

Growing Risk of Steep Natural Gas and Electricity Price Spikes

IECA Spring Meeting
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About Andy Weissman

- **CEO, EBW AnalyticsGroup**

- Premier energy market analysis service since 2003; publishes:
 - **Market Quick Takes**, weekly snapshot of the nexus between weather and the cost of natural gas and electricity
 - **Energy Risk Report**, the only analysis designed specifically to aid energy procurement professionals
 - **Energy Flash Report**, a daily analysis with the latest changes to weather and the natural gas supply/demand balance
- To learn more, please visit **www.EBWAnalytics.com**

- **Senior Counsel at Pillsbury Winthrop Shaw Pittman**

- 30+ years experience providing strategic advice at C-suite level
- Highly regarded energy regulatory attorney and Clean Air Act expert
- Couples legal expertise with deep industry expertise

- Major role in transforming U.S. energy and environmental policy

- Helped to pioneer emissions trading in United States

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Energy Flash Report

- Natural gas demand and weather changes and forecasts
- Forecasts for current and following two natural gas storage weeks
- Delivered daily before the bell

Andy Weissman's Energy Flash Report
 TUESDAY, MAY 1, 2018
 GRADING, HEDGING AND RISK MANAGEMENT
 Published by EBW Analytics Group - Weather Decision Technologies

Bulls Could Make One More Run This Week
 This time of year, shifts in weather forecasts often have little impact on total demand for natural gas. While geography matters, both space heating demand and air conditioning demand are generally weak. Further, lower-than-normal gHDDs often correlate with above-normal CDDs and vice versa.

• Rather than focusing on day-to-day shifts in the forecast, therefore, traders concentrate primarily on cash prices (which are weakening) and the size of reported weekly injections.

• Over the next few days, the potential for a below-normal injection (the first injection of the season) could give prices a temporary boost. Forecasts for a few days of summer-like weather could also push prices higher. By next week, though, the first of a string of 100+ Bcf injections is likely and summer-like weather is expected to quickly fade. As a result, any upward blip in prices should be brief, followed by further declines.

June Natural Gas Contract
 Monday's close: \$2.763
 Down 0.8 cents (-0.3%)

NYMEX Front-Month Natural Gas Contract Price Trends

Forecast Period	EBW Predicted Trend
7-10 days (June 2018 Contract)	Brief Blip Higher Then Further Decline
30-45 days (July 2018 Contract)	Prices Start to Recover Near Memorial Day

Storage Week 1: Apr 27 to May 3
 Projected Storage Change: +98 Bcf

Storage Week 2: May 4 to May 10
 Projected Storage Change: +130 Bcf

Storage Week 3: May 11 to May 17
 Projected Storage Change: +132 Bcf

Storage Week 1: Pop-Weighted CDDs

Actual/Forecast	30-Year Norm	9.8
17.3	Anomaly	+7.5
Δ Since Yesterday	gHDDs	49.9
+1.4		

Storage Week 2: Pop-Weighted CDDs

Forecast	30-Year Norm	13.1
21.8	Anomaly	+8.7
Δ Since Yesterday	gHDDs	22.0
+1.1		

Storage Week 3: Pop-Weighted CDDs

Forecast	30-Year Norm	16.9
24.7	Anomaly	+7.8
Δ Since Yesterday	gHDDs	16.8
+1.6		

Storage Week 1: PowerSector Demand

Actual/Forecast	Δ Since Yesterday	-0.3
29.3	Δ Since Last Year	-1.2

Storage Week 2: PowerSector Demand

Forecast	Δ Since Yesterday	-0.6
25.0	Δ Since Last Year	-4.1

Storage Week 3: PowerSector Demand

Forecast	Δ Since Yesterday	+0.0
24.1	Δ Since Last Year	-2.3

Cumulative Changes Since Yesterday

CDDs	Demand	Price Impact
+4.1	-6.2 Bcf	-2.1c/MMBtu

Cumulative Changes Since Last Friday

CDDs	Demand	Price Impact
+12.6	-5.7 Bcf	-1.9c/MMBtu

Projected mid-November natural gas storage at Monday's strip prices: 3,678 Bcf | Coal displacement: 4.0 Bcf/day

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 TUESDAY, MAY 1, 2018

Natural Gas Storage Change

Week Ending	CDDs	Injection	Changes	vs. 2017
04/19/2018 (actual)	8.0	-18	0	-92
04/26/2018 (forecast)	7.8	60	0	-7
05/03/2018 (forecast)	17.3	98	2	53
05/10/2018 (forecast)	21.8	130	4	62
05/17/2018 (forecast)	24.7	132	0	57

Total Underground Storage (Bcf)

Week Ending	Total Storage	vs. 2017	vs. 5-Year Avg
04/19/2018 (actual)	1,281	-897	-527
04/26/2018 (forecast)	1,341	-905	-544
05/03/2018 (forecast)	1,439	-856	-521
05/10/2018 (forecast)	1,568	-791	-481
05/17/2018 (forecast)	1,700	-733	-438

