

December 31, 2012

## **Natural Gas: From Shortages to Abundance in the U.S.**

Paul L. Joskow<sup>1</sup>

The recent dramatic and largely unanticipated growth in the current and expected future production of shale gas, and the related developments in the production of shale oil, have dramatically changed the energy future of the U.S. and potentially of the world compared to what experts were forecasting only a few years ago. These changes would not have been realized as quickly and efficiently absent deregulation of the wellhead price of natural gas, unbundling of gas supplies from pipeline transportation services, the associated development of efficient liquid markets for natural gas, and reforms to the licensing and regulation of prices for gas pipelines charge to move gas from where it is produced to where it is consumed. This economic platform supported the integration of technological advances in vertical drilling, down-hole telemetry, horizontal drilling, monitoring and control of deep drilling equipment, and hydraulic fracturing to exploit economically shale gas deposits that were identified long ago, but considered to be uneconomical until recently.

### **I. Natural Gas Wellhead Price and Pipeline Regulation**

Federal regulation of the natural gas industry began with the Natural Gas Act of 1938 (NGA). The NGA gave the Federal Power Commission (FPC), later the Federal Energy Regulatory Commission (FERC), the authority to license the construction and expansion of new interstate natural gas pipelines, to ensure that they are operated safely, and to regulate the prices

---

<sup>1</sup> Alfred P. Sloan Foundation, 630 Fifth Avenue, Suite 2550, New York, NY 10111 (email:joskow@sloan.org) and Massachusetts Institute of Technology. The Alfred P. Sloan Foundation has made several grants to support research related to shale gas resources, environmental impacts and regulation, and political economy. The author is on the Boards of Directors of Exelon Corporation and TransCanada Corporation. The views expressed here are those of the author and do not reflect the views of MIT, the Alfred P. Sloan Foundation, Exelon, TransCanada, or the Sloan Foundation's grantees.

that these pipelines charge for supplying gas to local distribution companies (LDC) and large direct service consumers (e.g. electric utility plants). Until the 1990s, pipelines sold a “bundled” product consisting of the natural gas they purchased from gas producers combined with the pipeline services required to transport the gas to their customers. Gas production, gas transportation, and gas distribution were linked together by long-term contracts. However, the contract prices that the interstate pipelines paid for natural gas in producing areas were initially not subject to regulation. This situation changed in 1954 when the Supreme Court determined in the *Phillips* decision (347 U.S. 672 (1954)) that under the NGA the FPC had the authority to regulate the wellhead prices of natural gas purchased by interstate pipelines for resale (Breyer and MacAvoy 1973).

The FPC then proceeded to try to exercise that authority. The basic theory that guided FPC regulation of natural gas field prices started with the assumption that the supply function for natural gas was inelastic in the short run, was upward sloping in the long run, and that the demand for natural gas would increase significantly as the pipeline transportation infrastructure expanded. Absent regulation of natural gas prices, low-cost producers would earn economic rents in the long run as the demand for natural gas increased and unregulated market prices increased along with it. The FPC tried to use cost of service principles to capture the rents associated with low-cost gas wells for consumers by keeping the prices low-cost producers were allowed to charge low while setting higher prices for higher-cost wells to provide incentives for producers to expand supplies sufficiently to balance supply and demand. This multi-price regulatory system was then “harmonized” by requiring pipelines to average together the prices they paid for gas from wells with different regulated prices and to charge the average price to their customers.

Breyer and MacAvoy (1973) and MacAvoy (2000, pages 12-15) describe the almost comical efforts of the FPC to apply cost of service regulatory principles developed for regulating, say, a single local monopoly gas distribution company, to thousands of natural gas wells, many producing both unregulated crude oil and regulated natural gas, to many production districts, in the context of an intrastate market where wellhead prices were unregulated. As described nicely by Breyer and MacAvoy and by Breyer (1982, Chapter 13), these regulatory efforts, like most rent control regulations, succeeded in keeping field prices below competitive market levels to the benefit of consumers with access to that gas, but eventually led to growing shortages of natural gas in the interstate market. Domestic natural gas production hit its local peak in 1970 (not reached again until 2010 as shale gas production ramped up) and shortages began to appear in the late 1960's and were growing before the first oil shock in late 1973.

Thus, at the time of the first oil shock in 1973-74, natural gas wellhead price regulation had already been in place for 20 years and was already causing significant gas supply shortages. To deal with these shortages a complex rationing scheme to allocate scarce supplies among existing customers was developed and potential new customers were turned away. The shortages continued to grow during the 1970s as oil prices increased, leading to an increase in the demand for natural gas since petroleum and natural gas were substitutes on the margin (e.g. as a boiler fuel for electric generating plants and manufacturing and in certain process industries). Breyer (1982, 244-245) estimates that curtailments of firm contracts for natural gas grew by a factor of 20 between 1970 and 1976 and that some states experienced very significant reductions in deliveries to industrial consumers. MacAvoy and Pindyck (1973, 491) predicted growing shortages from regulation out to 1980, the end of their simulation period, but the rapid end of shortages if wellhead prices were deregulated.

After creating the shortages, Congress and the FPC then spent the next fifteen years trying to adopt and implement policies to mitigate the shortages while only slowly phasing out the rent transfers associated with the existing wellhead price regulatory system. The basic regulatory mechanism to do so was to set different prices for different “categories” of natural gas and then to require pipelines to charge customers the average cost of their contracts with producers; high prices for various categories of “new” and “high cost” gas and much lower prices for various categories of low-cost “old gas” were averaged together to produce a sale price between the low and the high authorized wellhead ceiling prices.

In November 1978 Congress passed the Natural Gas Policy Act of 1978 (NGPA) to implement this strategy. According to MacAvoy (2000,15), eventually 30 different categories of natural gas with widely varying ceiling prices were created under the NGPA. In response to this new regulatory framework, pipelines rushed to sign long-term contracts with suppliers that were now willing to sell additional supplies of “new gas” at high regulated or unregulated import prices. It was expected that the NGPA would lead to rising average prices and ultimately to de facto deregulation of wellhead prices as “old gas” supplies declined, and existing “old gas” wells were able to be reclassified as high cost producers subject to much higher price ceilings, and supplies of high-priced “new gas” became a larger and larger share of the “blend.” The NGPA did not work out as anticipated.

## **II. Regulatory Induced Surpluses Lead to Pipeline Restructuring**

The second oil shock(s) of 1979-1980, when real crude oil prices quickly doubled, occurred soon after the NGPA was passed. The jump in petroleum prices exacerbated shortages of natural gas as customers sought to switch from oil to natural gas. Pipelines responded to the existing and apparently growing shortage of natural gas by taking advantage of the opportunities

created by the NGPA to negotiate long term “take-or-pay” contract supply commitments with producers for “new gas” at high ceiling prices and for imported gas at high unregulated prices. These contracts committed them to take minimum quantities of gas based on the pricing provisions in the contracts. Pipelines expected to be able to sell the gas to consumers because the prices of all these categories of natural gas were blended together, creating an average sale price significantly below the ceiling prices established by the NGPA (MacAvoy 2000,15) and the demand for natural gas at these prices was expected to continue to grow. However, as blended gas prices rose, the demand for natural gas fell. This effect was exacerbated by falling oil prices after 1981-- real crude oil prices peaked in 1981 and fell by nearly 2/3 by 1986 making gas less economical compared to oil at the now higher regulated bundled price charged by pipelines. This in turn led to a “take-or-pay contract bubble” in which the demand for natural gas by LDCs and direct service customers was significantly lower than the contractual obligations undertaken by the pipelines. (See Makhholm 2012 for an excellent history of the evolution of natural gas and oil pipeline regulation.)

Efforts to deal with the “take or pay contract surplus” led to a series of additional regulatory policy changes that dramatically changed the structure of the natural gas pipeline sector. In the early 1980s, as price sensitive gas consumers switched from gas to oil and coal, some pipelines created Special Marketing Programs (SMPs) to retain these customers. SMPs allowed selected (elastic) customers to purchase “unbundled” transportation services from pipelines, so that these customers could buy gas directly at lower prices in producing areas and simply pay the pipelines to transport it, bypassing the higher regulated prices. However, in 1985 the DC Circuit declared that these arrangements were discriminatory and ordered FERC to terminate them. FERC responded with Order 436 which allowed pipelines voluntarily to offer

unbundled pipeline services as long as they offered these services on a non-discriminatory basis to all customers. Eventually all major pipelines voluntarily agreed to offer unbundled transportation services to all customers.

Of course, this exacerbated the “take or pay contract problem” as a growing number of customers sought unbundled transportation service to “bypass” the high regulated contract prices reflected in bundled pipeline charges. The Court of Appeals for the D.C. Circuit upheld most of the provisions of order 436, but remanded the challenges to it to FERC to resolve the “take-or-pay” problem. In 1987 FERC issued order No. 500 which encouraged pipelines to negotiate buy-outs of their contractual obligations to producers and allowed them to pass along a portion of these costs in pipeline charges to their customers (a classic regulatory solution to a stranded cost problem.) and in 1989 Congress passed the Natural Gas Wellhead Decontrol Act of 1989 (NGWDA) which accelerated the process for deregulating wellhead prices and integrated intra-state and interstate markets. By January 1, 1993 all wellhead gas price regulation came to an end, though little gas was still subject to field price regulation by 1990 or so.

Faced with a natural gas market that was now largely deregulated, the challenge of dealing with the large overhang of high-priced take or pay contracts, and court orders requiring FERC to deal with these issues in a non discriminatory fashion, in 1992 FERC then issued order 636 which made unbundling of pipeline services mandatory, permitted pipelines to market natural gas only through “ring fenced” affiliates, required pipelines to provide a number of additional unbundled pipeline services (e.g. storage, capacity release programs) and to provide information about available pipeline services and prices to increase the flexibility with which LDCs and large customers could use pipeline capacity. As this new structure evolved, FERC also adopted more and more forms of “light handed” regulation of pipeline transportation rates,

relying increasingly on competition between existing and new pipeline developers to negotiate service contracts with gas producers through competitive bidding processes.

### **III. Natural Gas Markets Mature During the 1990s**

By the early 1990s, wellhead price regulation had come to an end, the intra-state and interstate markets had been integrated, the natural gas production sector was governed by competitive market forces, and gas shortages (and federal restrictions on the use of natural gas by power plants) disappeared. The natural gas market matured during the 1990s as liquid gas trading hubs (e.g. Henry Hub and Dawn Hub) developed, liquid spot, term, and derivatives markets developed, geographic basis differences declined. Wellhead prices were low and relatively stable during most of the 1990s. Domestic production increased slowly between 1991 and 2000 (+6%) while consumption grew more quickly. The difference was made up by an increase in imports (+15%), mostly from Canada.

The natural gas pipeline sector had also been substantially restructured to support both a competitive natural gas market and the entry and expansion of competing pipelines. Light handed regulation of pipeline certification and of unbundled transportation prices based on open season auctions and flexible bilateral transportation contracts replaced rigid cost-of-service regulation of pipeline services, except for captive customers who did not have access to competing pipelines. Pipeline capacity expanded and exploration, development and the geographic distribution of natural gas production shifted slowly to new (and more expensive) on-shore areas and off-shore producing areas.

### **IV. The Gas Surplus Comes to an End**

Natural gas prices remained low and stable during the 1990s and many expected this situation to persist for many years. However, natural gas prices began to rise during 2000 and

both increased significantly and became much more volatile over the next few years. The received wisdom (ex post) in the natural gas industry and within the federal government at that time was that there had been a gas supply “overhang” during the 1990s and that as demand caught up with supply more expensive gas production sources would have to be relied upon to balance supply and demand (National Petroleum Council 2003, AEO 2003, AEO 2004), including more imports from Canada, the construction of a pipeline to bring new supplies of gas from Northern Alaska through Canada to the U.S., and a large expansion of LNG imports from the rest of the world (2003 AEO, 41-42, 2004 AEO, 43-44).

The recent dramatic growth in shale gas production was unanticipated early in this century. The reference case in the Energy Information Administration’s (EIA) 2003 Annual Energy Outlook (AEO) did envision growing domestic production “unconventional” sources (coal bed methane, tight gas formations, and shale deposits, 2003 AEO, 35), but shale gas gets barely more than this mention and the forecast future production of shale gas identified is quite small. The 2004 AEO reflects a similar perspective. Unconventional gas production is forecast to account for 43% of lower 48 gas production, though the contribution of shale gas was forecast to be quite small (2004 AEO, 36, 38). LNG imports were forecast to be a larger incremental source of supply than all unconventional gas resources combined and a long list of proposed LNG import facilities is highlighted (2004 AEO, 41). The National Petroleum Council’s (2003) report on natural gas did not even mention shale gas, but focused on opening up more off-shore and on shore areas to exploration and development, the construction of a pipeline to bring gas from Northern Alaska to the lower-48 states, and speedier certification of LNG import facilities.

This view of the future supplies, demand and prices for natural gas began to change only a few years ago. Much of the growth of U.S. natural gas production is now forecast to come

from domestic shale gas deposits. Shale gas production is forecast in the 2012 AEO to increase to 49% of domestic gas supplies by 2035 in the reference case and total unconventional domestic gas production and total non-conventional gas supplies account for 70% of domestic supplies (2012 AEO, 93). By 2010 shale gas production was already 5 trillion cubic feet and forecast to rise to 13.6 trillion cubic feet in 2035 (2012 AEO Early Release, 1) and more recent forecasts of future shale gas production continue to grow (2013 AEO Early Release, 1). (Oil from deep shale deposits and tight sands has and is also forecast to increase dramatically, but that is a subject for another paper.) The 2012 AEO forecasts the U.S. to become a net exporter of LNG by 2016 and an overall (including pipelines) net exporter of natural gas by 2021 rather than a large net importer of natural gas. The 2013 AEO (Early Release) advances these dates.

