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Interstate Municipal Gas Agency
1310 West Jefferson
Auburn, IL 62615

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FERC Adopts Changes to Natural Gas Pipeline Nomination Timelines as Part of Gas-Electric Coordination Efforts

By: Kaleb Lockwood

In a move that will affect gas-fired generators, shippers on interstate natural gas pipelines, and the pipelines themselves, **FERC** has adopted changes to its rules that will modify the nomination timelines for scheduling interstate natural gas pipeline transportation service. The changes, set forth in an order issued concurrently with FERC;s April 16, 2015 monthly meeting, (1) extend the deadline for the day-ahead Timely Nomination Cycle from 11:30 am Central Clock time ("CCT") to 1:00 pm CCT, and (2) add a third intraday nomination cycle on top of the existing two, with new intraday nomination deadlines of 10:00 am, 2:30 pm, and 7:00 pm. The changes will become effective 75 days after the forthcoming publication of FERC's order in the Federal Register.

Crucially, FERC's final rules do not implement any change to the start of the natural gas operating day ("Gas Day"). In its proposed rules issued last year, FERC proposed moving the start of the Gas Day from 9:00 am CCT to 4:00 am CCT, but based in large part on the response of the natural gas industry, FERC decided it was unclear whether the benefits of the change outweighed the costs. Additionally, instead of adopting the two new intraday nomination cycles that it initially proposed, FERC has decided to add just one extra intraday nomination cycle. In the end, FERC's final rules reflect the results of the North American Energy Standards Board (NAESB) stakeholder process that took place in the middle of 2014 in response to FERC's proposed rules.

The difference between the proposed and final rules reflects in part the different interests of the electric and natural gas industries. For example, many in the electric industry favored moving the start of the Gas Day earlier in the day so that the Gas Day would better align with the electric operating day, which begins at 12:00 am. The gas industry, on the other hand, generally opposed moving the start of the gas day due to increased costs as well as safety and operational issues. FERC ended up deferring to the gas industry's concerns by maintaining the status quo. On the changes FERC did adopt in the final rule, there was more of a consensus between the electric and gas industries that the changes would be beneficial.

FERC's rule changes are part of the agency's effort to better coordinate natural gas and electric industry scheduling practices as a result to the growing use of natural gas as a fuel for electric generation. For instance, by extending the Timely Nomination Cycle deadline to 1:00 pm CCT, electric generators will have the opportunity to submit nomination in the Timely Nomination Cycle (when the market is most liquid) after they know whether their bids have been selected in the day-ahead electric market (and thus what their gas transportation needs will be). Likewise FERC believes that offering an additional intraday nomination cycle will give shippers (including electric generators) more flexibility to adjust their gas needs based on changes that occur during the Gas Day.

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EXTENDED RANGE FORECAST OF ATLANTIC SEASONAL HURRICANE ACTIVITY AND LANDFALL STRIKE PROBABILITY FOR 2015

By Philip J. Klotzbach and William M. Gray

We anticipate that the 2015 Atlantic basin hurricane season will be one of the least active seasons since the middle of the 20th century. It appears quite likely that an El Niño of at least moderate strength will develop this summer and fall. The tropical and subtropical Atlantic are also quite cool at present. We anticipate a below-average probability for major hurricanes making landfall along the United States coastline and in the Caribbean. Despite the forecast for below-average activity, coastal residents are reminded that it only takes one hurricane making landfall to make it an active season for them. They should prepare the same for every season, regardless of how much activity is predicted.

ATLANTIC BASIN SEASONAL HURRICANE FORECAST FOR 2015

Forecast parameter and 1981-2010 Median (in parentheses)	Issue Date 9 April 2015
Named Storms (NS) (12.0)	7
Named Storm Days (NSD) (60.1)	30
Hurricanes (H) (6.5)	3
Hurricane Days (HD) (21.3)	10
Major Hurricanes (MH) (2.0)	1
Major Hurricane Days (MHD) (3.9)	0.5
Accumulated Cyclone Energy (ACE) (92)	40
Net Tropical Cyclone Activity (NTC) (103%)	45

PROBABILITIES FOR AT LEAST ONE MAJOR (CATEGORY 3-4-5) HURRICANE LANDFALL ON EACH OF THE FOLLOWING COASTAL AREAS:

