in at $2.96/MMBtu, which was down 10¢ from July. But like the cash market, the Henry Hub captured the highest price in the Gulf region, reflecting the point's move away from a key role it — and the Louisiana and Texas regions — once played in supplying long-haul pipes aimed at the Northeast. So not surprisingly, the Gulf Coast and Southeast Texas regions posted the highest bidweek values.

With those flows now reversed, Appalachia production areas and the Northeast market centers ran a distinct discount to the Gulf Coast. Columbia Gas' Appalachian Pool (TCO) trailed the Henry Hub by 18¢, which matched July cash trading in which TCO also ran an 18¢ discount. Elsewhere in the region, Dominion South Point basis was held in check by takeaway constraints, coming in at $1.73/MMBtu, a steep $1.23 discount to the Henry Hub. In July, Dominion South averaged $1/MMBtu below the Hub.

Meanwhile, Western Canadian prices reflected the chaos seen in the cash market due to maintenance-related constraints on the TransCanada system as well as other regional pipelines (NGW Jul.31'17).

The August index for Aeco was $1.61/MMBtu, down 18¢ from last month. However, the Westcoast Station 2 index took an even bigger hit, sinking 46¢ to post a 97¢/MMBtu index for August, the lowest in the survey. But the price for Western Canadian supply flowing across the border into the US was more in line with prices in the Lower 48. For instance, the Sumas index was $2.48/MMBtu, close to the $2.60/MMBtu average seen in the Rockies.

Tom Haywood, Houston

Natural Gas Bidweek Prices (cont.)

Flow Dates: 8/1-8/31

Price Point	August Avg. $/MMBtu	Chg. from Prev.	High	Low	Vol.	Deals	Prev. Bid-Week
UPPER MIDWEST							
Alliance	—	—	—	—	—	—	2.91
ANR ML7	2.90	-0.06	2.97	2.88	3,031	4	2.96
Chicago Citygate	2.83	-0.05	2.88	2.75	30,030	8	2.88
Consumers	2.88	-0.10	2.97	2.84	184,446	35	2.98
MichCon	2.85	-0.10	2.98	2.84	245,922	33	2.94
Rex Zone 3 Delivered	2.82	-0.09	2.83	2.80	177,662	16	2.91
Regional Average	2.85	-0.08	—	—	—	—	2.93
SOUTHEAST							
Tetco M1	—	—	—	—	—	—	—
Transco Zone 4	2.92	-0.09	2.94	2.92	178,647	18	3.01
Transco Zone 5	3.01	-0.03	3.02	3.01	48,050	5	3.04
Regional Average	2.94	-0.08	—	—	—	—	3.02
APPALACHIA							
Col. Gas App. Pool	2.78	-0.10	2.80	2.76	142,747	34	2.88
Dominion North	1.74	-0.06	1.75	1.70	87,597	10	1.81
Dominion South	1.73	-0.08	1.78	1.69	205,714	42	1.81
Lebanon Hub	2.82	-0.08	2.82	2.81	34,701	4	2.90
Millennium, East Receipts	1.75	-0.02	1.77	1.74	13,754	8	1.77
TENN Z4 200-leg	1.93	-0.05	1.96	1.92	41,187	8	1.98
TENN Z4 300 leg, receipts	1.65	-0.05	1.67	1.64	35,568	12	1.70
TENN Z4 313 pool	1.87	-0.10	1.90	1.87	5,311	3	1.97
Transco Leidy Line	1.72	-0.04	1.79	1.70	176,226	21	1.76
Regional Average	1.99	-0.12	—	—	—	—	2.11
EASTERN CANADA							
Dawn	2.89	-0.10	2.90	2.74	276,754	60	2.99
Iroquois	2.86	0.03	2.86	2.83	2,245	3	2.83
Niagara	—	—	—	—	—	—	—
Regional Average	2.89	-0.10	—	—	—	—	2.98
NORTHEAST / MIDATLANTIC							
Algonquin	2.45	—	2.55	2.44	35,100	9	—
Dracut	—	—	—	—	—	—	—
Iroquois Zone 2	2.82	-0.05	2.87	2.80	10,500	6	2.87
Tenn Gas Zone 6	2.44	-0.23	2.49	2.41	78,917	18	2.67
Tetco M3	1.80	-0.12	1.86	1.77	46,904	14	1.91
Transco Z6 - Non-NY	2.30	-0.12	2.33	2.29	17,230	10	2.42
Transco Z6 - NY	2.30	-0.06	2.34	2.25	45,644	10	2.36
Regional Average	2.29	0.15	—	—	—	—	2.15
ROCKIES							
Cheyenne Hub	2.59	-0.05	2.59	2.59	15,000	2	2.64
CIG	2.58	—	2.58	2.58	45,000	2	—
Kern River / Opal	2.64	-0.03	2.66	2.61	74,662	12	2.67
NW Rockies	2.59	-0.02	2.60	2.58	117,500	4	2.61
Questar	2.52	-0.05	2.52	2.52	598	1	2.57
White River Hub	2.59	-0.05	2.60	2.57	18,300	4	2.64
Regional Average	2.60	-0.04	—	—	—	—	2.64
SAN JUAN BASIN							
El Paso Bondad	—	—	—	—	—	—	—
El Paso San Juan	2.61	-0.04	2.63	2.60	90,000	13	2.65
Transwestern San Juan	2.66	-0.03	2.69	2.62	89,400	13	2.69
Regional Average	2.64	-0.04	—	—	—	—	2.67
PACIFIC NORTHWEST/WESTERN CANADA							
AECO	1.61	-0.18	1.79	1.41	1,344,904	236	1.78
Kingsgate	—	—	—	—	—	—	—
Malin	2.70	-0.02	2.78	2.67	43,300	13	2.72
NW Sumas	2.48	0.20	2.51	2.47	15,000	4	2.29
Stanfield	2.59	0.08	2.59	2.59	5,000	1	2.51
Westcoast Station 2	0.97	-0.46	1.12	0.96	48,662	6	1.43
Regional Average	1.63	-0.23	—	—	—	—	1.86
CALIFORNIA							
Kern - Wheeler Ridge	—	—	—	—	—	—	—
PG&E Citygate	3.27	0.04	3.29	3.26	30,000	6	3.23
PG&E South	—	—	—	—	—	—	—
SoCal Border	2.85	0.00	2.90	2.82	65,000	8	2.85
SoCal Citygate	3.21	0.02	3.25	3.19	36,076	10	3.19
Regional Average	3.04	0.07	—	—	—	—	2.97