### **V. The Shale Gas Revolution**

What happened to change so dramatically the supply and import picture for natural gas (and oil) in such a relatively short period of time? The answer is unanticipated increases in production of natural gas from shale deposits located 1,000 to 13,500 feet below the surface (MIT, page 40). Shale gas is natural gas that has been trapped in deep shale deposits, which are fine-grained sedimentary rocks with very low permeability. Shale gas deposits differ from conventional gas deposits which are composed of gas that has migrated to pools in permeable rocks typically located much closer to the surface. So-called “shale plays” are located in many areas of the U.S.; in Texas, the South, the Northeast, the mid-West, the Rocky Mountain region, and in Western Canada (as well as in many other countries). In 2004 there was very little gas produced from shale deposits. Today shale gas already accounts for about 25% of domestic production and has helped to keep natural gas prices at relatively low levels for the last few years. In 2004 monthly wellhead prices varied between \$5.73/MCF and \$10.33/MCF, while in

during the first ten months of 2012 monthly wellhead prices varied between \$1.89/Mcf and \$3.50/Mcf, although the longer run equilibrium price is almost certainly significantly higher than these recent levels (2012 AEO, 92). How much higher gas prices will go is the subject of considerable debate at the moment, though the latest EIA forecasts (2013 AEO Early Release) have a lower gas price trajectory than the 2012 forecasts.

It has been known for many years that natural gas was embedded in deposits of shale deep in the earth. Unlike conventional deposits of natural gas, this gas did not accumulate in relatively shallow pools in permeable rock formations, but rather was embedded in deep shale deposits with low permeability. Commercial production of this gas was thought to be quite uneconomical with then existing technology. Several technological advances came together in the late 1990s to make the development of shale gas economical: advances in deep vertical drilling technology, horizontal drilling technology, down-hole telemetry, monitoring and control of drilling equipment, and hydraulic fracturing in horizontal wells.

In a typical shale gas well, a deep vertical well is drilled toward the shale deposit with drilling equipment and drilling “mud” to cool and lubricate the drill bit and to bring drilling fragments to the surface. The drilling equipment is withdrawn and the vertical well is lined with cement and steel. The steel and cement lining is reinforced extensively close to the surface and where the vertical well penetrates drinking water aquifers (typically far above the shale play). Drilling equipment is then reinserted, the vertical well is completed down to the shale deposit and then one, or typically multiple, horizontal wells are drilled for long distances along the shale seam. When the horizontal design distance is reached, the drilling equipment is withdrawn and the horizontal well is lined with steel and cement. A fracturing tool is inserted into the well which uses small explosive devices to create holes in the horizontal cement and pipe and to

“fracture” the shale deposit so that gas can flow more easily into the well. High pressure “fracking” fluid composed of water, sand and various chemicals (about 90% water, 9% sand, and 1% a variety of chemicals to keep the plumbing clear and gas flowing) is then inserted into the horizontal portion of the well to further loosen and keep open the shale rock formation so larger quantities gas can flow more easily. A typical shale gas well takes a few weeks to complete, though the hydraulic fracturing process itself takes a few days. <http://www.energyfromshale.org/shale-extraction-process> (accessed May 20, 2012)

Although most of the public controversy about shale gas focuses on hydraulic fracturing, it is not a new technology. Indeed, hydraulic fracturing has been used to stimulate well flows from traditional vertical oil and gas pools since at least 1947 and probably earlier. Public-private partnerships engaged in research, development, and demonstration projects involving hydraulic fracturing, horizontal drilling, imaging, and telemetry from the 1970s through the 1990s. The first economical use integrating all of these technological developments is generally attributed to the efforts of a Mitchell Energy project in the Barnett shale play near Fort Worth in 1998 (<http://www.economist.com/node/21558459> accessed November 22, 2011). The first major applications were slowly introduced in the Barnett shale play around Fort Worth, Texas in the early years of this century. The number of horizontal wells operating in the Barnett shale area increased from 400 in 2004 to 10,000 in 2010 and shale gas production increased from almost nothing in 2000 to about 5 billion cubic feet per day today. Information gained from the experience in the Barnett shale has helped to increase the efficiency of the exploitation of more recent shale gas production areas. Indeed, experience with shale gas production appears to have led to dramatic increases in productivity.

## **VI. The Supporting Role of Reforms of Wellhead Pricing and Pipeline Regulation**

Although the recent extraordinary developments in shale gas production are primarily a story about the interaction between geology, natural resources, the development of new technologies for using these resources, and associated learning and continuous improvement, the deregulation and regulatory reform policies of the 1980s and 1990s certainly played a role in supporting these developments. If wellhead prices were still regulated as they were from 1954 to at least 1980, the administrative apparatus for establishing prices alone would have slowed down development of these new resources. The cost-of-service mentality of the federal regulators would have undermined incentives to invest in a new and changing production technology. The absence of liquid spot markets, short-term term contract markets, derivative markets along with pipelines and customers tied up for years with long term contractual commitments would have reduced market opportunities for shale gas, especially in the early years when many of the most innovative producers were small firms.

Perhaps more importantly, many of the most promising shale plays (e.g. Marcellus, Utica) are not located in traditional producing areas and do not have in place the pipeline infrastructure to get the gas to market. The development of faster and more efficient pipeline permitting rules, pricing and contracting flexibility, and the evolution of a merchant pipeline sector that can develop and build new pipeline projects quickly and take on merchant financial risk, have made it possible for new and existing pipeline investors relatively quickly to build new pipeline capacity to serve these new producing areas.

## **VII. Benefits to the U.S.**

While the title of my colleague John Deutch's *Wall Street Journal* (2012) Opinion piece "The U.S. Natural-Gas Boom Will Transform the World," may be a little over the top, it is clear that there are substantial economic and national security benefits from a more abundant North

American supply of less costly natural gas (Deutch 2011). Less costly natural gas benefits residential, commercial and industrial consumers through lower prices. The development of domestic natural gas deposits, rather than deposits in other countries that would have been transported to the U.S. as LNG, has created an economic boom in the areas where these developments are taking place, and has a positive, though necessarily uncertain, U.S. employment effect in the natural gas (and shale oil) sectors, associated infrastructure sectors, and the sectors that manufacture the equipment used in the oil and gas and pipeline sectors (IHS CERA 2012). Cheap natural gas is in turn leading to higher capacity factors for existing natural gas electric generating plants, reducing the dispatch of coal plants, reducing CO<sub>2</sub> emissions as gas-fired power plants emit as much as 50% less CO<sub>2</sub> per unit of electricity than do coal plants. The return of relatively cheap natural gas is especially beneficial to certain industrial sectors, especially petrochemicals, fertilizer, cement, metallurgical process industries, and manufacturing plants that use natural gas as a boiler fuel (Ben Casselman and Russel Gold 2012, HIS CERA 2012). And, of course, it makes U.S. firms more competitive with firms in Asia and Europe where natural gas prices are two to four times higher than they are in the U.S.

There are also potential national security benefits. As recently as 2004, the conventional wisdom was that substantial imports of LNG from the Middle East and North Africa would have been required to balance the supply and demand. As with petroleum imports, the U.S. would have been at risk for natural or political disruptions in LNG trade and would have been transferring significant wealth to natural gas producing countries. The U.S. is now forecast to be a modest net exporter of natural gas by 2035, though there is considerable uncertainty about how important LNG exports, as opposed to pipeline exports to Mexico, will be. This in turn has some implications for long run equilibrium prices that I will not explore here. I note only that

liquefaction and shipping of LNG is expensive so that there will continue to be a significant basis difference in gas prices between the U.S., Asia and Europe. (International Energy Agency 2012, 130, EIA 2012 and NERA 2012).

### **VIII. Environmental Issues**

Of course, environmental regulation of natural gas exploration, development, and production continues at the state and federal levels. While the shale gas industry has a good environmental record and there are relatively few cases that have been credibly identified of serious environmental impacts (MIT 2011), shale gas development has attracted substantial public controversy in some areas of the country that has and will continue to slow down development of this resource if the public cannot be convinced that shale gas can be developed safely and responsibly. Over the next decade hundreds of thousands of new shale gas wells are expected to be drilled across the United States. Drilling likely will take place in areas of the country which do not have much recent experience with oil and gas drilling and its regulation (e.g. Pennsylvania, New York, Ohio), where new or revised regulatory frameworks need to be developed and strengthened, and where the public is more concerned about the environmental impacts of shale gas development than in states that have a long history of significant oil and gas production.

There are numerous pathways through which the various components of the exploration, development and production process can have potentially adverse environmental effects (Resources for the Future (a) 2012). The scope and quality of state regulation varies widely (Resources for the Future (b) 2012), best practices need to be developed, the division of responsibility between state and federal regulators needs to be defined more clearly, the societal

costs of various environmental impacts need to be measured much more precisely, and the industry needs to be more transparent about its operations to gain public acceptance.

Most of the focus of public opposition to shale gas development has been on the relationship between "fracking" and contamination of groundwater with natural gas. The 2010 documentary *Gasland* left the indelible picture that fracking leads to large quantities of natural gas being released into drinking water, which in turn could be set on fire inside people's homes. While this kind of contamination is possible in theory, the widespread direct leakage of natural gas from hydraulic fracturing into aquifers used for drinking water is unlikely because the shale gas deposits where hydraulic fracturing takes place are typically located thousands of feet below these water aquifers. If releases of methane from shale gas development into groundwater take place they are most likely to come from failures in the casings of the vertical well bores, shallow conventional gas deposits that are disturbed during the vertical drilling process, or from dissolved methane in fracking fluids that are spilled on the surface.

There are few credible documented cases of shale gas development leading to significant releases of methane into groundwater, fires in houses when faucets are turned on, etc., though the necessary "before and after" data to perform good studies is lacking (Alan Krupnick, Lucija Muehlenbachs, and Karlis Muelenbachs, 2011). Natural seepage of methane from shallow conventional deposits, leaks from conventional drilling from shallow pools of gas, and water well drilling that hits shallows deposits of natural gas are likely more significant sources of methane in aquifers. (I am told that releases of natural gas into drinking water in areas around Fort Worth pre-date shale gas development) It is clear, however, that regulations governing well completion to ensure proper steel casing and cementing of the vertical portions of shale needs to be tightened to ensure that such leaks into drinking water aquifers do not occur. More good

research that examines water quality before and after well completions and studies the pathways that may characterize water contamination is certainly needed as well.

The publicity around the relationship between hydraulic fracturing and drinking water contamination with natural gas has led to under-appreciation for other pathways of potential environmental concern (U.S. DOE 2011). These include contamination of groundwater from improper storage and disposal of drilling mud and toxic chemicals in hydraulic fracturing fluids, some of which may be unnecessary (e.g. diesel oil) or can be replaced at low cost with less toxic chemicals, air emissions from on site electric generators and vehicles, and disruption of local communities from large increases in heavy truck traffic bringing equipment into drilling sites and shipping out the waste and used equipment associate with drilling and hydraulic fracturing. Hydraulic fracturing also uses prodigious volumes of water during the well completion process (a few days for each horizontal well). This raises concerns not only about the disposal of the water and the chemicals in it, but the effects on local water resources and their allocation to different uses. Releases of methane into the atmosphere have also been identified as a concern because methane is a very potent greenhouse gas. However, the studies on this subject yield results that are all over the place, and if this is a problem it must be resolved across the entire oil and gas production and pipeline industries.

The shale gas boom has proceeded more rapidly than has the development of the associated environmental regulation, public information, and public education about the real and imagined risks and the actions state and federal governments are taking to deal with the important risks. The U.S. DOE's Shale Gas Production Subcommittee's Report (2011) makes many good suggestions for reducing environmental impacts and improving transparency and

public education. Developing good environmental regulatory frameworks is essential if the potential for shale gas development in the U.S. is to be realized.

Of course there are also environmental benefits from greater supplies of cheap natural gas, especially as it relates to displacing coal from utility and industrial boilers. While increased use of natural gas in North America is not going to achieve the greenhouse gas reductions necessary to stabilize global temperature increases it will provide a medium term economic benefit and reduce GHG emissions compared to forecasts made only a few years ago.

### REFERENCES

Breyer, Stephen. 1982. *Regulation and Its Reform*. Harvard University Press. Cambridge and London.

Breyer, Stephen and Paul W. MacAvoy. 1973. "The Natural Gas Shortage and the Regulation of Natural Gas Producers." *Harvard Law Review*, 86(6):941-987.

Casselman, Ben and Russell Gold. 2012. "Cheap Natural Gas Gives New Hope to the Rust Belt." *The Wall Street Journal*, October 24.

<http://online.wsj.com/article/SB10000872396390444549204578020602281237088.html> -- accessed November 22, 2012

Deutch, John. 2011. "The Good News About Gas." *Foreign Affairs*. 90(1): pp. 82-93.

Deutch, John. 2012. "The U.S. Natural Gas Boom Will Transform the World." August 15: A13.

IHS CERA. 2012. *America's New Energy Future: The Unconventional Oil and Gas Revolution and the U.S. Economy*. October. <http://www.ihs.com/products/cera/energy-report.aspx?ID=106592439> -- accessed November 22, 2012

International Energy Agency (IEA). 2012. *World Energy Outlook 2012*. Paris. <http://www.worldenergyoutlook.org/> -- accessed November 22, 2012.

Krupnick, Alan, Lucija Muehlenbachs, and Karlis Muelenbachs. 2011. "Shale Gas and Groundwater Contamination: Thoughts on a Recent Study." *Resources for the Future*. <http://www.rff.org/news/features/pages/shale-gas-and-groundwater-contamination.aspx> -- accessed November 20, 2012.

MacAvoy, Paul W. 2000. *The Natural Gas Market: Sixty Years of Regulation and Deregulation*. Yale University Press. New Haven and London.

MacAvoy, Paul W. and Robert S. Pindyck. 1973. "Alternative Regulatory Policies for Dealing with the Natural Gas Shortage." *Bell Journal of Economics and Management Science*. 4(2): 454-498.

Makholm, Jeff G. 2012. *The Political Economy of Pipelines*, University of Chicago Press. Chicago and London.

Massachusetts Institute of Technology (MIT). 2011. *The Future of Natural Gas*. <http://mitei.mit.edu/publications/reports-studies/future-natural-gas> --- accessed November 1, 2012.

National Petroleum Council (NPC). 1973. *Balancing Natural Gas Policy: Fueling the Demand of A Growing Economy*. Volume I. Washington, D.C.