1. Entire U.S. coastline– 28% (average for last century is 52%)

2. U.S. East Coast Including Peninsula Florida– 15% (average for last century is 31%)

3. Gulf Coast from the Florida Panhandle westward to Brownsville– 15% (average for last century is 30%)

PROBABILITY FOR AT LEAST ONE MAJOR (CATEGORY 3-4-5) HURRICANE TRACKING INTO THE CARIBBEAN (10-20˚N, 60-88˚W)

1. 22% (average for last century is 42%)

ABSTRACT

Information obtained through March 2015 indicates that the 2015 Atlantic hurricane season will likely have much less activity than the median 1981-2010 season. We estimate that 2015 will have only 3 hurricanes (median is 6.5), 7 named storms (median is 12.0), 30 named storm days (median is 60.1), 10 hurricane days (median is 21.3), 1 major (Category 3-4-5) hurricane (median is 2.0) and 0.5 major hurricane days
median is 3.9). The probability of U.S. major hurricane landfall is estimated to be about 55 percent of the long-period average.

Continued on page 3.

WANT TO AVOID SPENDING A DAY IN THE DARK? IT'S AS SIMPLE AS 8-1-1

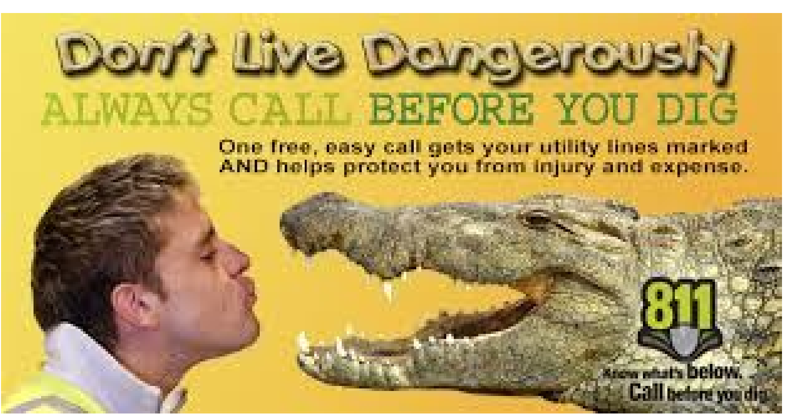
Call 811 from anywhere in the country a few days prior to digging, and your call will be routed to your local One Call Center. Tell the operator where you're planning to dig, what type of work you will be doing and your affected local utilities companies will be notified about your intent to dig. In a few days, they'll send a locator to mark the approximate location of your underground lines, pipes and cables, so you'll know what's below– and be able to dig safely. Do this before doing any digging project and you'll avoid injury, expense, embarrassment and a very inconvenient day in the dark.

The Common Ground Alliance (CGA) is a coalition of 1400 excavators, locators, road builders, electric, telecommunications, oil, gas, railroad, one call centers, public works, equipment manufacturing & suppliers, state regulators, insurance & engineering/design and emergency services. Officially formed in 2000, CGA represents a continuation of the United States Department of Transportation's Common Ground Study, which highlighted the need for one organization to continuously update best practices among the growing underground utility industry. The Common Ground Alliance was thus formed to prevent damages to underground infrastructure, reduce service disruptions, save lives, and improve safety practices industry-wide.

811 is a FCC-designated national N-11 number for homeowners and professional excavators to call before digging. 811 calls will be directed to the local One Call Center and the affected utilities, who will then mark underground lines for free. The national 811 campaign will increase awareness among the public about the importance of having utility lines marked before digging. Digging without calling can lead to severe consequences including harm to those who dig, costly damages to underground infrastructure and utility service disruptions.

Those who dig are aware of "Call Before You Dig" services, but often make risky assumptions about where utility lines are buried or when they should call. In fact a recent national survey showed that only 33% of homeowner do-it-yourselfers called to have their lines marked before starting digging projects. Simple digging jobs can damage utility lines, which can disrupt service to an entire neighborhood, harm diggers, and potentially result in fines and repair costs. 811 will let diggers know what's below when they call before they dig.