Comparative Fuel Prices

(Bidweek Market)

August 2017

Natural Gas	$/MMBtu	Comparative Fuel	Fuel Price	MMBtu equivalent
APPALACHIA				
Columbia Gas Appalachian Pool	2.78	Central Appalachian	$55.40/ton	$2.31/MMBtu
EAST COAST				
New York City	2.30	Heating Oil No. 2*	155.63¢/gal	$11.22/MMBtu
		Residual 0.30%	$53.48/bbl	$8.51/MMBtu
		Residual 1.00%	$48.48/bbl	$7.71/MMBtu
GULF COAST				
TX Onshore Dlvd	2.89	Heating Oil No. 2*	146.84¢/gal	$10.59/MMBtu
		Residual 0.70%	$48.68/bbl	$7.74/MMBtu
Louisiana Onshore	2.92	Residual 3.00%	$47.23/bbl	$7.51/MMBtu
		WTI Cushing	$50.21/bbl	$8.66/MMBtu

Residual = Residual Fuel Oil, priced exclusive of taxes. WTI = West Texas Intermediate crude oil. % = % of sulfur content. *Average sulfur content = 0.2%-0.5%. *Source: Gas: Natural Gas Week; all prices volume-weighted. Oil: The weekly average of Oil Daily's cash price postings.*

Citygate Prices

Price Point	August Avg. $/MMBtu	Chg. from Prev.	Prev. Bid-Week
Austin, Texas	2.71	-0.09	2.81
Detroit, Michigan	2.98	-0.05	3.03
Los Angeles, California	3.35	0.00	3.35
Minneapolis, Minnesota	2.83	-0.04	2.86
Nashville, Tenn	2.90	-0.10	3.01
Philadelphia, Pennsylvania	2.28	-0.06	2.34
Seattle, Washington	2.54	0.20	2.35
Washington, DC	2.26	-0.06	2.32

NGW's Monthly Weighted Averages

($/MMBtu)

