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U.S. DEPARTMENT OF ENERGY

Before the

SUBCOMMITTEE ON ENERGY AND POWER

COMMITTEE ON ENERGY AND COMMERCE

U. S. HOUSE OF REPRESENTATIVES

MARCH 6, 2014

Chairman Whitfield, Ranking Member Rush, and Members of the Committee, thank you for the opportunity to appear before you today.

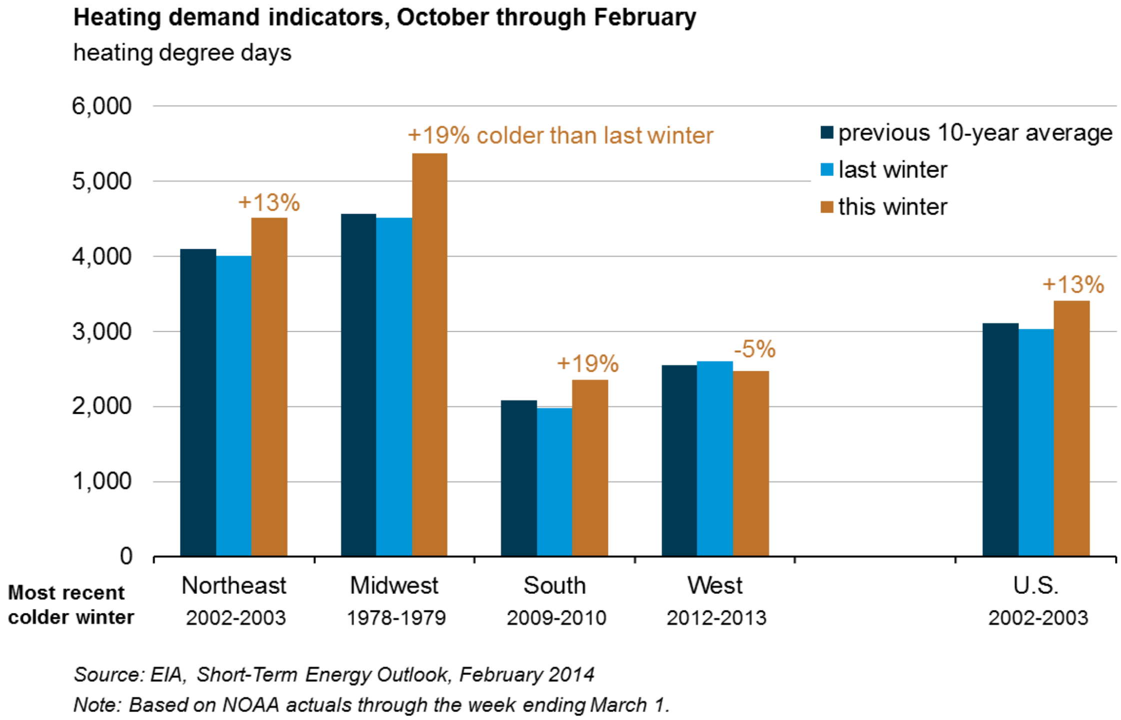
The U.S. Energy Information Administration (EIA) is the statistical and analytical agency within the U.S. Department of Energy. EIA collects, analyzes, and disseminates independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding regarding energy and its interaction with the economy and the environment. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government, so the views expressed herein should not be construed as representing those of the Department of Energy or any other Federal agency.

As discussed in my testimony, EIA is active in providing both data and analysis specifically related to winter fuels markets, including forecasts of average heating fuel expenditures by region and primary heating fuel. EIA reports on the status of fuels markets through many channels, including the Weekly Petroleum Status Report, This Week in Petroleum, the Weekly Natural Gas Storage Report, the Natural Gas Weekly Update, the monthly Short Term Energy Outlook and in numerous short analyses in Today in Energy. From October through March, in cooperation with participating States, EIA publishes the Heating Oil and Propane Update weekly. Since January EIA has had a dedicated Energy Market Alerts section on the website and has been working closely with the Department of Energy's Energy Response Organization to provide critical market information to the public officials, industry and consumers.

Every year, the October issue of the Short Term Energy Outlook, which reflects the latest available winter weather forecast provided by the National Oceanographic and Atmospheric Administration (NOAA), serves as the basis for EIA's presentation at the Winter Fuels Outlook conference organized by the National Association of State Energy Officials. All estimates are updated regularly as the winter progresses.

Weather

As we now know, temperatures east of the Rocky Mountains have been significantly colder this winter (October - February) compared with the forecast used in developing the Winter Fuels Outlook, the same period last winter, and the previous 10-year average, putting upward pressure on both fuel consumption and the prices of fuels used for heating. U.S. average heating degree days (HDD) were 13% higher than last winter (indicating colder weather) and 10% above the previous 10-year average. Compared to last winter, the Northeast has been 13% colder, the Midwest 19% colder, and the South 19% colder, while the West has been 5% warmer. For the United States as a whole, this October through February period has been the coldest since 2002-03, while the Midwest has not been colder since 1978-79.



Recent cold weather had the greatest effect on propane prices, particularly for consumers in the Midwest. Cold temperatures tightened supplies in the both the Midwest and the East that were already low heading into the winter heating season, in part due to late fall consumption of propane to dry a large and wet corn crop. Residential propane prices in the Midwest rose from an average of $2.08 per gallon (gal) on December 2, 2013, to $4.20/gal on January 27; retail prices fell back to $3.83/gal on February 3 and $2.78/gal by March 3. To a lesser extent, cold temperatures tightened heating oil supplies and helped drive up retail prices. However, while both average prices and consumer expenditures for homes heated with propane are likely to be substantially higher this winter than last, EIA still expects that U.S. heating oil prices this winter will average slightly below those in the winter of 2012-13.

Developments in wholesale propane and heating oil markets are quickly reflected in retail prices. Higher retail prices for propane and heating oil directly affect the out-of-pocket cost of fuels purchases by customers who use these fuels for heating. In recent years, propane and heating oil prices delivered to residential consumers have been substantially higher than delivered natural gas prices on an energy content basis, a situation that was exacerbated during recent price spikes. For example, the Midwest average retail propane price of $4.20/gal during the week of January 27 was five times the estimated national average delivered price of natural gas to residential consumers during January on an energy-equivalent basis.

EIA has been able to provide current pricing information during the winter fuels season because of our cooperative data collection efforts with the State Energy Offices through the State Heating Oil and Propane Program (SHOPP). For the months of October through Mid-March, EIA provides 50/50 cost sharing for the states that choose to participate to make weekly telephone calls to retail heating oil and propane outlets. EIA creates and maintains the sample for each State and releases the data, which is closely watched by policymakers, consumers, and analysts, every Wednesday as part of the Weekly Petroleum Supply Report.

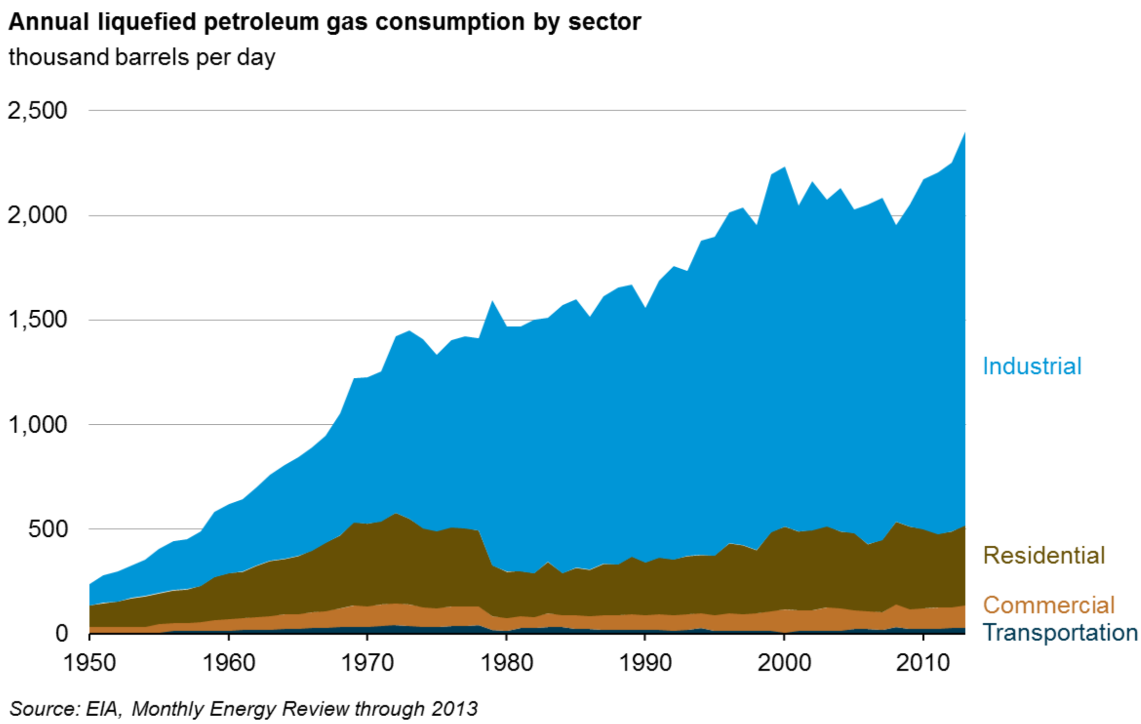
The rest of my testimony will focus on propane markets across the Midcontinent and on the natural gas market, with an emphasis on New England.

Propane

Propane is produced from natural gas at processing plants, usually located in areas where natural gas is produced, at fractionating plants that further process mixed natural gas liquids separated at processing plants, and from crude oil at refineries. Propane from natural gas has been the fastest-growing component of overall U.S. propane production. U.S. supply set record highs on an almost weekly basis in 2013 as a result of increased oil and natural gas drilling.

There are two major hubs for propane in the Midcontinent: Mont Belvieu, Texas (on the Gulf Coast) and Conway, Kansas (in central Kansas).   With the rapid growth in U.S. propane supply, domestic production has exceeded domestic consumption, and the United States has become a net propane exporter.   Exports from the United States, primarily shipped via tanker from the U.S. Gulf Coast (PADD 3) were 402,000 barrels per day in December. However, the United States has also continued to import significant amounts of propane (121,000 barrels per day in December) via tanker into Northeast (PADD 1) ports, and via several pipelines that carry supplies from Canada into the Midwest (PADD 2) particularly Minnesota and Michigan.

The largest market nationally for propane and propylene is the industrial sector, including agriculture. Propane is also used heavily in the residential and commercial sectors in more rural areas that may lack natural gas infrastructure. Residential and commercial demand has a strong seasonal pattern, with a winter peak to meet heating needs.



Last fall, a record corn harvest increased the demand for propane in the Midwest. Because propane is used for crop drying, a wet growing season in the Midwest combined with the largest corn yield in U.S. history greatly increased the demand for propane. On December 12, 2013, EIA reported in Today in Energy, Propane demand hits a record high for November, "For the week ending November 1, the United States consumed nearly 1.8 million barrels per day—a figure typically not seen until January or February, when the winter heating season reaches a peak. As a result, propane inventories in PADD 2 (the Midwest) were at their lowest level for November since 1996." (Attached as Exhibit A.) The winter heating season began with propane stocks already below the five-year average nationally.

The market for propane in the Midwest (PADD 2) is somewhat fragmented, with low concentrations in rural areas. On average, 7% of homes in the region use propane as a primary heating fuel. The most recent Propane Situation Update (attached as Exhibit B) shows the share and number of homes heated with propane in the Midwest and New England on page 5.

Cold weather hit the Midwest in late December and early January, with heating degree days in the region roughly 15% higher than the 10-year average levels. The states of Indiana, Iowa, Minnesota, Montana, Nebraska, South Dakota, and Wisconsin declared states of emergency to enable more delivery of propane throughout the Midwest.

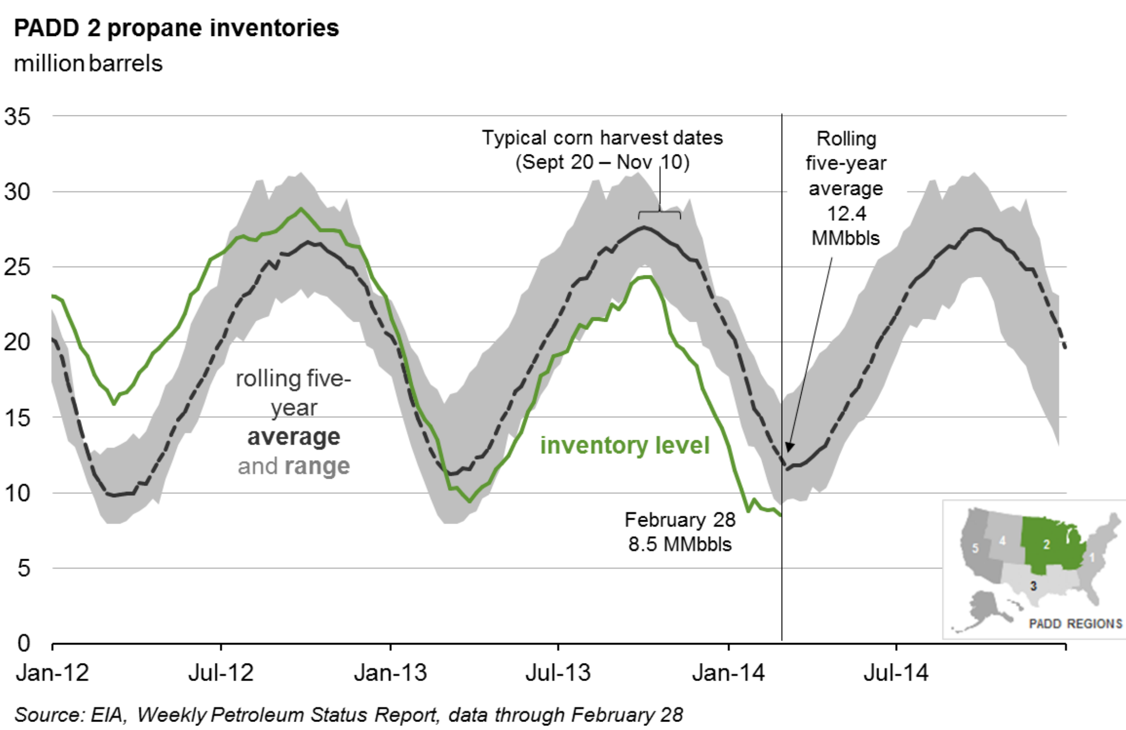
Propane Infrastructure developments

The growth of U.S. production of propane and other natural gas liquids (NGL) has led to several recent and proposed changes in NGL pipeline systems.

Some of the propane supply to the Midwest and Northeast is transported by common-carrier pipelines, which establish shipping schedules in advance and are constrained in rescheduling nominations to meet unexpected shortages in their delivery regions. In early February, the Federal Energy Regulatory Commission invoked its emergency authority under the Interstate Commerce Act, for the first time ever, to direct Enterprise TE Products Pipeline Company (TEPPCO) to temporarily provide priority treatment to propane shipments from Texas to the Midwest and the Northeast.

The Cochin pipeline, which carries propane from Canada into Minnesota, was out of service for planned maintenance in late 2013 related to plans to repurpose and reverse the pipeline as early as mid-2014. Import flows into the Upper Midwest via this pipeline were cut off during this planned outage.

Propane stocks in the Midwest stood at 8.5 million barrels for the week ending February 28, a 4 percent decrease from the previous week. Inventory levels are still below the five-year seasonal average, but the gap is diminishing—levels that had been as much as 8.6 million barrels below the five-year average on January 10 were 3.8 million barrels below the five-year average as of February 28.

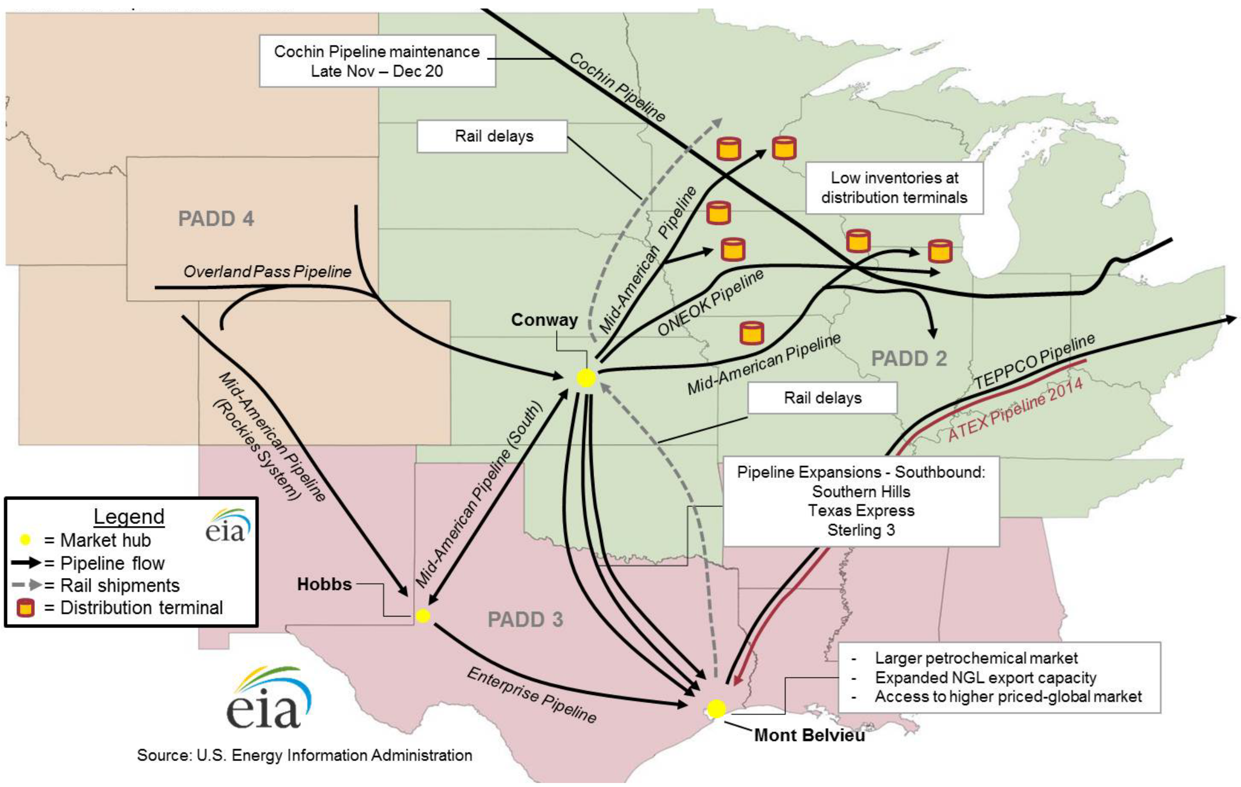


As noted above, Conway, Kansas and Mont Belvieu, Texas are the major propane hubs serving the Midwest and Gulf Coast, respectively. Under market conditions that prevailed from March 2010 to Nov 2013, prices at Mont Belvieu were generally above those at Conway, providing a signal for supplies to move towards the Gulf Coast. Pipelines linking Conway and Mont Belvieu, are set up to carry supplies from north to south – their long-standing orientation. Rail is the primary mode available to carry propane northward from Mont Belvieu to Conway, because there is limited pipeline capacity to move propane south to north from Texas and New Mexico to Kansas.

The development of extreme propane shortages in the Midwest in mid-January, and a significant rise in prices at Conway relative to those at Mont Belvieu, provided a strong incentive for flows of propane from south to north. Those flows, which occurred within the constraints of available infrastructure, resulted in a significant reallocation of supplies, as evident in PADD-level weekly inventory data. The spike in U.S. propane prices also led to increases in imports into Minnesota and Michigan via pipeline connections from Canada, and additional tanker cargoes imported into Northeast ports.

At the beginning of December, spot wholesale prices that are reported daily by Reuters were nearly equal at the trading hubs at Conway and Mont Belvieu, both near $1.20 per gallon. By the beginning of January, Conway was about 18 cents per gallon higher than Mont Belvieu ($1.43 versus $1.25). During January, the price spread peaked at $2.96 per gallon on January 23, with several smaller peaks through the rest of the month. In February, the price spread diminished and as of March 4 prices per gallon are roughly equal at $1.11 at Conway and $1.10 at Mont Belvieu.

The continuing development of U.S. hydrocarbon resources, resulting in the increasing supply of crude oil, natural gas, and propane and other natural gas liquids will continue to present both challenges and opportunities for the use of existing infrastructure and the development of additional infrastructure in the future.

