U.S. Energy Information Administration

Natural Gas

Natural Gas Year-in-Review

With Data for 2011 | **Release Date:** July 10, 2012 | **Next Release Date:** July 2013

Highlights

Continued growth in production, relatively low prices, and expanded electric power sector use characterized U.S. natural gas markets in 2011. Key observations for the year include:

- **Henry Hub spot prices** fell from an average of $4.37 per million British thermal units (MMBtu) in 2010 to $3.98 per MMBtu in 2011.
- **Marketed production** grew 7.9 percent, from 61.4 billion cubic feet per day (Bcf/d) in 2010 to 66.2 Bcf/d in 2011. This was the largest year-over-year change since 1984, despite falling rig counts in 2011.
- **Consumption** rose from 65.1 Bcf/d in 2010 to 66.8 Bcf/d in 2011, with the electric power and industrial sectors showing strong growth.
- **U.S. inventories of working natural gas in storage** hit new records in 2011. Inventories reached a weekly record of 3,852 Bcf the week ending November 18, 2011.
- **Net imports** posted a steep decline in 2011, from 7.1 Bcf/d the previous year to 5.3 Bcf/d, and were at the lowest levels since 1992.

Table 1. Natural gas supply and disposition (Bcf/d)

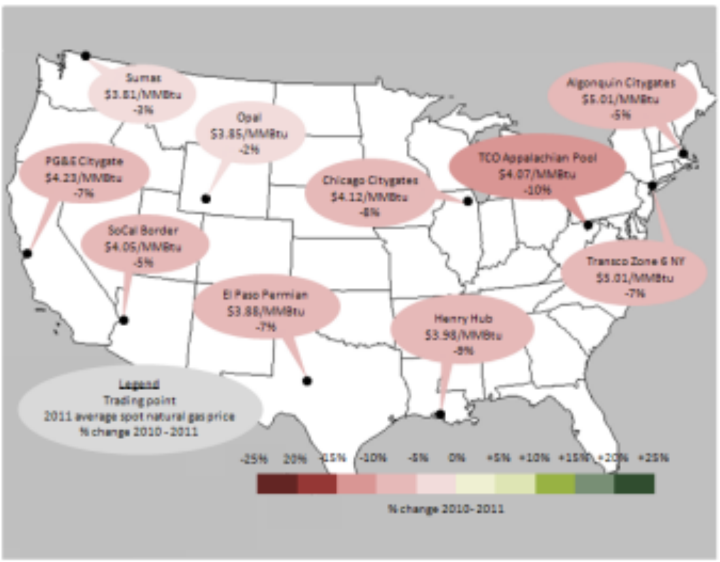
	2009	2010	2011	2010-2011 Change	Percent Change
Supply					
Marketed Production	59.3	61.4	66.2	4.8	7.9%
Federal Gulf of Mexico	6.7	6.2	5.0	-1.2	-19.0%
Lower-48 States	51.3	53.9	60.2	6.3	11.7%
Gross Imports	10.3	10.2	9.5	-0.8	-7.5%
Storage Withdrawals	8.1	9.0	8.7	-0.3	-3.0%
Disposition					
Consumption	62.8	65.1	66.8	1.6	2.5%
Gross Exports	2.9	3.1	4.1	1.0	32.6%
Storage Injections	9.1	9.0	9.7	0.6	7.0%

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

Prices

Strong year-over-year gains in natural gas production contributed to a continued low-price environment in 2011 from the previous few years. Prices dropped at natural gas trading locations in all regions in 2011 from their levels the previous year. The spot price at the Henry Hub in Erath, Louisiana, fell about 9 percent, averaging $3.98 per MMBtu in 2011. Particularly large price declines occurred at the end of the year, as a warm start to winter reduced natural gas consumption and storage inventory levels were elevated. The December 2011 Henry Hub spot price averaged $3.17 per MMBtu, the lowest average monthly price since September 2009. Prices continued to fall in 2012, and hit 10-year lows in March and April, remaining below $2.00 per MMBtu.

Figure 1. Natural Gas Price Changes in 2011

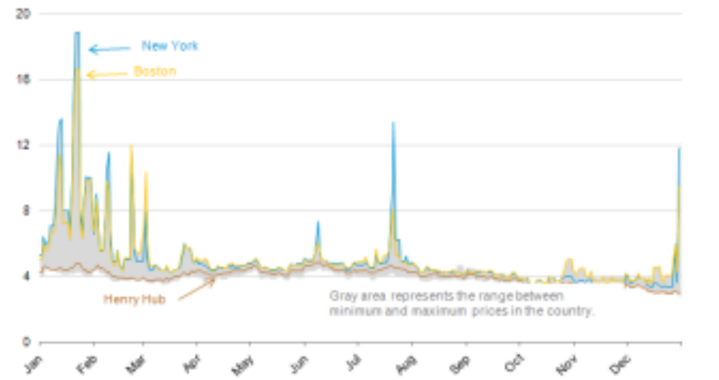


Source: U.S. Energy Information Administration, based on InterContinentalExchange data.
Note: Average spot natural gas prices reported in the map for 2011 are based on data from InterContinentalExchange and vary slightly from values reported in the current Short-Term Energy Outlook, which are based on Thomson Reuters data.