Naturalgas.Org, "The History of Regulation." <http://www.naturalgas.org/regulation/history.asp> --accessed November 20, 2012.

NERA Economic Consulting (NERA). 2012. "Macroeconomic Impacts of LNG Exports from the United States." [http://www.fossil.energy.gov/programs/gasregulation/reports/nera\\_lng\\_report.pdf](http://www.fossil.energy.gov/programs/gasregulation/reports/nera_lng_report.pdf) --- accessed December 20, 2012.

Resources for the Future (a). 2012. "Risk Matrix for Shale Gas Development." [http://www.rff.org/centers/energy\\_economics\\_and\\_policy/Pages/Shale-Matrices.aspx](http://www.rff.org/centers/energy_economics_and_policy/Pages/Shale-Matrices.aspx) -- accessed November 20, 2012.

Resources for the Future (b). 2012. "A Review of Shale Gas Regulations By State." [http://www.rff.org/centers/energy\\_economics\\_and\\_policy/Pages/Shale\\_Maps.aspx](http://www.rff.org/centers/energy_economics_and_policy/Pages/Shale_Maps.aspx) --- accessed November 20, 2012.

The Economist. 2012. "An unconventional Bonanza." Special Report. July 14<sup>th</sup>. 3-18.

U.S. Department of Energy. 2011. *Shale Gas Production Subcommittee 90-Day Report*. Secretary of Energy Advisory Board. August. Washington, D.C. [http://www.shalegas.energy.gov/resources/081811\\_90\\_day\\_report\\_final.pdf](http://www.shalegas.energy.gov/resources/081811_90_day_report_final.pdf) -- accessed November 20, 2012.

U.S. Energy Information Administration (EIA). Various Years. *Annual Energy Outlook (AEO)* (Early Release and Final). <http://www.eia.gov/forecasts/aeo/> --- accessed November 1, 2012.

U.S. Energy Information Administration (EIA). 2012. "Effects of Increased Natural Gas Exports on Domestic Energy Markets." [http://www.eia.gov/analysis/requests/fe/pdf/fe\\_lng.pdf](http://www.eia.gov/analysis/requests/fe/pdf/fe_lng.pdf) --- accessed December 1, 2012,

# Natural Gas: From Shortages to Abundance in the U.S.

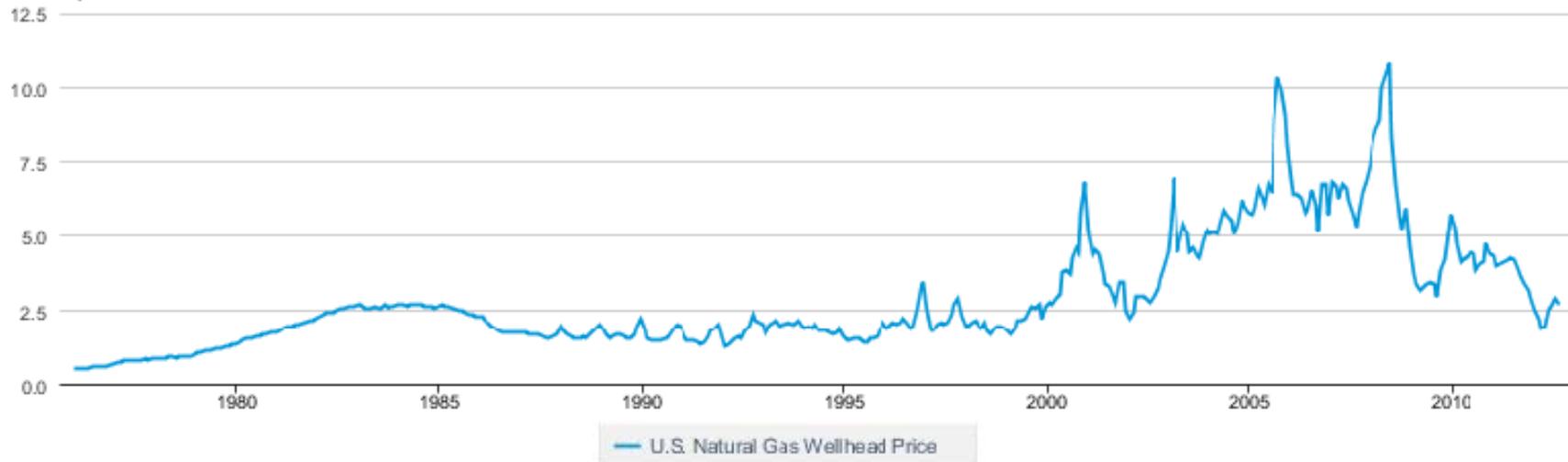
Paul L. Joskow  
January 4, 2013

# SUMMARY

- Tortured history of natural gas wellhead price and interstate gas pipeline regulation, deregulation and regulatory reform 1938- 1993: creating and responding to natural gas shortages and then contract surpluses 1970-1990
- Deregulation of wellhead prices, unbundling, and pipeline regulatory reform ultimately created a platform conducive to efficient static and dynamic performance on the supply and demand sides of the natural gas market
- Shale gas resources became economical to exploit due to technological innovations in drilling technologies that could easily be exploited without the burdens of inefficient economic regulation
- The magnitude of shale gas production was a “surprise”. Early 2000’s expectation was that U.S. would become a large importer of natural gas from Canada, Alaska, LNG from Middle East and North Africa.
- Expected North American production of shale gas keeps increasing year after year, gas prices have fallen significantly, but are probably below long run equilibrium levels, and the U.S. is now expected to be a gas exporter by about 2020.
- Natural gas consumers will benefit from lower gas prices, the trajectory of CO2 emissions will be lower, and there are national security benefits from going from an expected gas importer to an expected gas exporter
- Unresolved environmental concerns, along with misleading information and a lack of transparency, have led to public opposition in some areas. These issues can be and must be resolved if shale gas is to reach its full potential

## U.S. Natural Gas Wellhead Price

Dollars per Thousand Cubic Feet



Source: U.S. Energy Information Administration

Source: U.S. EIA <http://www.eia.gov/dnav/ng/hist/n9190us3m.htm> 12/26/12

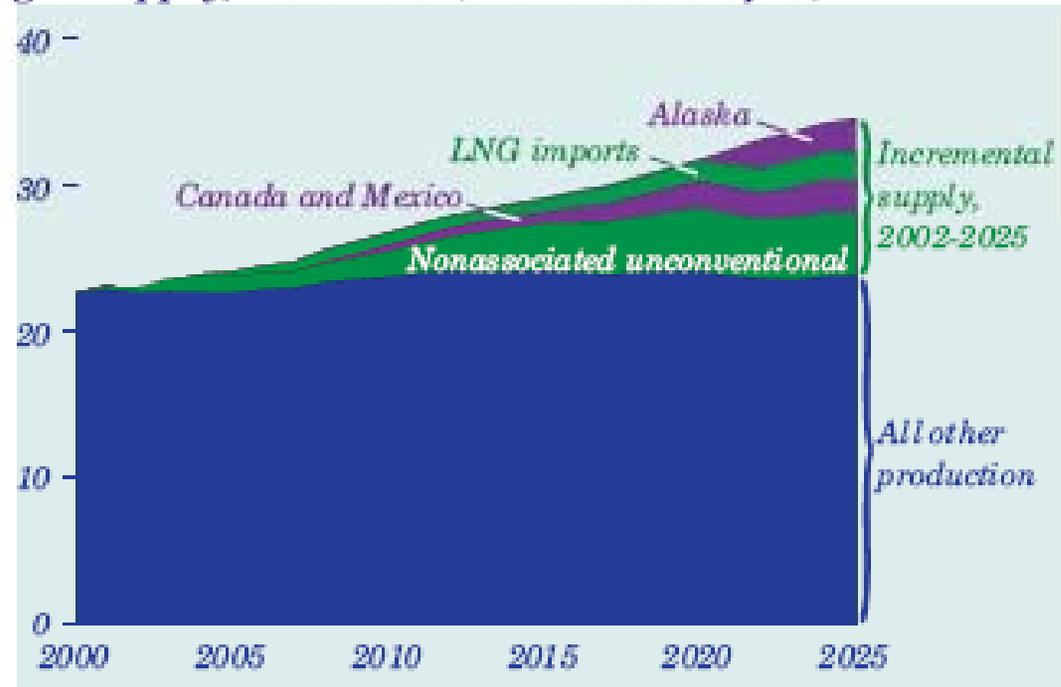
# Natural Gas Regulation, Deregulation and Regulatory Reform

- 1938 --- FPC pipeline regulation of bundled gas and pipeline services
- 1954 --- *Phillips Decision*: FPC Regulation of wellhead prices begins
- 1954 – 1979 --- Various approaches to cost of service regulation applied to set maximum wellhead prices.
- Blending and bundling of gas contracts by pipelines key to implementation
- 1970 – 1981 --- Shortages and rationing
- 1978: Natural Gas Policy Act: old gas, new gas, high cost gas ; category by category ceiling prices.
- Pipelines rush to sign long term contracts for “new gas” with high ceiling prices and “blend” diverse contract prices together to create average cost-based sale prices
- 1981: Oil prices peak and then fall 2/3 by 1986. “Take or pay” contract surpluses.

# Natural Gas Regulation, Deregulation and Regulatory Reform

- 1981- 85: SMPs for customers with fuel switching capabilities and the start of unbundling. Clear price discrimination leads to rejection by the courts
- 1985: FERC Order 436 voluntary unbundling available to all customers
- 1987: FERC Order 500 and take or pay contract renegotiation
- 1989: Natural Gas Wellhead Decontrol Act
- 1992: FERC Order 636 makes unbundling mandatory
- 1993: Regulation of wellhead prices formally ends
- 1990s: Competitive natural gas markets and light handed regulation of pipeline services mature --- prices low and stable
- 2000: (ex post) “Gas bubble” ends, gas prices rise and become volatile.
- 2001-2006: Large increase in pipeline imports from Alaska, Canada and LNG imports from other countries and higher prices expected to balance U.S. supply and demand in the future
- 2007: Shale gas slowly begins to be recognized as important future supply source
- 2009: Shale gas production starts to have significant effect on domestic gas supplies leading to much lower gas prices
- 2011: LNG exports begin to get serious attention in the U.S. and Canada

*Figure 20. Major sources of incremental natural gas supply, 2002-2025 (trillion cubic feet)*



