Independent Statistics & Analysis
U.S. Energy Information Administration

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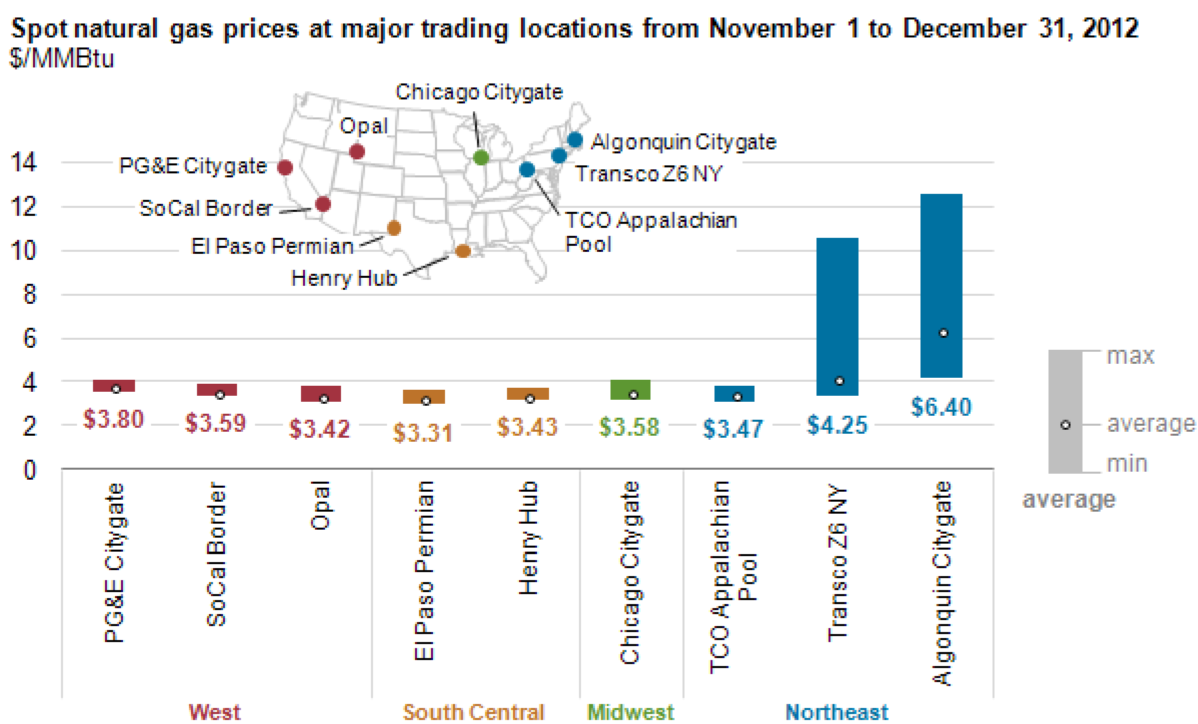
# Short-Term Energy Outlook Supplement: Constraints in New England likely to affect regional energy prices this winter

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

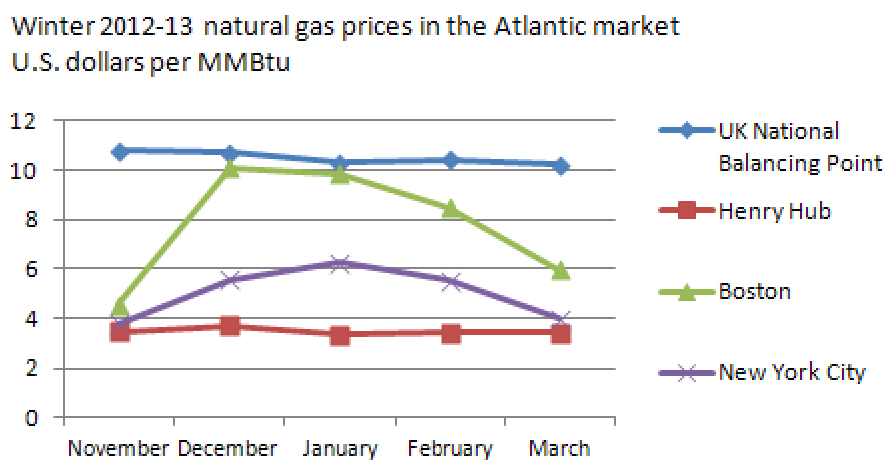



Source: U.S. Energy Information Administration based on Ventyx, Energy Velocity Suite.