Significant Developments

- A new report by Raymond James suggests a difficult road ahead for natural gas producers. While Raymond James leaves its 2018 forecast unchanged at \$2.75, it also contends that, over the long term, \$2.50/MMBtu should be adequate to balance supply and demand.
- While weather conditions next winter will play an important role, in our view Raymond James' \$2.25/MMBtu forecast for 2019 is a plausible scenario. At this price level, the financial pressure on some natural gas producers could be intense.
- A second report by Raymond James on energy storage takes a further negative view on future demand for natural gas. It contends that, as costs for storage continue to decline, by early in the next decade use of storage to meet peak demand could start to significantly erode the market for natural gas.
- On a more positive note, the Michigan PSC has approved a proposal by DTE to build a new 1,100 MW gas-fired combined-cycle unit to partially replace 2,200 MW of older coal-fired units on its system. The coal units slated for retirement have been a core component of DTE's generating fleet for more than 50 years. The new combined-cycle unit is expected to come online by 2021, potentially increasing power sector demand for natural gas in Michigan by as much as 0.25 Bcf/d.

What the Charts Are Telling Us

Month-over-Month Change in US Dry Gas Output by State, January v. February 2018 (Bcf/d)

- Lower 48 onshore dry natural gas production reached 75.8 Bcf/d in February, according to EIA's latest release of monthly production data — up more than 1.4 Bcf/d vs. January. Lower 48 dry gas production grew an estimated 7.7 Bcf/d since February 2017.
- Texas (recovering from January freeze-offs) and Pennsylvania accounted for 0.6 Bcf/d of the month-over-month surge, complemented by Louisiana (0.21 Bcf/d), Ohio (0.18 Bcf/d) and New Mexico and Oklahoma (0.16 Bcf/d apiece).
- With continued rig count additions in oil-directed plays and new pipeline capacity in the Northeast expected this year, Lower 48 onshore gas production should increase at a rapid clip.
- Even so, incremental output may be needed to replenish depleted US storage inventories before next winter, reducing the bearish impact on NYMEX natural gas futures.

Weekly Degree Days by EIA Region

Calendar

NG Storage Report	May 3	June Options Expire	May 25
EIA STEO	May 8	June Contract Expires	May 29
EIA DPR	May 14	EIA NG Monthly	May 31

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Energy Risk Report

- The only publication with *specific procurement recommendations* for large energy users
- Designed to assist buyers with optimizing timing of electricity and natural gas purchases
- Delivered in four easy-to-read issues each month: National, MISO + ISO-NE, ERCOT + CAISO, and PJM + NYISO

NATIONAL ISSUE
FEBRUARY 15, 2018

Energy Risk Highlights

Electricity futures gained in most regions over the past month, reflecting an increase in perceived risk following repeated scarcity pricing in the Northeast and ERCOT. Risk premiums for winter electricity futures increased over the past month, record cold in early January and a second bout of frigid temperatures mid-month. Looking forward, however, end users may benefit from lower prices as surging natural gas production helps reduce the cost of the marginal source of supply.

Significant regulatory developments—including FERC's rejection of the DOE's NOPR and the sweeping end-of-year tax overhaul—carry important implications for the future of the electricity sector. FERC rejected DOE's proposal to grant coal and nuclear operators cost recovery plus profits and pushed the issue down to the ISOs. For their part, grid operators—led by PJM, ISO-NE, and MISO—are considering changes to capacity or energy markets that will boost prices paid by end users to help support struggling coal and nuclear units.

The tax reform overhaul may lead to lower regulated rates-of-return on existing pipeline, transmission, and distribution infrastructure—potentially yielding lower prices for end users. Lower tax rates, however, may also diminish the value of renewable tax credits and slow the growth of the low marginal cost resource.

Record cold to begin 2018 led to scarcity prices—even though monthly average temperatures are close to normal—highlighting the asymmetric price risk faced by end users. Notwithstanding periods of extreme warmth to bring January 2018 within a few pIDs of normal, prices will likely register significantly above average. The ability of prices to skyrocket during extreme grid conditions should serve as a reminder of the benefits of hedging risks for end users.

Natural gas prices rose over the past month, but the coming deluge of production gains could push prices sharply lower over the next several months. After a record-breaking 2017, natural gas production growth may set an even quicker pace in 2018. New Appalachian pipelines and strong oil pricing indicate the key drivers of surging production are likely to continue this year, potentially setting up an extremely advantageous position for end users later this year for Cal 2019.

Andrew D. Weissman, Editor in Chief

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Change in Wholesale Market and Natural Gas Prices for Cal 2018 Futures since December 18, 2017

PJM REVIEW
PJM offers competing capacity market proposals.

OUR PROJECTIONS AND RECOMMENDATIONS

Time Period	EW* Recommendation	12/18/2017	1st Feb Month	1st Feb January	12 Month Range	1st Qtr Actual Price
Apr-Aug 2018	Portfolio	\$15.72	\$0.80	\$1.26	\$27.45-\$10.94	\$14.31
Sep-Dec 2018	Portfolio	\$14.26	\$0.58	\$1.03	\$11.09-\$14.06	\$12.84
Cal 2019	Wait	\$11.48	\$0.55	\$0.02	\$13.33-\$14.06	---
Cal 2020	Portfolio	\$15.00	\$0.55	\$0.39	\$10.49-\$15.34	---

Key Takeaways

- PJM finds FirstEnergy retirements have little reliability impact.** Nuclear retirements alone may increase ISO-wide energy costs by \$1.5 billion annually, however.
- Federal intervention to help coal and nuclear units a real possibility.** Secretary Perry could declare a grid emergency to grant coal and nuclear plants full cost recovery.
- PJM submits competing capacity market reform proposals.** Both may encounter difficulty with a Commission prioritizing stakeholder support, but long-term upside risk is intact.