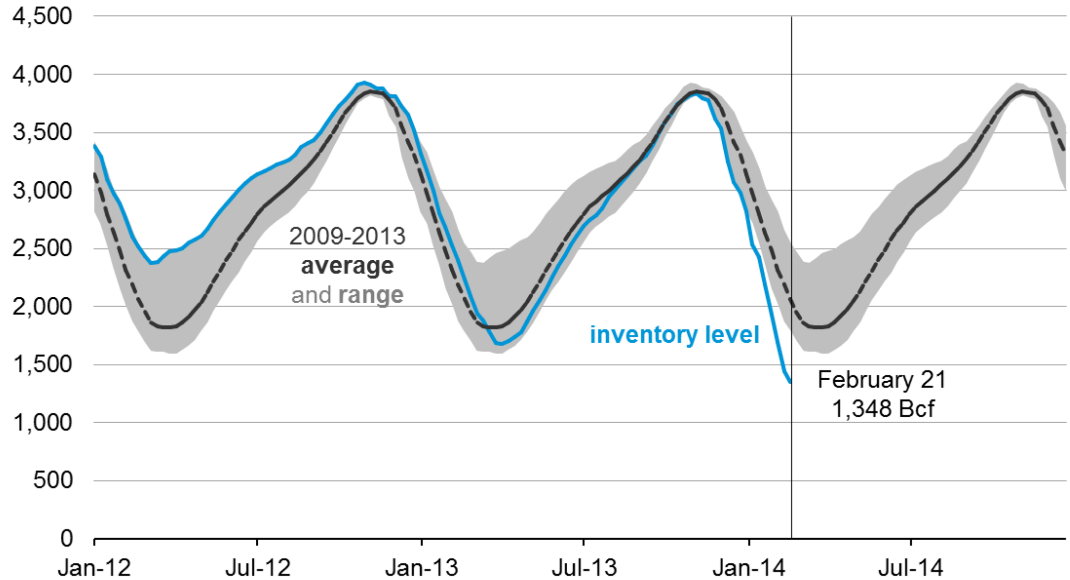


Natural Gas

Colder-than-normal weather, storage and pipeline constraints, and freeze-offs are key factors that have contributed to particularly high spot natural gas prices in the Midwest, Mid-Atlantic, and Northeast this winter. In areas that rely heavily on natural gas as a fuel for power generation, spot market prices for day-ahead, on-peak, electric power prices also rose to atypically high levels. However, in contrast to markets for propane and heating oil, where wholesale price movements are quickly reflected in retail prices, the retail electricity and gas rates paid by consumers who receive service through their local distribution utilities do not immediately reflect price spikes in the spot market.

Cold weather contributed to a new record-high withdrawal of natural gas from storage and a surge in natural gas spot prices. (Today in Energy, January 17, 2014, Attached as Exhibit C.) Natural gas working inventories on February 21 totaled 1,350 billion cubic feet (Bcf), 910 Bcf below the level at the same time a year ago, 710 Bcf below the previous five-year average (2009-13), and 450 Bcf below the previous five-year minimum. Henry Hub natural gas spot prices increased from $4.32 per million British thermal units (MMBtu) on January 2 to $8.15/MMBtu on February 10. The Henry Hub spot price was $4.81/MMBtu on February 26.

Working gas in underground storage
billion cubic feet

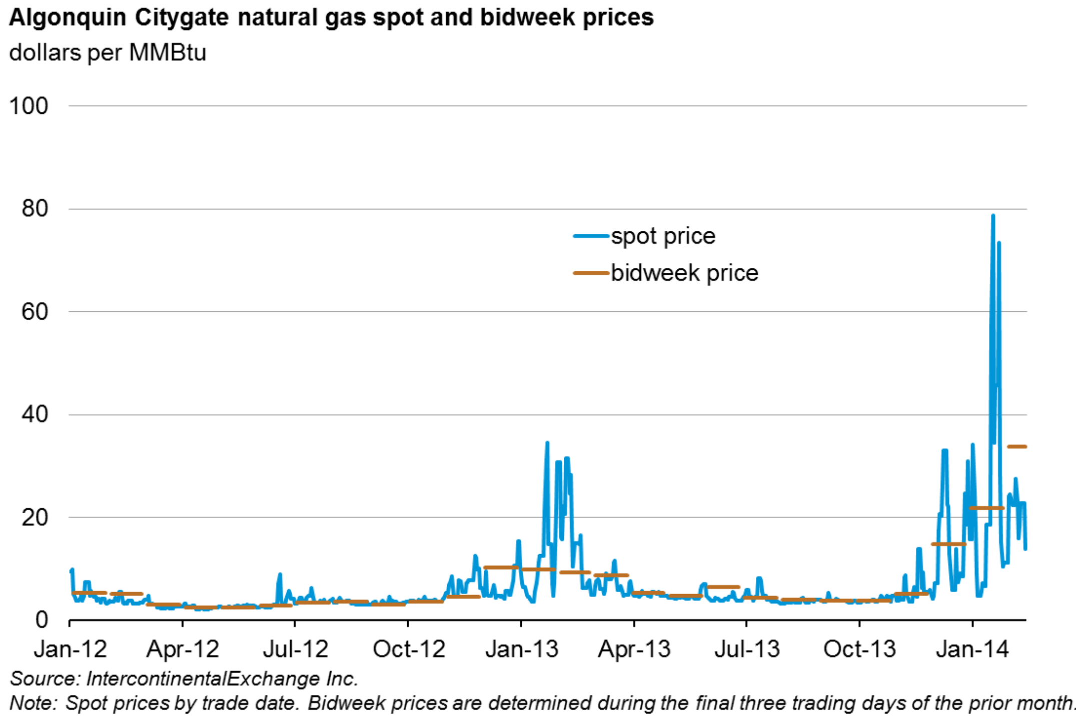


Source: Weekly Natural Gas Storage Report, data through February 21

New England faces some of the highest and most volatile spot natural gas prices. This volatility reflects both pipeline capacity constraints and significant growth in demand for natural gas, particularly for electricity generation, in the region. Reductions in imports of liquefied natural gas (LNG) and Canadian pipeline gas this winter added to the strain on pipelines serving New England that carry domestically–sourced natural gas.

New England spot natural gas prices hit record levels this winter. From January 1 to February 18, the day-ahead wholesale (spot) natural gas price at the Algonquin Citygate hub serving Boston averaged $22.53 per million British thermal units (MMBtu), according to data from Intercontinental Exchange (ICE). This price is a record high for these dates since the ICE data series began in 2001, and 50% above the same period in 2013, when cold weather drove New

England prices to their highest level since 2004.



(From [Today in Energy, February 21, 2014])

The challenges faced by natural gas markets in New England are not new. New England spot natural gas prices in the winter of 2012-13 were also higher on average and more volatile than elsewhere in the United States. EIA released a [supplement to the Short Term Energy Outlook in January of 2013]. (Attached as Exhibit D.) Yet, in contrast to New York and the Middle Atlantic states, as this winter began there were no pipeline expansions underway to relieve capacity constraints that have been affecting the region for some time.*

* Despite increased natural gas production in the Marcellus supply basin and the addition of new pipeline capacity, the Mid-Atlantic region and the New York metropolitan area also faced supply constraints and very high spot market prices during the coldest days this winter.

The February 7, 2014, *Issues and Trends* (attached as Exhibit E) report on natural gas in New England discussed a number of potential ways to lessen the impact of limited peak natural gas supply at peak demand times, including pipeline expansions, additional fuel substitution by electric generators and other gas customers, and demand curtailment. Higher electricity imports from Canada, which could reduce reliance on within-region natural gas generation to serve electricity load, are another potential option.

Thank you for the opportunity to testify before the Committee.

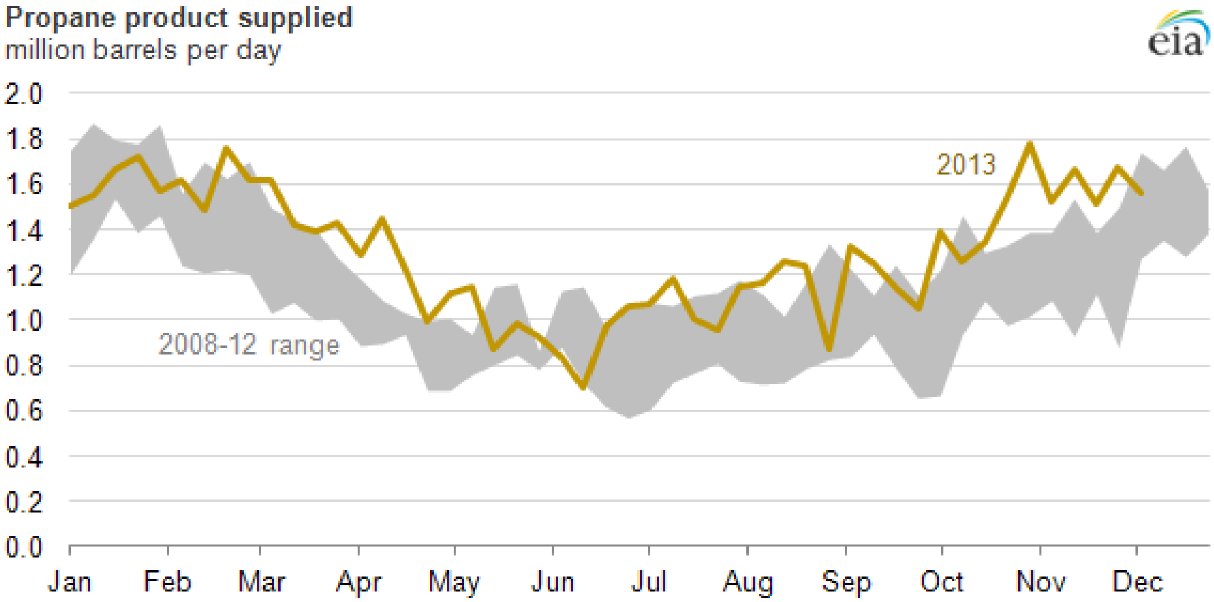
Exhibit A

U.S. Energy Information Administration

Today in Energy

December 12, 2013

Propane demand hits a record high for November

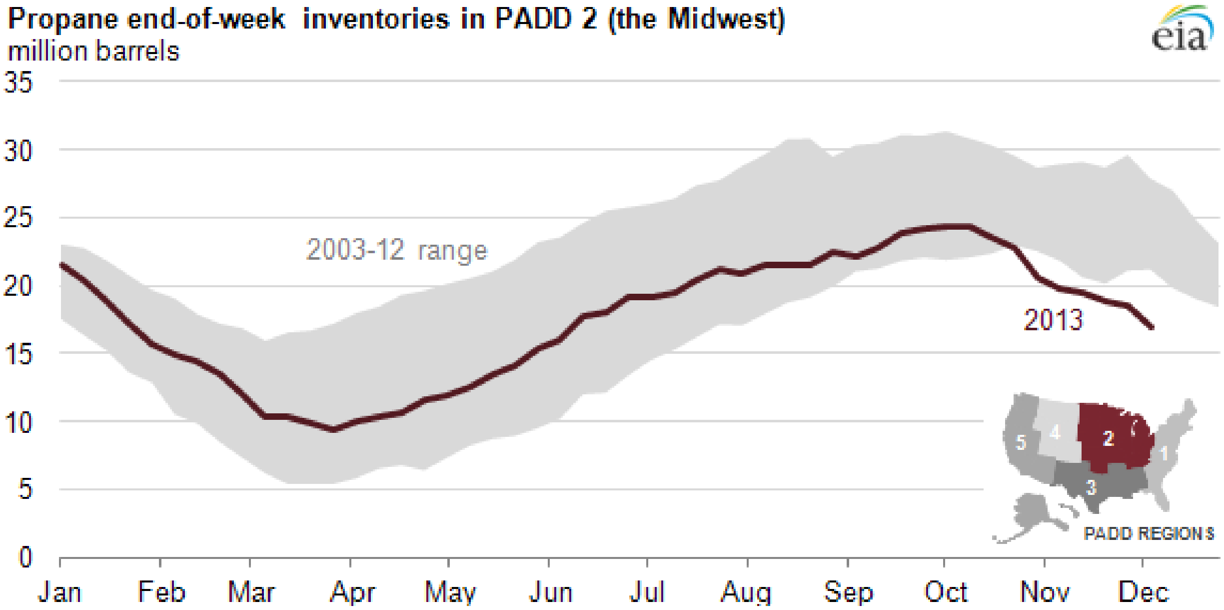


Source: U.S. Energy Information Administration, Weekly Petroleum Status Report
Note: Product supplied is a proxy for consumption.

Republished December 12, 2013, 11:55 a.m. text was modified to clarify content and propane inventories graph was updated.

Propane is produced from natural gas at processing plants and from crude oil at refineries. Propane produced from natural gas has been the fastest-growing component of overall U.S. propane supply. Propane production in the United States has set record highs on an almost weekly basis in 2013 as a result of increased oil and natural gas drilling. A record corn crop harvest has increased the demand for propane (shown in the graph above as product supplied) in the central United States. Expanded propane production met this agricultural demand, while continuing to supply other markets.

A record-setting corn harvest is currently underway in the United States. According to the U.S. Department of Agriculture, corn production is forecast to be a record 14.9 million bushels in 2013-14. Corn must be dried to a 15% moisture content before it can be stored to avoid mold and other quality problems. Because propane is used for crop drying, a wet growing season in the Midwest combined with the largest corn yield in U.S. history has greatly increased the demand for propane. Thus far, Indiana, Iowa, Minnesota, Montana, Nebraska, South Dakota, and Wisconsin have declared states of emergency to allow for more delivery of propane throughout the Midwest.



Source: U.S. Energy Information Administration, Weekly Petroleum Status Report
Note: Ending inventories measured at the end of the reporting period.

According to EIA weekly data, demand for propane is currently at the highest level ever recorded for November. For the week ending November 1, the United States consumed nearly 1.8 million barrels per day—a figure typically not seen until January or February, when the winter heating season reaches a peak. As a result, propane inventories in PADD 2 (the Midwest) have fallen to their lowest level for November since 1996. Along with spiking domestic demand, competitively-priced U.S. propane exports have also surged. Exports from the United States are currently estimated to be 288,000 barrels per day, not far from the record of 308,000 barrels per day set in May 2013.

This boost in propane demand has created a spike in propane prices across the country. The winter heating season is just beginning to affect consumption figures, so propane demand for the 2013-14 season could continue at a record pace into the spring.

Principal contributor: Alex Wood

Propane situation update

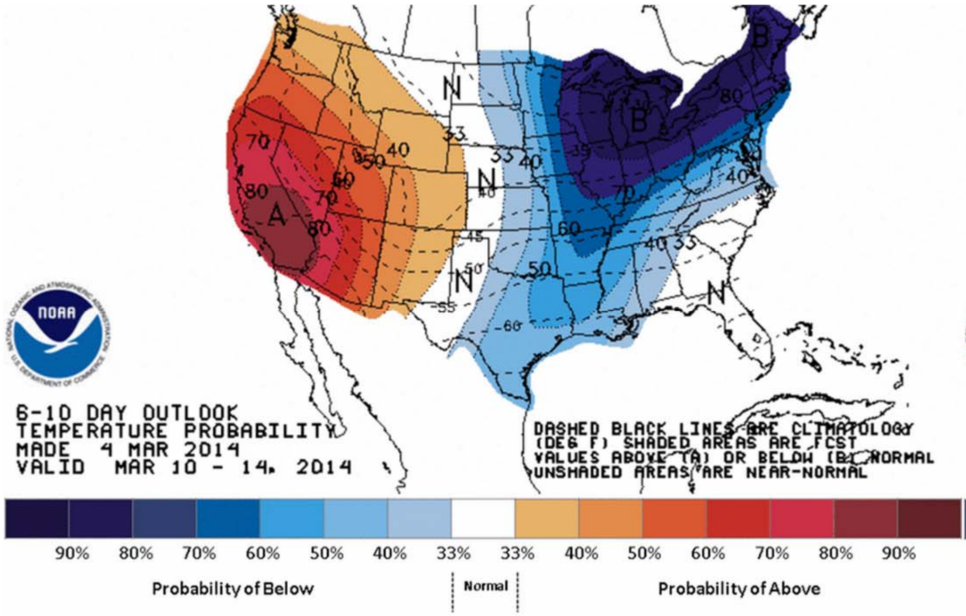
March 5, 2014 | Washington, DC

By

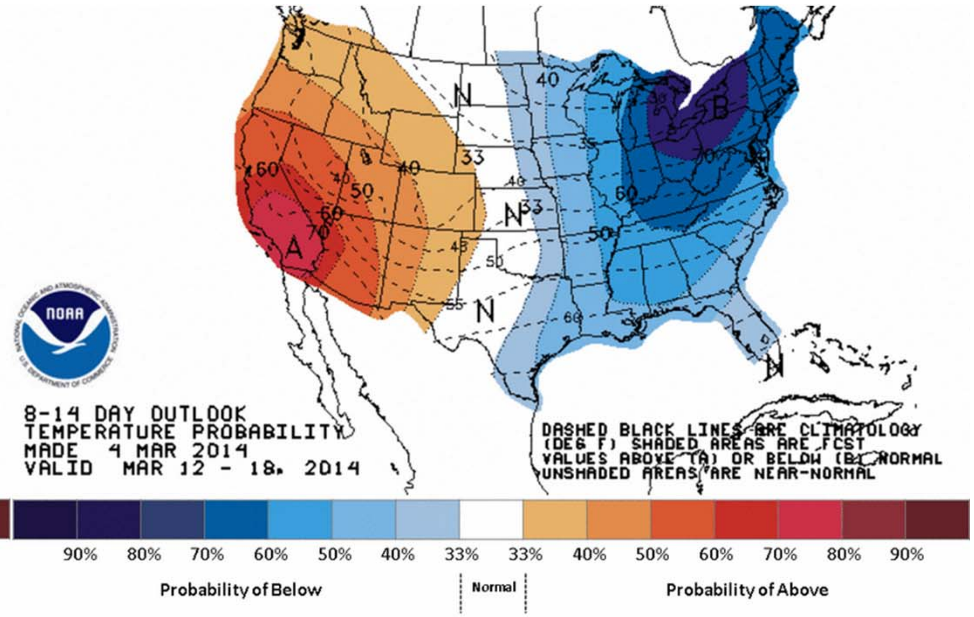
Energy Information Administration

NOAA forecast shows below normal temperatures across most of the Midwest for March 10 through March 18

6-10 day outlook



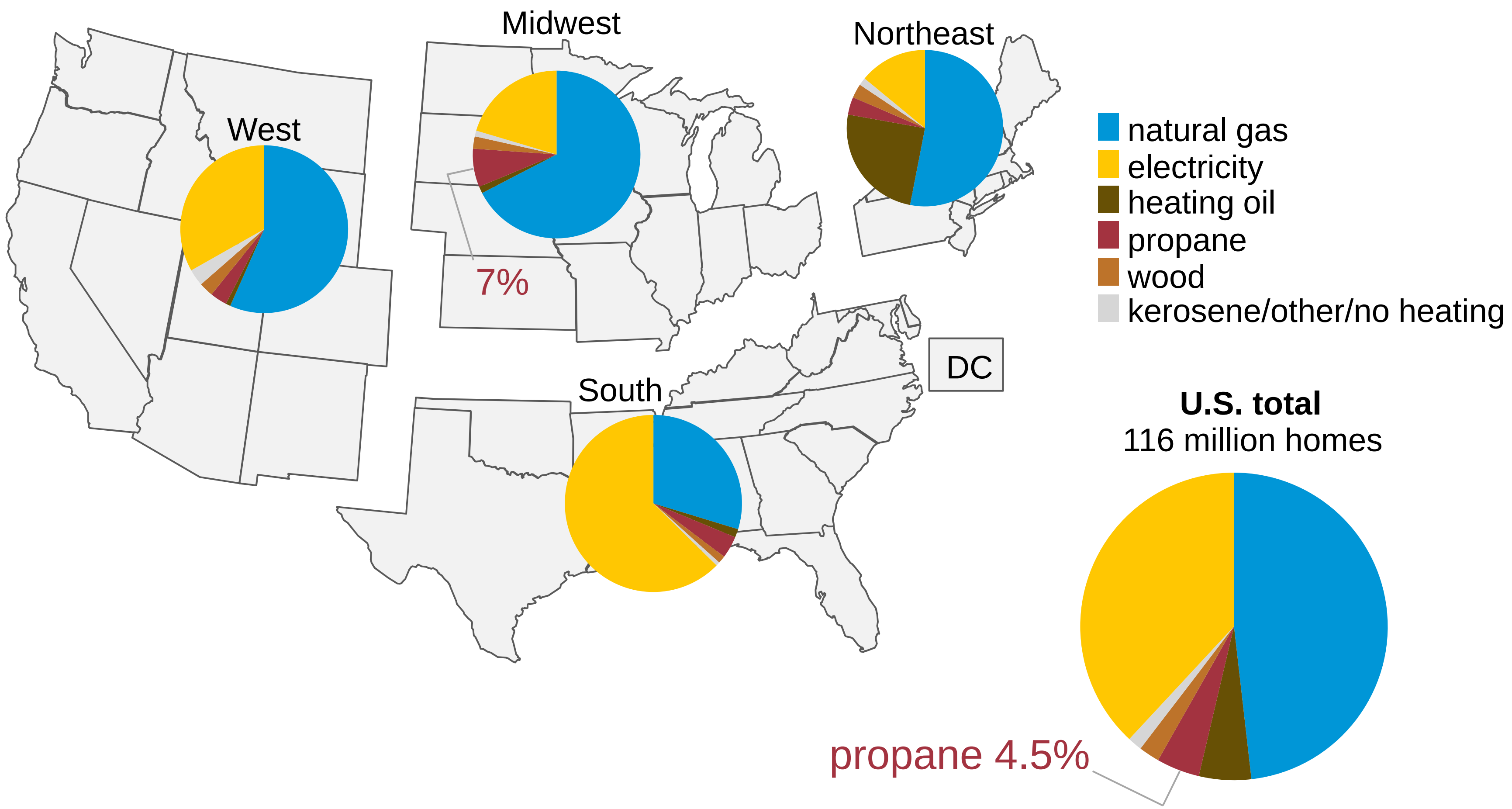
8-14 day outlook



Source: National Oceanic and Atmospheric Administration Climate Prediction Center, made March 4