The CGA's mission is to prevent damage to underground infrastructure. The national 811 number provides a once-in-a-lifetime opportunity to focus national attention on the importance of calling before digging as simple digging jobs can damage utility lines. CGA will work with its members, sponsors, and national launch partners in the 811 campaign to increase awareness about the number and create positive behavior change.



Natural Gas Storage Levels End Heating Season Higher Than Last Year

By Stephanie Ritenbaugh/ Pittsburgh Post-Gazette

As winter makes its exit, and with it peak demand for heating, the nation's natural gas storage inventories are higher than they were this time last year, despite 2015's late start to spring temperatures.

And as the industry prepares to restock inventories during the so-called injection season between April and October, robust production will keep the natural gas market oversupplied and prices low, analysts said.

Natural gas in storage clocked in at 1.48 trillion cubic feet on March 20, according to the U.S. Energy Information Administration, representing "the first positive net injection this year."

Storage levels are 63.6 percent above this time last year but 11.6 percent below the five-year average, according to the EIA.

Meanwhile, natural gas production, driven by fracking in shale plays, posted a year-to-date high of 73.2 billion cubic feet per day on March 22.

"This was largely because of record Northeast production, which hit an all-time high of 19.9 Bcf/d," said the EIA, citing data from Colorado analytics firm Bentek Energy.

Production is expected to grow this year despite a falling rig count and plummeting oil and gas prices.

"We're seeing an average 5.5 Bcf per day increase in production over last year," said Erica Bowman, vice president of research and policy analysis for Washington, D.C.-based trade group America's Natural Gas Alliance.

"That's the story right now. It was a very cold February, but production is so strong it's keeping storage up."

Houston-based oilfield service company Baker Hughes on Friday put the U.S. rig count at 1,048 rigs after shedding 761 rigs over the last 12 months. The number of rigs targeting natural gas was 233, down 85 compared to the same time last year. In the Marcellus Shale play, 70 rigs were operating as of Friday, down compared to 76 a year ago.

"The problem is that, unlike 20 years ago when production was regularly throttled back to avoid overwhelming the market during the low-demand summer months, there is little sign that producers are backing off supply ahead of this year's injection season," said Teri Viswanath, director of commodity strategy, natural gas for financial services firm BNP Paribas.

For one thing, more efficient drilling means producers can get more out of a well than they could years ago. Another factor is a backlog of wells that have been drilled, but not yet completed, she noted.

"According to our analysis, most major shale plays are currently carrying a three-to-six month well completion backlog," Ms. Viswanath wrote in an analyst report. "Consequently, we now expect that domestic production will increase by 3.77 Bcf/d over year-ago levels as these wells are brought online over the course of the year."

Meanwhile, storage facilities may be strained this summer as more gas floods the market and prices stay low. But that means other sectors of the market could take advantage of depressed prices.

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Natural Gas Storage Levels

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“We now expect that a more significant price-induced demand growth will be required to offset supply,” Ms. Viswanath said.

Electric generation opportunity

The biggest source of demand for the fuel is going to come from the power sector, said Bob Yu, senior energy analyst for Bentek.

“In the summer, there’s not really any heating demand, so the main source comes from storage injections and power burn,” Mr. Yu said. “If production keeps at 73-Bcf/d levels, we’re expecting record levels of power burn.”

More power plants are expected to switch from coal to natural gas or retire, putting the spotlight on natural gas. That’s partly due to stricter federal regulations on emissions. Bentek expects about 13,000 megawatts will be removed through coal retirements this year. The other factor is natural gas prices are expected to stay low, making it competitive against coal.

“It’s kind of a perfect storm,” Mr. Yu said.

Consumption of natural gas for electric power generation in 2015 hit record levels earlier this year and has remained elevated through March, according to an EIA report citing Bentek data, averaging 22.7 billion cubic feet per day from Jan. 1 through March 25.

“The increase in power burn has largely been the result of two factors: low natural gas prices and cold weather,” according to EIA.

Ms. Bowman noted that while power plants are poised to consume excess supply, more sources of demand will be needed to make a dent in the market.

“There are (liquefied natural gas) exports and petrochemical plants, but those are still some time out, so it’s in a holding pattern where we have significant production struggling to find a home,” Ms. Bowman said.

“Going forward there is a concern about demand, but it’s also a great opportunity for the states that produce the gas and the states that consume it.”