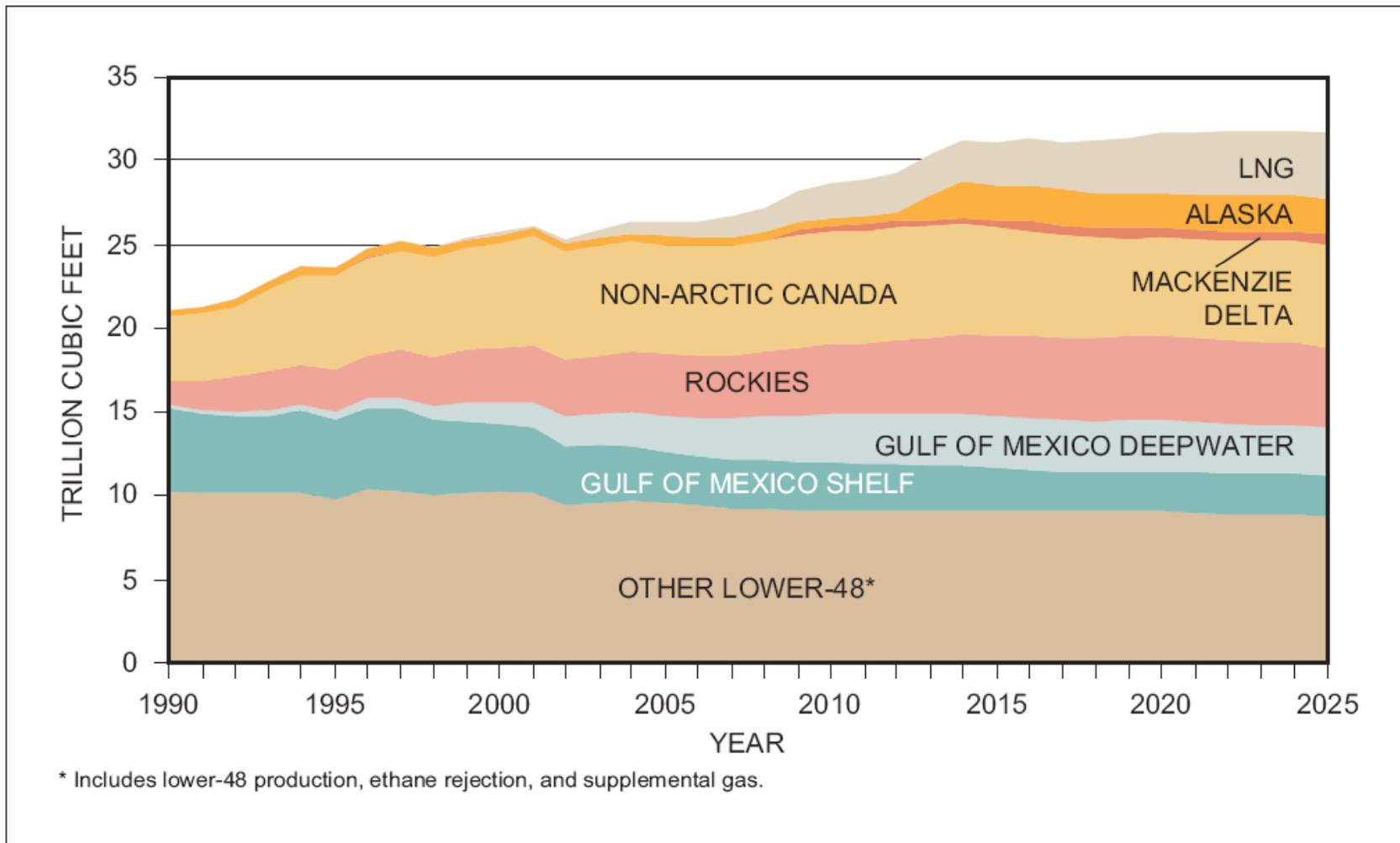
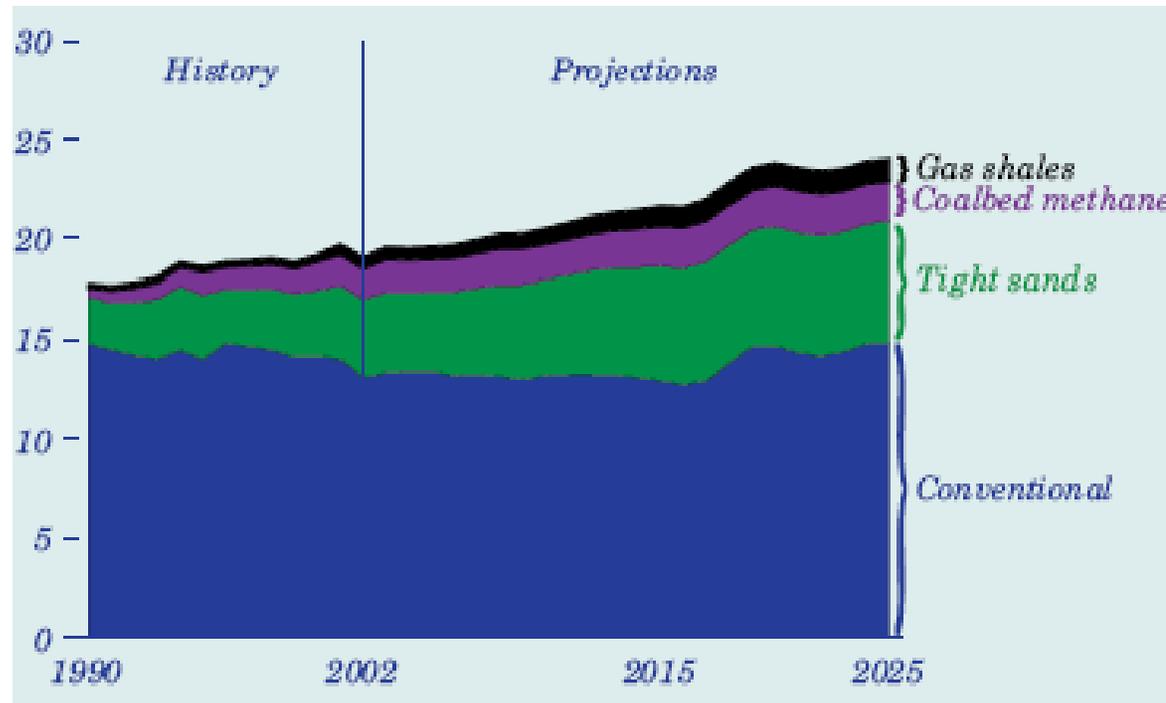
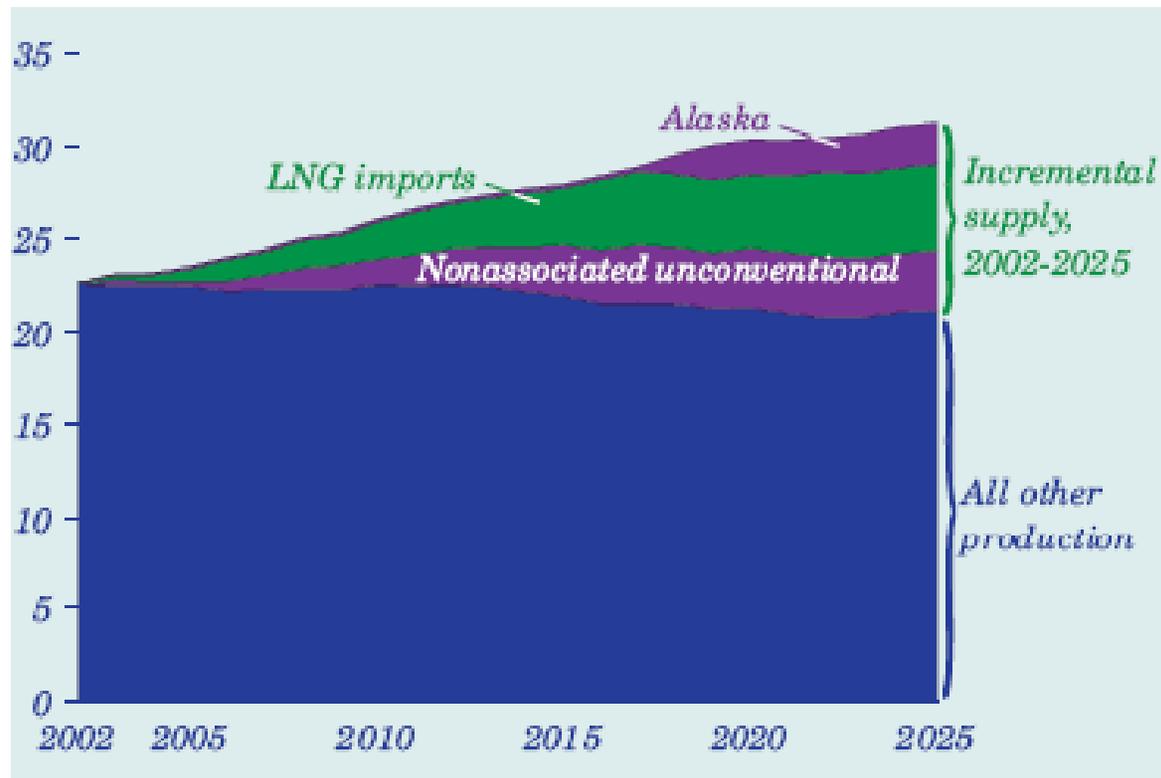


Figure 38. U.S. and Canadian Natural Gas Supply

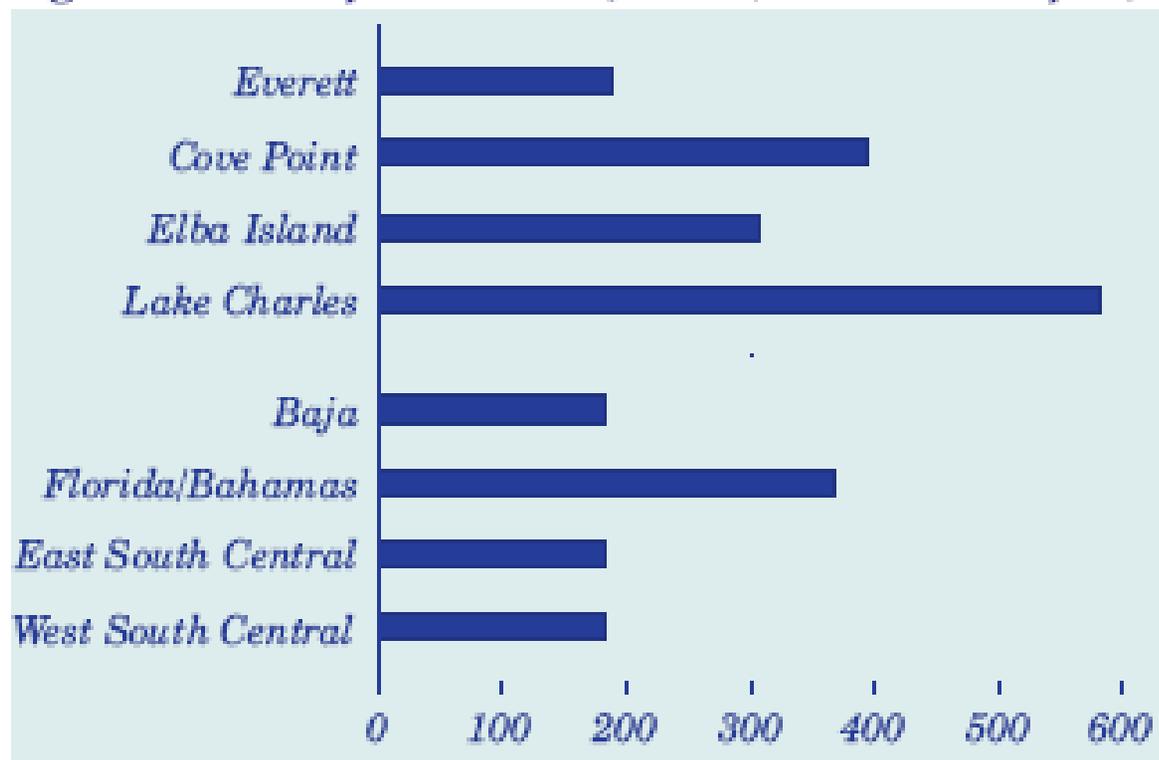
*Figure 14. Lower 48 natural gas production by resource type, 1990-2025 (trillion cubic feet)*



*Figure 17. Major sources of incremental natural gas supply, 2002-2025 (trillion cubic feet)*



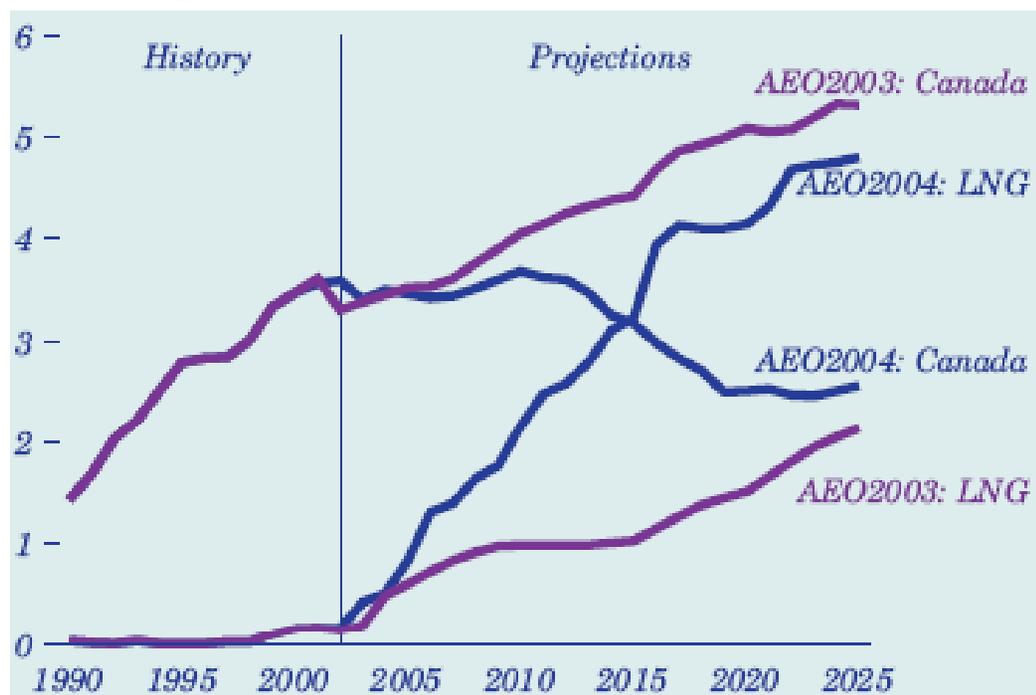
*Figure 21. Projected LNG imports by terminal and region in the reference case, 2025 (billion cubic feet)*



*Table 12. North American LNG regasification proposals as of December 1, 2003 (million cubic feet per day)*

<i>Project</i>	<i>Owners</i>	<i>Location</i>	<i>Start year</i>	<i>Capacity added</i>
<b>West Coast</b>				
<i>Terminal GNL Mar Adentro de B.C.</i>	<i>ChevronTexaco</i>	<i>Baja California, Mexico (offshore)</i>	<i>2007</i>	<i>750</i>
<i>Tijuana Regional Energy Center</i>	<i>Marathon/Golar LNG/Grupo GGS</i>	<i>Baja California, Mexico</i>	<i>2006</i>	<i>750</i>
<i>Sound Energy Solutions</i>	<i>Mitsubishi</i>	<i>Long Beach, California</i>	<i>2007</i>	<i>700</i>
<i>Terminal LNG de Baja California</i>	<i>Shell</i>	<i>Baja California, Mexico</i>	<i>2007</i>	<i>1,000</i>
<i>Energia Costa Azul LNG</i>	<i>Sempra Energy</i>	<i>Baja California, Mexico</i>	<i>2007</i>	<i>1,000</i>
<i>Crystal</i>	<i>Crystal Energy</i>	<i>Oxnard, California (offshore)</i>	<i>2006</i>	<i>600</i>
<i>Tractebel Mexico</i>	<i>Tractebel</i>	<i>Lazaro Cardenas, Mexico</i>	<i>2007</i>	<i>500</i>
<i>Cabrillo Port LNG</i>	<i>BHP Billiton</i>	<i>Oxnard, California (offshore)</i>	<i>2008</i>	<i>1,500</i>
<b>Florida/Bahamas</b>				
<i>Ocean Express LNG</i>	<i>AES</i>	<i>Ocean Cay, Bahamas</i>	<i>2006</i>	<i>850</i>
<i>Freeport</i>	<i>El Paso</i>	<i>Freeport Grand Island, Bahamas</i>	<i>2007</i>	<i>500</i>
<i>Calypso</i>	<i>Tractebel Bahamas LNG</i>	<i>Freeport Grand Cayman, Bahamas</i>	<i>2007</i>	<i>832</i>
<b>Gulf Coast</b>				
<i>ExxonMobil LNG</i>	<i>ExxonMobil</i>	<i>Quintana Island, Texas</i>	<i>2007</i>	<i>1,000</i>
<i>Sabine Pass/Cheniere</i>	<i>Cheniere</i>	<i>Sabine Pass, Texas</i>	<i>2008</i>	<i>2,000</i>
<i>Port Pelican</i>	<i>ChevronTexaco</i>	<i>Louisiana (offshore)</i>	<i>2007</i>	<i>1,600</i>
<i>Cameron LNG</i>	<i>Sempra Energy</i>	<i>Hackberry, Louisiana</i>	<i>2007</i>	<i>1,500</i>
<i>Altamira</i>	<i>Shell</i>	<i>Altamira, Mexico</i>	<i>2004</i>	<i>500</i>
<i>Corpus Christi LNG</i>	<i>Cheniere Energy</i>	<i>Corpus Christi, Texas</i>	<i>2008</i>	<i>2,000</i>
<i>ExxonMobil/Sabine Pass LNG</i>	<i>ExxonMobil</i>	<i>Sabine Pass, Texas</i>	<i>2008</i>	<i>1,000</i>
<i>Liberty</i>	<i>HNG Storage/Conversion Gas</i>	<i>Cameron, Louisiana</i>	<i>2007</i>	<i>3,000</i>
<i>Main Pass Energy Hub</i>	<i>Freeport-McMoRan Sulphur</i>	<i>Gulf of Mexico (offshore)</i>	<i>2006</i>	<i>1,500</i>
<i>Gulf Landing</i>	<i>Shell</i>	<i>West Cameron, Louisiana (offshore)</i>	<i>2008-2009</i>	<i>1,000</i>
<i>Vermilion 179</i>	<i>Conversion Gas Imports</i>	<i>Louisiana</i>	<i>2008</i>	<i>1,000</i>
<i>Mobile Bay LNG</i>	<i>ExxonMobil</i>	<i>Mobile Bay, Alabama</i>	<i>2008</i>	<i>1,000</i>
<i>Freeport LNG</i>	<i>Freeport, Cheniere, Contango</i>	<i>Freeport, Texas</i>	<i>2006</i>	<i>1,500</i>
<i>Energy Bridge</i>	<i>El Paso</i>	<i>Floating Dock (offshore)</i>	<i>2005</i>	<i>500</i>
<b>East Coast</b>				
<i>Canaport</i>	<i>Irving Oil/Chevron Texaco</i>	<i>Canaport, New Brunswick, Canada</i>	<i>2006</i>	<i>500</i>
<i>Weaver's Cove</i>	<i>Poten</i>	<i>Fall River, Massachusetts</i>	<i>2007</i>	<i>400</i>
<i>Access Northeast Energy</i>	<i>Access Northeast Energy</i>	<i>Bearhead, Nova Scotia, Canada</i>	<i>2008</i>	<i>500</i>
<i>Fairwinds LNG</i>	<i>TransCanada, ConocoPhillips</i>	<i>Harpswell, Maine</i>	<i>2009</i>	<i>500</i>
<i>Providence LNG</i>	<i>Keyspan, BG LNG Services</i>	<i>Providence, Rhode Island</i>	<i>2005</i>	<i>500</i>
<i>Crown Landing</i>	<i>BP</i>	<i>Logan Township, New Jersey</i>	<i>2008</i>	<i>1,200</i>
<i>Somerset LNG</i>	<i>Somerset LNG</i>	<i>Somerset, Massachusetts</i>	<i>2007</i>	<i>430</i>