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.

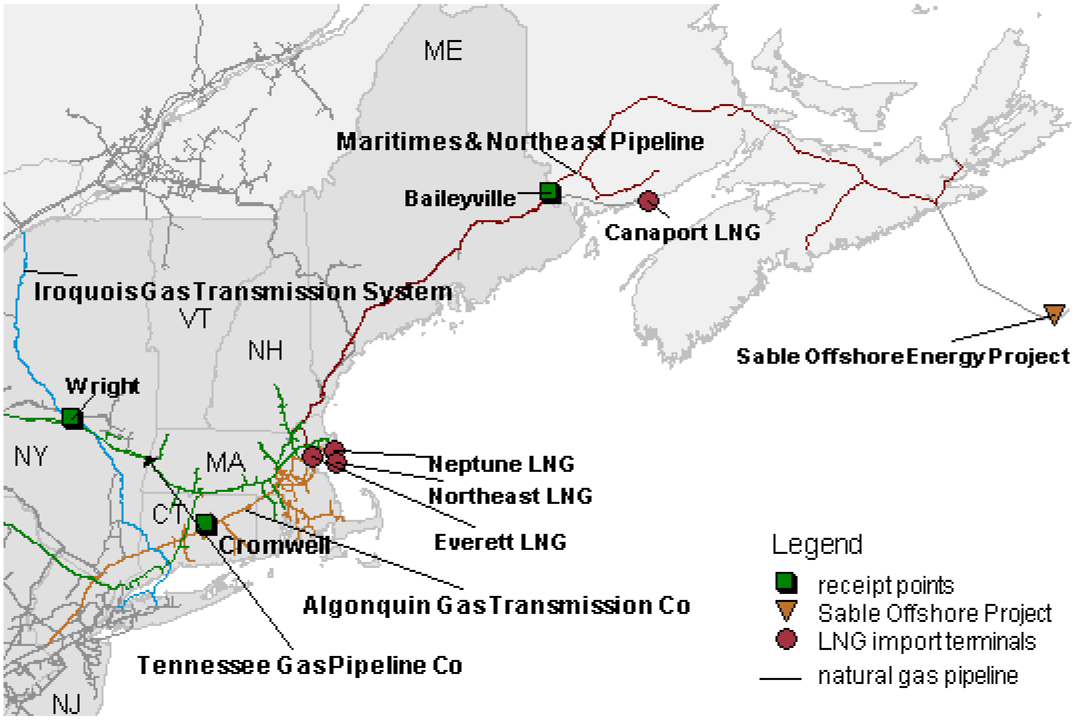
Note: Forward values reflect market closes on December 27, 2012, for the January, February, and March futures contracts. The November and December forward values reflect the settlement prices as of the dates the New York Mercantile Exchange (NYMEX) natural gas futures contracts expired, or settlement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