FERC Adopts Changes to Natural Gas Pipeline Nomination Timelines as Part of Gas-Electric Coordination Efforts

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Aside from the nomination timeline changes, FERC’s order also requires pipelines to offer upon request, multi-part transportation contracts, whereby multiple shippers share pipeline capacity under a single firm transportation service agreement. FERC believes that the use of share capacity will make the purchase of firm capacity more affordable for gas-fired generators.

FERC indicated at its April 16 meeting that it will continue to explore improvements to natural gas and electric industry scheduling practices and coordination. One possibility, suggested by Chairman Norman Bay, is that the use of computerized scheduling could reduce nomination processing time for natural gas transportation and allow for additional intraday scheduling options. Commenting on the April 16 rule changes, Commissioner Cheryl La Fleur stated that they were an “important step, but not the last step.”

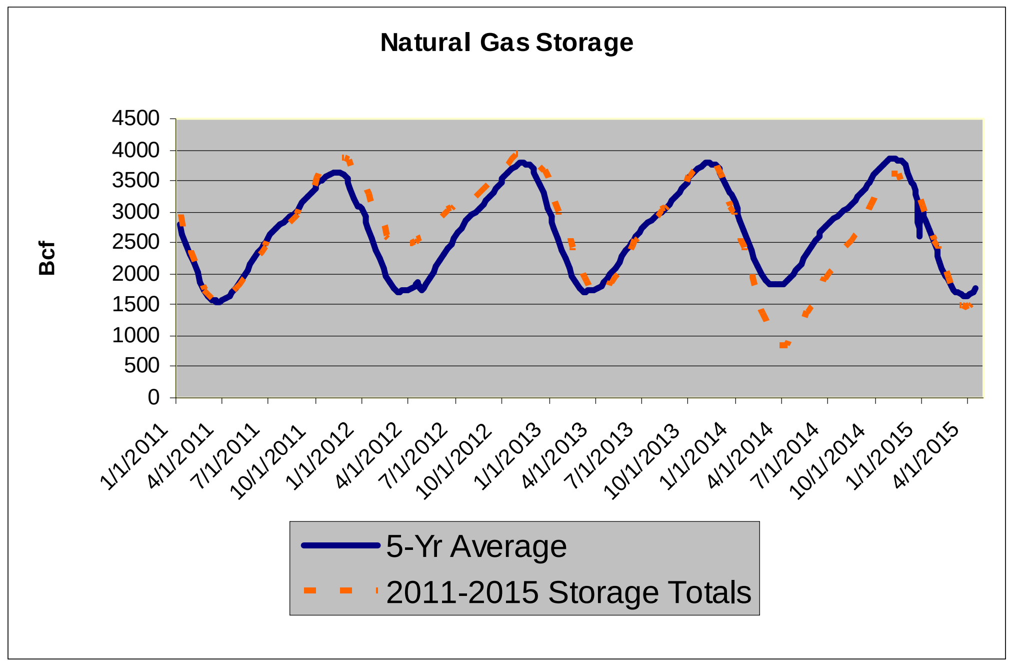
EXTENED RANGE FORECAST OF ATLANTIC SEASONAL HURRICANE ACTIVITY

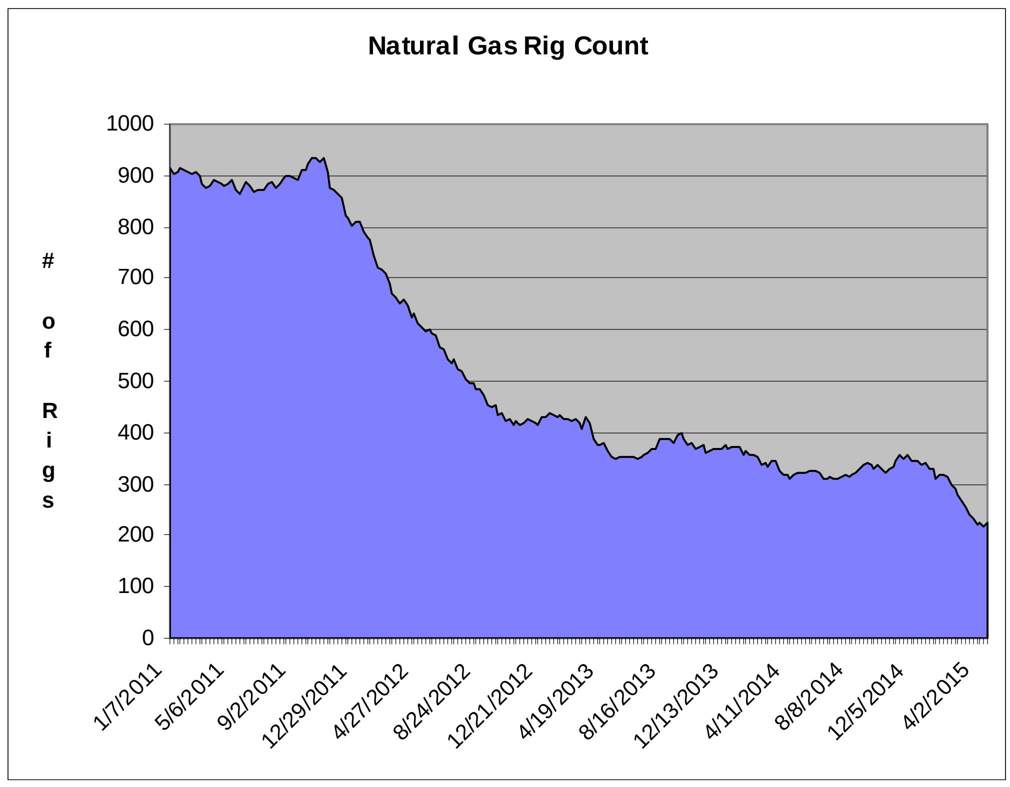
Continued from page 1.

We expect Atlantic basin Accumulated Cyclone Energy (ACE) and Net Tropical Cyclone (NTC) activity in 2015 to be approximately 45 percent of their long-term averages.

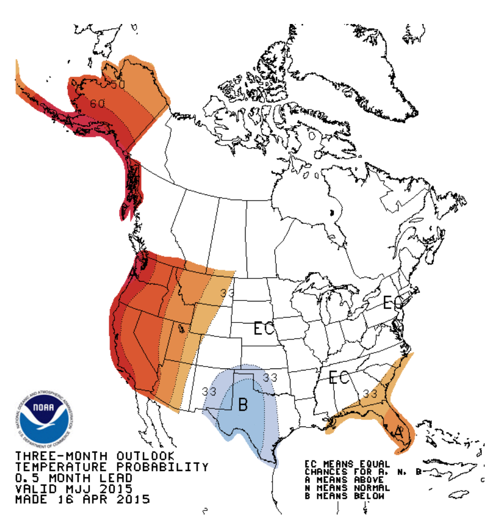
This forecast is based on an extended-range early April statistical prediction scheme that was developed utilizing 29 years of past data. Analog predictors are also utilized. We anticipate a below-average Atlantic basin hurricane season due to the combination of a high likelihood of at least a moderate El Niño event and a relatively cool tropical Atlantic. Coastal residents are reminded that it only takes one hurricane making landfall to make it an active season for them, and they need to prepare the same for every season, regardless of how much activity is predicted.