Prices in the Northeast tend to average somewhat higher than prices in the rest of the lower-48 States, in part due to transportation constraints creating bottlenecks in times of high natural gas demand. In 2011, Northeast prices spiked both in the winter (due to cold weather pushing up demand for space heating) and in the summer (due to warm weather pushing up demand for electricity to power air conditioning). While the same pattern occurred in other areas of the country, Northeast spikes were much more pronounced (Figure 2).

Figure 2. 2011 Natural Gas Prices at Selected Hubs

dollars per MMBtu



Source: U.S. Energy Information Administration, based on Bloomberg.
Note: The chart shows Boston and New York daily spot prices in comparison to the range of maximum and minimum prices at the major trading hubs (including Boston and New York) in the lower-48 states.

In 2011, natural gas prices fell as other commodity prices rose. The price of coal delivered to the electric power plants rose year-over-year, from $2.27 per ton in 2010 to $2.40 per ton in 2011. The price of crude oil rose substantially in 2011, and as a result, the prices of petroleum products, including heating oil and residual fuel oil, also rose year over year.

Production

Total marketed production grew by 7.9 percent in 2011, from 61.4 Bcf/d in 2010 to 66.2 Bcf/d in 2011. 2011 was the sixth consecutive year of growth in marketed production, and the largest year-over-year percentage increase since 1984. Production gains continued despite falling prices, as producers continued to capitalize on more efficient drilling technologies and target wet gas. Additionally, a number of other factors helped to buoy production, including foreign joint venture partners financing production, increases in natural gas production associated with oil production, and drilling required for producers to hold leases.

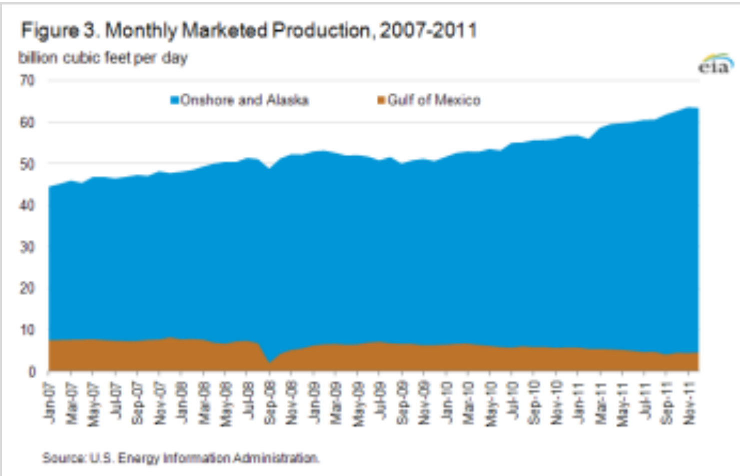
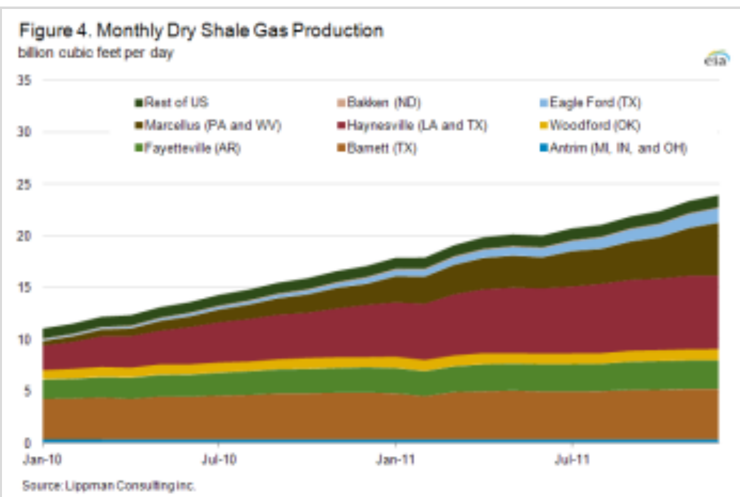


figure data

The increase in production came exclusively from the onshore, lower-48 States, where marketed production rose from 53.9 Bcf/d to 60.2 Bcf/d. In the Federal offshore Gulf of Mexico (GOM), marketed production fell from 6.2 Bcf/d in 2010 to 5.0 Bcf/d in 2011, continuing a long-term trend (Figure 3). Following the Macondo well blowout in April 2010, a temporary moratorium affected some GOM drilling; however, natural gas production in the Gulf has been declining for the past several years as producers shift to more economical areas of production.[1]



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Onshore production growth was largely concentrated in shale plays. The increase in shale natural gas production in the past several years is largely due to strong production in the Haynesville Shale in Louisiana and the Marcellus Shale in Pennsylvania. Production out of Texas, particularly in the Eagle Ford shale, has also grown, particularly in the past year (Figure 4).