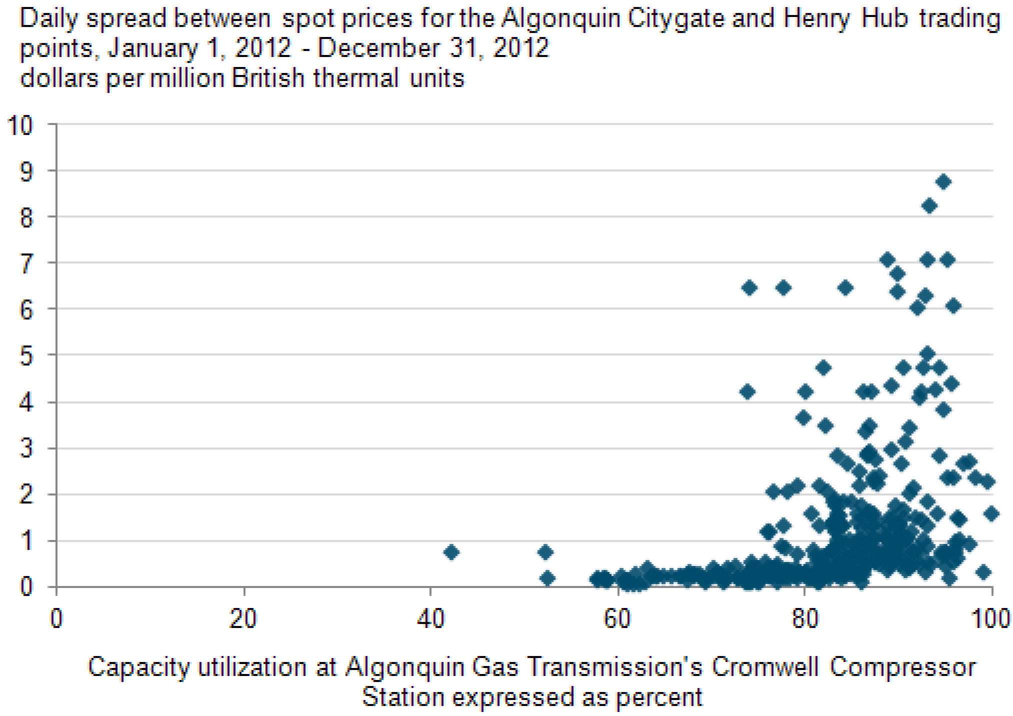



Source: U.S. Energy Information Administration based on Ventyx's Energy Velocity Suite.

**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.

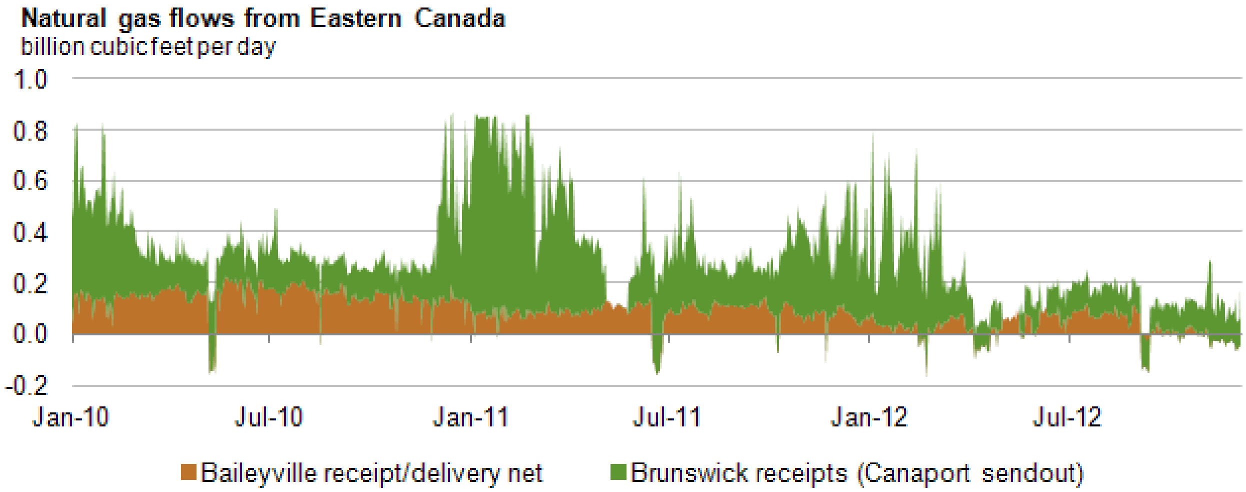
Algonquin throughput is up for the last year because:

- 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

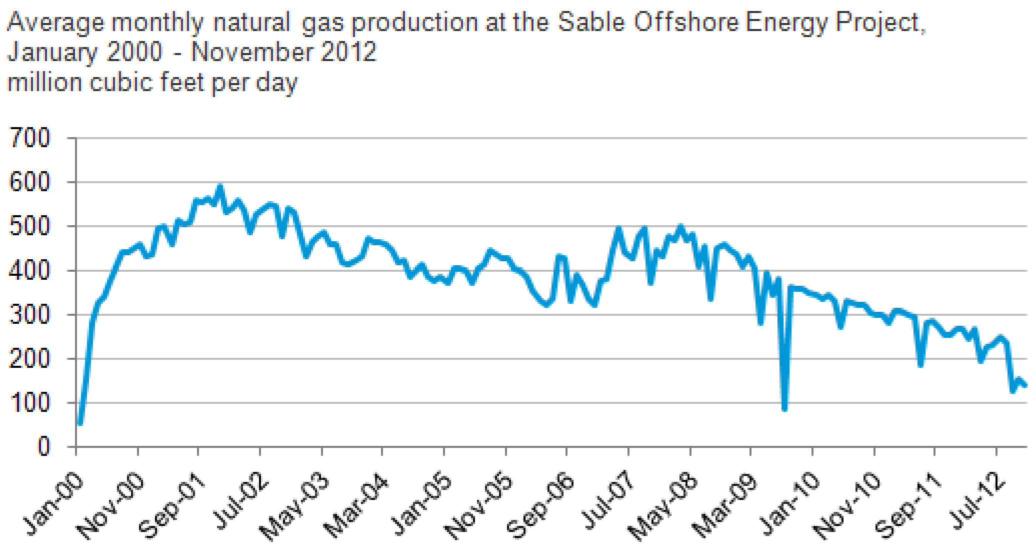



Source: U.S. Energy Information Administration based on Bentek Energy LLC.

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

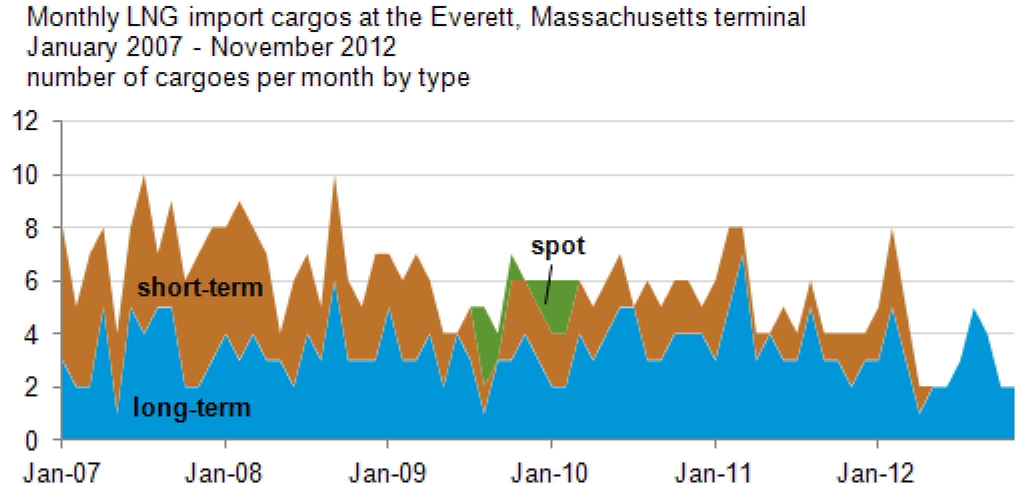
Since November 2010, LNG has supplied about 25% of New England's daily natural gas demand and, on a peak day, LNG in the winter has sometimes accounted for 60% of New England's total natural gas supply needs.

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.