FirstEnergy Retirements Won't Threaten Reliability, PJM Finds

PJM West electricity futures trended higher in April. Summer and fall 2018 strips ticked higher by 48¢/MWh (1.3%) and 71¢ (2.2%) month-over-month, while winter 2018-2019 contracts gained 61¢ (1.8%) on average. Cal 2019 and Cal 2020 reflected near-term upward price movement, adding 71¢ (2.0%) and 22¢ (0.6%) spikes over the same period.

Wholesale electricity futures may be bounded higher on (i) the growing market expectation that PJM would pass price reforms designed to increase generator compensation, and (ii) FirstEnergy's retirement announcements.

Dominion South natural gas futures generally declined since late March. Balance of Cal 2018 contracts gained 1¢/MMBtu (0.3%) since the end of March, while Cal 2019 slid 6¢ (2.7%) and Cal 2020 depreciated by 4¢ (1.6%). That wholesale power futures trended higher month-over-month despite flat-to-declining natural gas prices underscores the impact of regulatory and retirement-related price risk on the electricity side.

PJM finds FirstEnergy's announced retirements would not impact grid reliability. FirstEnergy filed for bankruptcy in late March after petitioning Department of Energy Secretary Rick Perry to utilize his authority under the Federal Power Act (FPA) to declare a grid emergency to grant coal and nuclear plants cost-of-service treatment.

PJM initially lambasted the idea of a pending crisis and recently issued a report finding Pennsylvania and Ohio would not face reliability issues even if all of FirstEnergy's announced retirements occurred. Still, retirements could yield higher zonal capacity and energy prices. Analysis by the Brattle Group found PJM end users could pay an extra \$1.3 billion annually if FirstEnergy's three nuclear plants were closed and replaced by a 73:25 mix of gas and coal generation.

PJM's reliability finding may not prevent more aggressive federal intervention to reduce baseload retirement pressures, however. Although DOE spokespeople have previously suggested such a move was unlikely, recent public comments from Secretary Perry himself have raised concerns he is taking FirstEnergy's request seriously.

2 Energy Risk Report DO NOT DISTRIBUTE

NATURAL GAS
NATIONAL OVERVIEW

NYMEX Front-Month Natural Gas Contract (\$/MMBtu), Since 2016
Winter risk premiums have deteriorated substantially

Gas in Storage in Second Week of January, Last Six Years (Bcf)
Storage 30% Bcf below five-year average

reversed, with new pipelines entering service and strong oil market fundamentals reflected in multi-year record prices.

Given these stronger circumstances, it would not be surprising to see 2018 production growth eclipse 2017's record output gains, putting very strong downward pressure on natural gas by mid-2018 and carrying into Cal 2019.

Associated gas production has been a critical part of recent natural gas production growth, increasing ties between global oil markets and U.S. natural gas and electricity markets. Roughly half of record production growth in 2017 came from shale basins traditionally driven more by oil economics than natural gas prices.

Currently, oil market fundamentals are strong and oil prices are hovering near multi-year highs, encouraging more oil production and increased associated gas output.

Should oil prices weaken, however, these market signals would reverse, reducing associated gas output and total natural gas supply, ultimately putting upward price pressure on both domestic gas and power markets.

The potential for seasonal LNG weakness to emerge may weigh on gas prices during the shoulder season. Dominion's Cove Point LNG facility has been delayed until late March or early April, nearly six months from the initially projected in-

service date. The delay has already erased 125 Bcf of projected demand, and further delays should not be ruled out.

In addition, other prominent natural gas analysts are beginning to share our outlook that a relative lack of international storage capacity may weigh on natural gas prices, possibly sending global LNG prices below \$1.00/MMBtu and resulting in temporary U.S. capacity shortages.

We recommend end users take risk off the table through the end of winter—with those willing to shoulder a slightly higher-risk scenario waiting for weak fundamentals to push more attractive pricing for the balance of Cal 2018 and Cal 2019, and adopting a portfolio procurement approach for Cal 2020. Weather-driven upside price risks continue in the immediate term, with the potential for cold weather to return and send natural gas spot market prices spiking erratically.