The growth in onshore production has made production disruptions from freezing weather more important; "freeze-offs" (gas flow blockages resulting from water vapor freezing in the gas stream) could rival hurricanes as the major weather-related disruption at least for short periods. Indeed, frigid weather led to major production curtailments for several days in February 2011. Natural gas dry production averaged about 59.2 Bcf/d the last week of January 2011 and fell to an average of 53.5 Bcf/d during the first week of February, based on estimates from BENTEK Energy LLC (Bentek) (Figure 5). It should be noted, however, that while the effects of shut-ins resulting from hurricanes can last months—with some wells never returning to service—recovery time for cold-weather-related shut-ins typically is only a few days, as was the case for the February 2011 freeze-offs.

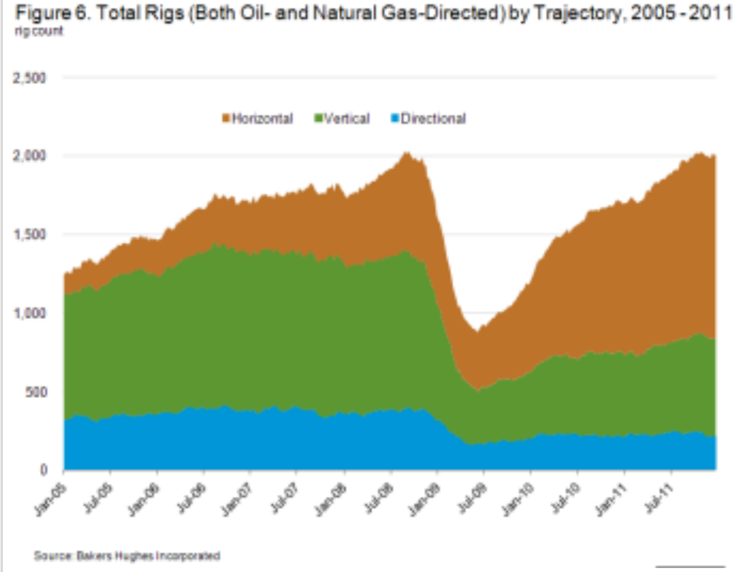
Natural gas rotary rig count declines

figure data

U.S. production growth continued even as natural gas rotary rig counts declined. The weekly overall natural gas rig count, as reported by Baker Hughes Incorporated, averaged 887 rigs in 2011, compared with 943 rigs in 2010. The shift towards horizontal rigs, which continued in 2010 and 2011, underlies the increase in production (Figure 6). Horizontal wells, especially when combined with hydraulic fracturing, typically have significantly higher initial production rates than vertical wells.

Figure 5. 2010 and 2011 Dry Natural Gas Production

Figure 6. Total Rigs (Both Oil- and Natural Gas-Directed) by Trajectory, 2005 - 2011



Shift towards crude oil and natural gas liquids contributes to production growth

figure data

By the end of 2011, the oil rig count overtook the natural gas rig count by nearly 100 rigs, as drillers shifted their focus to oil to take advantage of its much higher price relative to gas (Figure 7). As the price of Brent crude oil remained well over $100 per barrel, and natural gas prices fell through 2011, the widening price spread provided an incentive for producers to focus on oil production. In addition to increasing oil production, expanding oil-directed drilling programs also generated increases in natural gas produced in association with the oil.

Also related to the relatively high oil prices is an increase in drilling in areas rich in natural gas liquids (NGLs), prices for which are linked more closely to crude oil than natural gas. Throughout 2011, natural gas rigs have increased in key areas where NGLs, lease condensate, and crude oil production occurs, such as the Utica Shale in Ohio and the Eagle Ford shale in Texas, according to Smith Bits data. NGLs, the hydrocarbons that are extracted from natural gas, include ethane, propane, butane, and pentane. Because of the comparatively high market values for NGLs, drilling for natural gas in liquids-rich areas is usually profitable for natural gas producers. For example, throughout 2010 and 2011, Chesapeake Energy began ramping up its investments in the liquids-rich portion of Ohio's Utica Shale, which underlies the Marcellus Shale.

Several projects have been proposed to address processing and handling the expanding volumes of NGLs. In 2011, Enterprise Products Partners LP announced plans to build a 1,230-mile pipeline to transport ethane to the Gulf Coast from the Marcellus and Utica shales.[2] The company has also announced numerous plans for new fractionators, which break NGLs into their separate components.

Other forces affect production levels

Joint ventures and foreign investment may have helped to boost production in 2011. Foreign companies partnered with U.S. producers to gain expertise in the development of shale natural gas, which has helped spur drilling even in a low-price environment. Korea National Oil Corporation (KNOC), for example, entered into a $1.6 billion joint venture with Anadarko to drill in the Eagle Ford shale. Five major joint venture deals were reached in the United States in 2011 for a total of $3.7 billion (Table 2).

Table 2. Major shale gas and tight oil joint ventures in 2011[3]

Foreign Partner	Domestic Partner	Shale Play	Deal Amount ($B)

CNOOC	Chesapeake	Eagle Ford	1.1
KNOC	Anadarko	Eagle Ford	1.6
Marubeni	Marathon	Niobrara	0.3
Mitsui	SM Energy	Eagle Ford	0.7
GAIL	Carrizo	Eagle Ford	0.1

Source: U.S. Energy Information Administration based on trade press and company announcements.