*Figure 20. U.S. net imports of LNG and Canadian natural gas, 1990-2025 (trillion cubic feet)*

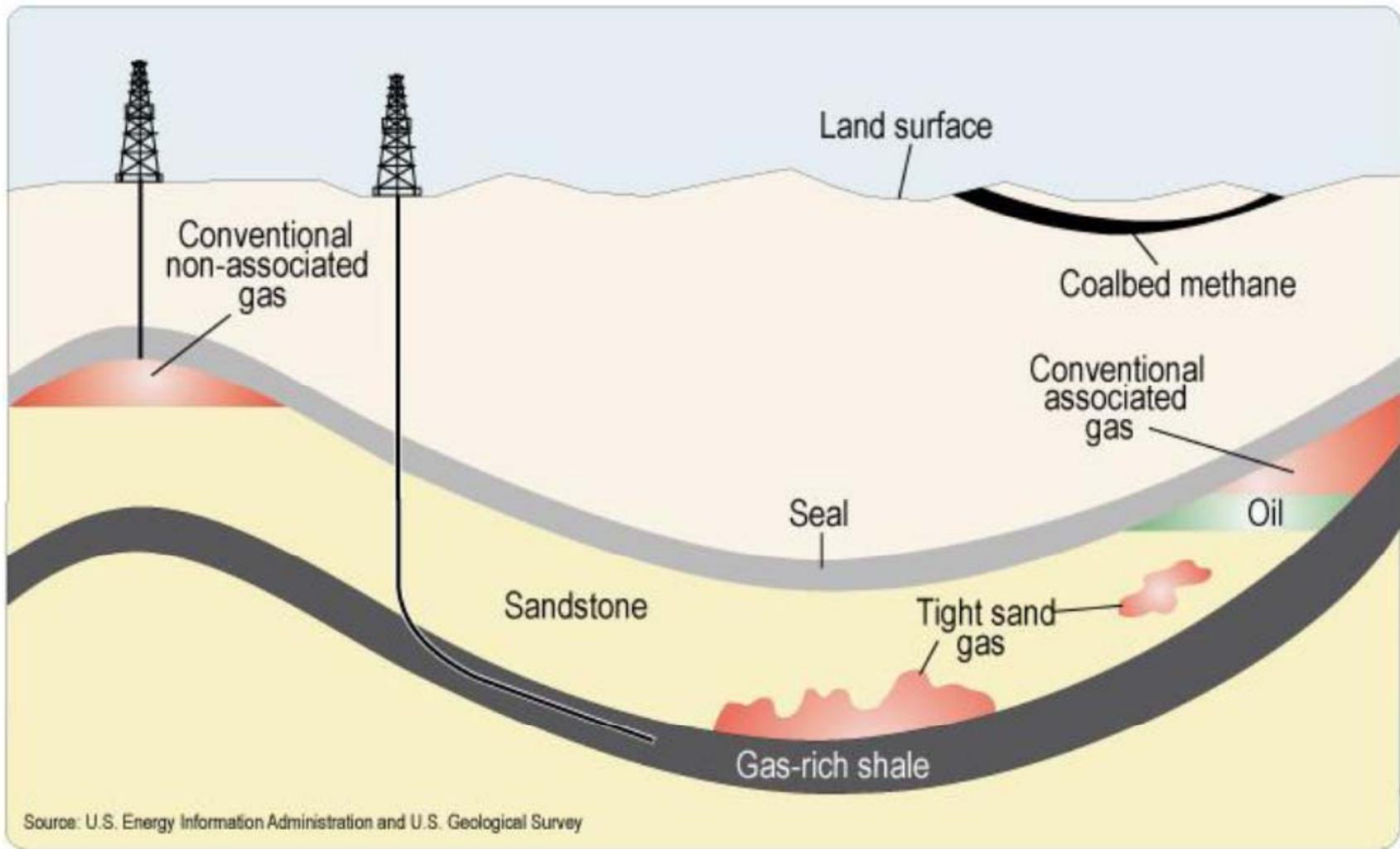


# North American shale plays



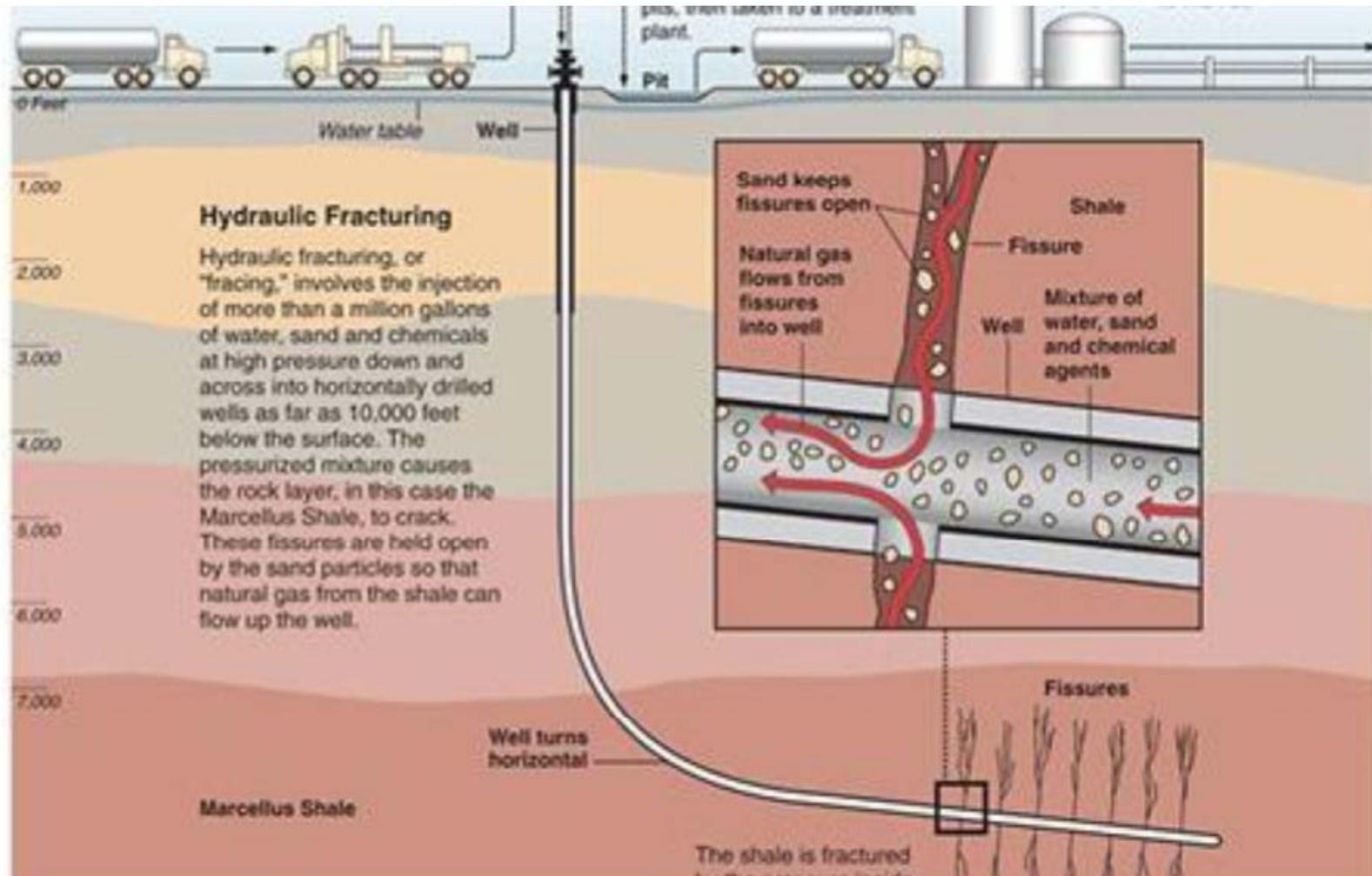
Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.

# Underground sources of natural gas



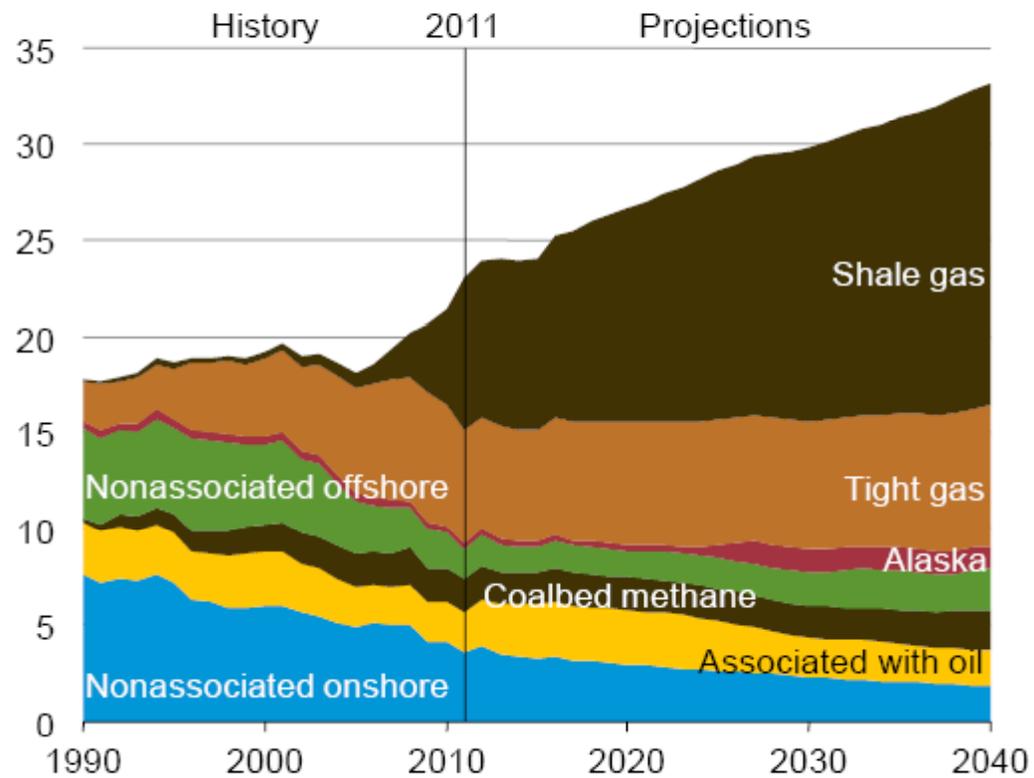
Source: modified from U.S. Geological Survey Fact Sheet 0113-01