Price Point	Jul.'17	Jun.'17	May.'17	Apr.'17	Mar.'17	Feb.'17	Jan.'17	Dec.'16	Nov.'16	Oct.'16	Sep.'16	Aug.'16	Jul.'16	2017 Average	2016 Average
GULF COAST															
ANR SE	2.86	2.82	3.07	3.01	2.80	2.74	3.32	3.49	2.37	2.74	2.86	2.75	2.71	2.95	2.38
COL. GULF - ERATH	2.86	2.85	3.03	3.00	2.69	2.73	3.24	3.48	2.28	2.82	2.88	2.69	2.73	2.92	2.28
COL. GULF - RAYNE	2.84	2.83	3.05	2.97	2.74	2.68	3.24	3.47	2.36	2.75	2.86	2.69	2.72	2.90	2.38
FLORIDA ZONE 1	—	—	2.96	—	—	—	—	—	—	—	—	—	—	2.96	2.07
FLORIDA ZONE 2	2.98	2.82	2.91	—	2.95	—	—	—	—	—	2.97	—	2.86	2.96	2.84
FLORIDA ZONE 3	2.92	2.89	3.13	3.04	2.79	2.76	3.30	3.51	2.40	2.93	2.93	2.75	2.86	2.97	2.43
HENRY HUB	2.94	2.92	3.13	3.08	2.70	2.83	3.37	3.53	2.48	2.81	2.94	2.78	2.80	3.00	2.50
MILLENNIUM, EAST RECEIPTS	2.01	1.85	2.50	2.61	2.58	—	—	—	—	—	—	—	—	2.15	—
SONAT	2.86	2.86	3.06	2.99	2.78	2.60	3.27	3.50	2.39	2.81	2.92	2.72	2.74	2.93	2.42
TENN 500 SO LA Z1	2.85	2.83	3.03	3.01	2.80	2.68	3.22	3.44	2.48	2.92	2.96	2.73	2.76	2.90	2.53
TENN 800 SO LA Z1	2.87	2.84	3.04	2.98	2.78	2.71	3.27	3.46	2.30	2.84	2.90	2.74	2.71	2.97	2.35
TENN Z4 313 POOL	2.11	2.08	2.82	2.71	—	—	—	—	—	—	—	—	—	2.31	—
TETCO ELA	2.86	2.83	3.05	3.00	2.78	2.63	3.25	3.47	2.28	2.85	2.87	2.70	2.70	2.88	2.43
TETCO WLA	2.86	2.88	3.03	3.04	2.75	2.70	3.21	3.48	2.26	2.90	2.88	2.72	2.73	2.89	2.44
TGT ZONE SL	2.84	2.84	3.02	3.01	2.90	2.79	3.27	3.47	2.02	2.70	2.90	2.86	2.70	2.96	2.75
TRANSCO STATION 45	2.91	2.83	3.04	3.00	2.79	2.70	3.24	3.40	2.36	2.84	2.89	2.72	2.72	2.94	2.35
TRANSCO STATION 65	2.92	2.88	3.07	3.02	2.85	2.74	3.25	3.54	2.34	2.86	2.91	2.70	2.73	2.96	2.32
TRUNKLINE ELA	2.80	2.82	3.11	2.99	2.72	2.65	3.24	3.43	2.59	3.03	2.94	2.68	2.68	2.86	2.25
TRUNKLINE WLA	—	—	2.82	—	—	—	—	3.40	—	—	—	2.66	—	2.82	3.14
TRUNKLINE ZONE 1A	2.82	2.79	3.04	2.98	2.71	2.72	3.27	3.48	2.41	2.71	2.83	2.70	2.69	2.89	2.40
TEXAS (SOUTH/EAST)															
CARTHAGE HUB	2.88	2.82	3.03	2.94	2.71	2.72	3.21	3.44	2.44	2.82	2.90	2.72	2.75	2.91	2.38
HSC	3.00	3.04	3.22	3.04	2.82	2.82	3.21	3.50	2.46	2.99	2.90	2.73	2.72	3.02	2.43
KATY HUB	2.94	3.02	3.20	3.08	2.83	2.79	3.23	3.46	2.44	3.01	2.89	2.73	2.74	2.97	2.52
NGPL-SOUTH TEXAS	2.91	2.83	3.00	2.96	2.76	2.74	3.16	3.39	2.44	2.84	2.90	2.69	2.67	2.90	2.33
NGPL-TEXOK	2.79	2.81	2.98	2.87	2.70	2.70	3.18	3.42	2.41	2.81	2.83	2.65	2.67	2.85	2.35
TENN ZONE 0	2.70	2.81	2.91	2.93	2.72	2.68	3.18	3.39	2.28	2.89	2.85	2.63	2.64	2.85	2.21
TETCO-EAST TEXAS	2.82	2.84	3.05	2.95	2.83	2.59	3.18	3.46	2.35	2.73	2.87	2.73	2.70	2.92	2.48
TETCO-SOUTH TEXAS	2.90	2.91	3.14	3.05	2.77	2.76	3.18	3.45	2.54	2.92	2.89	2.73	2.71	3.01	2.33
TGT ZONE 1	2.85	2.83	3.01	2.98	2.78	2.64	3.19	3.48	2.55	2.78	2.89	2.69	2.70	2.91	2.33
TRANSCO STATION 30	2.88	2.84	3.06	3.05	2.84	2.74	3.18	3.44	2.43	2.75	2.84	2.70	2.73	2.92	2.37
Texas (West)															