Natural gas and electricity are the major heating fuels for most of the United States

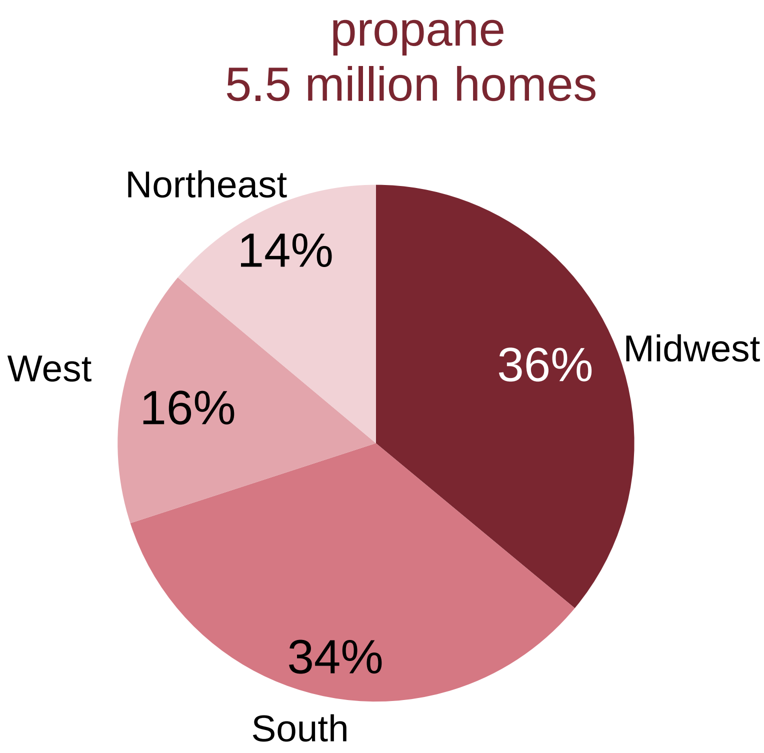
Share of homes by primary space heating fuel within each Census Region
(fuels add to 100%)

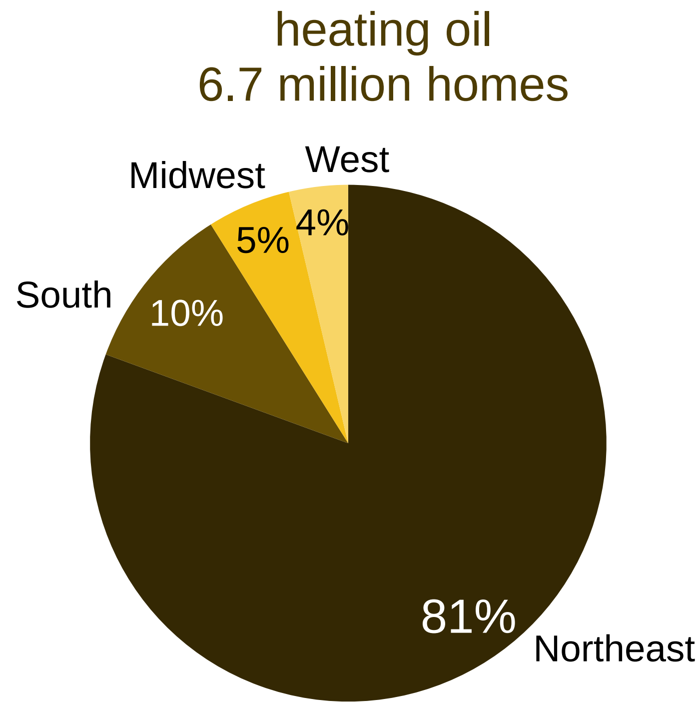


Source: U.S. Census Bureau, 2012 American Community Survey

Of all homes heated by propane, 36% are in the Midwest

Location of homes by primary space heating fuel across Census Regions
(regions add to 100%)





Source: U.S. Census Bureau, 2012 American Community Survey

Propane share of space heating demand by key regions and states

State	Propane-Heated Homes	Share of Total Homes
Michigan	320,522	8%
Wisconsin	245,071	11%
Ohio	240,185	5%
Minnesota	213,359	10%
Missouri	212,317	9%
Illinois	189,025	4%
Indiana	176,520	7%
Iowa	162,117	13%
Kentucky	113,175	7%
Tennessee	110,486	4%
Oklahoma	103,017	7%
Kansas	83,386	7%
Nebraska	57,442	8%
South Dakota	54,015	17%
North Dakota	38,617	13%
Midwest Total	**2,319,254**	**7%**

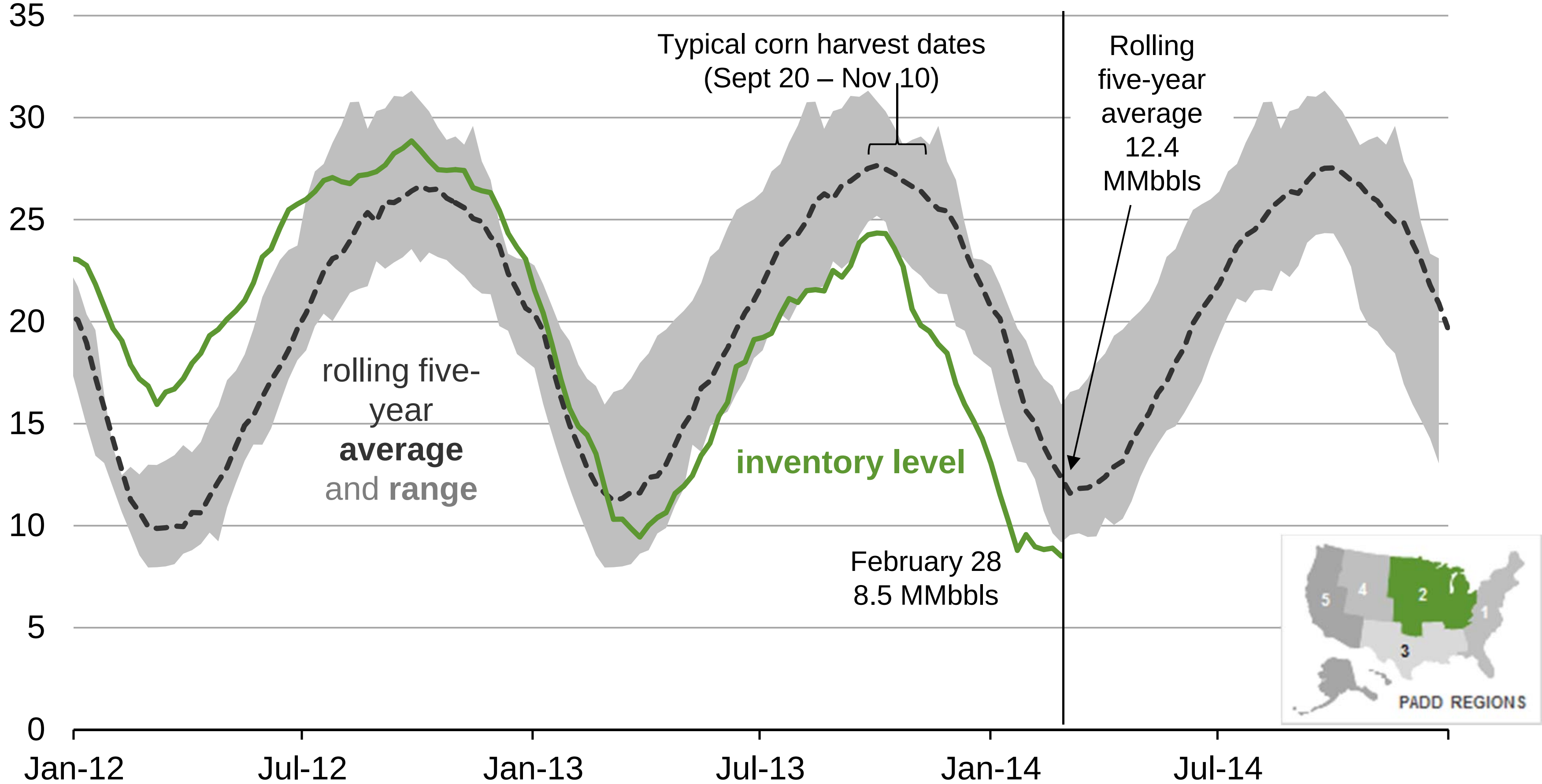
State	Propane-Heated Homes	Share of Total Homes
New York	237,738	3%
Pennsylvania	188,880	4%
New Hampshire	72,091	14%
Massachusetts	68,517	3%
New Jersey	60,990	2%
Connecticut	43,849	3%
Maine	41,477	7%
Vermont	38,497	15%
Rhode Island	10,361	3%
Northeast Total	**762,400**	**4%**

Source: Census Bureau, 2011

PADD 2 (Midwest) propane inventories have trended lower on strong crop drying and extremely cold temperatures

PADD 2 propane inventories

million barrels

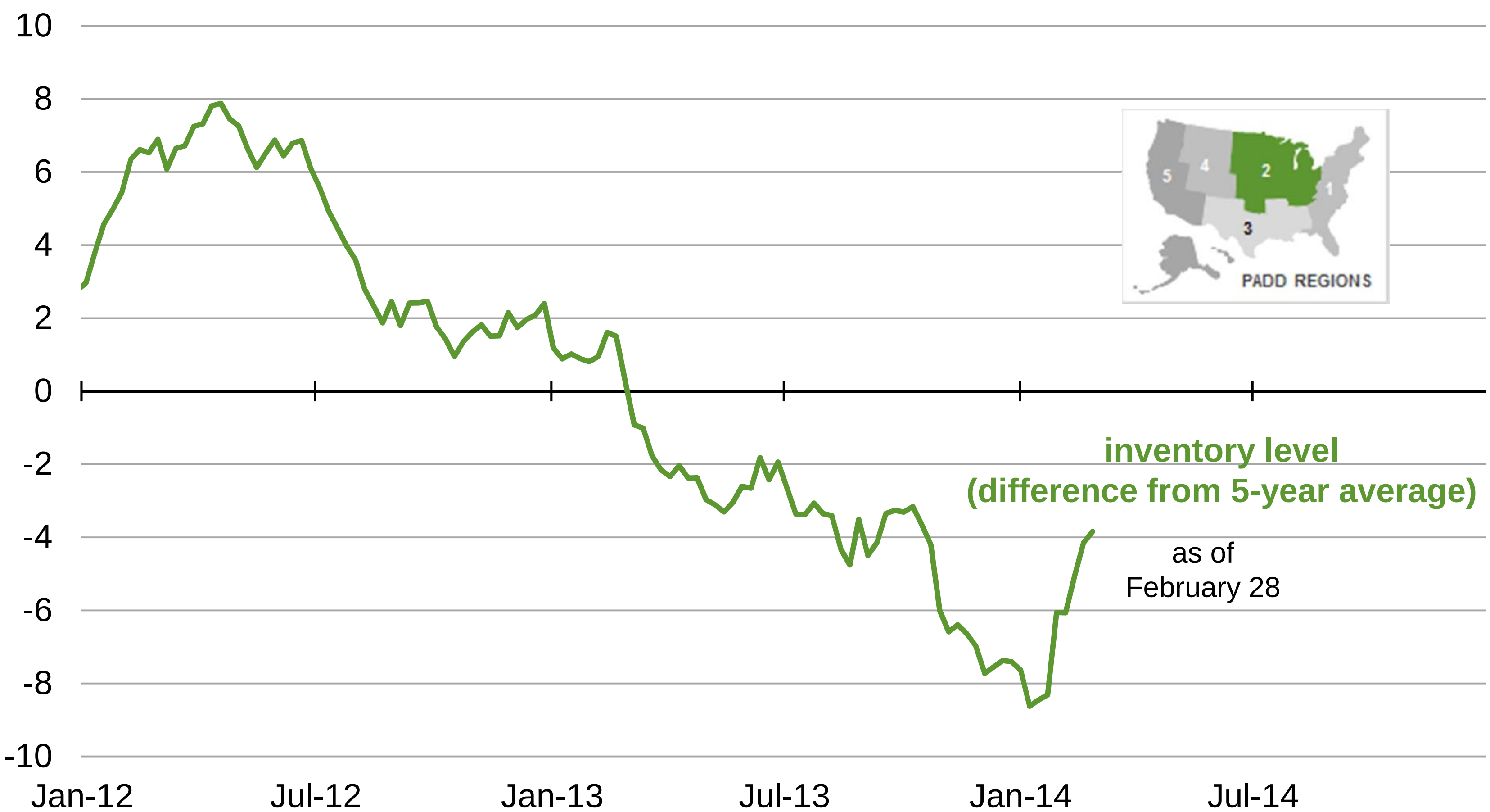


Source: EIA, Weekly Petroleum Status Report, data through February 28

PADD 2 (Midwest) propane inventories remain below the 5-year average, but gap is narrowing

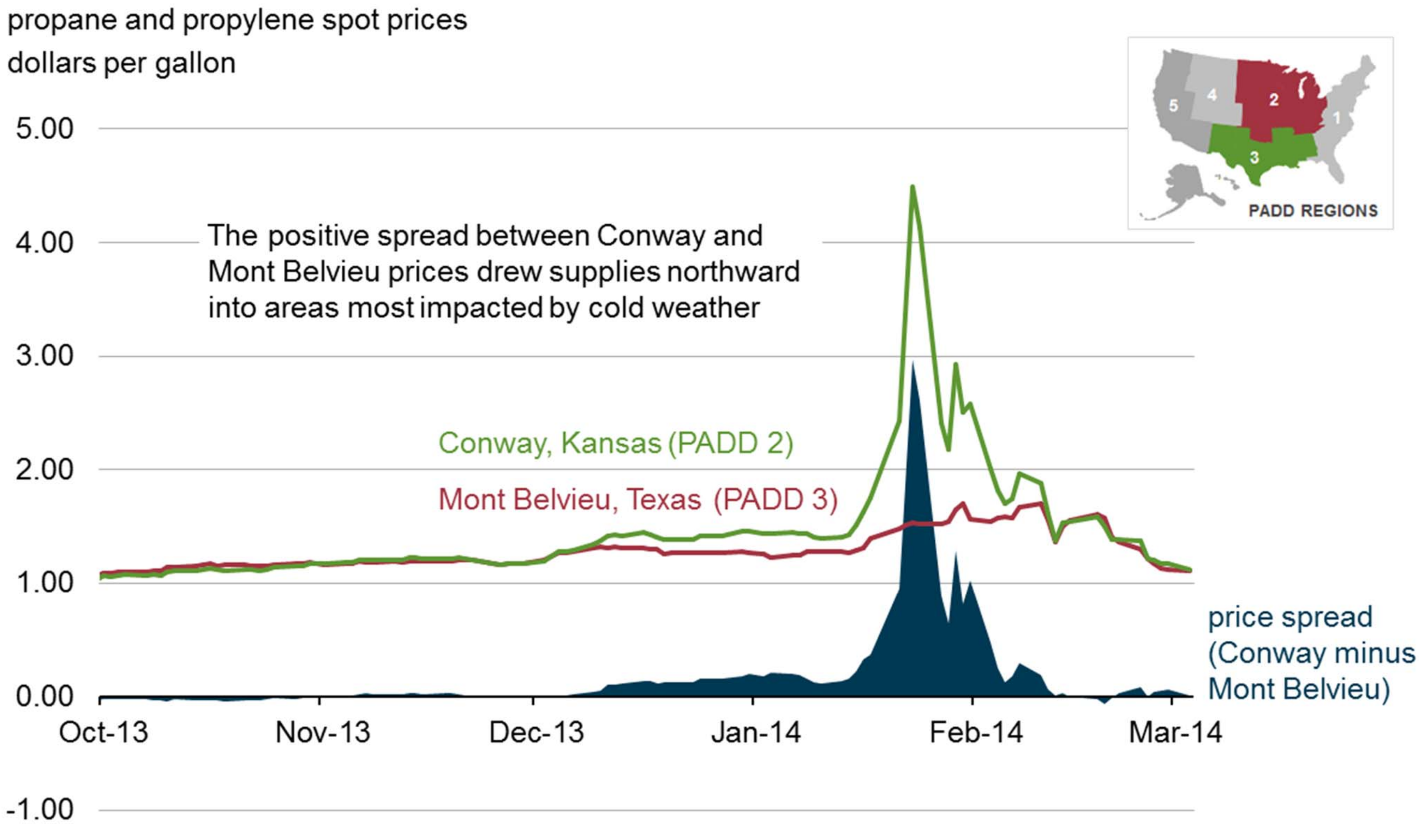
PADD 2 propane inventories, difference from 5-year average

million barrels



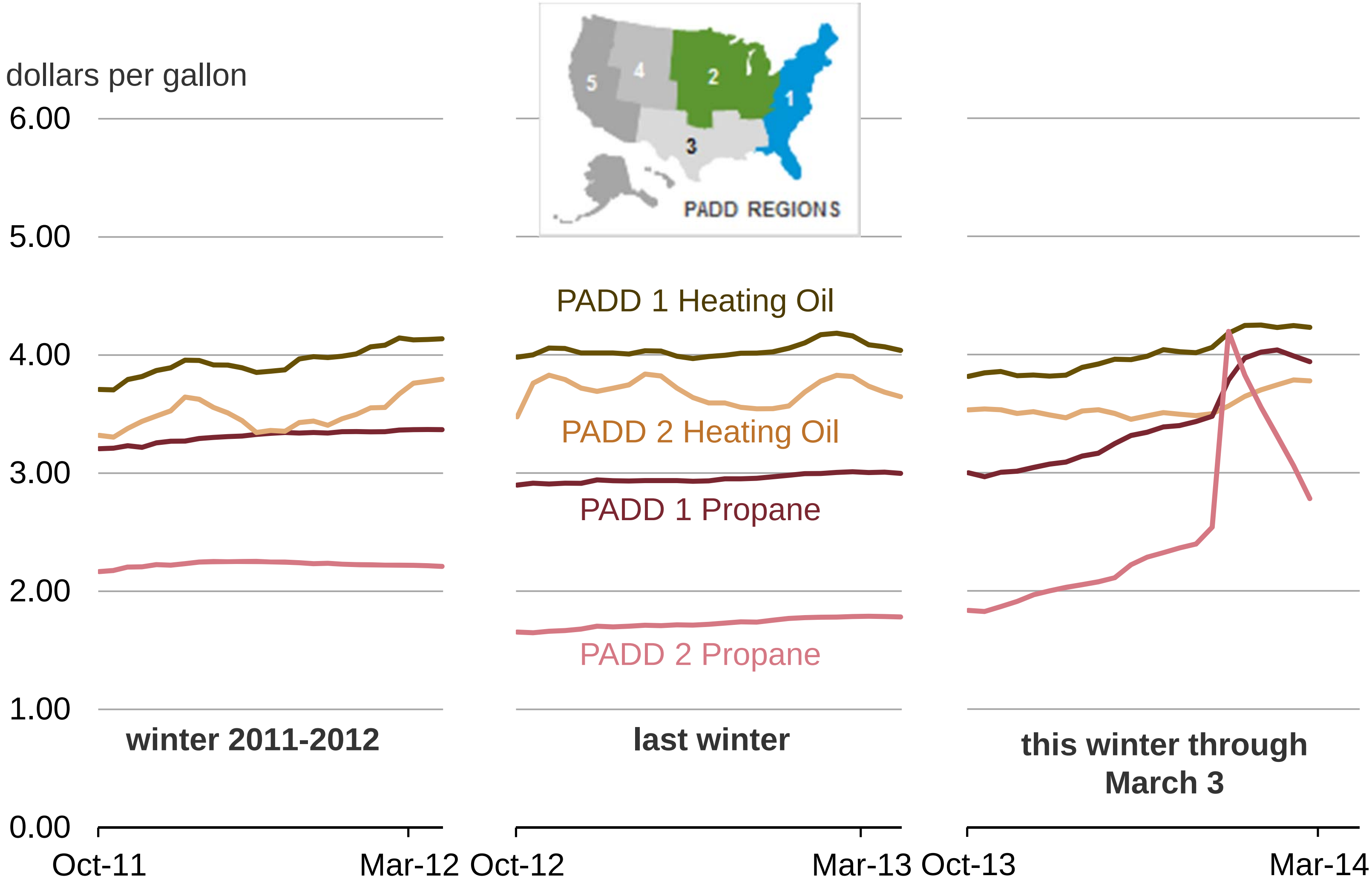
Source: EIA, Weekly Petroleum Status Report, data through February 28