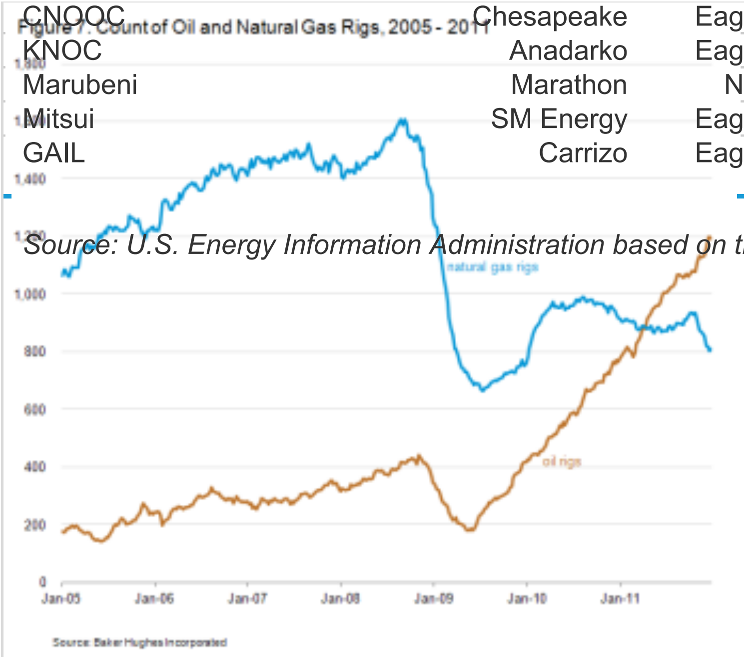


Figure 7. Count of Oil and Natural Gas Rigs, 2005 - 2011

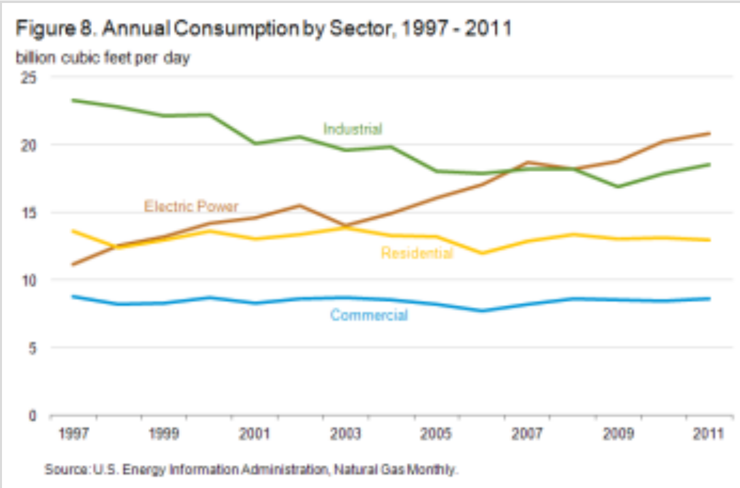
Footnotes

[1]Although natural gas production from the Gulf of Mexico has been declining since 2002, new large projects directed toward liquids developments are projected to reverse the decline in natural gas production from the Gulf of Mexico in 2014, according EIA's Annual Energy Outlook 2012 Early Release.

[2]More information about Enterprise's plans is available on the company's investor relations webpage: http://phx.corporate-ir.net/preview/phoenix.zhtml?c=80547&p=irol-newsArticle&ID=1615550&highlight

[3]Tight oil refers to oil produced from shale, or other very low-permeability rocks, with horizontal drilling and multi-stage hydraulic fracturing technologies.

Consumption



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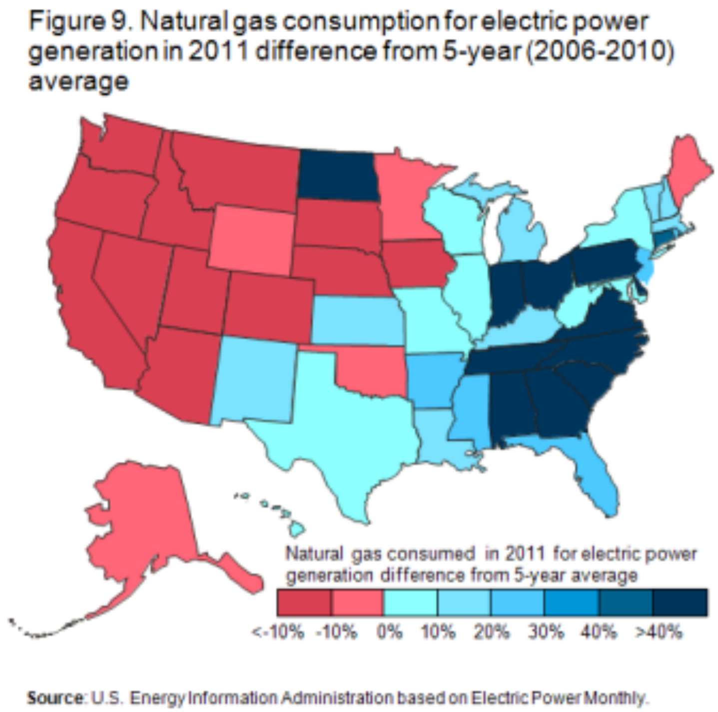
Total natural gas consumption rose from 65.1 Bcf/d in 2010 to 66.8 Bcf/d in 2011. Consumption in the electric power and industrial sectors showed the largest increases, (Figure 8).