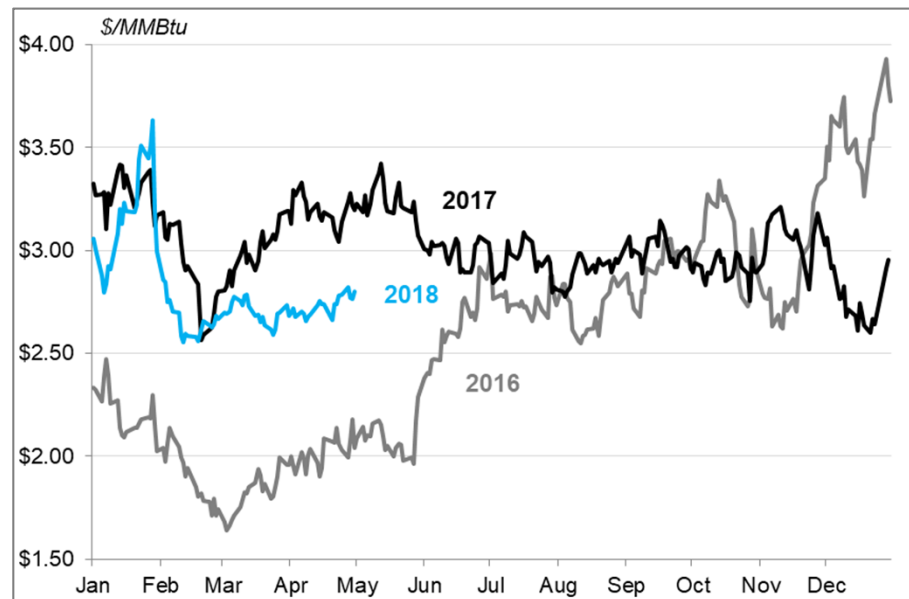
In the medium-to-longer term, however, the natural gas supply spigot appears wide open, and—although timing remains difficult to pinpoint—strong downward pressure on gas futures is likely to emerge by the back half of Cal 2018 and into Cal 2019.

By Cal 2020, however, factors driving the likely medium-term price weakness, including a strong oil market and weak global LNG dynamics, could fade and lead to a more balanced risk/reward procurement outlook. ■

Good News First

- Growth in natural gas supply greatly outpacing demand
- While winter still matters, 2018-2019 electricity and natural gas prices in most regions likely to be at or near multi-year lows
 - Potential doomsday scenario for some natural gas producers
 - Could trigger new wave of coal and nuclear retirements

Front-Month Natural Gas Contract Prices,
2018 v. Last Two Years (\$/MMBtu)

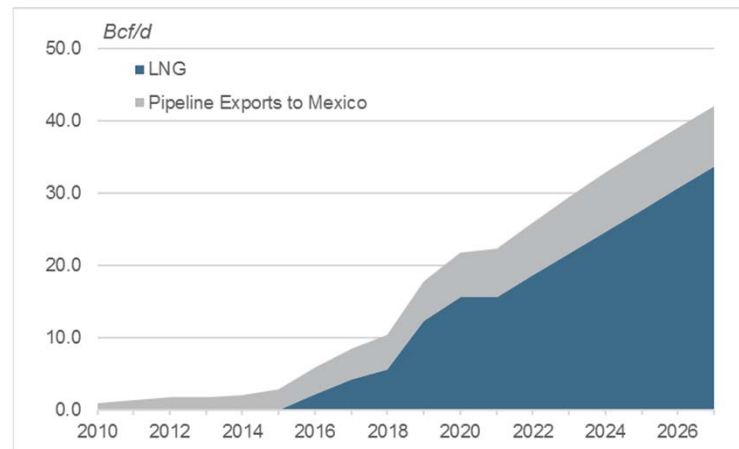


Source: Bloomberg, EBW Analytics

Far-reaching Transformation of US & Global Energy Market

- Past *not* necessarily prologue
- Massive changes
 - US in the process of becoming #1 oil producer and oil exporter in the world
 - Huge surge in production of associated gas
 - Massive increases in US LNG and natural gas pipeline exports
 - Sweeping changes in composition of electricity grid
 - Unprecedented coal and nuclear retirements
 - More stable cost structure than natural gas
 - Dramatic increases in on-shore wind, utility-scale solar, off-shore wind and energy storage
 - Increased reliance on transmitting power over long distances
- Dysfunctional FERC market rules
 - Stunning failure by the Commission to adapt to changing market needs
 - Operating almost entirely in the dark

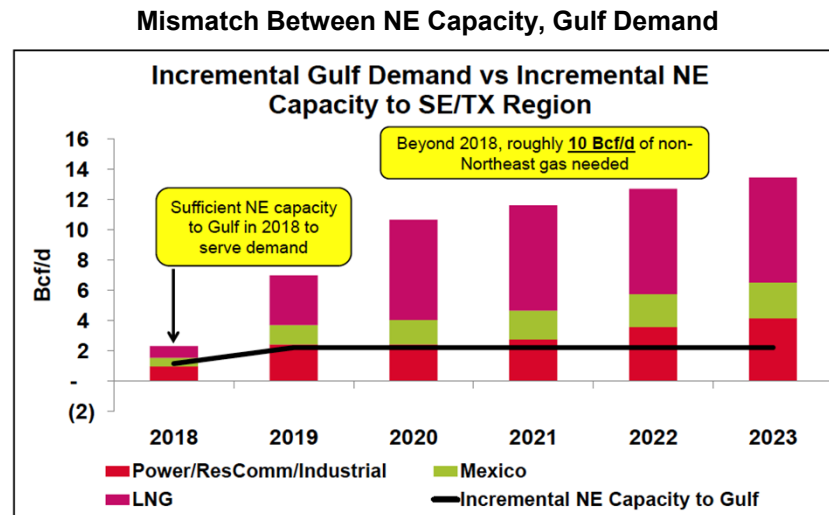
Total Natural Gas Demand for LNG and Pipeline Exports to Mexico, 2010-2027 (Bcf/d)