# Diagram of a typical hydraulic fracturing operation



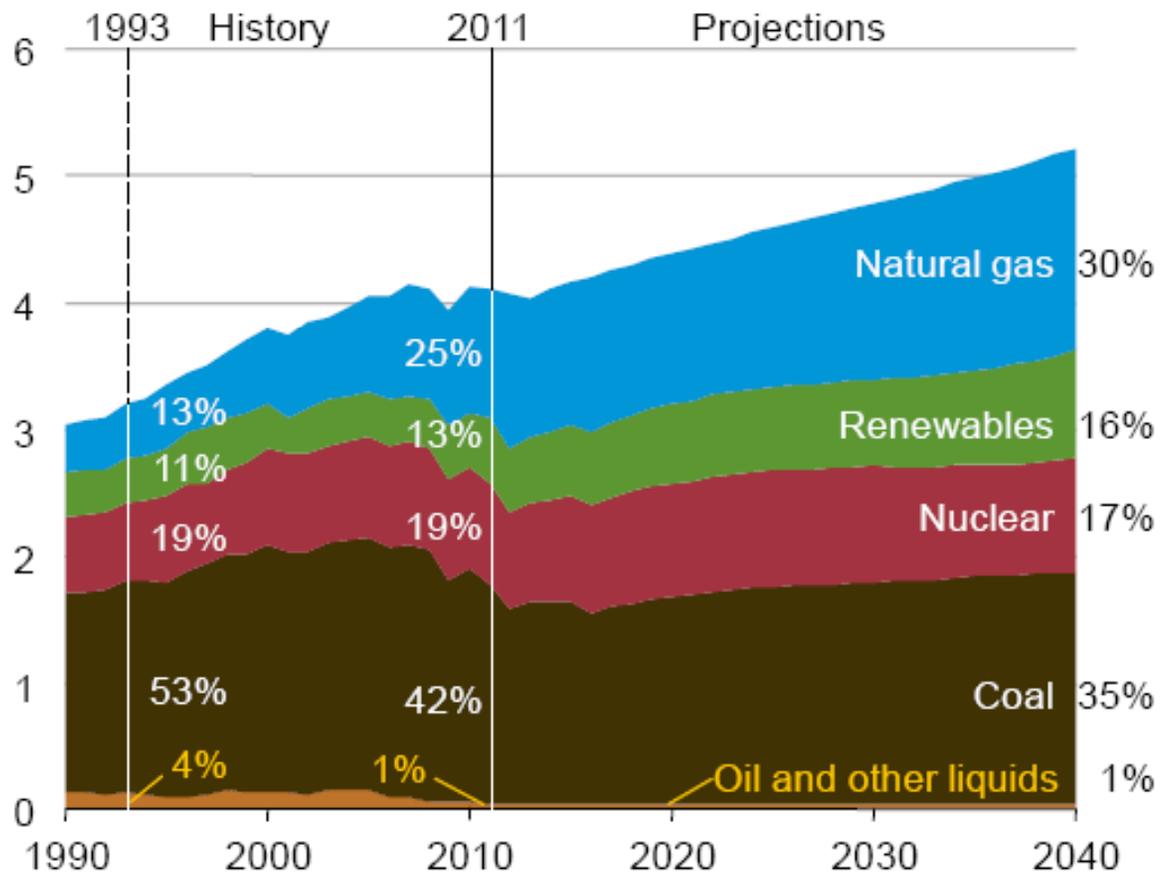
Source: ProPublica, <http://www.propublica.org/special/hydraulic-fracturing-national>

**Figure 3. U.S. dry natural gas production by source, 1990-2040 (trillion cubic feet)**

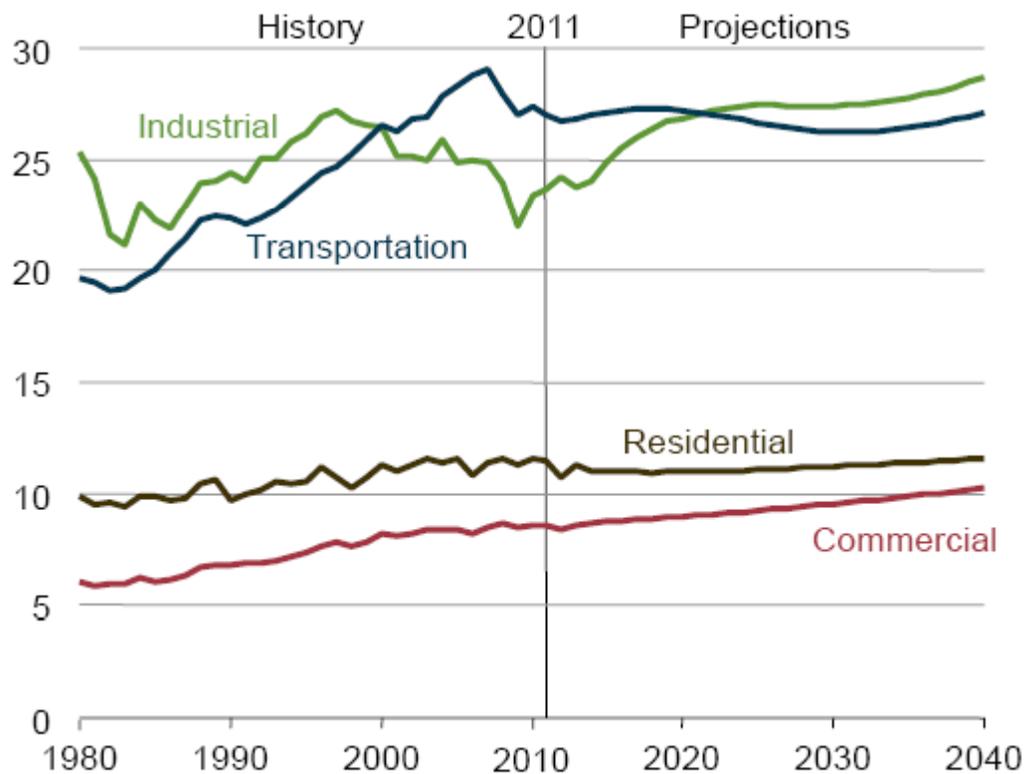


EIA AEO 2013 Early Release (December 2012)

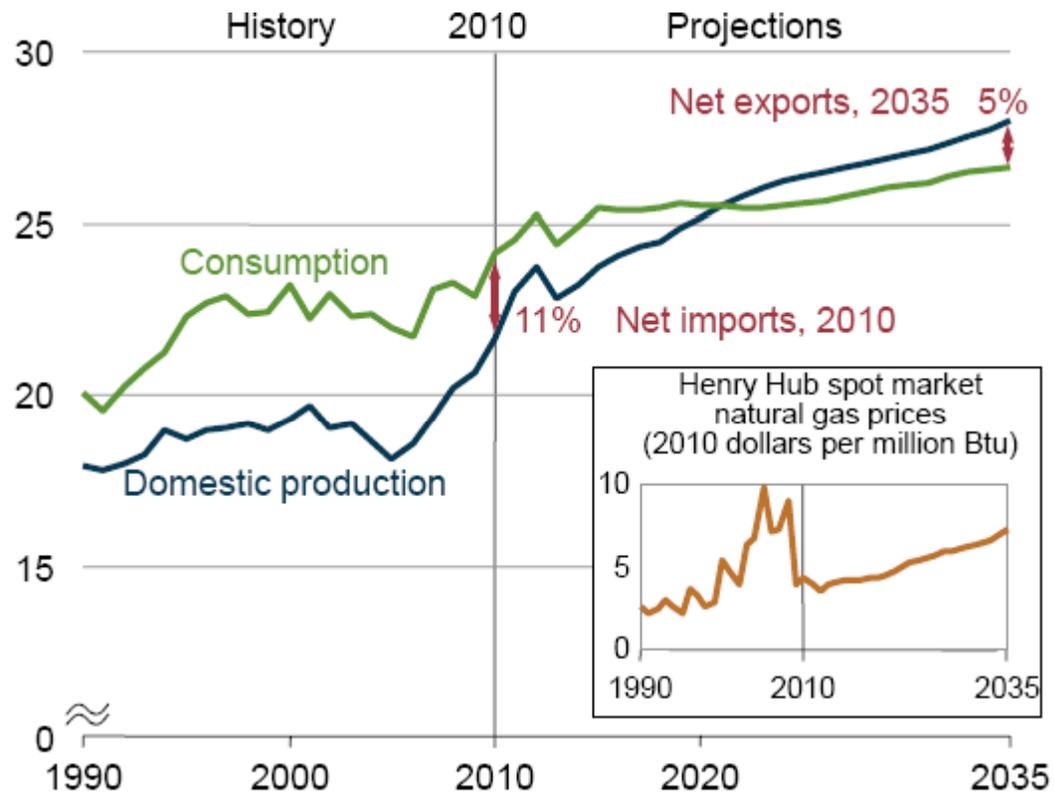
**Figure 12. Electricity generation by fuel, 1990-2040  
(trillion kilowatthours per year)**



**Figure 6. Delivered energy consumption by sector, 1980-2040 (quadrillion Btu)**



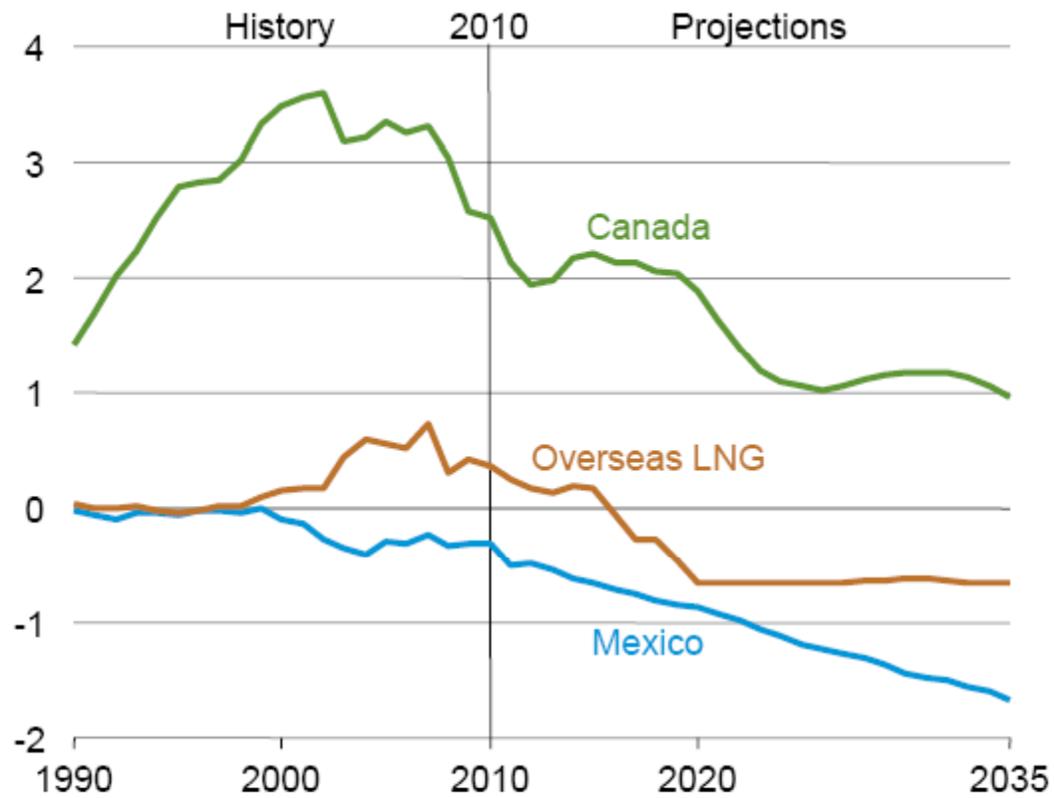
**Figure 4. Total U.S. natural gas production, consumption, and net imports, 1990-2035 (trillion cubic feet)**



Source: EIA AEO 2012

## The U.S. becomes a net natural gas exporter

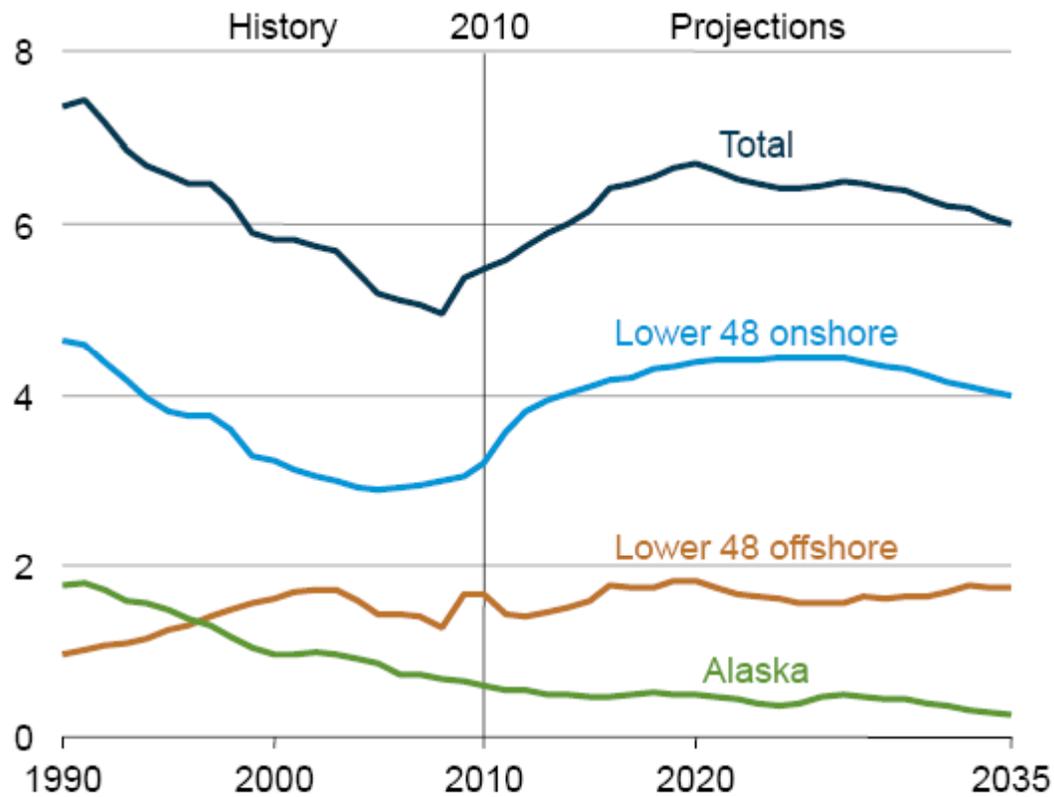
Figure 109. U.S. net imports of natural gas by source, 1990-2035 (trillion cubic feet)