Electric Power



Use of natural gas for electric power generation continued its overall upward trend, as natural gas prices fell both in absolute terms and in relation to coal prices, providing an incentive for fuel substitution. Use of natural gas for electric power rose to 21.6 Bcf/d in 2011 from 21.0 Bcf/d in 2010. Major consuming regions in the eastern United States saw natural gas consumed for electric power generation significantly exceed the previous 5-year average (Figure 9).

Increased air conditioning load in much of the country, which experienced particularly high temperatures during the summer of 2011, contributed to the increased use of natural gas for electric power generation. The increase in natural gas consumed during the summer months contributed to twenty states setting 10-year highs for natural gas consumption for electric generation for the entire year. Most of these records occurred in states located in the eastern half of the United States.

Texas did not set an annual record for natural gas consumed for power generation, but did set new monthly records. Texas averaged an estimated 6.3 Bcf/d during July 2011 (compared to 5.1Bcf/d in July 2010), and reached a 10-year high of 6.8 Bcf/d in August 2011 (compared to 6.2 Bcf/d in August 2010).[4], Extreme temperatures stressed Texas' power generation capacity, leading to increased use of natural gas for summer generation in a State that already depends very heavily on natural gas-fired power generation. During the summer, the Electric Reliability Council of Texas (ERCOT), which manages the power grid for the state, warned of rolling blackouts and urged consumers to conserve energy as temperatures hit record highs.

In contrast, the western United States saw natural gas consumed for electric power generation below the 5-year average. For example, in the Pacific Northwest, the volume of natural gas consumed for power generation dropped dramatically. The region's exceptionally strong hydropower season led the Bonneville Power Administration to issue limits on the use of natural gas, coal, and wind for power generation.[5] Although Pacific Northwest natural gas-fired power generation is very small compared to the rest of the country, the effect of the limits brought natural gas consumption for power generation down to very low levels, about 0.2 Bcf/d in July 2011, compared to 0.5 Bcf/d in July 2010. Despite temperatures that were warmer than the previous year, power burn levels were substantially below normal through October.

Industrial

Industrial consumption of natural gas rose for the second consecutive year in 2011, from 17.9 Bcf/d in 2010 to 18.5 Bcf/d in 2011. The increase in industrial use was driven by the continued economic recovery, reflected in the natural gas industrial production index.[6] Industrial prices, following the general trend of wholesale natural gas prices, remained relatively low for the third consecutive year at $4.89 per MMBtu (in 2008, prices averaged about $9.40 MMBtu).

Although data related to industrial activity for 2011 are currently unavailable, the industrial sector was poised to benefit from lower natural gas prices in 2011. Manufacturing industries, such as chemicals and steel, use natural gas for heat and power in their production processes. The chemical industry also uses natural gas as an input, or feedstock, in the manufacture of certain chemicals and products such as hydrogen, nitrogenous fertilizer, and methanol. Lower natural gas prices have allowed some fertilizer plants to boost production, with at least one stating that the shift in production costs will lead to plant expansions.[7] Moreover, the recent boom in natural gas production from wet plays (those with high liquids content) has been accompanied by record-breaking NGL production, which has led to greater petrochemical cracking of NGLs.

Residential and Commercial

Consumption of residential and commercial gas is driven largely by weather, since the primary use of natural gas in this sector is space heating. While 2011 was, on average, warmer than 2010 (4,460 heating degree-days in 2010 compared with 4,320 heating degree-days in 2011), some key natural gas consuming areas experienced a colder winter. For example, in New England, heating degree-days rose 3 percent year-over-year. Nearly 20 percent of homes that heat with natural gas are located in the Northeast.[8] Overall, residential natural gas consumption fell by about 1 percent and commercial consumption rose by about 2 percent.

Footnotes

[4]July and August were extremely hot months, both in Texas and globally. July was the fourth warmest on record for the United States, according to NOAA: http://www.noaanews.noaa.gov/stories2011/20110808_julystats.html, and August was the eighth warmest globally since record-keeping began in 1880: http://www.noaanews.noaa.gov/stories2011/20110915_globalstats.html

[5]Curtailments were issued beginning in May when high levels of runoff from the Columbia River led to a temporary oversupply of hydroelectric power. More information available here: http://www.bpa.gov/corporate/BPANews/ArticleTemplate.cfm?ArticleId=article-20110518-01

[6]The natural gas-weighted industrial production index reflects trends in output in natural gas intensive industries. For example, a year-over-year increase in the natural gas weighted industrial production index indicates year-over-year strength in natural gas intensive industries. Some of the major natural gas intensive industries are petroleum refining, fertilizer production, organic chemical production, and paper and pulp production.