EL PASO PERMIAN	2.55	2.55	2.72	2.67	2.50	2.53	3.16	3.36	2.15	2.63	2.67	2.57	2.56	2.66	2.29
NNG CUSTER	2.68	—	—	—	—	—	—	—	—	—	—	—	—	2.68	—
TRANSWES E OFTHOREAU	2.63	2.54	2.72	2.69	2.55	2.53	3.17	3.47	2.18	2.68	2.74	2.61	2.56	2.66	2.35
WAHA HUB	2.66	2.61	2.80	2.75	2.61	2.59	3.15	3.45	2.22	2.68	2.74	2.61	2.65	2.73	2.31
Midcontinent															
ANR SW	2.61	2.61	2.79	2.75	2.57	2.62	3.15	3.39	2.26	2.69	2.66	2.53	2.55	2.71	2.23
CENTERPOINT EAST	2.83	2.83	2.91	2.85	2.70	2.67	3.18	3.41	2.33	2.74	2.77	2.56	2.67	2.86	2.35
CENTERPOINT WEST	—	—	—	—	—	—	—	—	2.63	—	—	—	—	—	2.63
NGPL-MC	2.65	2.65	2.85	2.79	2.57	2.61	3.17	3.41	2.24	2.78	2.77	2.62	2.56	2.70	2.25
ONEOK	2.48	2.57	2.78	2.73	2.47	2.59	3.17	3.41	2.26	2.58	2.68	2.51	2.54	2.66	2.30
PANHANDLE	2.50	2.58	2.75	2.76	2.59	2.51	3.14	3.44	2.23	2.65	2.66	2.57	2.54	2.68	2.27
SOUTHERN STAR	2.53	2.58	2.80	2.73	2.54	2.62	3.22	3.42	2.04	2.63	2.63	2.53	2.53	2.75	2.39
Great Plains															
EMERSON	2.67	2.62	2.75	2.76	2.59	2.54	3.06	3.43	2.27	2.72	2.67	2.59	2.50	2.74	2.37
NBVENTURA TP	2.66	2.66	2.87	2.85	2.78	2.70	3.26	3.58	2.40	2.81	2.76	2.68	2.62	2.83	2.37
NNG DEMARC	2.66	2.67	2.89	2.87	2.71	2.65	3.32	3.68	2.45	2.82	2.83	2.67	2.62	2.81	2.30
NNG VENTURA	2.71	2.67	2.88	2.85	2.75	2.71	3.31	3.64	2.32	2.80	2.80	2.67	2.63	2.85	2.39
Upper Midwest															
ALLIANCE	2.78	2.77	3.03	2.96	2.79	2.75	3.34	3.71	2.38	2.72	2.86	2.73	2.69	2.94	2.69
ANR ML7	2.83	2.85	3.05	3.12	2.73	2.65	3.47	3.61	2.51	2.93	2.81	2.72	2.73	2.77	2.51
CHICAGO CITYGATE	2.79	2.78	3.01	2.95	2.86	2.75	3.29	3.71	2.46	2.86	2.87	2.73	2.72	2.90	2.43
CONSUMERS	2.88	2.87	3.14	3.14	2.82	2.80	3.33	3.57	2.35	2.82	2.92	2.74	2.71	2.99	2.46
MICHCON	2.87	2.87	3.09	3.11	2.87	2.79	3.30	3.58	2.50	2.81	2.91	2.73	2.69	2.97	2.48
REX ZONE 3 DELIVERED	2.80	2.79	2.99	2.90	—	—	—	—	—	—	—	—	—	2.87	—
Southeast															
TETCO M1	2.87	2.86	3.14	2.95	2.86	2.61	3.23	3.56	2.15	2.77	2.90	2.71	2.73	2.99	2.37
TRANSCO ZONE 4	2.93	2.87	3.09	3.01	2.82	2.75	3.26	3.51	2.41	2.85	2.93	2.73	2.77	2.96	2.44
TRANSCO ZONE 5	3.01	2.94	3.07	3.06	3.39	2.91	3.40	3.71	2.39	2.75	3.01	2.79	2.82	3.12	2.61
Appalachia															
COL. GAS APP. POOL	2.77	2.75	2.97	2.95	2.74	2.68	3.16	3.38	2.27	2.72	2.80	2.66	2.73	2.86	2.33
DOMINION NORTH	1.93	1.91	2.67	2.58	2.57	2.45	2.97	2.97	2.00	1.00	1.08	1.28	1.38	2.47	1.62
DOMINION SOUTH	1.91	1.93	2.69	2.63	2.59	2.45	3.01	2.93	1.90	0.90	1.07	1.28	1.40	2.42	1.49
LEBANON HUB	2.79	2.77	2.98	2.94	2.74	2.69	3.22	3.54	2.39	2.77	2.85	2.68	2.67	2.86	2.28
TENN Z4 200-LEG	2.18	2.07	2.84	2.81	2.66	2.65	3.03	3.17	2.35	—	—	—	—	2.51	2.83
TENN Z4 300 LEG, RECEIPTS	1.92	1.77	2.64	2.48	—	—	—	—	—	—	—	—	—	2.06	—
TENN Z4 313 POOL	2.11	2.08	2.82	2.71	—	—	—	—	—	—	—	—	—	2.31	—
TRANSCO LEIDY LINE	2.01	1.87	2.72	2.58	2.50	2.27	2.91	2.89	2.23	—	—	—	—	2.34	2.63