Conway (KS) price premium over Mt. Belvieu (TX) grew rapidly in late January, but has since narrowed



Source: U.S. Energy Information Administration, Thomson Reuters, data through March 3

Retail propane prices in the Midwest, which rose sharply in late January, have moved lower



Source:State Heating Oil and Propane Program, data through March 3

State-reported residential retail prices for states in the East Coast

	1/20/14	1/27/14	2/3/14	2/10/14	2/17/14	2/24/14	3/3/14
Residential retail propane price (dollars per gallon, excluding taxes)							
Connecticut	3.528	3.653	3.792	3.918	3.870	3.902	3.902
Delaware	3.422	3.734	3.823	3.790	3.927	3.911	3.910
Maine	3.302	3.469	3.558	3.607	3.669	3.637	3.624
Maryland	3.603	3.865	3.956	4.055	4.134	4.144	4.125
Massachusetts	3.552	3.695	3.816	3.794	3.925	3.974	3.992
New Hampshire	3.539	3.672	3.706	3.728	3.835	3.827	3.835
New Jersey	3.984	4.235	4.451	4.433	4.460	4.436	4.431
New York	3.525	3.797	3.961	4.004	4.042	4.060	4.053
North Carolina	3.221	3.711	4.067	4.153	3.995	3.779	3.614
Pennsylvania	3.415	3.755	3.904	3.991	4.032	4.010	3.962
Rhode Island	4.037	4.207	4.399	4.456	4.538	4.615	4.660
Vermont	3.798	4.037	4.210	4.134	4.362	4.361	4.351
Virginia	3.378	3.753	4.039	4.069	4.066	3.915	3.818

Note: Florida, Georgia, South Carolina, West Virginia, and the District of Columbia do not report information

Source: EIA, State Heating Oil and Propane Program, data through March 3

http://www.eia.gov/petroleum/heatingoilpropane/

State-reported residential retail prices for states in the Midwest

	1/20/14	1/27/14	2/3/14	2/10/14	2/17/14	2/24/14	3/3/14
Residential retail propane price (dollars per gallon, excluding taxes)							
Indiana	2.939	4.215	4.265	4.043	3.753	3.472	3.248
Iowa	2.584	4.709	3.590	3.220	2.811	2.591	2.149
Kentucky	2.577	3.785	3.852	3.677	3.584	3.417	2.942
Michigan	2.638	3.611	3.766	3.620	3.692	3.359	3.247
Minnesota	2.439	4.610	3.967	3.471	3.264	2.985	2.658
Missouri	2.433	3.997	3.672	3.484	3.131	2.960	2.657
Nebraska	2.005	4.073	3.357	2.995	2.601	2.393	2.048
North Dakota	2.322	4.569	3.839	3.283	2.905	2.651	2.333
Ohio	2.999	3.731	3.908	3.755	3.733	3.615	3.489
South Dakota	2.088	4.107	3.664	3.408	3.019	2.797	2.751
Wisconsin	2.276	4.490	3.945	3.686	3.344	2.967	2.650

Note: Illinois, Kansas, Oklahoma, and Tennessee do not report information

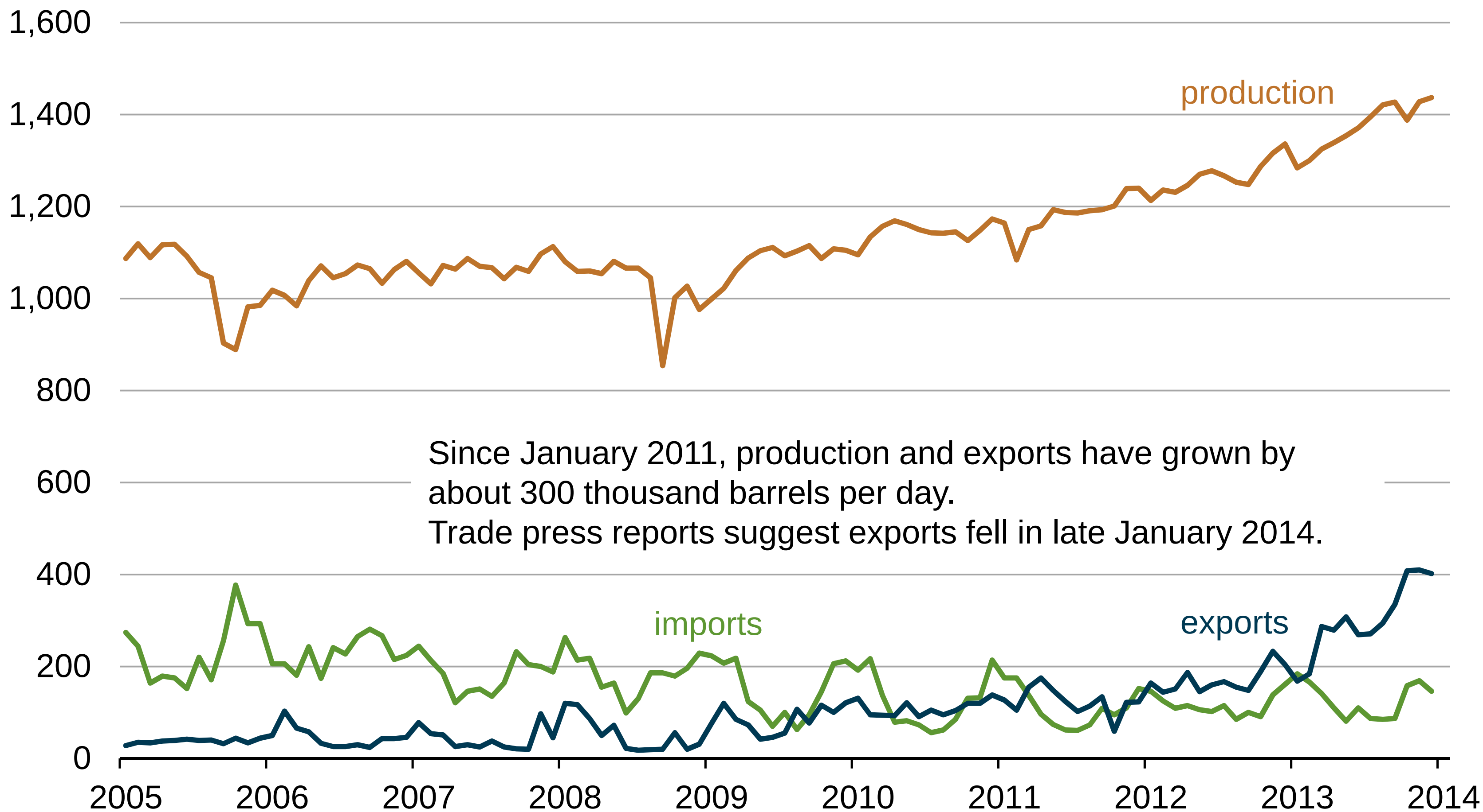
Source: EIA, State Heating Oil and Propane Program, data through March 3

http://www.eia.gov/petroleum/heatingoilpropane/

U.S. propane production and trade trends

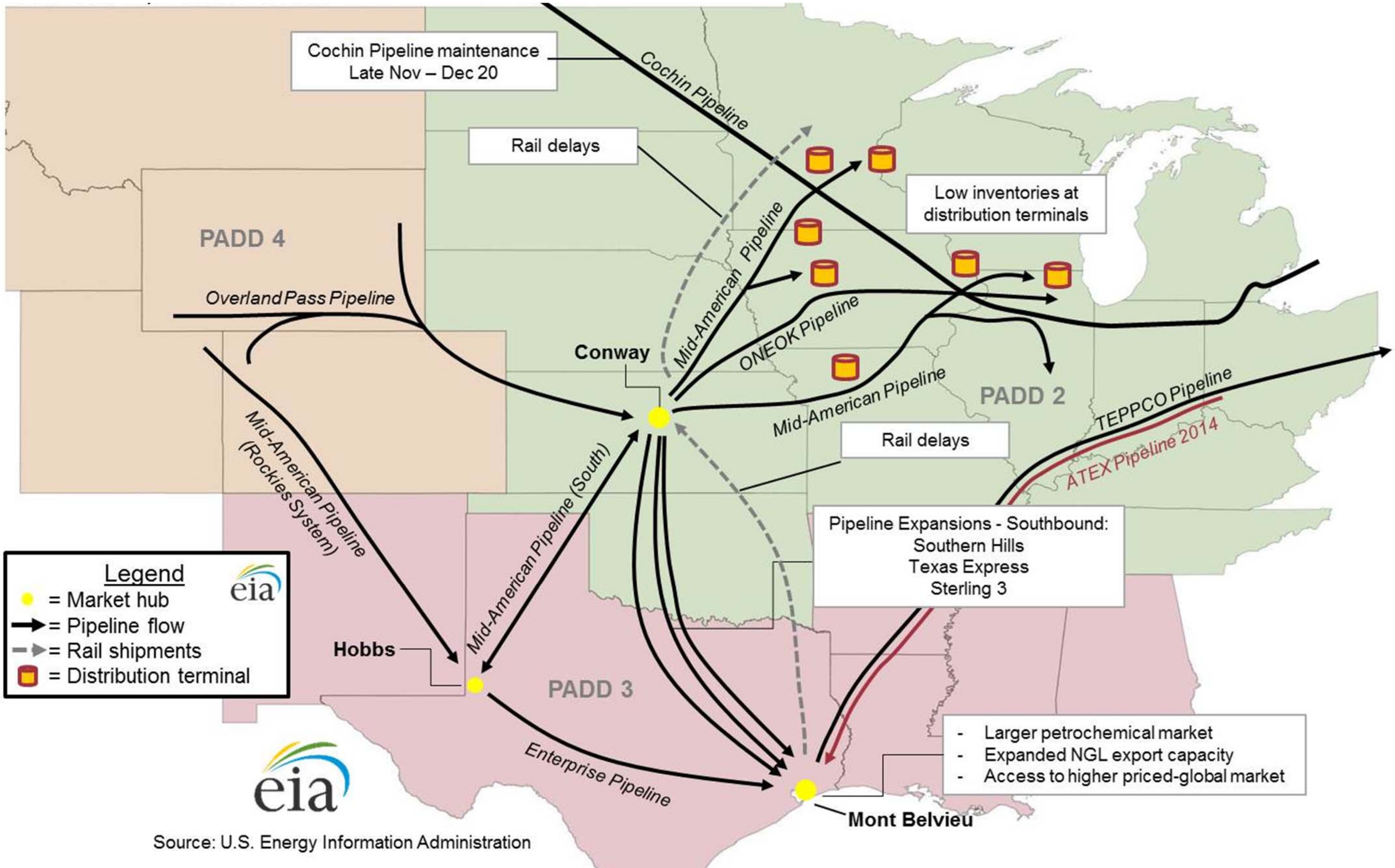
U.S. propane and propylene production, imports, and exports

thousand barrels per day



Source: EIA, Petroleum Supply Monthly through December 2013

Winter 2013 propane supply diagram



For more information

U.S. Energy Information Administration home page | www.eia.gov

Short-Term Energy Outlook | www.eia.gov/steo

Annual Energy Outlook | www.eia.gov/aeo

International Energy Outlook | www.eia.gov/ieo

Monthly Energy Review | www.eia.gov/mer

Today in Energy | www.eia.gov/todayinenergy

State Energy Portal | www.eia.gov/state

Drilling Productivity Report | www.eia.gov/petroleum/drilling

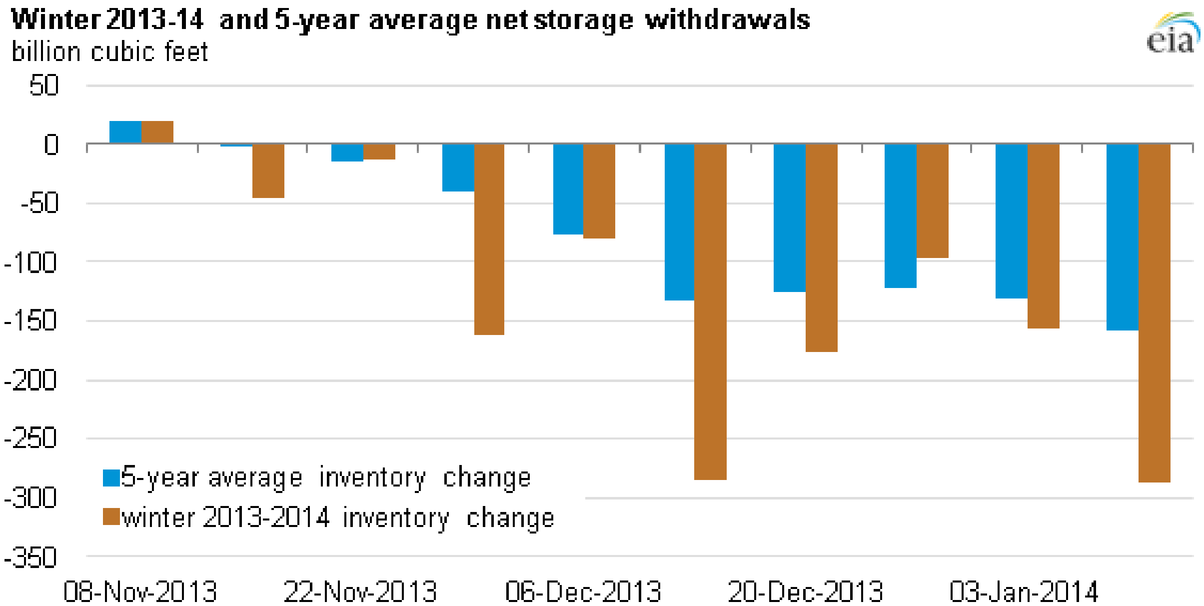
Exhibit C

U.S. Energy Information Administration

Today in Energy

January 17, 2014

Cold weather led to record-high natural gas storage withdrawals

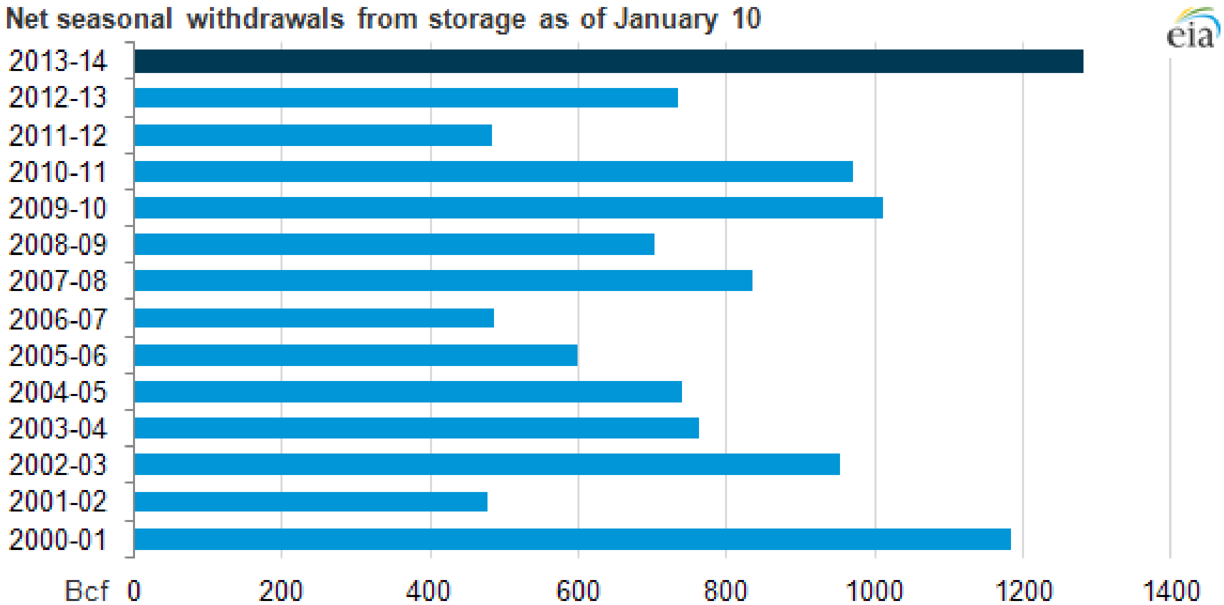


Source: U.S. Energy Information Administration, Weekly Natural Gas Storage Report

Last week's widespread, record-breaking cold weather had significant effects across virtually all segments of the U.S. natural gas market. The frigid temperatures led to record highs in demand, storage withdrawals, and prices.

The week ending January 10 posted a record-high net withdrawal of 287 billion cubic feet (Bcf) from underground, natural gas storage facilities. The January 10 withdrawal is the largest for the 20 years for which data exist and the latest in a season already characterized by withdrawals much larger than average. This week's storage withdrawal was the second record-breaking weekly stock draw this season; the withdrawal of 285 Bcf for the week ending December 13 exceeded the previous record of 274 Bcf from January 2008. Cumulative net withdrawals, as of January 10, 2014, exceeded the previous record levels posted during the 2000-2001 heating season. Bentek Energy estimated stock draws hit 57.1 Bcf on January 6, and then 67.9 Bcf the following day. The next-highest draw was 52.9 in February 2011.

High storage withdrawals were expected to meet surging demand for heating from the residential, commercial, and electric power sectors, with analyst estimates, as published by Bloomberg, ranging between 278 and 321 Bcf. The cold weather also impacted natural gas production. Freeze-offs occurred in the parts of the Marcellus Shale in northeastern Pennsylvania and in the Fayetteville Shale in Arkansas, according to Bentek Energy. Dry natural gas production dropped to 61.9 Bcf on January 8, the lowest level since September 2012, and has been gradually increasing since then, reaching nearly 66 Bcf as of January 16.



Source: U.S. Energy Information Administration, Weekly Natural Gas Storage Report
Note: Data above reflect withdrawals between October 31 and January 10. 2008-13 average = 780 Bcf.

In the Northeast, where more than half of homes use natural gas as their primary space-heating fuel, several pipelines issued critical notices and operational flow orders (OFOs) to prevent system imbalances. Additionally, Texas Eastern Pipeline, a major interstate pipeline supplying the Northeast, issued a force majeure (which frees both parties from upholding contractual obligations in the event of extraordinary circumstances) following unplanned maintenance at a compressor station in Pennsylvania.

Natural gas prices in the Northeast spiked to between $30 and $40 higher than the benchmark Henry Hub price. On the Transcontinental Pipeline's Zone 5 line, which serves Mid-Atlantic customers, prices reached $72.43/MMBtu on Monday. Prices in New York and New England also rose far into the double digits, with Transco's Zone 6 delivery point, serving New York City, at $56.59/MMBtu, and the Algonquin Citygate, serving Boston, at $34.14/MMBtu.