[7]"Shale Gas Boom Spurs Race," Wall Street Journal, December 27, 2011.

[8]The Northeast region is comprised of the New England States (Connecticut, Rhode Island, Massachusetts, Vermont New Hampshire, and Maine) and the Middle Atlantic (New Jersey, New York, and Pennsylvania).

Storage Inventories

U.S. inventories of working natural gas in storage reached new records in 2011. While the natural gas storage injection season traditionally ends on October 31, injections continued into November. EIA's *Weekly Natural Storage Report* posted a new record inventory level of 3,852 Bcf for the week ending November 18, 2011, and remained at 3,843 Bcf at the end of November, the second-highest monthly level on record, after 3,851 recorded in October 2010.[9] Much of the injection activity came near the end of the injection season, coinciding with the continued high production levels through the end of the summer cooling season. Storage inventories lagged behind both the 5-year (2006-2010) average and the previous year's levels until autumn. A warmer-than-normal start to the winter heating season, as well as abundant production, kept levels high through the rest of 2011 (Figure 10).

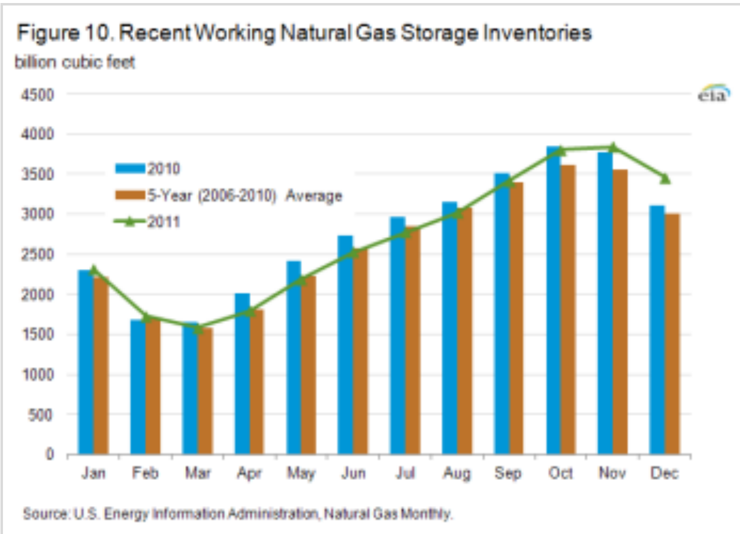


figure data

Inventories in the Producing Region, which includes Texas and the rest of the West South Central Census region, posted net declines for five consecutive weeks in July and August, to supply natural gas for power generation for air-conditioning load during the extreme heat.[10] Although net withdrawals are not uncommon in the middle of summer in the Producing Region, five consecutive weeks of withdrawals was unprecedented until recent years.[11] Despite the summer withdrawals, the Producing Region hit record-high levels at the end of the injection season, and was the biggest contributor to the new inventory record. Additionally, the majority of increases in both demonstrated peak working gas capacity and design capacity occurred in the Producing Region.[12] According to an annual EIA report, as of April 2011, demonstrated peak working gas capacity in the United States rose to 4,103 Bcf, an increase of 54 Bcf from the previous year, with most of the increase occurring in the Producing Region.

Footnotes

[9] EIA reports monthly storage values from Form-191, a census of all storage facilities. This is different from the *Weekly Natural Storage Report*, which, released once a week, provides an estimate of total working gas inventories based off a survey of selected storage fields in the country. More information is available here: http://ir.eia.gov/ngs/mthdiff.html

[10]Storage inventories are reported by three different regions, the Producing Region (including Texas, Oklahoma, Louisiana, and other neighboring states); the East Region, including the Mid-Atlantic and Midwest; and the West Region, including the West Coast, Rocky Mountain areas, and parts of the Upper Midwest. A complete map of the regions is available here: http://ir.eia.gov/ngs/notes.html

[11]In 2010, the Producing Region also withdrew natural gas for five straight weeks in the summer.

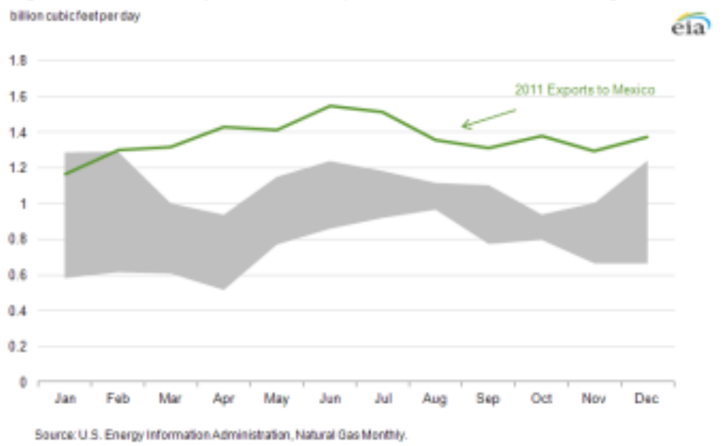
[12]'Demonstrated peak working gas capacity' is the sum of the highest storage inventory level of working gas observed in each facility over the prior 5-year period as reported by the operator on the Form EIA- 191M, "Monthly Underground Gas Storage Report."