Source: EIA, EBW Analytics

Impacts Not Yet Fully Understood

- Creates tight linkage between US natural gas, electricity and oil prices and global markets
- Requires massive infrastructure buildout not yet occurring
 - Interstate oil and gas pipelines, natural gas storage and electric transmission
 - High risk infrastructure expansion will lag market needs
- Radically changes gas flows within the US
 - Already resulting in Henry Hub selling at a significant premium to most other hubs
- Combination of these factors greatly increases risk of extreme price volatility by early in the next decade

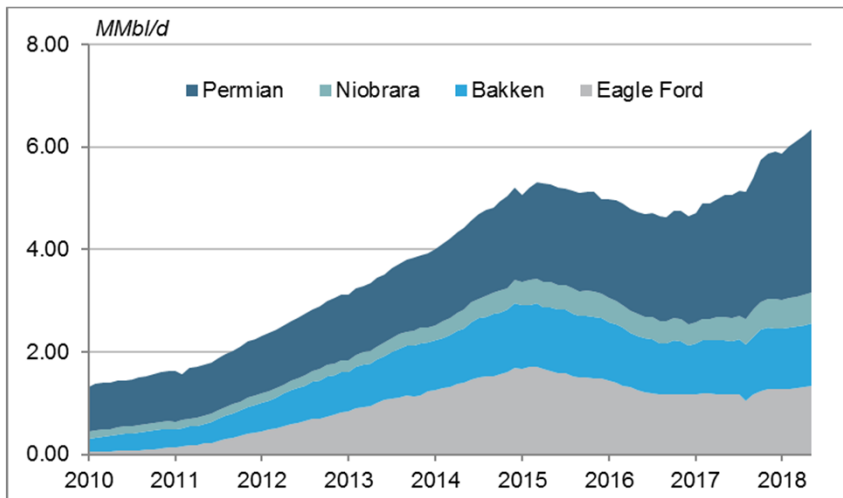


Source: Platts

Emergence of US as #1 Oil Producer in the World

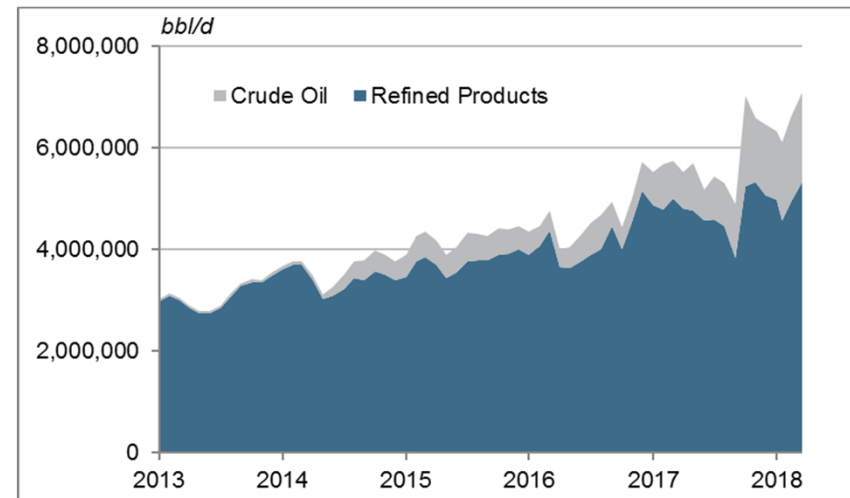
- Dramatic increases in US production and exports
- Global supply deficit emerging much earlier than previously expected
 - Stronger than expected growth in global demand
 - Rapid depletion of other supply sources
- Sharp decline in global CapEx starting four years ago and current low prices creates high risk of major supply deficits
 - Potentially as early as next year, but nearly certain by 2020-2021
- US = swing supplier
- Production likely to soar, potentially exceeding nearly every projection
- Huge implications for production of associated gas

Monthly Crude Oil Production from the Four Largest US Shale Plays, 2010-2018 (MMbbl/d)



Source: EIA

US Monthly Crude and Refined Product Exports, 2013-2018 (MMbbl/month)