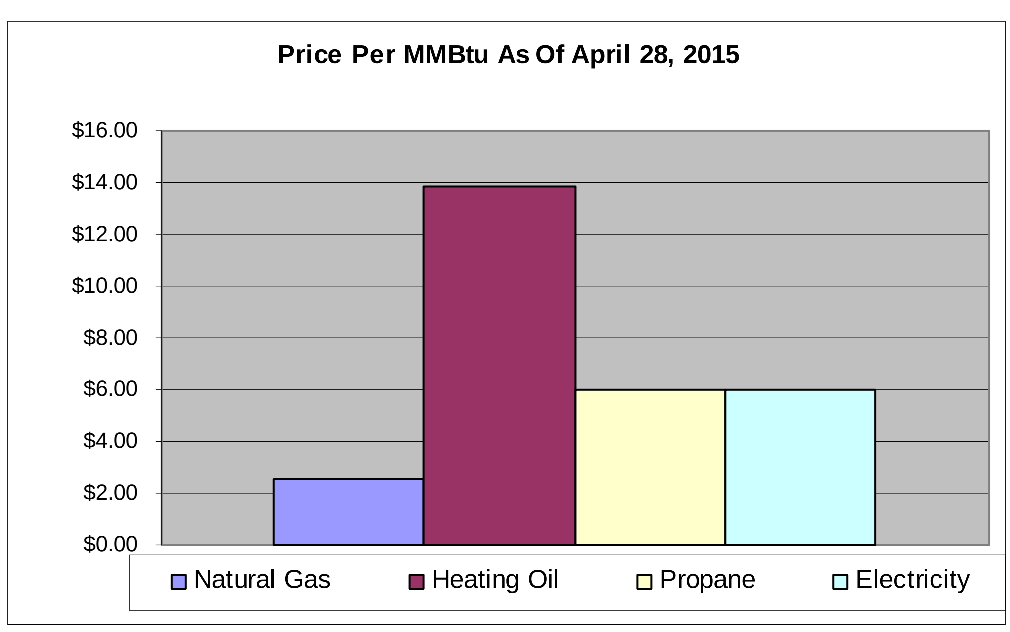
Snapshots





Seasonal Temperature Outlook
May – June – July





Annual Energy Outlook 2015

Excerpts from Annual Energy Outlook 2015 with projections to 2040 by U.S. Energy Information Administration

Future natural gas prices will be influenced by a number of factors, including oil prices, resource availability, and demand for natural gas.

Projections of natural gas prices are influenced by assumptions about oil prices, resource availability, and natural gas demand. In the Reference case, the Henry Hub natural gas spot price (in 2013 dollars) rises from $3.69/million British thermal units (Btu) in 2015 to $4.88/million Btu in 2020 and to $7.85/million Btu in 2040, as increased demand in domestic and international markets leads to the production of increasingly expensive resources.

In the AEO2015 alternative cases, the Henry Hub natural gas spot price is lowest in the High Oil and Gas resource case, which assumes greater estimated ultimate recovery per well, closer well spacing, and greater gains in technological development. In the High Oil and Gas Resource case, the Henry Hub natural gas spot price falls from $3.14/million Btu in 2015 to $3.12/million Btu in 2020 (36% below the Reference case price) before rising to $4.38/million Btu in 2040 (44% below the reference case price). Cumulative U.S. domestic dry natural gas production from 2015 to 2040 is 26% higher in the High Oil and Gas Resource case than in the Reference case and is sufficient to meet rising domestic consumption and exports-both pipeline gas and liquefied natural gas (LNG)-even as prices remain low.

Henry Hub natural gas spot prices are highest in the High Oil Price case, which assumes the same level of resource availability as the AE02015 Reference case, but different Brent crude oil prices. The higher Brent crude oil prices in the High Oil Price case affect the level of overseas demand for U.S. LNG exports, because international LNG contracts are often liked to crude oil prices-although the linkage is expected to weaken with changing market conditions. When the Brent spot price rises in the High Oil Price case, world LNG contracts that are liked to oil prices become relatively more competitive, making LNG exports from the United States more desirable.

In the High Oil Price case, the Henry Hub natural gas spot price remains close to the Reference case price through 2020; however, higher overseas demand for U.S. LNG exports raises the average Henry Hub price to $10.63/million Btu in 2040, which is 35% above the Reference case price. Cumulative U.S. exports of LNG from 2015 to 2040 in the High Oil Price case are more than twice those in the Reference case. The opposite occurs in the Low Oil Price case; low Brent crude oil prices cause oil-linked LNG contracts to become relatively less competitive and make U.S. LNG exports less desirable. Lower overseas demand for U.S. LNG exports causes the average Henry Hub price to reach only $7.15/million Btu in 2040, 9% lower than in the Reference case.

Net natural gas trade, including LNG exports, depends largely on the effects of resource levels and oil prices

In all the AE02015 cases, the United States transitions from a net importer of 1.3 Tcf of natural gas in 2013 (5.5% of the 23.7 Tcf delivered to consumers) to a net exporter in 2017. Net exports continue to grow after 2017, to a 2040 range between 3.0 Tcf in the Low Oil Price case and 13.1 in the High Oil and Gas Resource case.