Imports and Exports

Net imports posted a steep decline in 2011, dropping from 7.1 Bcf/d to 5.3 Bcf/d. The decrease was the result of both expanded gross exports[13] and reduced gross pipeline and LNG imports.

Pipeline Imports and Exports

Figure 11. 2011 Monthly Natural Gas Exports to Mexico and 5-Year Range



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

figure data

While gross pipeline imports fell significantly, from 9.1 Bcf/d in 2010 to 8.5 Bcf/d in 2011, they still served as a marginal source of supply during times of high natural gas demand or when U.S. pipelines were down for maintenance. For example, when Ruby Pipeline, which brings gas from the Rocky Mountains to the West Coast, went offline in December, imports from Canada to the West rose to about 3.0 Bcf/d, according to data from Bentek, up from around 2.5 Bcf/d earlier in the month.

Pipeline exports to Mexico increased substantially in 2011 (Figure 11). Mexico has focused on expanding natural gas-fired power generation in the past several years, and the country's Federal Electricity Commission (Comisión Federal de Electricidad or CFE) has called for additional natural gas-fired generation. In its 2006-2016 outlook, the CFE forecasted increasing use of natural gas in the electric generation sector, as well as some growth in gas consumption in the industrial sector.[14] These projected increases are combined with declining natural gas production from Mexico's national oil company, Petróleos Mexicanos (Pemex). In 2011, Pemex's natural gas production declined 6 percent.[15] While Mexico has LNG import capacity, low prices have made importing U.S. natural gas via pipeline an economically favorable option.

LNG imports and exports

LNG imports fell to 1.0 Bcf/d in 2011, a decline from the previous year's level of 1.2 Bcf/d. Strength in domestic natural gas production reduced the need for imports, and LNG cargoes were able to take advantage of higher prices at other international markets, including the United Kingdom, Japan and Belgium, where prices generally traded several dollars higher than at Henry Hub during the year. While there are eight LNG import terminals in the United States, only two (Everett Marine Terminal in Massachusetts and Elba Island in Georgia) received the vast majority of LNG cargoes, largely to fulfill long-term contract obligations. Everett also served as a marginal source of supply during cold snaps, when high Northeastern prices could attract international cargoes.

While LNG imports declined to modest levels, re-exports of LNG increased.[16] Total re-exports in 2011 equaled 53.4 Bcf, compared to 34.5 Bcf in 2010 (both total about 0.1 Bcf/d).[17] A total of 19 cargoes were re-exported, all from the Gulf Coast, with major destinations including India, Chile, China, and Brazil. An increasing spread between prices in the United States and around the world led to more cargoes being re-exported. In 2011, the United States exported a very small volume of LNG from a liquefaction terminal in Kenai, Alaska; the amount totaled 16.4 Bcf, or 0.04 Bcf/d, according to the Department of Energy's Office of Fossil Energy. The terminal was slated to be idled in early 2011, but remained open until November. It primarily sent cargoes to Japan, which needed more natural gas for power generation following damage to the Fukushima nuclear power generator in the March 2011 earthquake. The terminal last sent a cargo in November 2011, and another in spring of 2012.

The combination of high global prices and low U.S. prices has led several companies to apply for permission to construct U.S. LNG liquefaction facilities to export domestically-produced natural gas. As of May 2012, the Office of Fossil Energy has received 14 applications to export LNG; only Sabine Pass has received authorization to export both to countries with which the United States has a free trade agreement and to those with which the United States does not have a free trade agreement.[18],[19] Most of the proposed terminals are located in the Gulf Coast area, including Sabine Pass, which has already signed several long-term export contracts and plans to begin exporting LNG by 2016. Exceptions include the Jordan Cove Energy Project, situated off the coast of Oregon, and Dominion's Cove Point facility, an existing import terminal located on the Chesapeake Bay south of Baltimore, Maryland.

Footnotes

[13]Gross exports are the sum of natural gas exports leaving the United States via pipeline to Canada and Mexico and the Kenai LNG terminal in Alaska.

[14]PEMEX's outlook is available here: http://www.sener.gob.mx/res/PE_y_DT/pub/Propect%20Gas%20Natural%202007%20English.pdf

[15]PEMEX data available here: http://www.ri.pemex.com/index.cfm?action=content&sectionID=21&catID=12177