Source: EIA AEO 2012

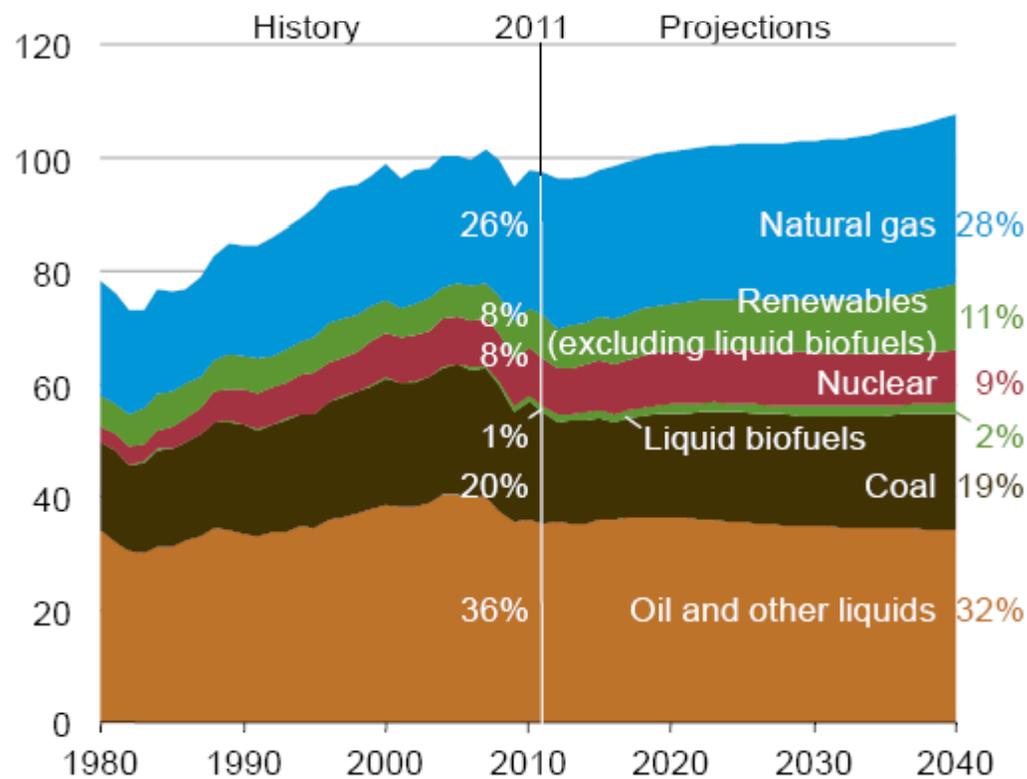
## U.S. crude oil production increases, led by lower 48 onshore production

Figure 112. Domestic crude oil production by source, 1990-2035 (million barrels per day)

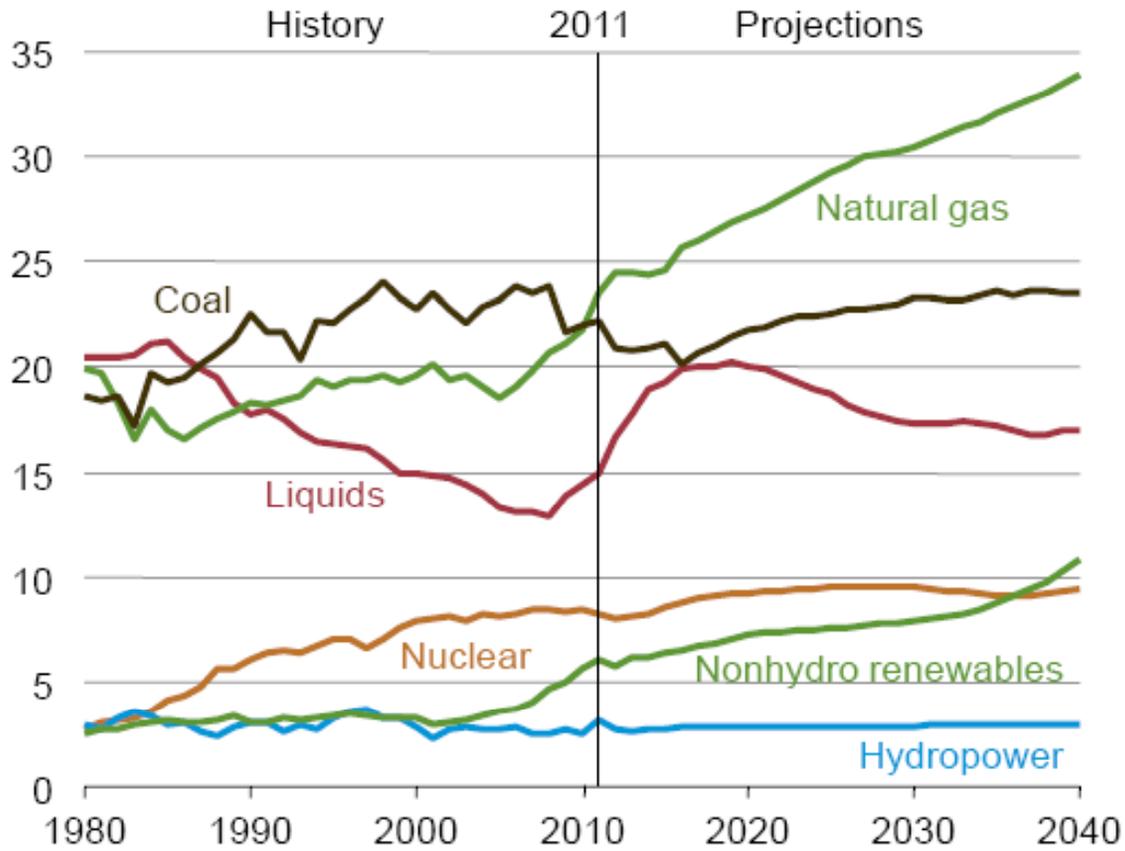


Source: EIA AEO 2012

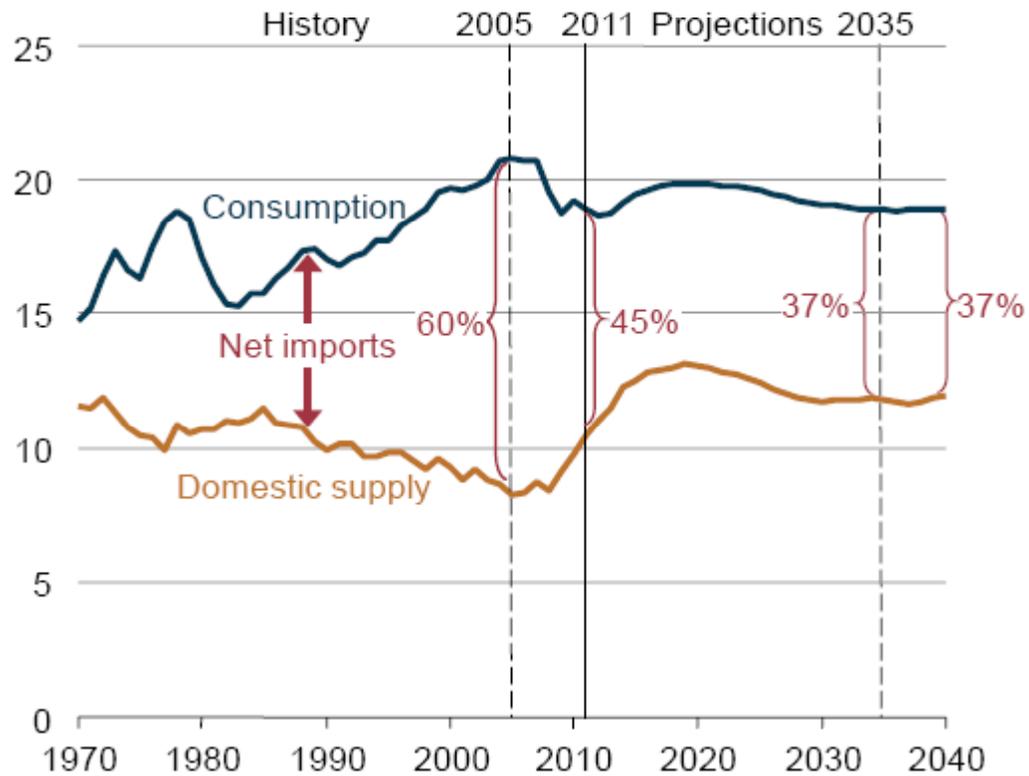
**Figure 7. U.S. primary energy consumption by fuel, 1980-2040 (quadrillion Btu per year)**



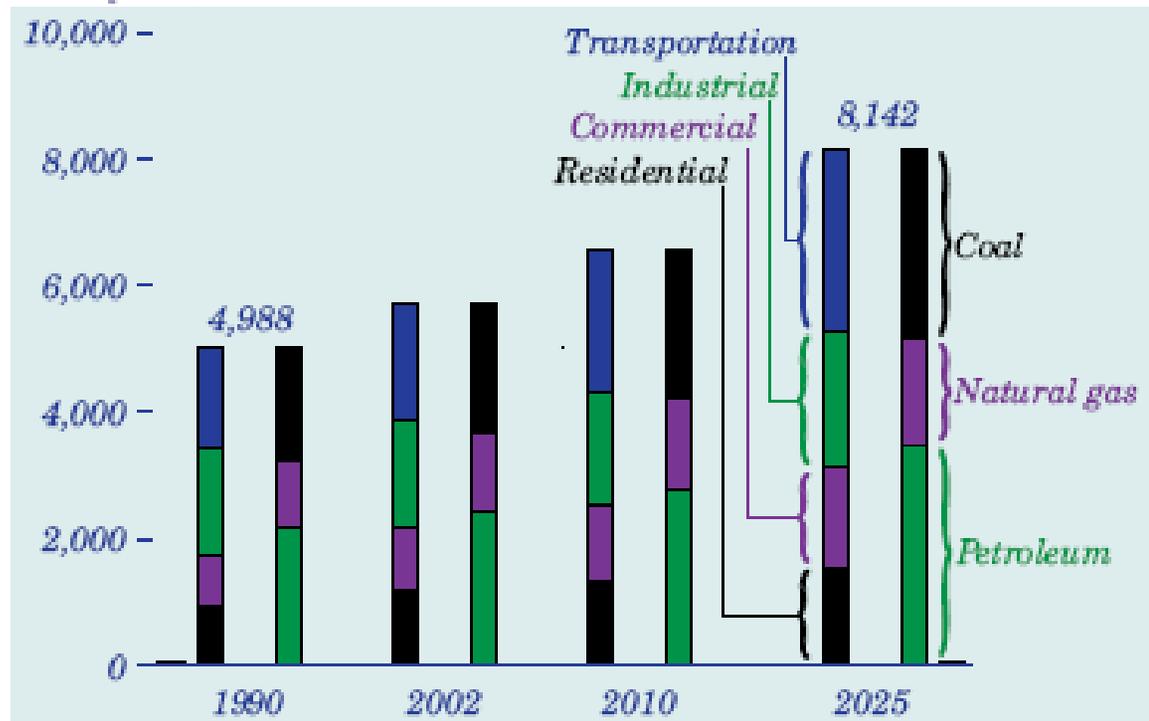
**Figure 10. U.S. energy production by fuel, 1980-2040  
(quadrillion Btu)**



**Figure 11. U.S. liquid fuels supply, 1970-2040  
(million barrels per day)**

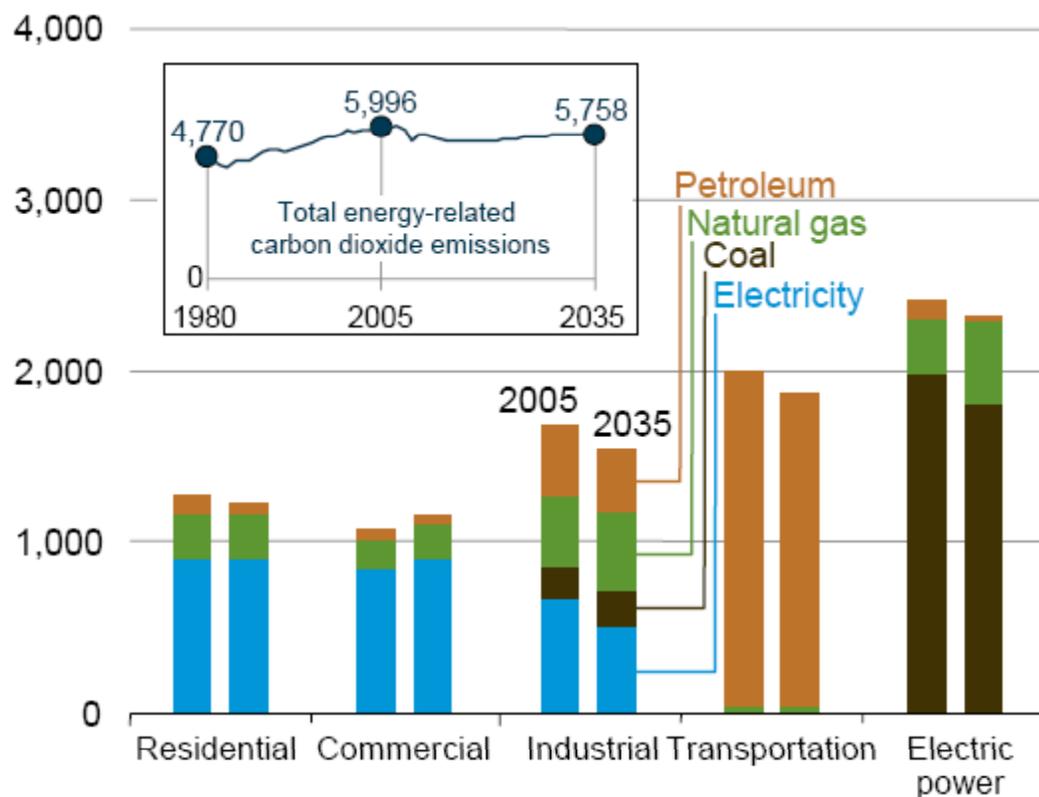


*Figure 115. Carbon dioxide emissions by sector and fuel, 1990-2025 (million metric tons)*