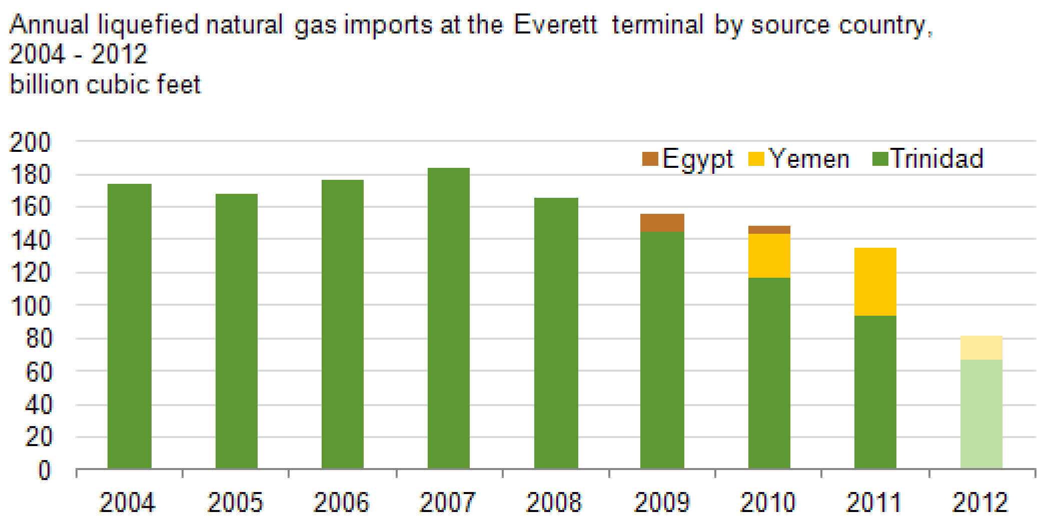
Figure 7. Monthly imports of liquefied natural gas at the Everett terminal




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



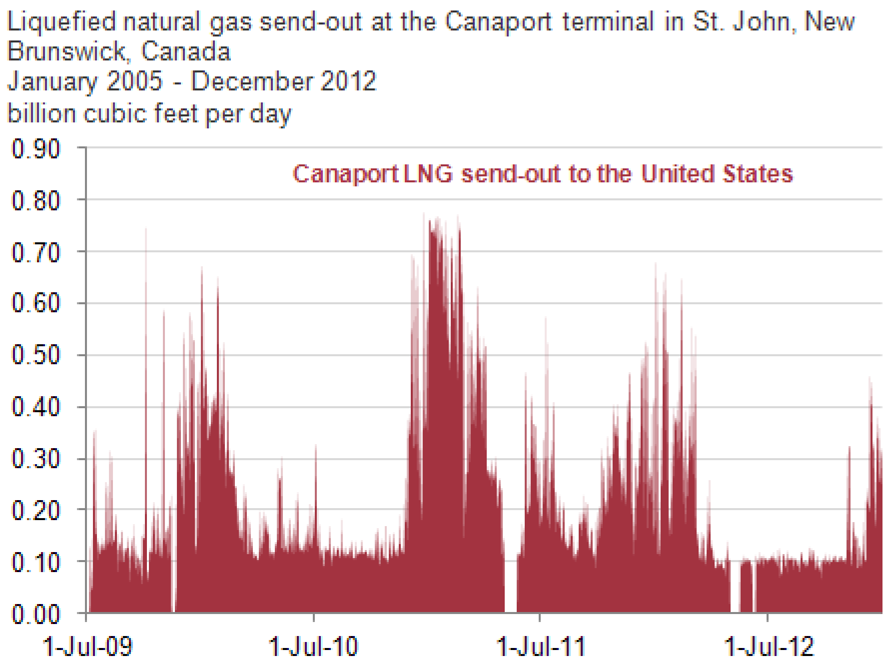

Source: U.S. Energy Information Administration based on the U.S. Department of Energy, Office of Fossil Energy.

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.