The extreme cold temperatures that affected Northeast natural gas markets during the first half of last week arrived earlier in the Midwest, where about 68% of households use natural gas for heating. While it is common for prices to spike in the Northeast during times of high demand, Midwest prices are normally close to Henry Hub prices, as the region does not typically have major supply bottlenecks. Prices at the Chicago Citygate rose to levels almost $10/MMBtu greater than Henry Hub prices on Friday, January 3, as temperatures in the Midwest dipped to levels that prompted the Chicago Zoo to bring its polar bear indoors. Both ANR Pipeline and NGPL, major interstate pipelines that send natural gas to the Midwest, issued OFOs, and many other pipelines in the region issued critical notices that curtailed normal gas-flow scheduling to maintain balance on their systems.

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Independent Statistics & Analysis
U.S. Energy Information Administration

January 18, 2013

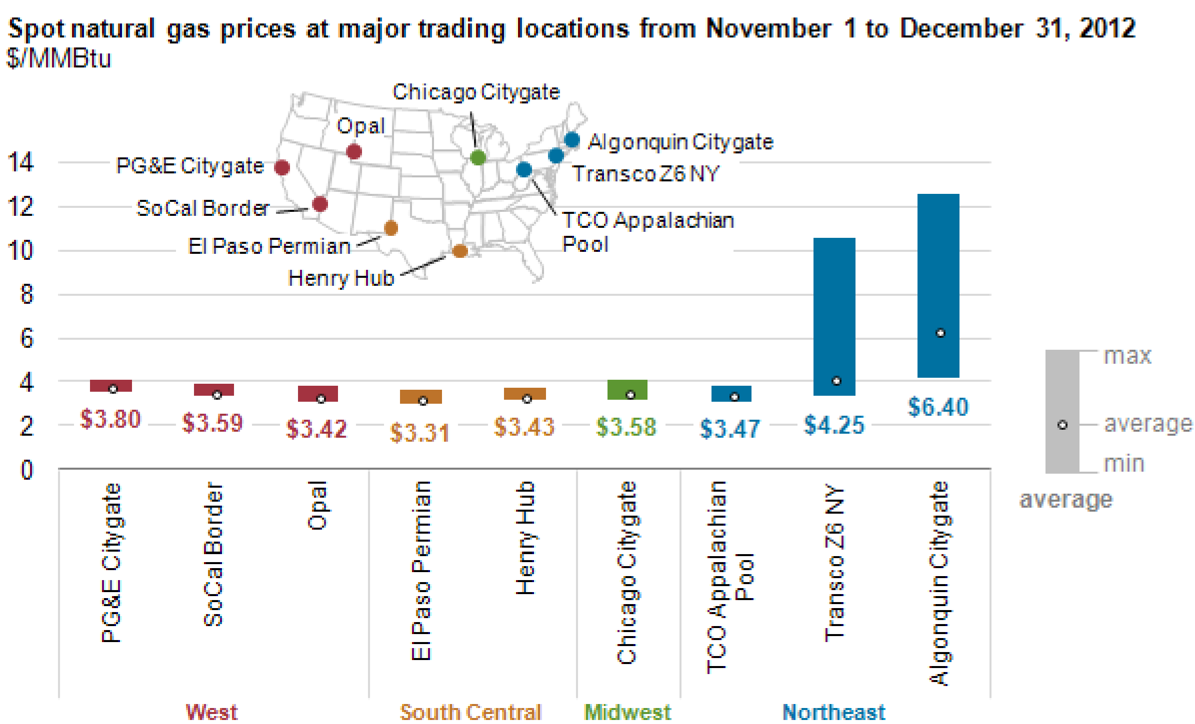
Short-Term Energy Outlook Supplement: Constraints in New England likely to affect regional energy prices this winter

Since November, New England has had the highest average spot natural gas prices in the nation. Average prices at the Algonquin Citygate trading point, a widely used index for New England natural gas buyers, have been $3 per million British thermal units (MMBtu) higher than natural gas prices at the Henry Hub, and more than $2 per MMBtu higher than average spot price at Transco Zone 6 NY, which serves New York City and has historically traded at prices similar to those in New England (see Figure 1).

Full pipelines from the west and south limit further deliveries from most of North America, while high international prices and declining production in eastern Canada pose challenges in making up the difference from the north and east, except at higher prices.

As a result of these market conditions, New England natural gas and electric power prices this winter could be volatile at times. During November and December, spot natural prices in the northeastern United States seesawed in relation to weather-driven pipeline constraints. This price volatility has continued into January 2013 to date.

Figure 1. Spot natural gas prices at major trading locations

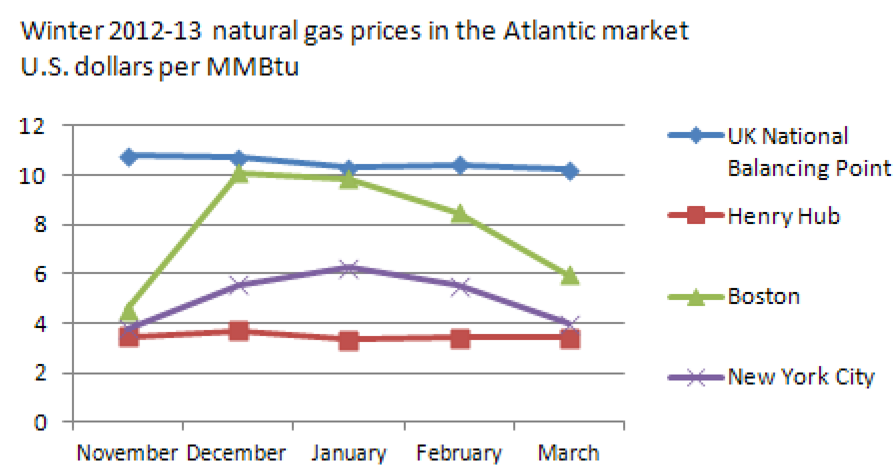


Source: U.S. Energy Information Administration based on Ventyx, Energy Velocity Suite.

However, spot natural gas prices in New England so far this winter have still been less expensive than those in northwestern Europe, meaning that it continues to be more attractive to deliver a spot (or unscheduled) cargo of liquefied natural gas (LNG) to Europe than to New England.

Looking to the rest of this winter, recent forward market prices indicate that New England's high natural gas prices could persist and rival northwestern European prices, especially this month (see Figure 2). In that case, New England may receive spot cargos of LNG.

Figure 2. Forward prices of natural gas in the United States and United Kingdom



Source: U.S. Energy Information Administration based on Bloomberg, L.P.

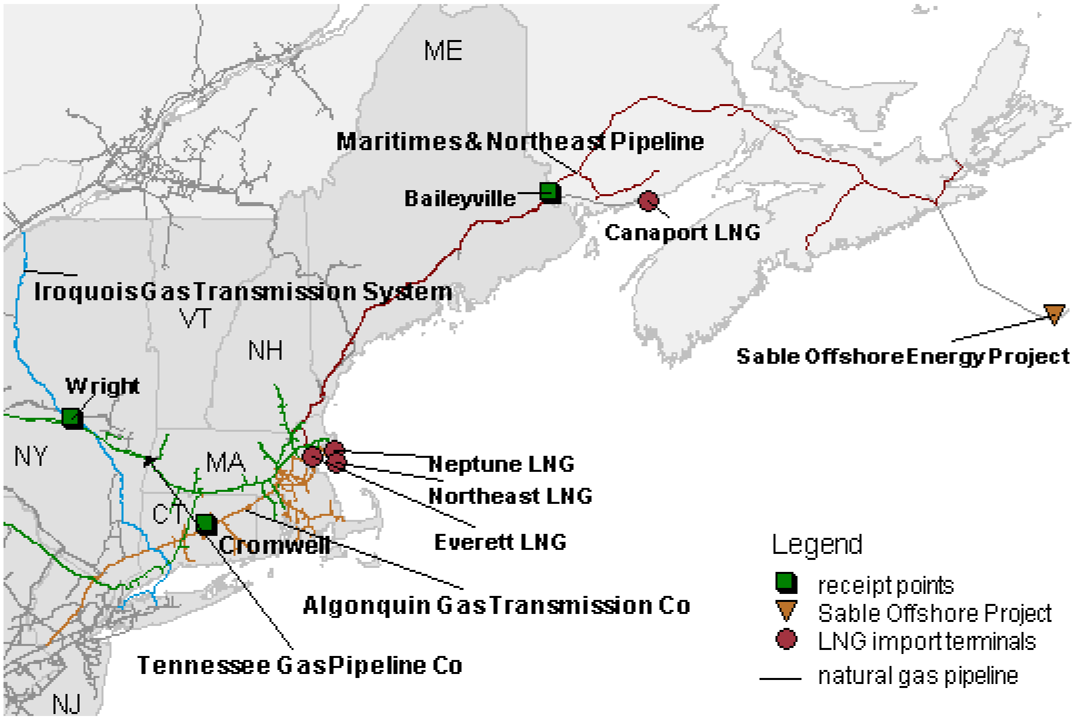
Note: Forward values reflect market closes on December 27, 2012, for the January, February, and March futures contracts. The November and December forward values reflect the settlement prices as of the dates the New York Mercantile Exchange (NYMEX) natural gas futures contracts expired, or settlement prices on October 29, 2012 (for November), and November 28, 2012 (for December).

Forward prices reflect monthly values. In the Northeast, forward natural gas prices in the winter typically reflect expectations that for some days, weather-driven constraints may lead to very high prices, while other days may see more moderate weather and prices. For example, a natural gas basis swap (which reflects the difference in effective price between a given point and the reference pricing point of Henry Hub) for the month of January covers 31 days. A forward basis swap valued at $6 per MMBtu could underpin an assumption of 20 days, with average prices of $4.35 per MMBtu and 11 days with prices averaging more than double that, or about $9 per MMBtu.

Why are prices at the Algonquin Citygate trading point so high? Several factors act simultaneously to constrain natural gas deliveries into New England, and therefore raise regional prices:

- Natural gas from the west and south is flowing at or near the capacities of existing pipelines
- LNG shipments into the Boston area and New Brunswick, Canada declined in 2012 because global market conditions have directed shipments elsewhere, and because of supply disruptions in Yemen
- Natural gas wellhead production from the Sable Offshore Energy Project (SOEP) in Nova Scotia has declined to a small fraction of its levels in previous years

Figure 3. New England natural gas infrastructure overview map

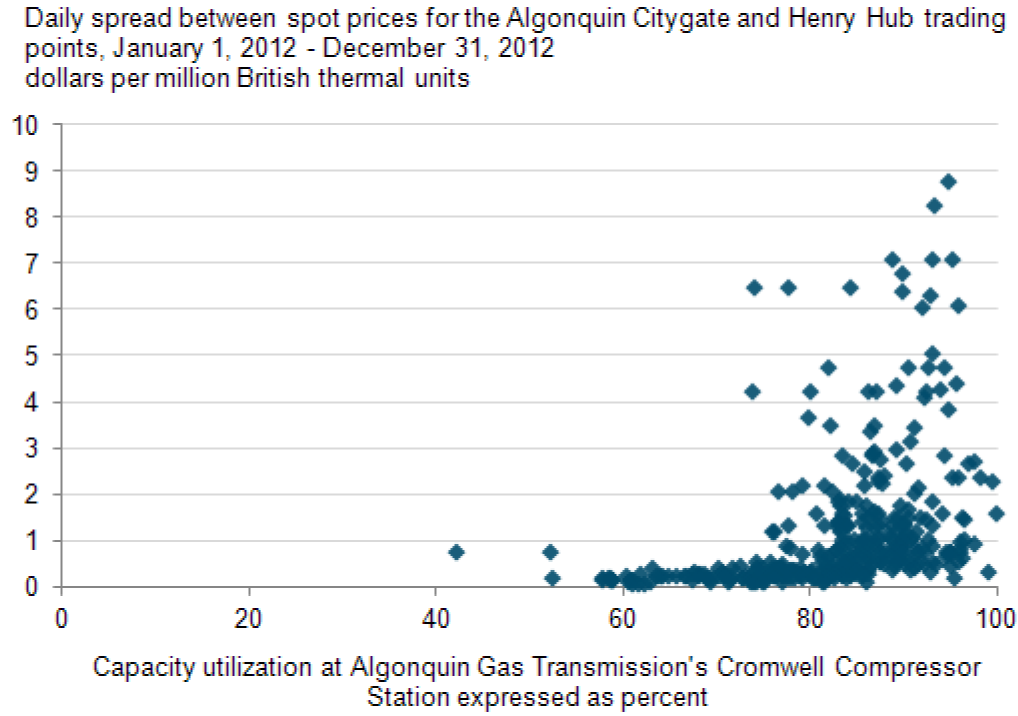


Source: U.S. Energy Information Administration based on Ventyx's Energy Velocity Suite.

Pipeline Constraints. Key natural gas pipelines from supply areas to New England are full or nearly full. The Algonquin Gas Transmission (Algonquin) system and the Tennessee Gas Pipeline (TGP) transport most of the natural gas into the New England market. Recently, both of these systems have been constrained.

Algonquin has run at high utilization (load factors calculated as average daily natural gas flows divided by peak use) since mid-2012. The Cromwell Compressor Station, a key throughput point on the Algonquin system (near Hartford, Connecticut), with a peak-day capacity of almost 1 billion cubic feet per day (Bcf/d), averaged about 86% utilization between November 1, 2012 and December 31, 2012. As a rule, when pipeline utilization at Cromwell exceeds 85%-90%, the constraint tends to bind and the spread between the Algonquin Citygate price and the Henry Hub price begins to rise (see Figure 4).

Figure 4. Daily natural gas basis (spread) between the Henry Hub and the Algonquin Citygate versus capacity utilization at Cromwell Compressor Station for 2012



Source: U.S. Energy Information Administration based on the Ventyx Energy Velocity Suite.

Note: The spread reflects the daily difference between the spot prices of natural gas at the Algonquin Citygate and Henry Hub trading points.

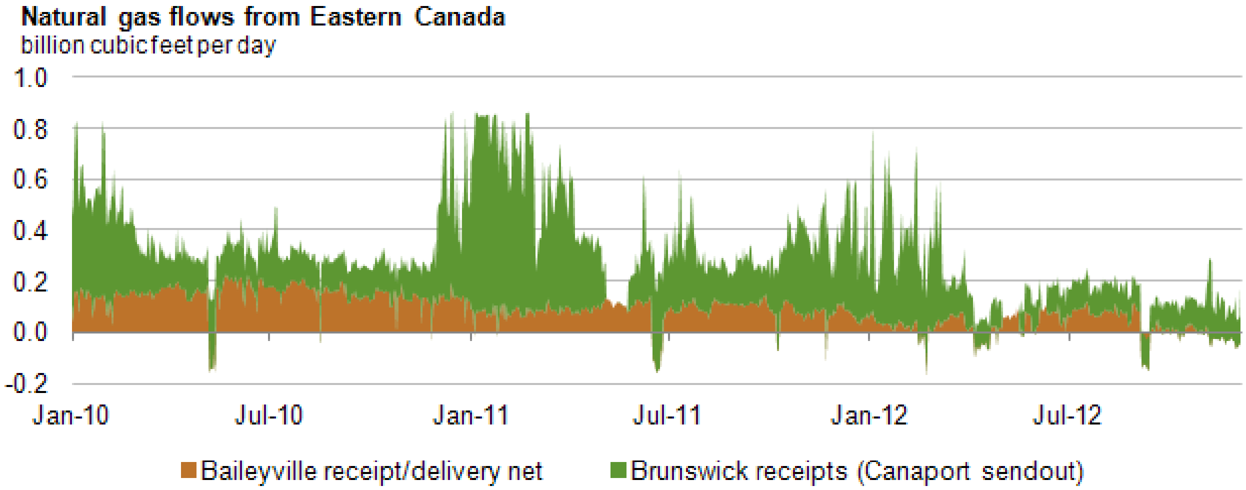
Algonquin throughput is up for the last year because:

- It serves as an outlet for growing natural gas production levels in the Marcellus basin; Bentek Energy estimates that about two-thirds of the gas flowing through the Cromwell Compressor Station comes from the Marcellus Basin and the remainder likely comes from the Gulf Coast
- Algonquin throughput is substituting for declines in other sources (regional LNG deliveries and SOEP production)
- Demand for natural gas has remained strong in New England, even during the summer

Natural gas flows on the Tennessee Gas Pipeline system into New England have also been high this winter.

Declining Supplies in Eastern Canada. Contributions of eastern Canadian natural gas production to New England's gas supply have been falling. Figure 5 below shows natural gas flows on the Maritimes and Northeast Pipeline between Canada and the United States. There are two principal sources of natural gas in eastern Canada that can be delivered into the United States at the Baileyville interconnect: production from the Sable Offshore Energy Project and send-out from the Canaport LNG terminal in St. John, New Brunswick. Both sources of potential supply have been limited so far this winter.

Figure 5. Natural gas flows between eastern Canada and the United States

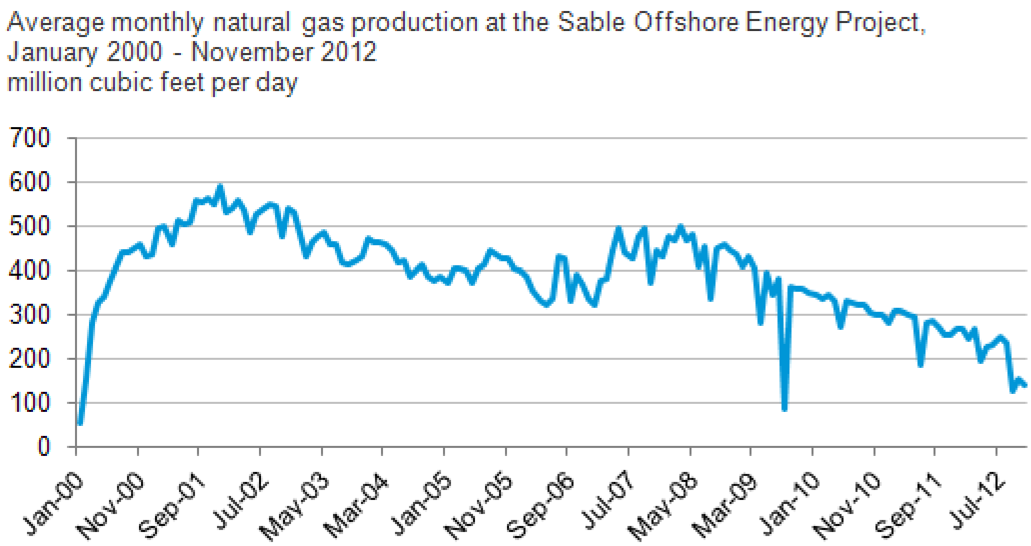


Source: U.S. Energy Information Administration based on Bentek Energy LLC.

Note: Baileyville is an interconnect between the Maritimes and Northeast Pipeline (Canada) and Maritimes and Northeast Pipeline (U.S.). Shippers on Maritimes and Northeast Pipeline can schedule to receive or deliver natural gas at this point. When natural gas deliveries at Baileyville exceed receipts, on a net basis, the customers on the Maritimes and Northeast system are effectively exporting natural gas to eastern Canada.

Natural gas supplies from the Sable Offshore Energy Project (SOEP), in Eastern Canada to New England are down because of two main factors: (1) reduced production at the SOEP), and (2) repairs that reduce or halt gas flows from SOEP. Bentek Energy reports that only three of five producing fields at Sable Island are operating now because of required repairs to a subsea flow line. As a result, SOEP production may continue to be curtailed until spring 2013, when these repairs can be made. Based on data from the Canada-Nova Scotia Offshore Petroleum Board, SOEP production in October 2012 was down about 30% compared to average production for the first three-quarters of 2012. Moreover, Encana's Deep Panuke offshore natural gas project which could have offset some of SOEP's lost production, was slated to begin commercial operations in early 2013 but now has deferred start-up, possibly until mid-2013.

Figure 6. Average monthly natural gas production at the Sable Offshore Energy Project



Source: U.S. Energy Information Administration based on Canada-Nova Scotia Offshore Petroleum Board.

Note: Production figures reported on a dry natural gas equivalent basis.