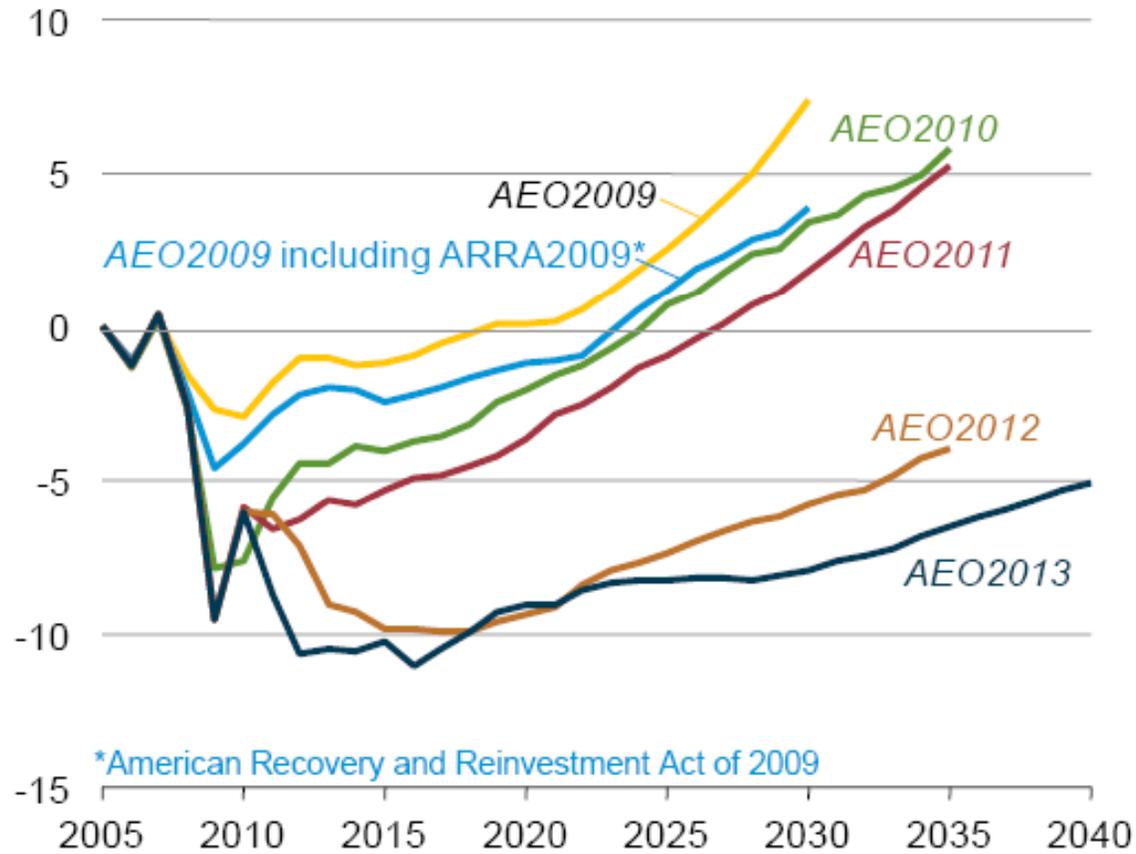
## Projected energy-related carbon dioxide emissions remain below their 2005 level

**Figure 122. U.S. energy-related carbon dioxide emissions by sector and fuel, 2005 and 2035 (million metric tons)**



Source: EIA AEO 2012

**Figure 13. U.S. energy-related carbon dioxide emissions in recent AEO Reference cases (percent change from 2005)**



**Figure 10: 2010 LNG Trade (Tcf)**

From\To	Africa	Canada	China/ India	C&S America	Europe	FSU	Korea/ Japan	Middle East	Oceania	Sakhalin	Southeast Asia	U.S.	Total Exports
Africa		0.03	0.05	0.31	1.33		0.24	0.21			0.07	0.31	<b>2.54</b>
Canada													<b>0.00</b>
China/India													<b>0.00</b>
C&S America		0.00		0.01	0.02		0.00					0.01	<b>0.05</b>
Europe				0.01	0.11		0.05	0.01			0.00		<b>0.18</b>
FSU													<b>0.00</b>
Korea/Japan													<b>0.00</b>
Middle East		0.01	0.44	0.08	1.15		1.28	0.10			0.15	0.08	<b>3.29</b>
Oceania			0.17				0.62				0.04		<b>0.83</b>
Sakhalin			0.02				0.39	0.00			0.02		<b>0.43</b>
Southeast Asia			0.14	0.06			1.92	0.01			0.21		<b>2.34</b>
U.S.							0.03						<b>0.03</b>
<b>Total Imports</b>	<b>0.00</b>	<b>0.04</b>	<b>0.81</b>	<b>0.47</b>	<b>2.61</b>	<b>0.00</b>	<b>4.53</b>	<b>0.34</b>	<b>0.00</b>	<b>0.00</b>	<b>0.49</b>	<b>0.40</b>	<b>9.70</b>

Source: "The LNG Industry 2010," GIIGNL.

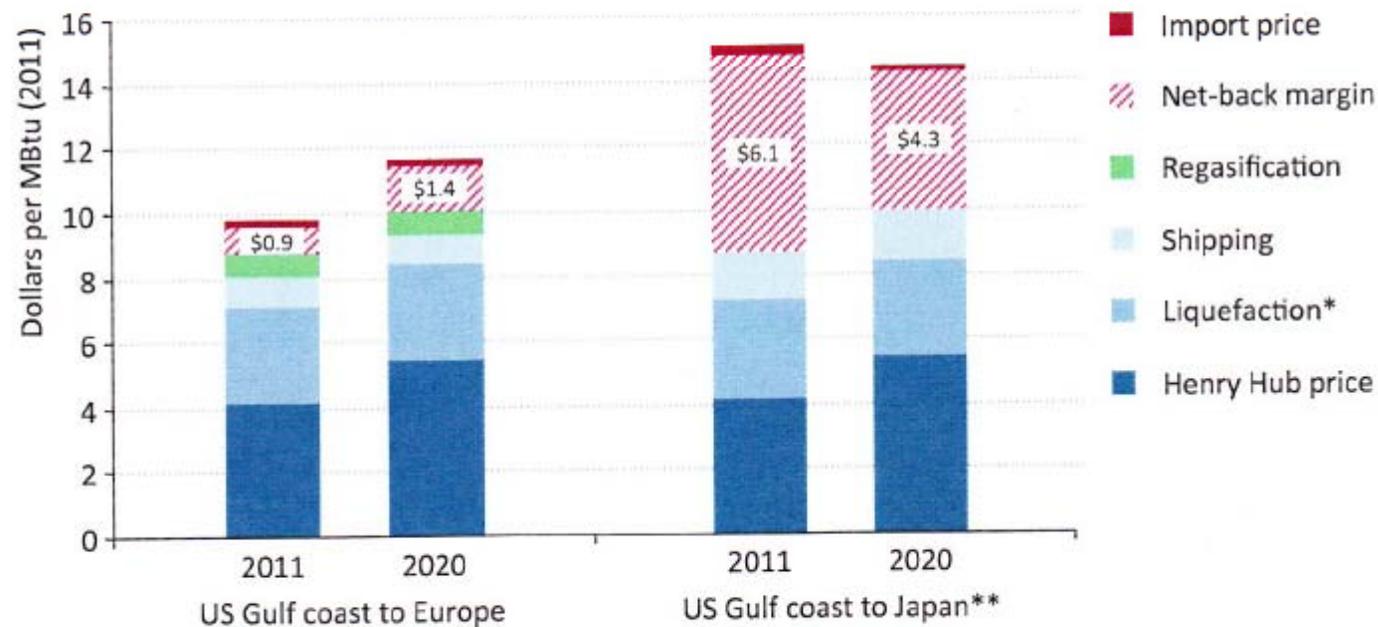
Global Production ~ 120 Tcf

NERA Economic Consulting (2012)

**Figure 16: Projected Wellhead Prices (2010\$/MMBtu)**

	2010	2015	2020	2025	2030	2035
Africa	\$1.75	\$1.89	\$2.09	\$2.31	\$2.55	\$2.81
Canada	\$3.39	\$3.72	\$4.25	\$5.20	\$5.64	\$6.68
China/India	\$12.29	\$12.86	\$13.00	\$13.25	\$13.57	\$13.51
C&S America	\$2.00	\$2.16	\$2.39	\$2.64	\$2.91	\$3.22
Europe	\$9.04	\$9.97	\$10.80	\$11.95	\$12.39	\$13.23
FSU	\$4.25	\$4.60	\$5.08	\$5.61	\$6.19	\$6.84
Korea/Japan	\$14.59	\$15.30	\$15.47	\$15.79	\$16.19	\$16.11
Middle East	\$1.25	\$1.35	\$1.49	\$1.65	\$1.82	\$2.01
Oceania	\$1.75	\$1.89	\$2.09	\$2.31	\$2.55	\$2.81
Sakhalin	\$1.25	\$1.35	\$1.49	\$1.65	\$1.82	\$2.01
Southeast Asia	\$2.00	\$2.16	\$2.39	\$2.64	\$2.91	\$3.22
U.S.	\$3.72	\$3.83	\$4.28	\$5.10	\$5.48	\$6.36

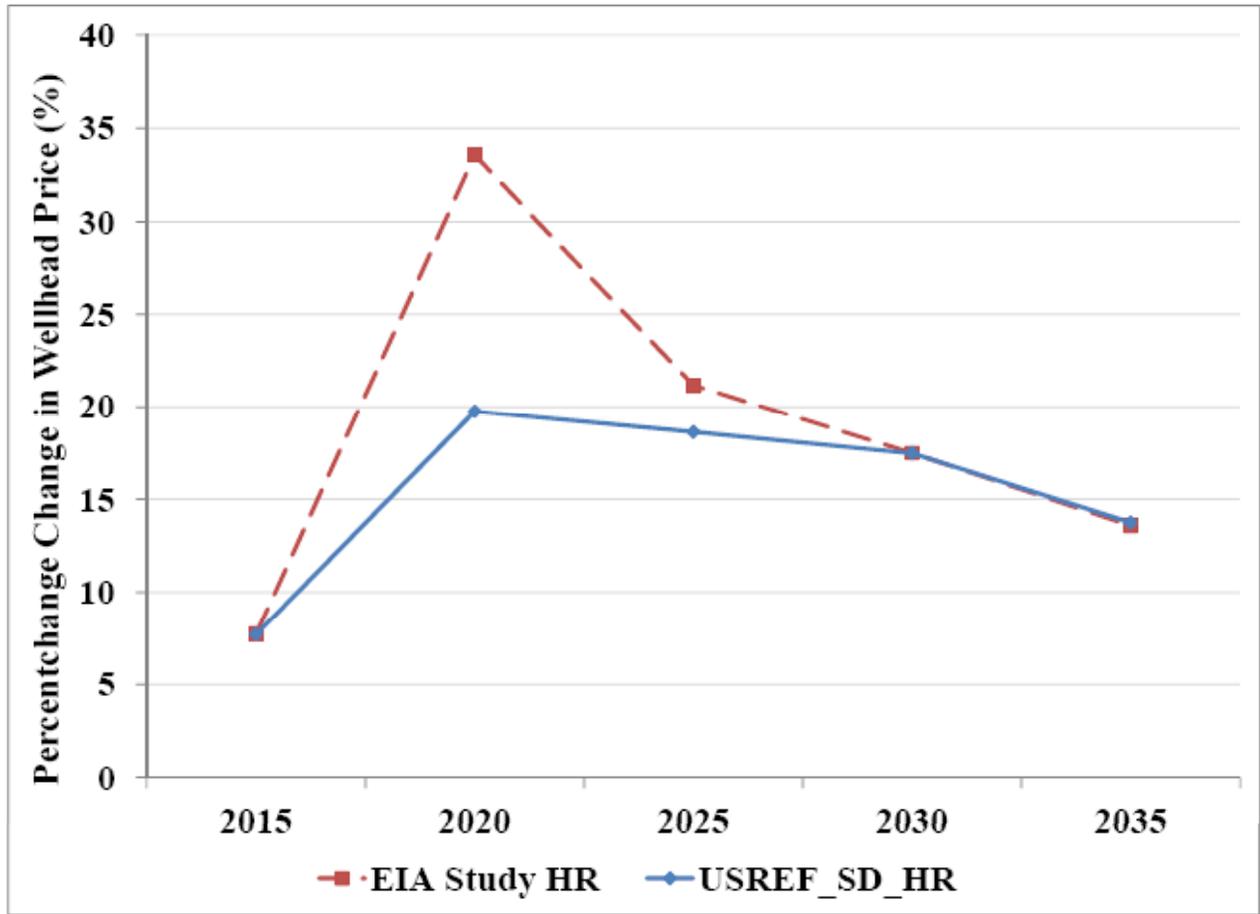
**Figure 4.3** ▷ Indicative economics of LNG exports from the United States



\* Includes cost of pipeline transport to export terminal. \*\* Widening of the Panama Canal, due to be completed in 2014, will allow for more LNG tanker traffic.

Notes: LNG costs are levelised assuming asset life of 30 years and a 10% discount rate. The Japanese import price is for liquefied gas, so it does not include regasification.

**Figure 7: Comparison of EIA and NERA Maximum Wellhead Price Increases**



# Environmental Issues

- Does “fracking” lead to contamination of drinking water aquifers with methane?
  - Hydraulic fracturing has been used in the oil and gas industry since at least 1947 and probably earlier
  - Fracking in shale deposits per se is unlikely to lead directly to drinking water contamination because it takes place thousands of feet below water aquifers
  - If there is contamination of drinking water it is much more likely due to failures in the vertical well casing, stray gas releases from conventional pools during vertical drilling, or surface spills of fracking fluids and drilling mud
  - The connection between shale gas production and groundwater contamination is weak and the studies that claim to document a connection are deficient --- little if any “before and after” analysis

# Environmental Issues

- There are more important pathways leading to potential environmental impacts that are probably of more concern
  - Vertical well failures
  - Above ground spills of toxic fracking fluids and drilling mud and inadequate long-term disposal methods
  - Air emissions from drilling and support equipment
  - Increased truck traffic delivering equipment and disposing of wastes
  - Fresh water use
  - Earth tremors from below-ground disposal of fluids
  - Methane emissions
- Regulatory frameworks and capabilities vary widely from state to state and between states and federal government
- Best practices for regulatory frameworks have not been developed
- Lack of transparency by the industry has created suspicions that environmental impacts are not being taken into account adequately