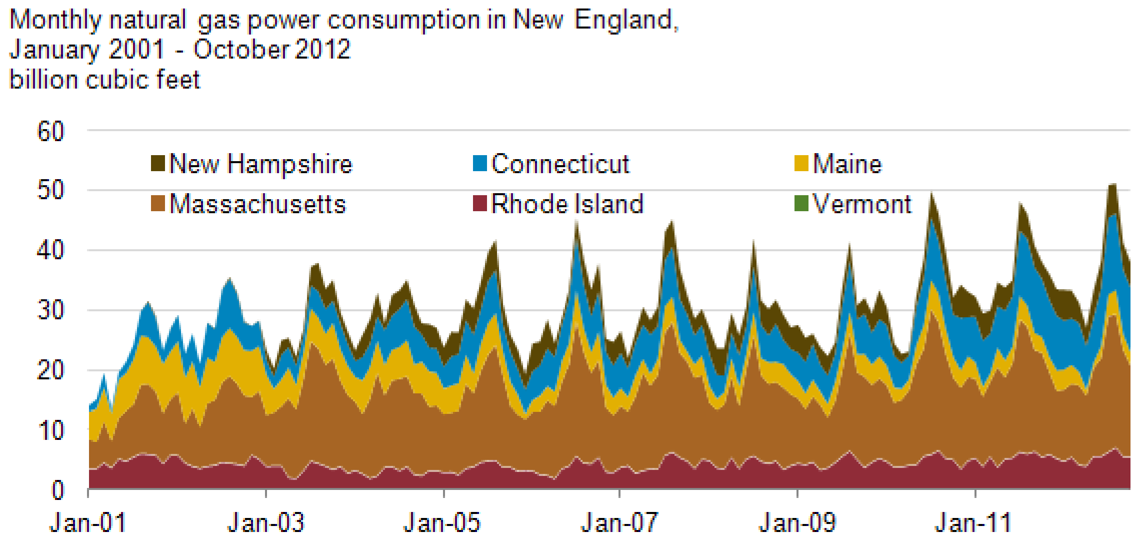
### *Offshore Terminals*

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



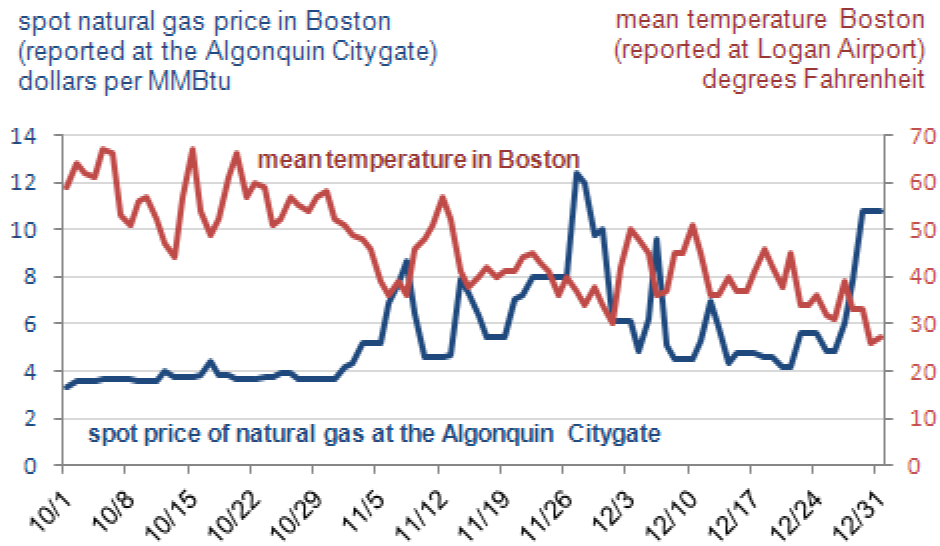

Source: U.S. Energy Information Administration, Natural Gas Monthly.