In the Reference case, LNG exports reach 3.4 Tcf in 2030 and remain at that level through 2040, when they account for 465% of total U.S. natural gas exports. The growth in U.S. LNG exports is supported by differences between international and domestic natural gas prices. LNG supplied to international markets is primarily priced on the basis of world oil prices, among other factors. This results in significantly higher prices for global LNG than for domestic natural gas supply, particularly in the near term. However, the relationship between the price of international natural gas supplies and world oil prices is assumed to weaken later in the projection period, in part as result of growth in U.S. LNG export capacity. U.S. natural gas prices are determined primarily by the availability and cost of domestic natural gas resources.

In the High Oil Price case, with higher world oil prices resulting in higher international natural gas prices, U.S. LNG exports climb to 8.1 Tcf in 2033 and account for 73% of total U.S. natural gas exports in 2040. In the High Oil and Gas Resource case, abundant U.S. dry natural gas production keeps domestic natural gas prices lower than international prices, supporting the growth of U.S. LNG exports, which total 10.3 Tcf in 2037 and account for 66% of total U.S. natural gas exports in 2040. In the Low Oil Price case, with lower world oil prices, U.S. LNG exports are less competitive and grow more slowly, to a peak of 0.8 Tcf in 2018, and account for 13% of total U.S. natural gas exports in 2040.

Additional growth in net natural gas exports comes from growing natural gas pipeline exports to Mexico, which reach a high of 4.7 Tcf in 2040 in the High Oil and Gas Resource case (compared with 0.7 Tcf in 2013). In the High Oil Price case, U.S. natural gas pipeline exports to Mexico peak at 2.2 Tcf in 2040, as higher domestic natural gas prices resulting from increased world demand for LNG reduce the incentive to export natural gas via pipeline. Natural gas pipeline net imports from Canada remain below 2013 levels through 2040 in all the AE02015 cases, but these imports do increase in response to higher natural gas prices in the latter part of the projection period.

Industrial energy use rises with growth of shale gas supply

Production of dry natural gas and natural gas plant liquids (NGPL) in the United States has increased markedly over the past few years, and the upward production trend continues in the AE02015 Reference, High Oil Price, and High Oil and Gas Resource cases, with the High Oil and Gas Resource case showing the strongest growth in production of both dry natural gas and NGPL. Sustained high levels of dry natural gas and NGPL production at prices that are attractive to industry in all three cases contribute to the growth of industrial energy consumption over the 2013-40 projection period and expand the range of fuel and feedstock choices.

Increased supply of natural gas from shale resources and the associated liquids contributes to lower prices for natural gas and hydrocarbon gas liquids (HGL), which support higher levels of industrial output. The energy-intensive bulk chemicals industry gas and HGL feedstock increase by more than 50% from 2013 to 2040 in the Reference case, mostly as a result of growth in the total capacity of U.S. methanol, ammonia (mostly for nitrogenous fertilizers), and ethylene catalytic crackers. Increase availability of HGL leads to much slower growth in the use of heavy petroleum-based naphtha feedstocks compared to the lighter HGL feedstocks (ethane, propane, and butane). With sustained low HGL prices, the feedstock slate continues to favor HGl at unprecedented levels.

Other energy-intensive industries, such as primary metals and pulp and paper, also benefit from the availability and pricing of dry natural gas production from shale resources. However, factors other than lower natural gas and HGL prices, such as changes in nonenergy costs and export demand, also play significant roles in increasing manufacturing output.

Manufacturing gross output in the High Oil and Gas Resource case is only slightly higher than in the Reference case, and most of the difference in industrial natural gas use between the two cases is attributable to the mining industry-specifically, oil and gas extraction. With increase extraction activity in the High Oil and Gas Resource case, natural gas consumption for lease and plant use in 2040 is 1.6 quadrillion Btu (68%) higher than in the Reference case.

Increased production of dry natural gas from shale resources (e.g., as seen in the High Oil and Gas Resource case relative to the Reference case) leads to a lower natural gas price, which leads to more natural gas use for combined heat and power (CHP) generation in the industrial sector. In 20140, natural gas use for CHP generation is 12% higher in the High Oil and Gas Resource case than in the Reference case, reflecting the higher levels of dry natural gas production. Finally, the increase supply of dry natural gas from shale resources leads to the increased use of natural gas to meet heat and power needs in the industrial sector.