Reduced liquefied natural gas imports. New England has historically depended on imports of LNG for several reasons:

- Lack of local area storage facilities
- High seasonal demand peaks—especially in the winter
- Lack of locally produced natural gas
- Remoteness from the rest of the North American natural gas grid

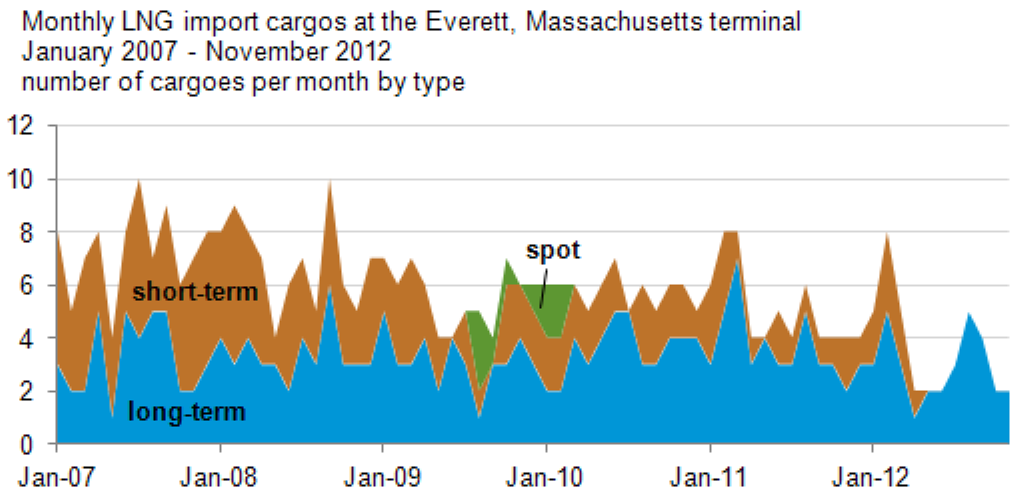
Since November 2010, LNG has supplied about 25% of New England's daily natural gas demand and, on a peak day, LNG in the winter has sometimes accounted for 60% of New England's total natural gas supply needs.

New England can receive LNG from four existing North Atlantic regasification terminals—three in the United States and one in Saint John, New Brunswick, in Canada. The U.S. terminals are the Everett, Massachusetts facility near Boston, now operated by GDF SUEZ Gas NA, and two offshore terminals—Neptune and Northeast Gateway. New England LNG is delivered in the following ways: by pipeline directly to customers; by truck to several dozen regional satellite storage tanks; and to an adjacent natural gas-fired electric generating plant, Exelon Corp.'s Mystic Generating Station in Charlestown, Massachusetts.

Everett Terminal

LNG imports at the Everett terminal have been declining. The Everett terminal has two storage tanks with a combined capacity of 3.4 billion cubic feet (Bcf), or only a little more than typical single-cargo deliveries. For most of 2012, Everett has only received LNG cargoes contracted on a long-term basis (see Figure 7). Short-term (contracts of up to two years) and spot cargoes have been diverted to other markets. Previously, Everett routinely received 6 to 10 cargoes per month, but through most of 2012 it got only 2 to 4 cargoes per month.

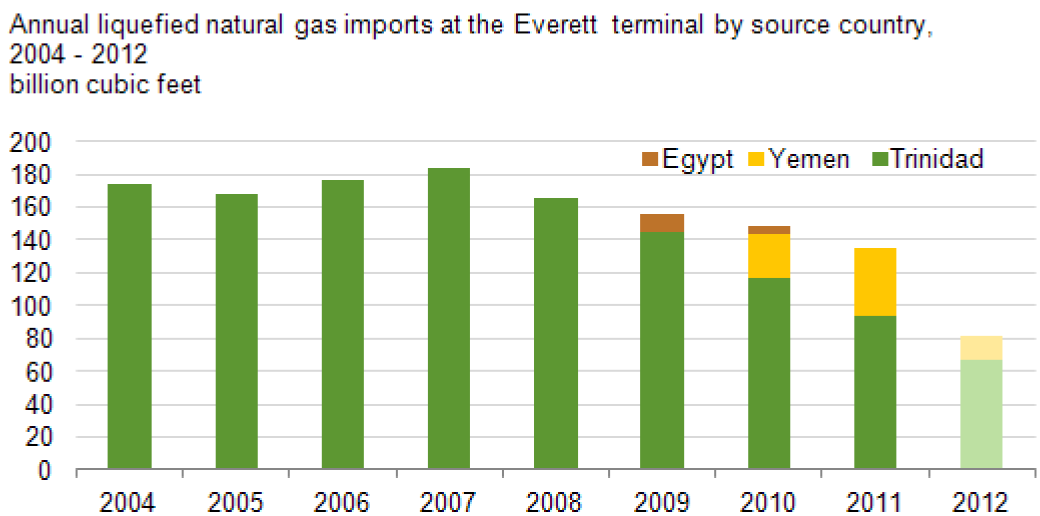
Figure 7. Monthly imports of liquefied natural gas at the Everett terminal



Source: U.S. Energy Information Administration based on the U.S. Department of Energy, Office of Fossil Energy. Data reported through November 2012.

Most of Everett's LNG comes from Trinidad and Tobago, but it is supplemented with supplies from elsewhere. Shipments from Yemen were down in 2012 because attacks on Yemeni pipeline infrastructure affected operations at the Balhaf liquefaction terminal on the Gulf of Aden. Everett's LNG imports have been declining since 2008; from 2004 to 2008, Everett's annual imports topped 160 Bcf each year.

Figure 8. Everett liquefied natural gas imports by country of origin



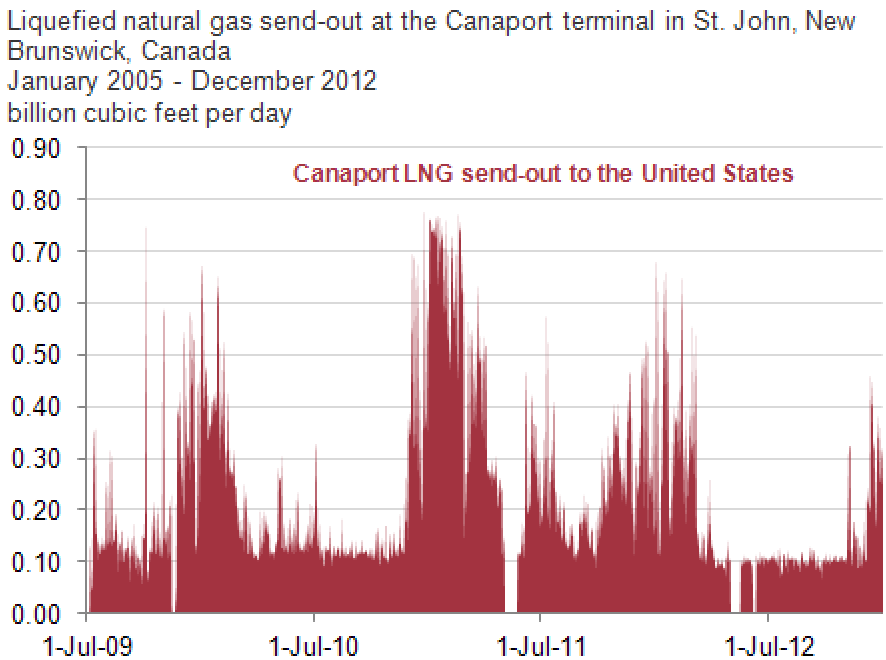
Source: U.S. Energy Information Administration based on the U.S. Department of Energy, Office of Fossil Energy.

Note: Data for 2012 reflect partial year figures from January through October.

Canaport Terminal

LNG imports at the Canaport terminal have been down throughout much of 2012. Since May 2012, Canaport deliveries to the United States averaged 100 million cubic feet per day MMcf/d; peak sendout at Canaport can top 700 MMcf/d.

Figure 9. Canaport LNG terminal deliveries to the Maritimes and Northeast Pipeline at the Brunswick Pipeline meter station



Source: U.S. Energy Information Administration based on Bentek Energy LLC.

Note: Canaport deliveries to the U.S. measured on Maritime and Northeast, Canada's Brunswick Pipeline meter station. Data reported for July 2009 through December 31, 2012.

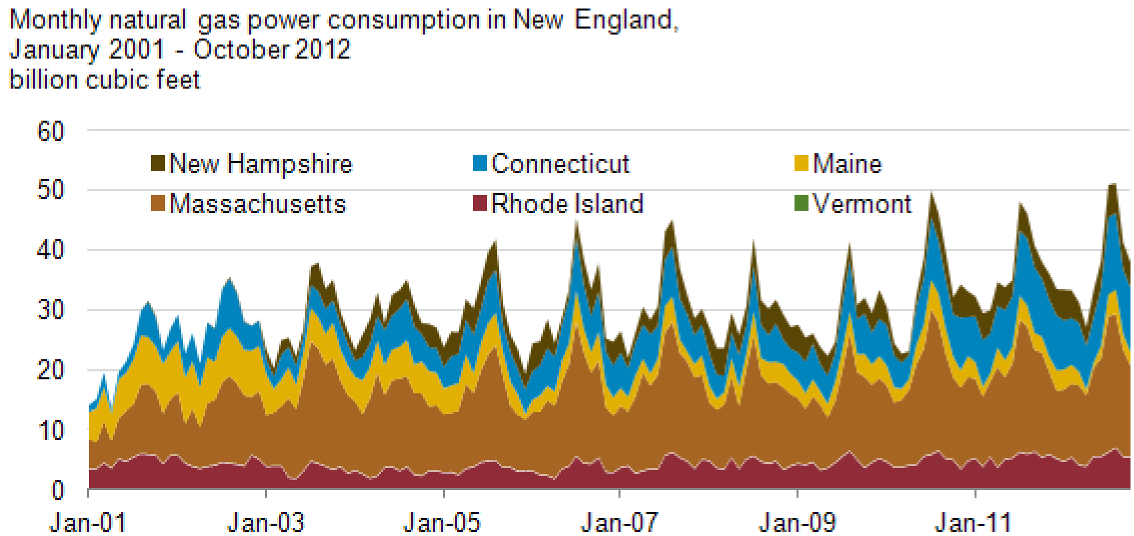
Offshore Terminals

Both offshore terminals receive LNG shipments only occasionally. The receipts are generally tied to market circumstances when both New England demand and natural gas prices are high. Lately, these terminals have received few cargoes because competing markets in western Europe (the United Kingdom, the Netherlands, Belgium, and Spain) or Asia (Korea, Japan, China, or India) typically offer higher prices—sometimes approaching $20 per MMBtu. Excelerate Energy's Northeast Gateway offshore terminal is located 13 miles off the coast of Massachusetts; it started commercial service in 2008 and has a sendout capacity of 0.6 Bcf/d. GDF SUEZ Gas NA's Neptune LNG LLC offshore terminal is located about 10 miles off the coast of Massachusetts; it began service in 2009 and has a sendout capacity of 0.4 Bcfd. Both of these LNG facilities have interconnections to the Algonquin's HubLine pipeline.

Rising demand. Natural gas demand in New England will likely be higher during the winter of 2012-13 compared with the winter of 2011-12 (one of the warmest winters in 60 years), and this could put upward pressure on natural gas and power prices in New England. On January 17, the National Oceanic and Atmospheric Administration (NOAA) released its [8-14 day temperature outlook] calling for below-normal temperatures in the northeastern United States. By contrast, NOAA's three-month outlook, February through April, called for above-normal temperatures in the northeastern United States. Natural gas demand in eastern Canada this winter has already absorbed the more-limited Sable Island production that usually augments New England's natural gas supplies.

Natural gas use for power is rising in New England. Average natural gas use for power generation in New England was up about 3% from January to October in 2012, compared to the same period in 2011. Natural gas accounted for 51% of total generation in ISO New England in 2011.

Figure 10. Monthly natural gas use for power trends in New England



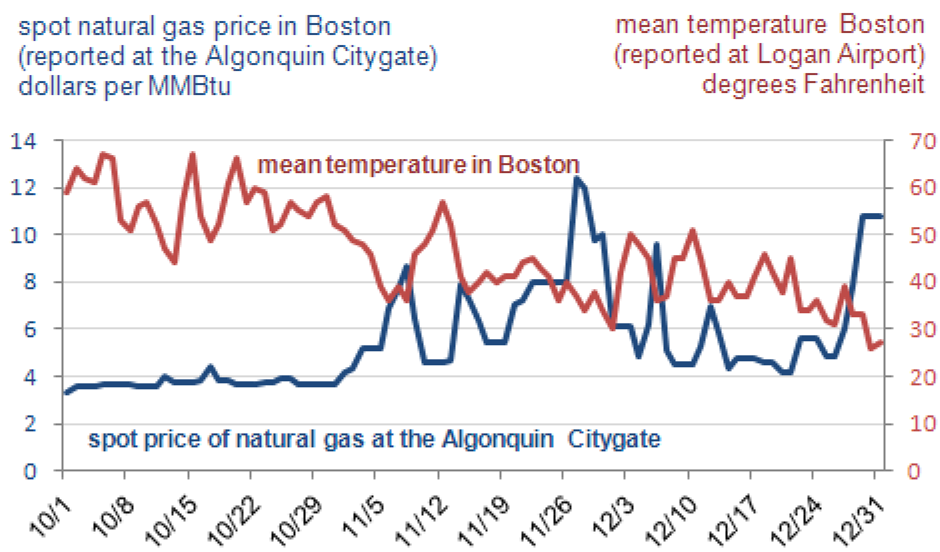
Source: U.S. Energy Information Administration, Natural Gas Monthly.

Note: New England states include Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. Monthly data reported for January 2001 – October 2012.

What are the ramifications of constrained supplies for New England?

As a result of these market conditions, New England natural gas and electric power prices this winter could be volatile at times. During November and December, prices seesawed in relation to weather-driven pipeline constraints.

Figure 11. Recent trends in spot natural gas prices and mean temperatures in Boston

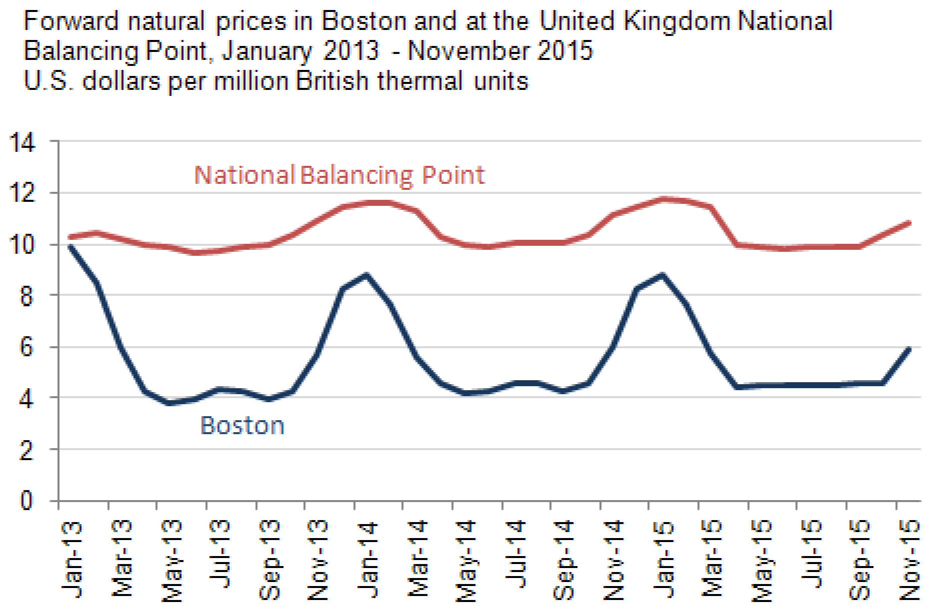


Source: U.S. Energy Information Administration based on Bloomberg, L.P.

Note: Daily temperatures reflect mean values recorded at Logan Airport in Boston, Massachusetts. Spot natural prices reported at the Algonquin Citygate.

These market conditions are affecting current, spot market prices as well as forward prices. Forward expectations for prices can be assessed by examining trends in natural gas basis swaps. Natural gas swaps for the Algonquin Citygate trading point have topped $6 per MMBtu for the peak winter months of January and February. Forward curves for natural gas in Boston and at the National Balancing Point (NBP) benchmark in the United Kingdom, as of December 27, 2012, show that although expectations for natural gas prices were somewhat comparable for January 2013, the NBP market reflected premiums compared to natural gas in Boston through 2015.

Figure 12. Forward natural gas prices in Boston and the United Kingdom



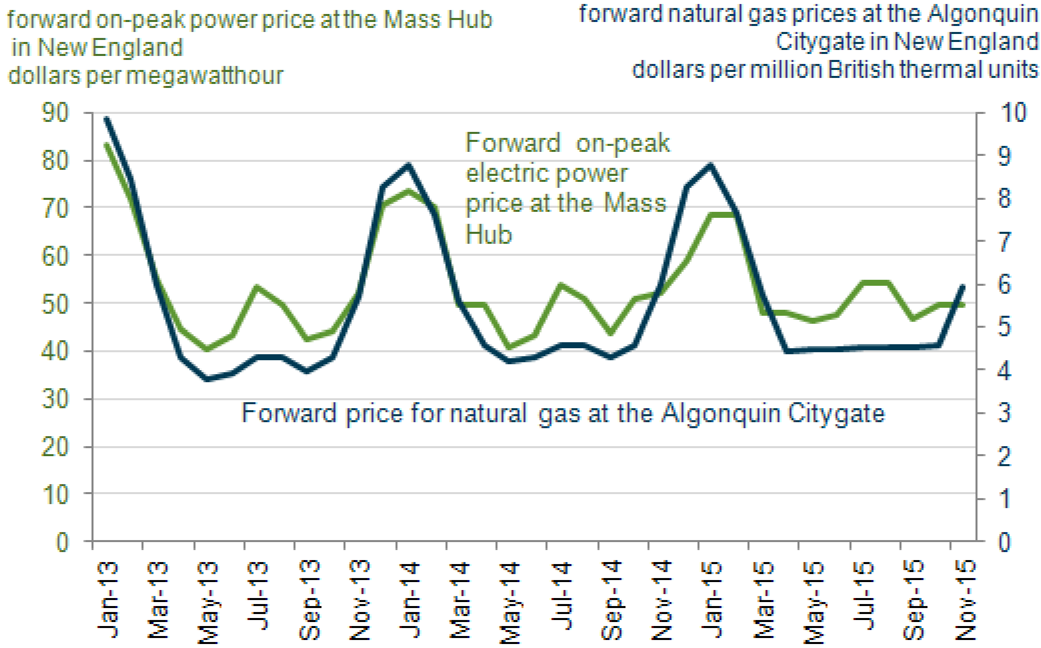
Source: U.S. Energy Information Administration based on Bloomberg, L.P.

Note: Forward curves reflect the futures contracts reported by the IntercontinentalExchange for the U.K. National Balancing Point and the NYMEX natural gas futures contract at Henry Hub plus a basis swap at the Algonquin Citygate trading point. A natural gas basis swap is a financial instrument reflecting market participants' future valuation of the difference in price between the Henry Hub natural gas futures contract for a given month and the price of gas in a downstream market location like Boston, Massachusetts, for the same, future month. Forward curves shown are based on settlement values as of December 27, 2012.

Because generators using natural gas often set the market-clearing price for electric power, wholesale electric power prices often trend together with natural gas prices. In these circumstances, natural gas is referred to as being the "fuel on the margin." As a result, higher spot natural gas prices may contribute to higher electric power prices. Natural gas is generally the fuel on the margin much of the time in New England.

The shape of the forward curve for natural gas in New England between January 2013 and November 2015, using the Algonquin Citygate price as a proxy, is fairly similar to the shape of the forward electricity curve at the Mass Hub—a proxy for the price of power in New England (see Figure 13). The chart indicates that there will be highly seasonal price patterns during the next three years with pronounced winter peaks.

Figure 13. Forward electric power and natural gas prices in New England



Source: U.S. Energy Information Administration based on Bloomberg, L.P.

Note: Forward curves reflect a Bloomberg-reported index for an over-the-counter forward price for electric power in New England at the Mass Hub expressed in dollars per megawatthour and the NYMEX natural gas futures contract at Henry Hub plus a financial basis swap at the Algonquin Citygate trading point expressed in dollars per MMBtu.