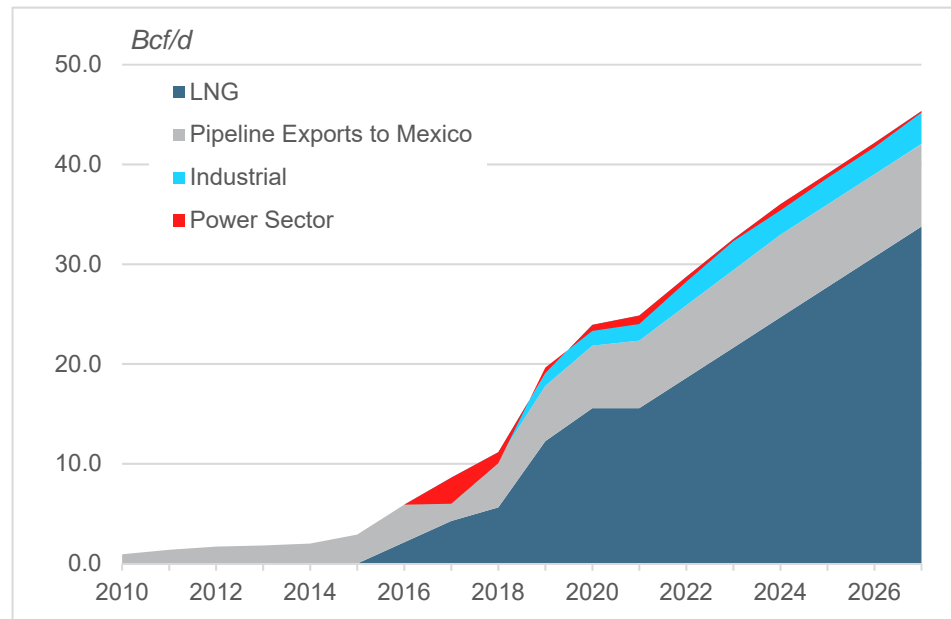


Source: EIA

Unprecedented Growth in Demand

- Driven primarily by four factors:
 - Pipeline exports to Mexico
 - LNG exports
 - Strong growth in industrial demand
 - Continued growth in power sector demand

Natural Gas Demand for LNG and Exports to Mexico Plus Net Growth in Industrial and Power Sector Demand from 2016 Onward, 2010-2027 (Bcf/d)

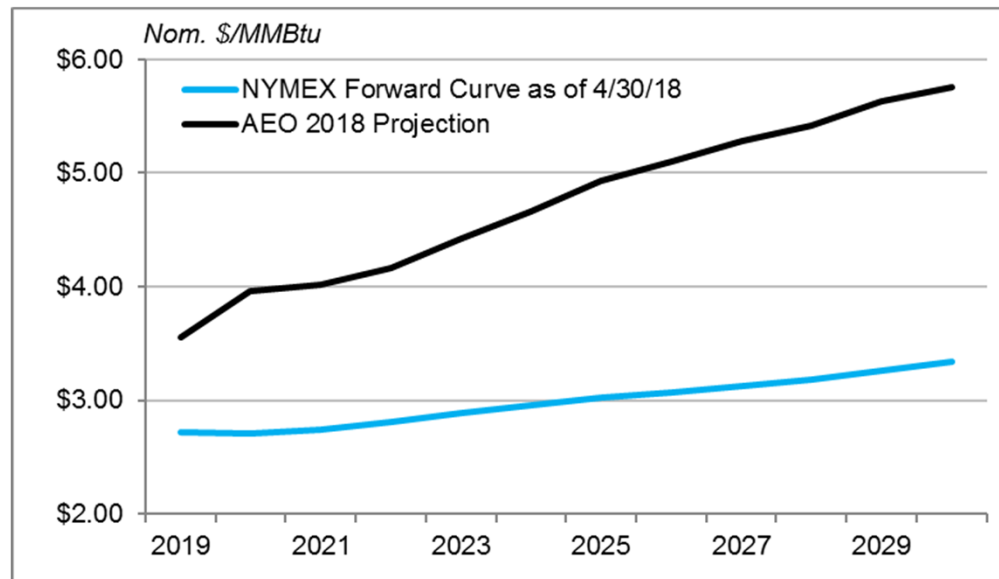


Source: EIA, EBW Analytics

Is There Enough Gas to Keep Prices Moderate?

- Huge disconnect between EIA forecast and NYMEX forward curve
 - Potential prices could significantly exceed EIA forecast
 - Particularly at Henry Hub
- Upside price risks include:
 - Potential that “sweet spots” in major shale plays will soon be exhausted
 - Infrastructure constraints
 - Both pipelines and storage
 - Increases in oilfield service costs

NYMEX Henry Hub Forward Curve v. EIA Henry Hub Price Outlook, 2019-2030 (Nom. \$/MMBtu)