(continued on p2)

NGW's Monthly Weighted Averages

($/MMBtu)

Price Point	Jul.'17	Jun.'17	May.'17	Apr.'17	Mar.'17	Feb.'17	Jan.'17	Dec.'16	Nov.'16	Oct.'16	Sep.'16	Aug.'16	Jul.'16	2017 Average	2016 Average
Eastern Canada															
DAWN	2.89	2.89	3.18	3.25	3.07	2.94	3.59	4.09	2.63	2.80	2.94	2.75	2.70	3.10	2.51
IROQUOIS	3.01	2.81	3.18	3.23	4.10	3.37	4.55	5.03	2.91	2.42	2.22	2.90	2.73	3.76	2.87
NIAGARA	—	—	—	3.19	3.04	2.97	3.67	3.56	2.54	—	1.53	—	—	3.37	2.44
Northeast / MidAtlantic															
ALGONQUIN	2.58	2.48	3.14	3.10	4.53	3.48	4.90	6.84	2.56	2.23	2.53	3.02	2.71	3.27	2.98
DRACUT	—	—	—	4.20	8.00	5.33	—	11.06	—	—	—	—	—	5.82	9.46
IROQUOIS ZONE 2	2.91	2.50	3.19	3.14	4.39	3.24	5.05	5.43	2.77	2.28	2.66	3.12	2.96	3.62	3.01
TENN GAS ZONE 6	2.55	2.48	3.08	3.32	4.75	3.69	5.43	7.26	2.89	2.11	2.52	2.99	2.70	3.39	3.13
TETCO M3	1.98	1.99	2.76	2.68	2.84	2.58	3.42	3.37	2.12	1.03	1.16	1.37	1.47	2.63	1.68
TRANSCO Z6 - NON-NY	2.49	2.39	2.85	2.84	3.28	2.83	3.80	3.79	2.14	1.33	1.57	2.07	2.24	2.82	2.33
TRANSCO Z6 - NY	2.57	2.47	2.81	2.94	3.92	3.13	3.71	4.12	2.25	1.03	1.49	2.03	2.05	3.11	2.45
Rockies															
CHEYENNE HUB	2.51	2.55	2.73	2.71	2.55	2.60	3.33	3.48	2.26	2.66	2.62	2.53	2.51	2.76	2.20
CIG	2.48	2.59	2.75	2.66	2.49	2.55	3.27	3.45	2.27	2.60	2.59	2.52	2.54	2.70	2.30
KERN RIVER / OPAL	2.59	2.57	2.77	2.73	2.53	2.56	3.29	3.51	2.23	2.62	2.64	2.59	2.56	2.74	2.31
NW ROCKIES	2.58	2.59	2.74	2.73	2.50	2.53	3.16	3.49	2.33	2.65	2.75	2.56	2.52	2.71	2.37
QUESTAR	2.53	2.49	2.73	2.67	2.49	2.54	3.21	3.42	2.43	2.58	2.64	2.61	2.53	2.70	2.52
WHITE RIVER HUB	2.51	2.54	2.76	2.69	—	—	—	—	—	—	—	—	—	2.57	—
San Juan Basin															
EL PASO BONDAD	2.60	2.59	2.72	2.66	2.43	2.54	3.20	3.46	2.27	2.65	2.73	2.58	2.59	2.62	2.26
EL PASO SAN JUAN	2.60	2.57	2.73	2.70	2.48	2.57	3.21	3.45	2.21	2.64	2.71	2.60	2.56	2.70	2.24
TRANSWESTERN,SAN JUAN	2.61	2.58	2.77	2.67	—	—	—	—	—	—	—	—	—	2.64	—
Pacific Northwest/Western Canada															
AECO	1.42	1.85	2.11	2.00	1.84	1.86	2.18	2.44	1.89	2.19	1.90	1.57	1.73	1.90	1.53
KINGSGATE	2.06	2.23	2.53	2.43	2.31	2.46	3.16	3.39	2.05	2.44	2.35	2.49	2.30	2.31	1.97