Exhibit E

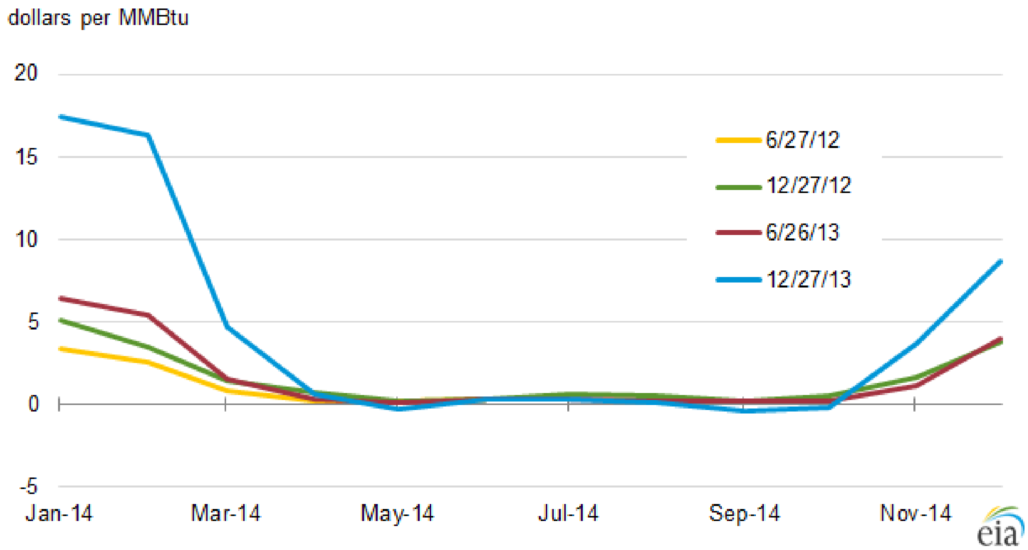
February 7, 2014

High Prices Show Stresses in New England Natural Gas Delivery System

Abstract. Since 2012, limited supply from the Canaport and Everett liquefied natural gas (LNG) terminals coupled with congestion on the Tennessee and Algonquin pipelines have led to winter natural gas price spikes in New England. The problem continued in the winter of 2013-14, as indicated by New England's forward basis for January 2014 reaching $17.41. Pipeline expansions could ease price spikes, but their cost-effectiveness, including their ultimate cost to consumers, remains a challenge. This article reviews possible alternatives. The data are presented in three summary tables and in detailed state tables.

During the past two winters, New England natural gas winter prices have risen significantly. The average bidweek natural gas price reached a high of $14.52 per million British thermal units (MMBtu) for December 2013 and more than $20/MMBtu for January 2014. The January New England forward basis[1] , reflecting the relationship between market conditions at a specified regional hub and those at Louisiana's Henry Hub, settled at $17.41,[2] and the forward basis curves indicate a market expectation of a record-high winter basis (Figure 1). The high winter prices in New England suggest a natural gas delivery system that is stretched significantly.[3]

Figure 1. Forward basis curves for natural gas in New England

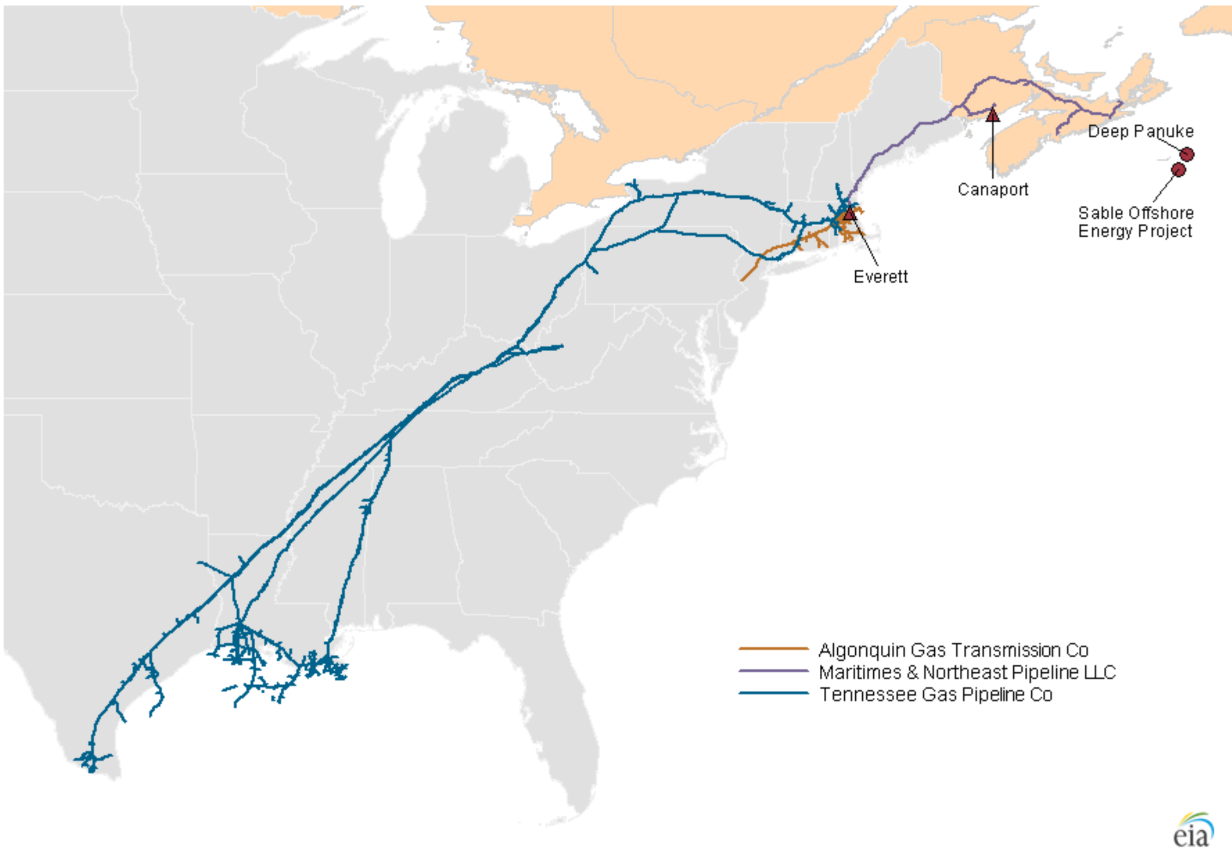


Source: U.S. Energy Information Administration, Bloomberg LP

[1]In the natural gas industry, basis is the difference between a natural gas price at a given location and the benchmark Henry Hub (Louisiana) price; a forward price of a given forward month is a contract price for delivering a specified amount of natural gas in the given month. A forward basis of a given location is the difference between the forward prices at the given location and at Henry Hub. A spot price is a contract price for delivering natural gas on the next day. A spot basis at a given location is the difference between spot prices at the given location and Henry Hub.
[2]This specific basis was at the Algonquin Citygate.
[3]See also Constraints in New England likely to affect regional energy prices, Market Alerts, and the Market Prices and Uncertainty Report.

New England receives natural gas from several sources. Most natural gas delivered into New England flows through the Tennessee Gas Pipeline (TGP) and Algonquin Gas Transmission pipeline (AGT), both of which flow gas into the region from the south. Massachusetts's Everett liquefied natural gas (LNG) terminal also supplies natural gas to the region and is connected with the AGT and TGP pipelines.[4] Canada's Canaport LNG import terminal also sends natural gas into the region through the Maritimes & Northeast (M&N) pipeline, which has the option of delivering natural gas to New England from the production fields in the Sable Offshore Energy Project and Deep Panuke in Nova Scotia, Canada (Figure 2).

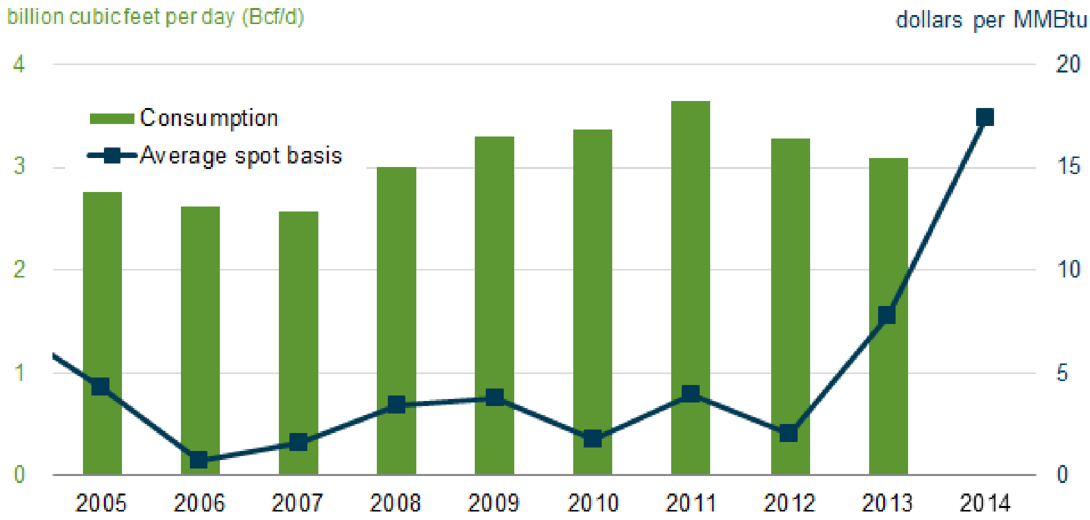
Figure 2. New England natural gas supply system



The TGP and AGT pipelines have a combined transport capacity of about 3.5 billion cubic feet (Bcf) per day delivered into New England, including gas from domestic production and storage withdrawal, Canadian production, and imported LNG. Although transport capacity is greater than average January consumption (Figure 3), peak-demand days determine the stress on the delivery system.

[4] Everett also provides LNG directly to the Mystic Power Plant and the National Grid utility company. In addition, Everett is capable of delivering LNG directly to utilities or even end users by truck at the capacity of 0.1 Bcf/day. Two additional regasification terminals, offshore buoy-systems Neptune and Northeast Gateway, both near Everett, are usually inactive.

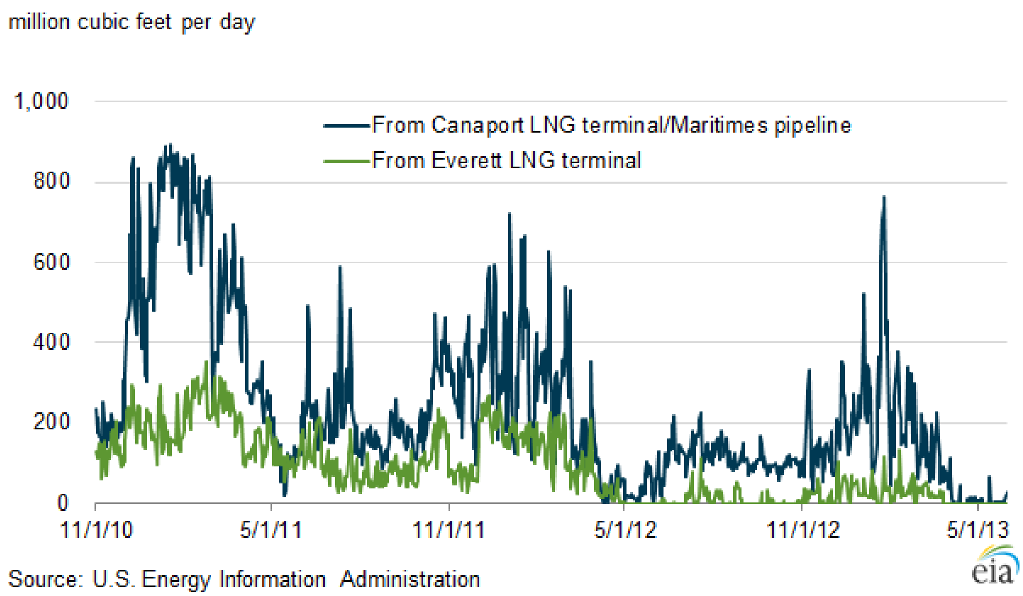
Figure 3. January average natural gas basis and daily consumption in New England



Source: U.S. Energy Information Administration, Bloomberg LP

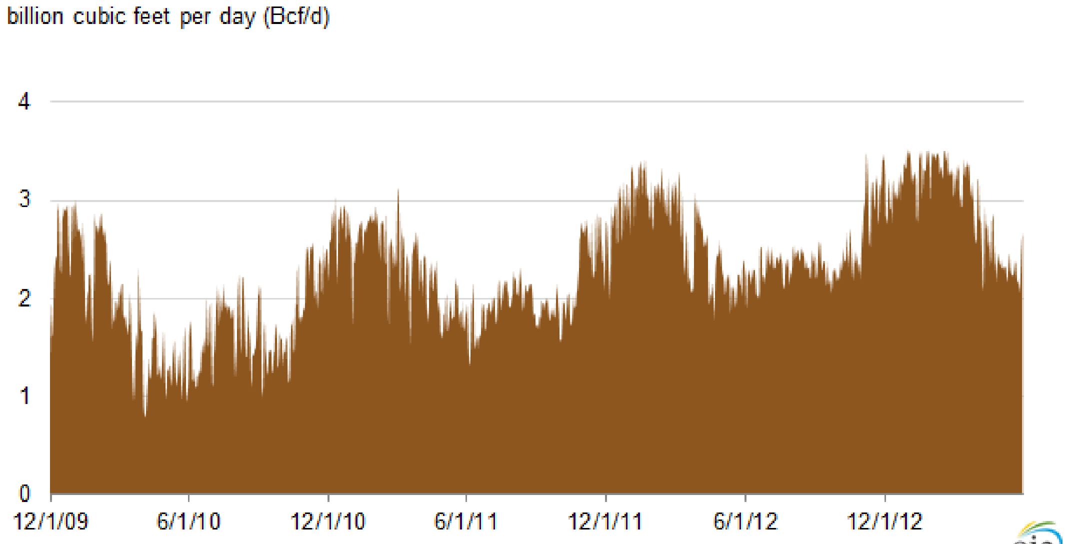
In the winter of 2012-13, LNG supply from Canaport via M&N and from Everett declined (Figure 4), and as a result, the other primary sources of supply, the AGT and TGP pipelines, were almost fully utilized and thus stressed in many days of the winter (Figure 5). This situation has been repeated as the winter of 2013-14 reaches a midpoint, and the forward basis continues to spike.

Figure 4. New England's swing supply of natural gas



Source: U.S. Energy Information Administration

Figure 5. New England natural gas supply from TGP & AGT pipelines

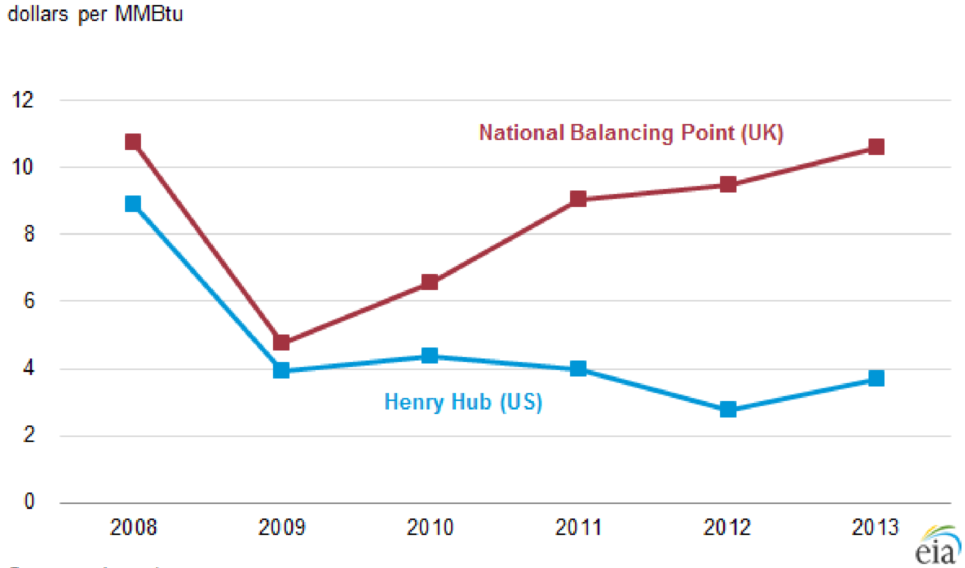


Source: U.S. Energy Information Administration

Some of the natural gas from M&N and Everett is delivered to New England through their interconnections to TGP and AGT. In addition, Everett delivers up to 0.7 Bcf per day directly to the 1,951-magawatt (MW) Mystic power plant, the National Grid utility company, and LNG users. New England also receives natural gas directly from M&N, Iroquois, and the Pacific Northern Gas pipelines in addition to the delivery points on TGP and AGT.

International natural gas and LNG markets. The reduction in LNG imports into New England is a consequence of the growth in U.S. shale gas production since 2010, which has contributed to a reduction in U.S. natural gas market prices relative to those in other world markets. The price spread between the U.S. benchmark price at Henry Hub and the United Kingdom (U.K.) benchmark price at National Balancing Points widened to $6.91/MMBtu in 2013 from $0.83/MMBtu in 2009 (Figure 6).

Figure 6. Average spot natural gas prices

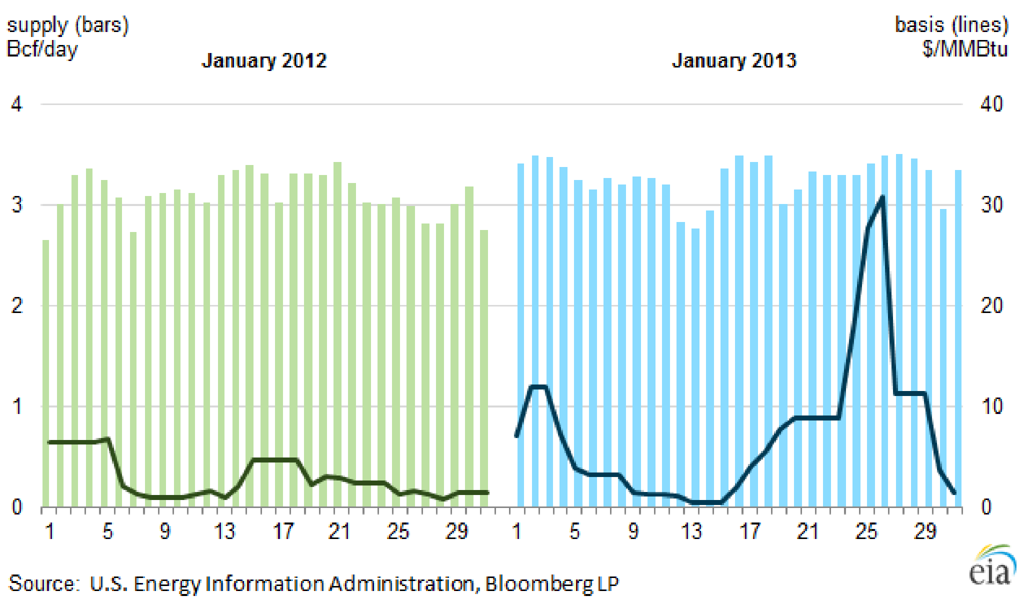


Source: Bloomberg LP

The growing price spread between U.S. and global markets led to the reduction in LNG imported and then sent from the Canaport (through M&N) and Everett LNG terminals (through TGP and AGT), and contributed to the upward price pressure in the New England market.

Effect of limited peak supply on New England prices. The price effect of a decline in peak supply is evident when comparing January 2013 with January 2012. Both months had several days when the market called for supply close to peak capacity of 3.5 Bcf/day from TGP and AGT. The basis in January 2013, however, rose substantially higher than the basis in January 2012, reaching over $30/MMBtu on January 26, 2013, while remaining under $9/MMBtu the entire month of January 2012 (Figure 7).

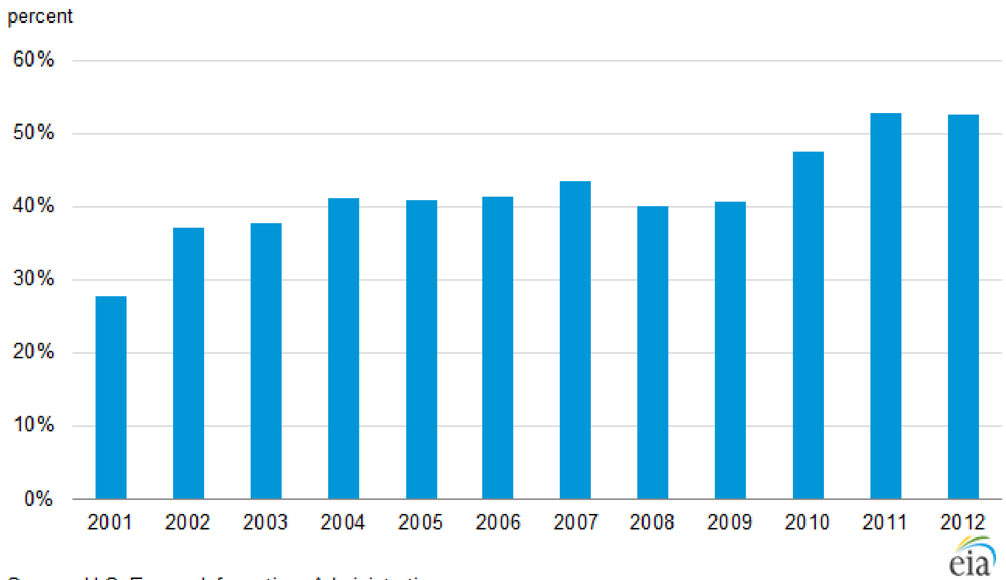
Figure 7. NE natural gas supply from TGP and AGT and basis, Jan 2012 vs. Jan



Source: U.S. Energy Information Administration, Bloomberg LP

Increasing electric power sector natural gas use in New England. Relatively lower natural gas prices in the United States, compared with the United Kingdom, not only led to declines in LNG imports but contributed to increased use of natural gas in power generation. In New England, natural gas use for electricity generation made up about a third of the region's natural gas consumption in 2013, averaging 1.2 Bcf per day. Since 2010, a trend of less expensive natural gas relative to other fuels has led to an increase in the share of total electricity generated by natural gas in the region (Figure 8).