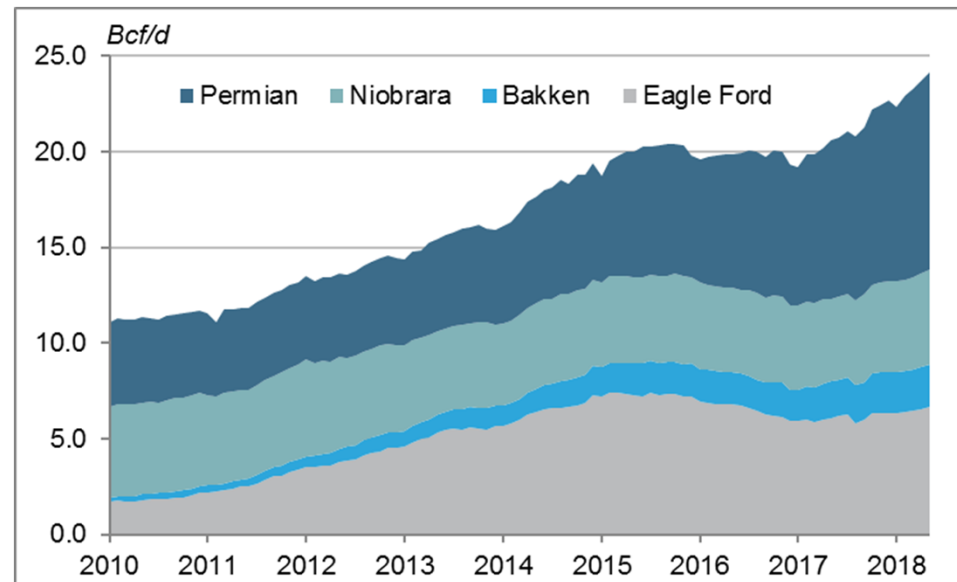


Source: Bloomberg, EIA AEO

Countervailing Factors

- Factors that could keep prices moderate next 5-10 years:
 - Vast increases in production of associated gas
 - Much lower decline rate than previously expected
 - Could reach 30 Bcf/day from Permian Basin alone
 - Ability to tap additional sources of supply still at an early stage in development
 - High Alpine
 - Canada
 - Continued improvements in technology
 - Future costs for Tier II and III reserves could prove to be inline with current Tier I
 - Enhancing future production from existing wells
 - Development of multiple seams

Associated Gas Production in the Four Largest US Shale Oil Plays, 2010-2018 (Bcf/d)



Source: EIA DPR

Major Upside Price Risks Not Primarily Due to Limitations on Available Supply

- Most significant risk factors:
 - Failure to build-out adequate infrastructure in timely manner
 - Inability to deliver sufficient natural gas to key regional markets in winter
 - Potential for runaway basis differentials at Henry Hub
 - Volatility of demand for US LNG exports
 - Bidding wars possible with some of the deepest pockets in the world

Regulatory Failure Has Cost End Users More than \$500 Billion

- Infrastructure risks due primarily:
 - Monumental CapEx requirements
 - Lack of coherent FERC policy or sound planning by RTOs
 - Failure to examine electricity and natural gas market in an integrated manner
 - Failure to plan or provide mechanisms to pay for system needs
 - Primary cause of \$500 billion in unnecessary costs since industry restructuring began
 - Concerted campaign to stop development through litigation
- ***FERC natural gas pipeline review most important FERC rulemaking for industrial energy users in years***
 - One of the biggest regulatory failures ever

Gas Deliverability Most Critical Issue Facing Markets in Northeast and California

- Resilience NOPR profoundly misguided
 - Key issue = gas deliverability
 - Not yet being examined by FERC
 - PJM just starting
- RTOs in the Northeast pay massive amounts to ensure adequate total generation to meet peak demand – but nothing to ensure availability of gas to gas-fired generating units
- At height of this year’s cold snap event, nearly 45,000 MW of gas-fired generation in three Northeast ISOs remained idle
 - Zero benefit to end users, despite tens of billions of capacity payments over past decade
 - “Paper” reserve margins were just that
 - PJM and other RTOs attribute ideal status to dispatch cost
 - In fact, even at record high natural gas prices, no supplies remained available to dispatch these units
- Under entirely plausible scenarios, Northeast could have been short as much as 20,000-30,000 MW of generation, with potentially catastrophic consequences

Total and Idle Gas-Fired Capacity by ISO, January 1-January 7, 2018

	PJM	NYISO	ISO-NE	Total (MW)
Idle Capacity (MW)	12,480	19,118	13,125	44,723
Total Gas-Fired Capacity (MW)	37,066	22,170	17,091	76,327
% Idle Capacity	33.7%	86.2%	76.8%	58.6%

Source: ISO-NE, NYISO, PJM, EBW Analytics

At highest PJM capacity price in the last three years (\$164.77/MW-day), the total capacity payment for the 44,723 MW of idle Northeastern gas capacity would be \$7,369,009/MW-day, or \$2.69 billion/MW-year.

Ensuring Adequate Deliverability of Natural Gas on Peak Winter Days a Huge Challenge

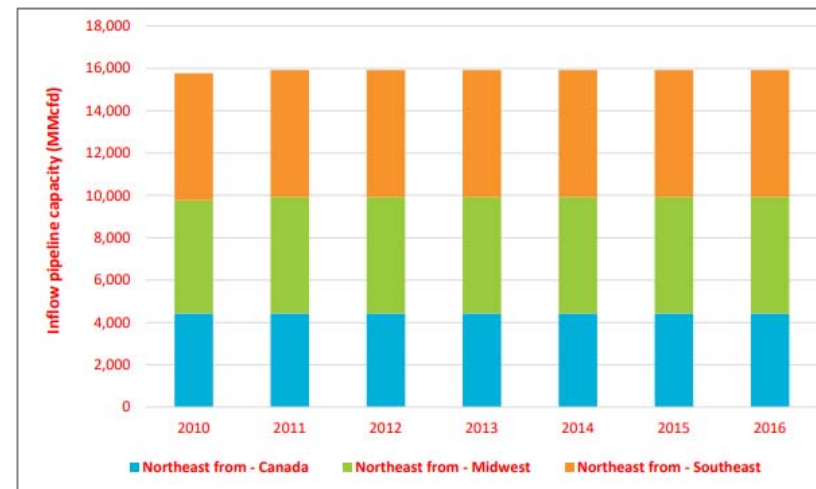
- Needle peak in demand for natural gas three to four times steeper than mid-summer peak in electricity demand
 - On January 1st (the coldest day), total US demand for natural gas was twice total US production
 - Ratio even steeper in Northeast
 - Only 35-40% of gas utilized in the region obtained from wells in the Northeast
- Only remaining sources of supply were pipeline imports into the region + withdrawals from regional storage
 - Both were fully tapped out, limiting total supplies available for use in the three RTOs in the Northeast to 58-60 Bcf/day
- *All* of this gas was utilized for space heating and dispatch of small amounts of gas-fired capacity
 - No more gas available to operate 45,000 MW of idle gas-fired capacity
- Only way to balance supply and demand of gas was to bid regional prices for natural gas high enough so that these generating units were no longer in the money
 - Left *zero* generation available to be dispatched