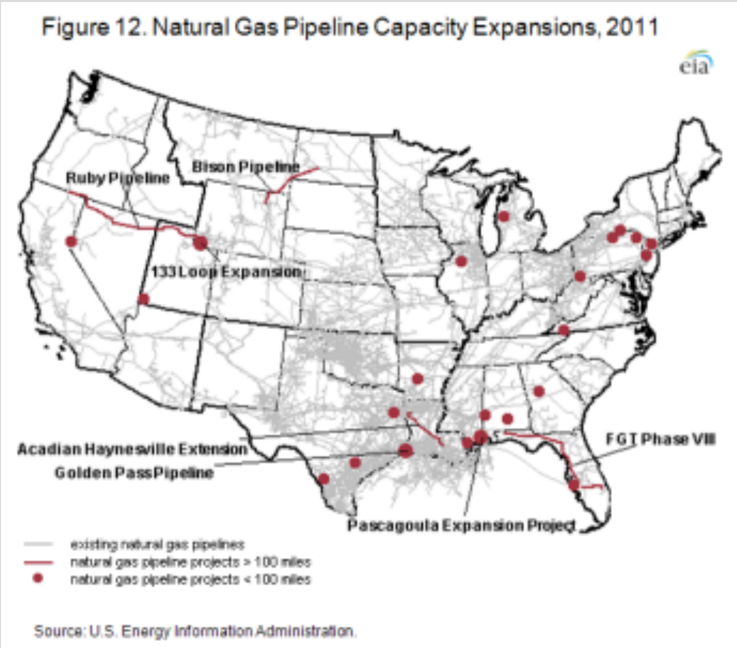
[16]Re-exports occur when a terminal receives a cargo and sends it out to another destination. Typically, low utilization at these terminals has created available LNG storage capacity in the terminals' storage tanks. Re-exportation of LNG lets marketers and suppliers store gas, while waiting for price signals before delivering their LNG to the higher-paying markets in Asia, Europe, and South America.

[17]Information from DOE's Office of Fossil Energy; the 2010 report is available here: http://www.fe.doe.gov/programs/gasregulation/publications/Dec10LNG.pdf and the 2011 report is available here: http://www.fe.doe.gov/programs/gasregulation/publications/LNG_2011_rev.pdf

[18]A summary of applications and approvals is available here: https://eapps.fossil.energy.gov/app/fergas/DocketOrderList.go

[19]DOE issues permits separately to export to free-trade countries and non-free trade countries.

Pipeline Construction



At least 25 pipeline projects were completed in 2011, adding a total of about 2,400 miles of pipeline and 13.7 Bcf/d of capacity. While most of the projects, which include new pipelines and expansions, took place in the Southeast, several large projects were completed in the Northeast and West. Table 3 lists major pipeline projects for 2011.[20] Figure 12 shows new expansion projects.

Table 3. Selected Major Pipeline Projects in 2011

Project	Existing System	Length of Entire System	Capacity of Entire System	Length of Expansion	Capacity of Expansion	Regions
Ruby Pipeline	-	680 miles	1.8 Bcf/d	-	-	West
FGT Phase VIII Expansion	Florida Gas Transmission	~5,000 miles	2.3 Bcf/d	483 miles	0.8 Bcf/d	Southeast
Tennessee 300 Line Project	Tennessee Pipeline	~14,000 miles	6.7 Bcf/d	127 miles	0.4 Bcf/d	Northeast
Bison Pipeline	-	302 miles	0.4 Bcf/d	-	-	West
Pascagoula Expansion	Transcontinental Pipeline, FGT	-	Varies	16 miles	0.8 Bcf/d	Southeast
Golden Pass	Golden Pass LNG Terminal	-	-	33 miles	1.2 Bcf/d	Southeast

Source: U.S. Energy Information Administration based on trade press and company postings.

Ruby Pipeline came into service on July 28, 2011. The 680-mile pipeline links Rockies natural gas with West Coast markets, ending at an interconnection on Pacific Gas & Electric's system. Ruby displaced some imports to the West that came in on the Gas Transmission Northwest (GTN) pipeline from Canada, although some of the displaced imports from Canada served as a marginal source of supply when necessary. Flows on GTN in early July 2011 were over 1.8 Bcf/d; by mid-September GTN's flows slipped to about 1.0 Bcfd.

Florida Gas Transmission's (FGT) Phase VIII Expansion project added 483 miles to FGT's existing system,[21] which begins near the Gulf Coast of Texas and ends close to Miami, with several branches along the way. With no natural gas storage, Florida is dependent on two major pipelines to bring natural gas in times of high demand. The lack of storage and the state's peninsular geography often create bottlenecks and cause price spikes during very hot or very cold weather.Â The expansion came into service on April 1, 2011.

Tennessee Pipeline's 300 Line Project added seven looping segments onto Tennessee Pipeline's existing system in New York and New Jersey, for a total of 127 miles. The project is designed to add natural gas from the Marcellus Shale area to the interstate pipeline system. As soon as the pipeline went into service, prices rose at Tennessee's Zone 4 Line 300 pricing point, where an abundance of supply and insufficient takeaway capacity had depressed prices.

The 302-mile Bison Pipeline, a major new pipeline that came online in January 2011, originates in Wyoming, runs through Montana, and ends in North Dakota where it interconnects with Northern Border Pipeline Company's system.

The Pascagoula Expansion and the Golden Pass pipeline projects were built to link LNG import terminals on the Gulf with existing pipeline systems.

Footnotes

[21]A detailed map of the system is available here: http://www.panhandleenergy.com/Map_LO-Package_v3.pdf