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

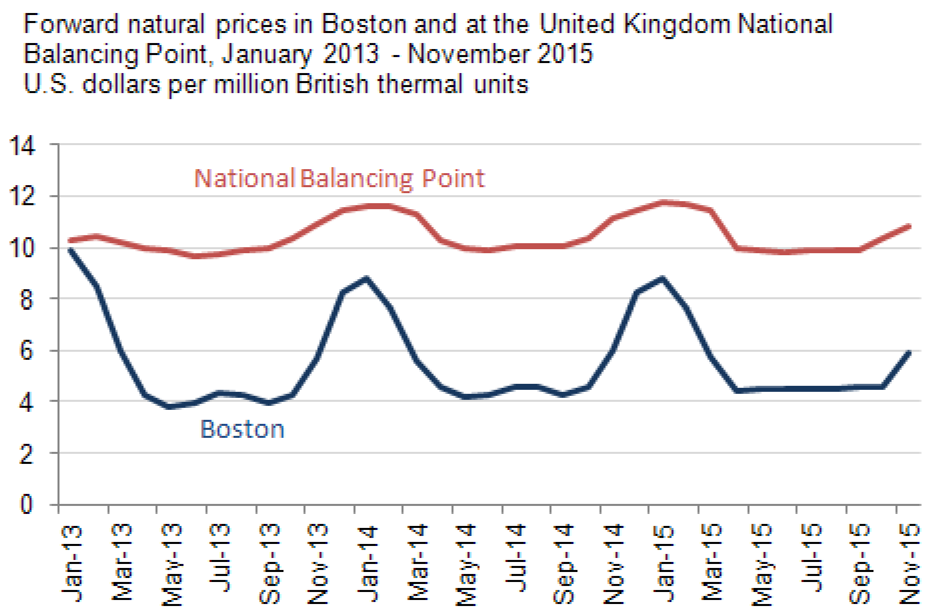



Source: U.S. Energy Information Administration based on Bloomberg, L.P.

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



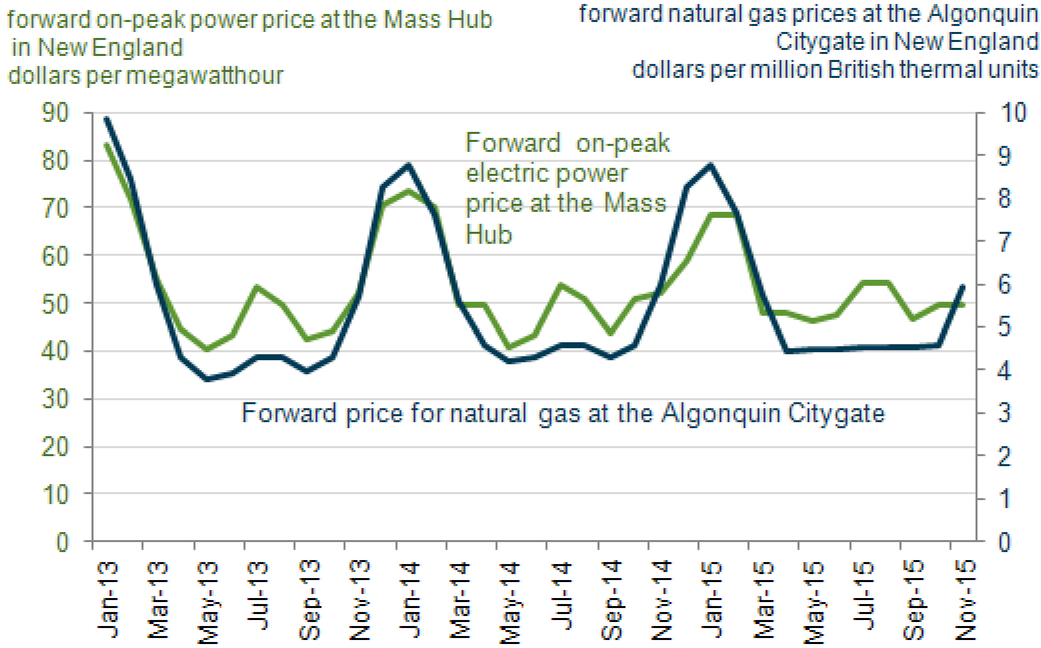

Source: U.S. Energy Information Administration based on Bloomberg, L.P.

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.