Daily Natural Gas Demand (including exports), April 1 2017 to March 31 2018



Source: Platts

Pipeline Inflow Capacity into the Northeast, 2010-2016 (MMcf/d)



Source: Department of Energy National Energy Technology Laboratory

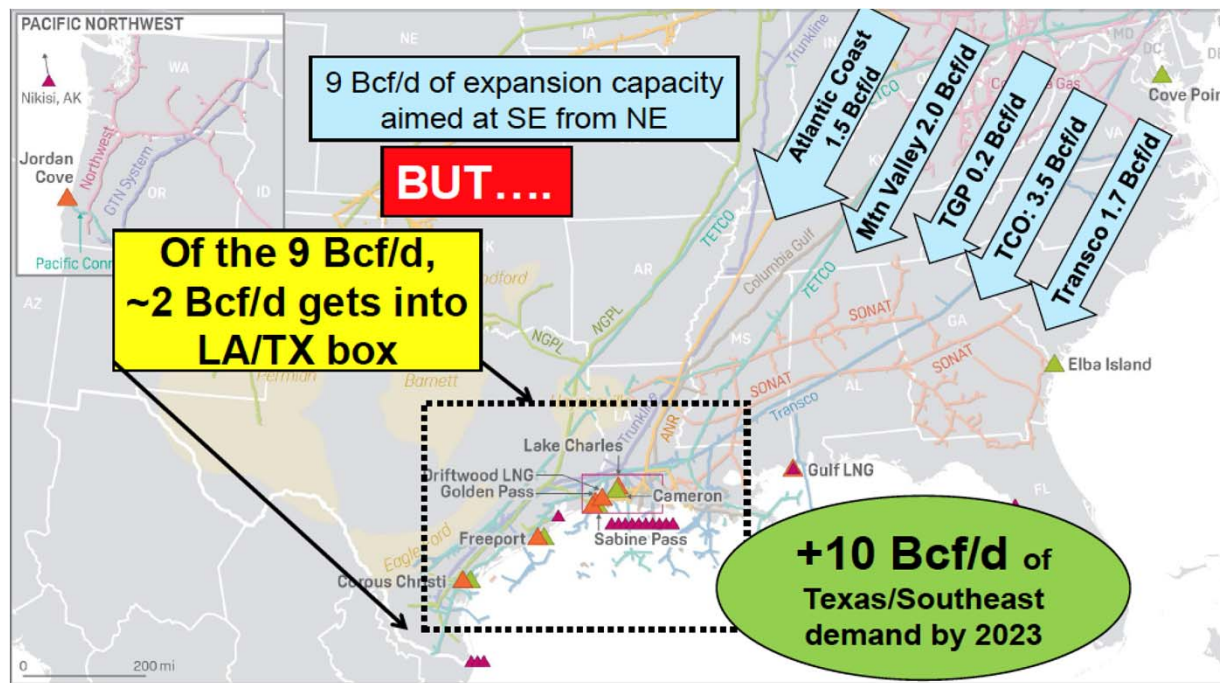
Conditions Could Easily Have Been *Much* Worse

- Any of a long list of factors could have reduced supplies available for power generation and/or required more generation to be dispatched
 - By comparison, \$175/MMBtu price for natural gas and \$300/MW+ prices for electricity would have seemed modest
- Factors that could have led to more severe crisis – none of which require extreme assumptions – include:
 - Coldest day occurring one day later, on January 2nd (a normal workday) vs January 1st holiday when nearly all commercial electricity users and some industrials were shut down
 - Colder temperatures (increasing space heating demand)
 - Future coal and nuclear plant retirements (including those already scheduled for next winter)
 - Multiple cold weather episodes that depleted on-site oil supplies at dual-fired plants that burned oil during the first week in January (when some plants were nearly running out of oil and system-wide on-site storage was reduced to 19% of maximum capacity)
 - Higher incidence of well-head or pipeline shutdowns
 - Higher forced-outage rate for coal and nuclear retirements
 - Firm commitments by producers in Marcellus Shale to ship gas to other regions
- Electricity and natural gas prices could have spiked to two to four times early January levels
 - Excess costs to end users could easily have been \$50 billion or more
- Even *with* all-time record prices, the lights would have gone out over large portions of the Northeast

Henry Hub Basis Differential Just as Significant an Issue

- Basis differential vs. Chicago and many other regional highs already at record levels
- As regional demand continues to increase, likely to get much worse
 - May lead to serious challenges in hedging prices for electricity and gas
- No quick fix

The Last Mile Problem: New Northeast Capacity Falls Short of Southeast Markets



Source Platts

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