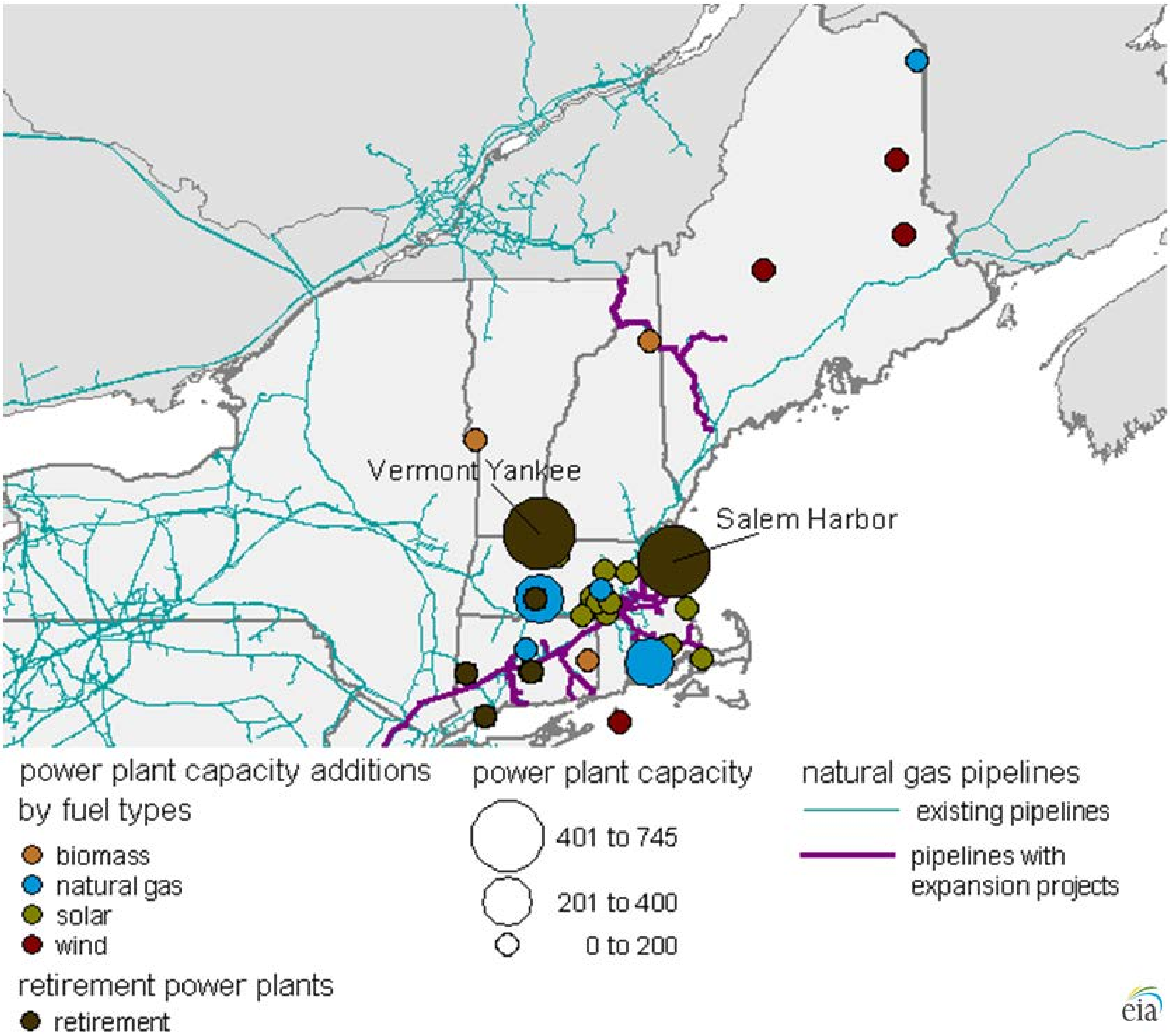
Figure 8. Natural gas share of total generation



Source: U.S. Energy Information Administration

This price pattern has increased the use of natural gas-fired capacity in the region and contributed to generally lower wholesale power prices. The lower wholesale power prices along with some environmental regulations at the regional and national levels have contributed to planned retirements of some large electric power plants in New England that use other fuels **(Figure 9)**, including Vermont Yankee (a 620-MW nuclear generator with a planned retirement date of December 2014) and Salem Harbor (a 744-MW coal- and oil-fired power plant with a planned retirement date of June 2014). The planned retirement of the Vermont Yankee and Salem Harbor power plants could result in as much as 0.11 Bcf per day of additional natural gas demand in the power sector during winter months, if typical demand patterns hold and all the output of these units is replaced by natural gas generation.

Figure 9. New England planned energy infrastructure changes between 2013 and 2016



Source: U.S. Energy Information Administration.

Increased pipeline utilization rates on peak days create physical stress on the natural gas transport system, which leads to reliability concerns for electric power sector deliveries. These deliverability concerns led the Independent System Operator of New England (ISO-NE), the electric grid operator for the region, to create a special winter reliability program for this winter. The program includes:

- demand-response program;
- incentives to ensure oil-fired generators increase their fuel inventories;
- payments to dual-fueled units for testing their capacity to use oil; and
- some changes to the market-monitoring procedures aimed at increasing the flexibility of dual-fueled units

The deliverability problems cited in the ISO-NE winter reliability program are a key reason to have oil-fired backup and dual-fired unit capacity in the region.

Potential solutions

There are a number of potential solutions to lessen the impact of limited peak supply at peak demand times.

Pipeline expansion to New England. With rising natural gas output from the Marcellus production field, pipeline expansion to move this gas to New England is one option for alleviating market stress. The key is to deliver more natural gas to Massachusetts, especially the Boston area, because it is the largest market in New England. Major energy infrastructure projects in metropolitan areas such as Boston and New York City, however, are capital intensive. Regulated pipeline companies typically seek financial assurance by signing long-term firm transport capacity contracts with shippers. Companies that sign firm capacity contracts will benefit financially when spreads widen substantially in New England. On the other hand, firms signing these contracts also assume the financial liability.

In 2011, Spectra Energy (operator of the Algonquin pipeline) proposed the Algonquin Incremental Market (AIM) Project to expand its citygate capacity by a nonbinding nomination of 1 Bcf/day. In December 2013, the proposed capacity expansion was 0.33 Bcf/day, with the target completion in November 2016.[5] The size of the pipeline capacity expansion was reduced 65% from the original proposal because of lack of interest in signing up for long-term firm transport capacity contracts.[6] So far, only regulated utilities, including UIL Holdings, Northeast Utilities, National Grid, and NiSource, have shown a willingness to absorb the financial cost embedded in the long-term firm contracts.[7] In addition to Spectra, Tennessee Pipeline proposed an expansion project of up to 1.2/day into the Boston area, with expected completion in 2018.[8]

In general, public utility commissions (PUCs) require utilities to seek approval for signing long-term contracts and the rate hikes required to pay for them. The reduction in the proposed expansion capacity of the AIM project may indicate hesitation by and their regulators. Pipeline rates approved by FERC and utility rates approved by PUCs need to be consistent for success in pipeline expansion.

U.S. LNG. Utilities in New England might also enhance winter supply reliability by investing directly in proposed U.S. LNG liquefaction plants and receiving occasional LNG cargoes as a stipulation of their investment. It may be possible that investing a relatively small amount of capital could provide access to this source of swing supply during periods of high winter demand in New England.

Physical peaking option contracts. To mitigate the market risk of such high-price patterns, one effective instrument is a physical peaking option to manage the physical supply and financial price risk on peak

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[5]Algonquin Incremental Market (AIM) Project, Spectra Energy, http://www.spectraenergy.com/Operations/New-Projects-and-Our-Process/New-Projects-in-US/Algonquin-Incremental-Market-AIM-Project/ and DEEP Electric IRP Gas Stakeholder Meeting, Hartford, CT, September 20, 2011, Spectra Energy, http://www.ct.gov/deep/lib/deep/energy/irp/naturalgas/irp_2012_stakeholdermtg_naturalgas_spectraenergy_092011.pdf

[6]Utilities seek boost in region's natural gas, the Boston Globe, November 5, 2013, http://www.bostonglobe.com/business/2013/11/05/agreements-with-utilities-moving-pipeline-expansion-forward/8uyv2tJ9dqhXReB3BxgkYN/story.html.

[7]*NGA Pre-Winter Briefing*, Spectra Energy, November 6, 2013,

[8]*Northeast Gas Association Pre-Winter Briefing 2012 / 2013*, Kinder-Morgan, December 3, 2012, www.northeastgas.org/pdf/d_skipworth.pdf

demand days.[9] The contract buyer purchases a fixed quantity of gas from a peak supplier, such as an LNG storage facility, for a specified open window of time, price, and number of days on which the buyer can call for delivery of the gas at the agreed price and volume. The buyer pays the option premium to the LNG facility for this right. Volumes tend to be small, as the right to buy the gas would only be exercised as an emergency on days of peak demand, such as a very cold day when the spot price spikes.

However, in recent years, New England has developed problems that may prevent the economic use of an LNG-based peaking option:

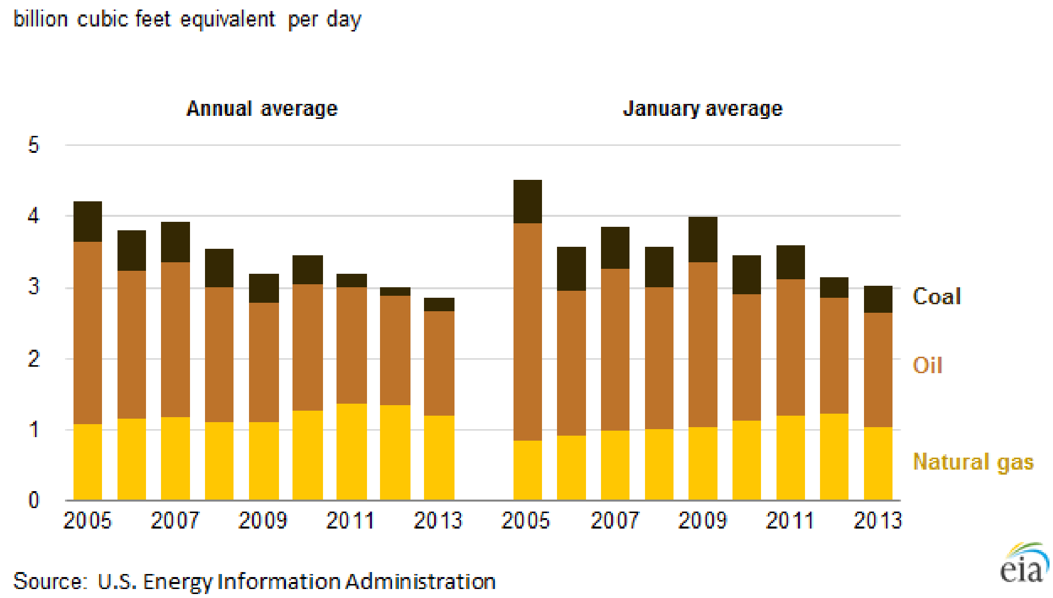
- The increased frequency of price spikes has made options more expensive.
- Supplies from Canada's eastern offshore production areas declined, making the overall premium more expensive.
- Because LNG is traded globally, higher international LNG prices have increased competitive buying pressure for the gas.

With the increase in the forward basis for the winter of 2013-14 as described above, Canaport and Everett may be able to lock in LNG supplies to New England, but the cost to consumers is higher than in recent years because of the above factors.

Fuel substitution. In periods of high natural gas prices, users could substitute less-expensive fuels if possible. Natural gas consumption by the power sector declined in January 2013 compared to January 2012 (Figure 10), encouraged in part by higher natural gas spot prices. When natural gas prices hit a historic low in the summer of 2012, it was widely reported that many power generating units switched from eastern coal to natural gas. More importantly, during the peak-demand season when natural gas prices spike, power generating units tend to switch from natural gas to fuel oil. In addition to power generation, other natural gas consumers, such as universities, factories, or even residential customers, also benefit from optimizing their fuel strategy when a backup-fuel is available. Regulatory restrictions and other issues, however, may limit the extent that fuel substitution can occur, which will constrain the effect of fuel switching even in periods of peak demand.

[9] *Imported LNG: a Reliable Peaking Option for New England*, Repsol Presentation, April 30, 2013, www.northeastgas.org/pdf/v_morrissette_repsol.pdf and *GDF Suez Gas NA*, GDF Suez Presentation, December 3, 2012, www.northeastgas.org/pdf/g_whitney.pdf.

Figure 10. New England fuel consumption for power generation, annual vs. January average



Demand curtailment. Utilities in both New England and New York City are able to offer interruptible services to customers with dual-fuel capability. New York City has a widely used feature in which utilities offer retail customers firm services and interruptible services. Natural gas consumers with dual-fuel backup have an option to buy interruptible natural gas services at a substantial discount. Consumers with interruptible services can choose to switch from natural gas if another fuel is less expensive. If market activities fail to reduce peak demand below available supply, however, utilities make curtailment calls to ensure supply reliability, which require natural gas consumers with interruptible services to switch from natural gas to another fuel regardless of costs. Customers who fail to comply will incur monetary penalties.[10]

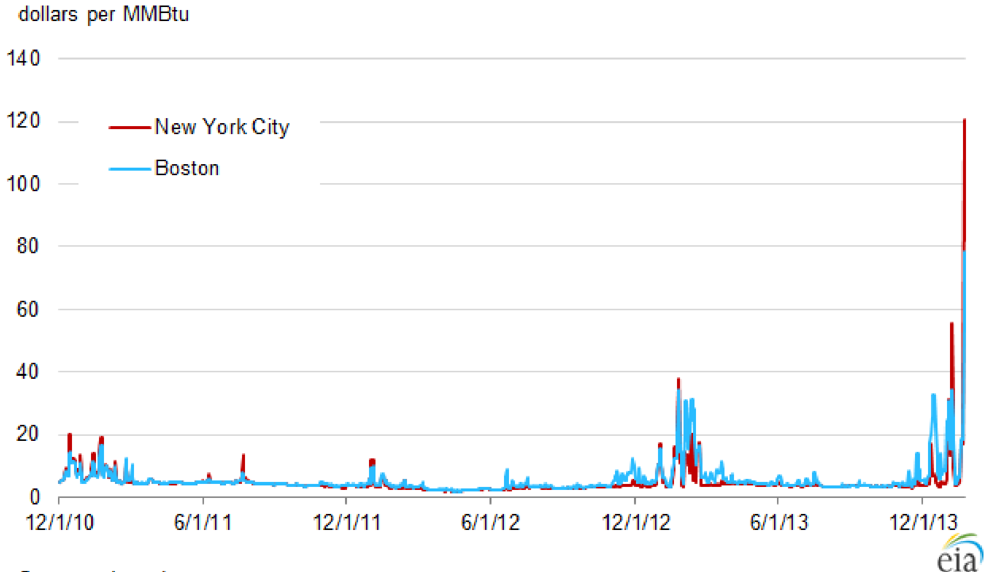
The retail curtailment mandate lowers peak demand, which helps reduce price spikes during high-demand periods. When curtailment is called, customers may have to pay higher prices to switch from natural gas to alternative fuels, but they may still be better off than paying higher premiums up front to purchase firm services.

Price comparison between New England and New York City. Both Boston and New York City had natural gas price spikes in the winter of 2012-13 (Figure 11). So far in the winter of 2013-14, however, natural gas price spikes in New York City remained less frequent than in Boston, although on the coldest days the spot prices tend to be higher in New York City than in Boston. Natural gas pipeline expansion into the New York City area may be providing a buffer against the frequency of price spikes this winter. Encouraged by the proximity to Marcellus natural gas production and rising baseload consumption, pipeline capacity increased, and this likely contributed to the mitigation of price spikes in the New York

[10] OFO and Curtailment, SCANA Energy Marketing, http://www.scanaenergymarketing.com/SCANA.ESS.Templates/Content/Content100.aspx?NRMODE=Published&NRNODEGUID=%7bF78CDC8B-8C39-40A8-961E-D84EB1183F1A%7d&NRORIGINALURL=%2fen%2fnatural-gas-education%2fofo-and-curtailment%2f&NRCACHEHINT=Guest#curtailment

City area. In addition, effective retail demand curtailment in New York City provides peak supply reliability and, in turn, reduces price volatility.

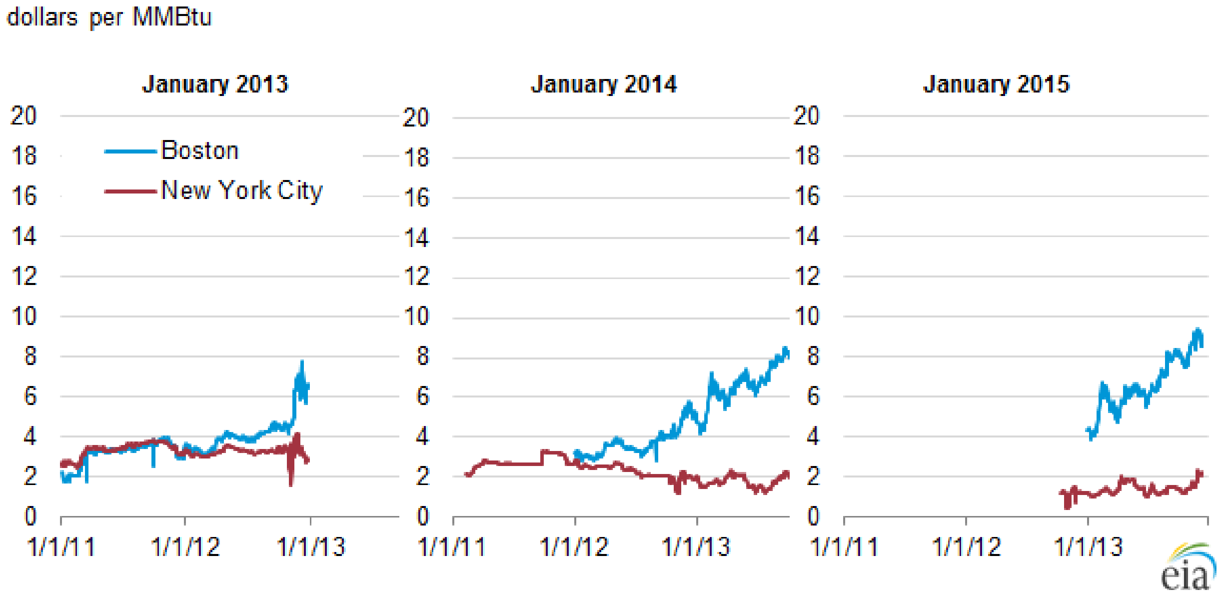
Figure 11. Natural gas spot prices in Boston and New York City



Source: Bloomberg LP

The forward basis markets have also shown widening differentials (Figure 12). At Transco Zone 6 New York, the January 2013 forward basis settled around $3/MMBtu, while the Algonquin Citygate January 2013 forward basis reached more than $6/MMBtu. The deviation widened rapidly in 2013. The January 2014 forward basis at Transco Zone 6 New York settled at $4.89/MMBtu, but the Algonquin Citygate forward basis for the same contract settled at $17.41/MMBtu. The 2015 basis differential also remains wide, indicating the market expectation that New England's peak supply problems will continue into the winter of 2014-15.

Figure 12. Natural gas forward basis for January 2013, January 2014, and January 2015



Source: Bloomberg LP

Conclusion. Limited peak supply contributed to substantial increases in New England natural gas prices and basis on high-demand days this winter and last winter. New York City reduced spikes in prices and basis by adding pipeline capacity and by using retail demand curtailment, solutions that could help New England as well. Companies have proposed pipeline expansion, but getting the financial commitments to move forward has been difficult because the additional capacity may only be necessary for short periods during the year. Pipeline expansion may become more viable if baseload consumption of natural gas to generate electricity continues to increase. The high January 2015 forward basis for Boston indicates that market participants do not expect a resolution to these peak supply issues before next winter.