MALIN	2.61	2.57	2.88	2.78	2.58	2.67	3.37	3.56	2.20	2.71	2.70	2.64	2.60	2.78	2.36
NW SUMAS	2.18	2.32	2.53	2.61	2.38	2.43	4.12	3.90	2.16	2.56	2.60	2.50	2.32	2.60	2.29
STANFIELD	2.42	2.42	2.71	2.64	2.42	2.47	3.44	3.56	2.38	2.56	2.60	2.54	2.53	2.83	2.41
WESTCOAST STATION 2	1.13	1.42	1.74	1.71	1.76	1.65	1.92	2.14	1.41	1.78	1.30	1.32	1.39	1.60	1.25
California															
PG&E CITYGATE	3.23	3.14	3.41	3.30	3.12	3.27	3.62	3.77	3.09	3.28	3.34	3.18	3.04	3.30	2.61
PG&E SOUTH	2.74	2.72	2.85	2.78	2.56	2.60	3.23	3.53	2.49	2.71	2.70	2.69	2.68	2.75	2.36
SOCAL BORDER	2.79	2.82	2.84	2.80	2.58	2.73	3.37	3.58	2.28	2.73	2.77	2.82	2.93	2.90	2.54
SOCAL CITYGATE	3.06	3.15	3.18	3.14	2.81	3.03	3.68	3.70	2.71	2.90	2.82	2.83	2.88	3.17	2.57
Intrastates															
OKLAHOMA INTRAS	2.48	2.57	2.78	2.73	2.47	2.59	3.17	3.41	2.26	2.58	2.68	2.51	2.55	2.67	2.29
SOUTH TEXAS INTRAS	3.03	—	3.00	2.94	2.86	2.77	3.40	3.36	2.39	3.01	2.92	2.63	—	2.99	2.90

Note: The prices above are volume-weighted average prices for the price point and period indicated. The annual average and year-to-date prices are volume-weighted averages of the entire period shown and not simple averages of the component monthly averages.

Composite Spot Wellhead Price

January 2013 to Present

($/MMBtu)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
2017	3.18	2.66	2.69	2.87	2.93	2.68	2.72						
2016	2.18	1.82	1.57	1.74	1.74	2.35	2.59	2.57	2.70	2.67	2.28	3.41	2.32
2015	2.84	2.73	2.63	2.36	2.65	2.57	2.66	2.60	2.50	2.17	1.97	1.85	2.46
2014	4.61	6.64	5.05	4.46	4.35	4.38	3.89	3.71	3.71	3.56	3.92	3.25	4.39
2013	3.30	3.29	3.74	4.20	3.97	3.73	3.51	3.29	3.52	3.58	3.51	4.19	3.66

Composite Spot Delivered-To-Pipeline Price

January 2014 to Present

($/MMBtu)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
2017	3.38	2.72	2.93	2.88	2.92	2.57	2.64						
2016	2.33	1.98	1.55	1.77	1.74	2.33	2.55	2.54	2.53	2.47	2.31	3.79	2.35
2015	3.29	4.13	2.82	2.37	2.56	2.42	2.51	2.49	2.45	2.26	2.06	1.81	2.61
2014	7.68	7.74	6.17	4.46	4.21	4.21	3.81	3.54	3.56	3.35	4.10	3.23	4.80