

The Cloudy Future of U.S. LNG Imports*

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Abstract

For over half a century, the potential of LNG to meet growing demand for natural gas in the USA has been a tantalizing, but generally disappointing, opportunity for American utilities as well as the energy investment community. Despite a renewal of optimism about the future of imported LNG over the past several years, events of 2008 – exclusive of the global recession that was confirmed in the last months of 2007 – have raised doubts about the commercial viability of these expensive undertakings. This paper explores the question of whether 2008 was simply a “bear year” for the U.S. LNG industry, or does recent experience – and the reminder of similar experiences in the 1980’s – illustrate a fundamental risk that potential investors in such projects will want to avoid over the longer-term?

Introduction

Despite the renewal of optimism in recent years about the future of U.S. LNG imports, serious issues of price, demand and alternative supplies arose in 2008 raising doubts about the commercial viability of these expensive undertakings. Was 2008 simply a “bear year” for the U.S. LNG industry, or does that experience – and its reminder of similar experiences in the 1980’s – illustrate a fundamental structural risk that potential investors in such projects will want to avoid over the longer-term?¹

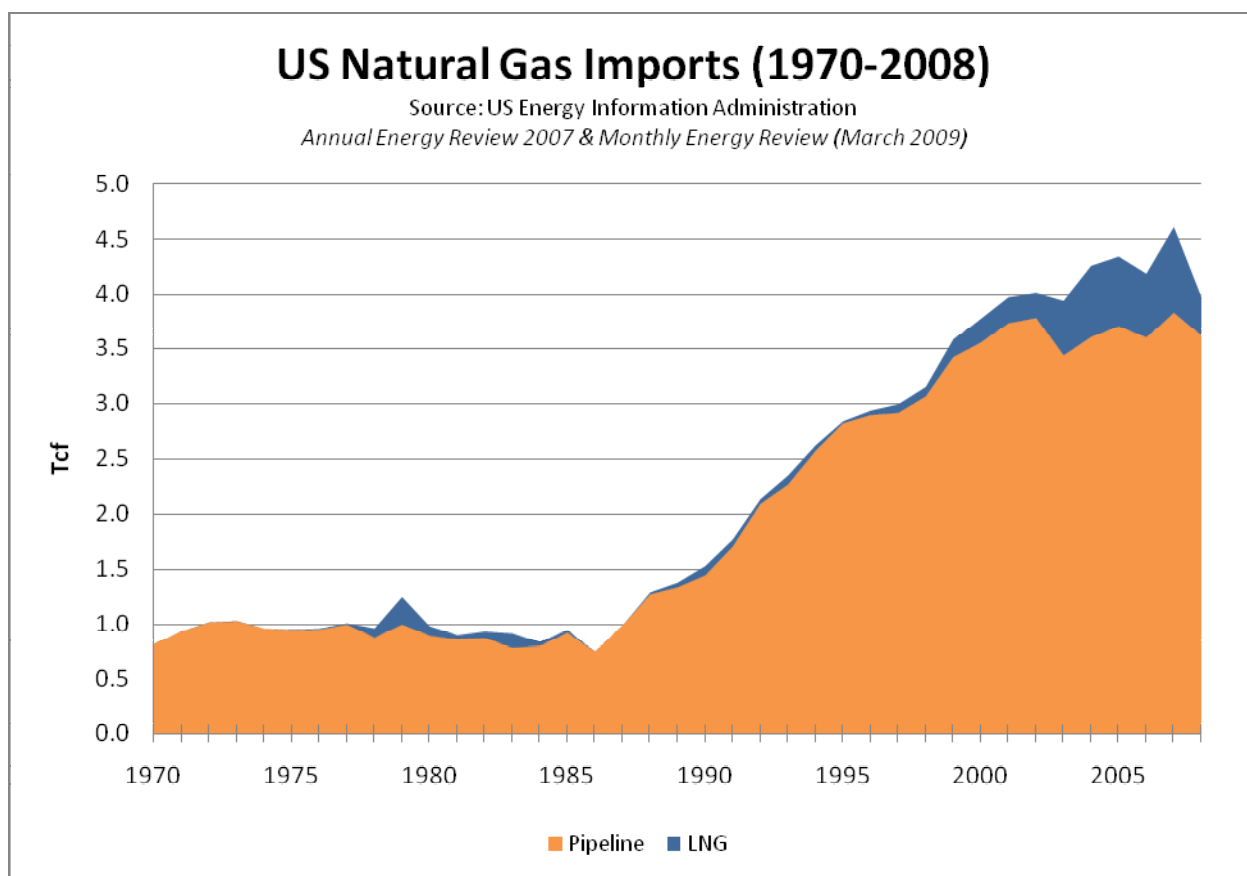
The History of U.S. LNG Imports

Since 1959, when the *Methane Pioneer*, a converted World War II “Liberty Ship”, sailed from Lake Charles, Louisiana, carrying the first of eight shipments of LNG across the Atlantic to Canvey Island, U.K., there have been two major phases of enthusiasm for projects to bring imported LNG to U.S. markets. That first successful demonstration that natural gas could be shipped in a trans-oceanic trade was the impetus for imports of LNG from Algeria to the U.K. that began in 1965, as well as a U.S. project to export LNG from Kenai, Alaska, to Japan that began in 1969 and is still in operation. It wasn’t until November 1971, however – during a period of rising natural gas prices and nearly universal forecasts of even higher energy costs in the future – that the U.S. began to import LNG from Algeria to Distrigas’ terminal in Everett, Massachusetts.

Over the period 1971-1982, integrated, capital-intensive ventures involving dedicated fleets of cryogenic tankers were developed to deliver LNG to specially-constructed terminals and re-gasification facilities at Elba Island, Georgia; Lake Charles, Louisiana and Cove Point, Maryland.

As shown in Figure 1, these projects delivered relatively modest volumes to the U.S. market for several years reaching a peak annual delivery in 1979 of 253 Bcf, which was 1.3% of U.S. natural gas consumption in that year.

Figure 1

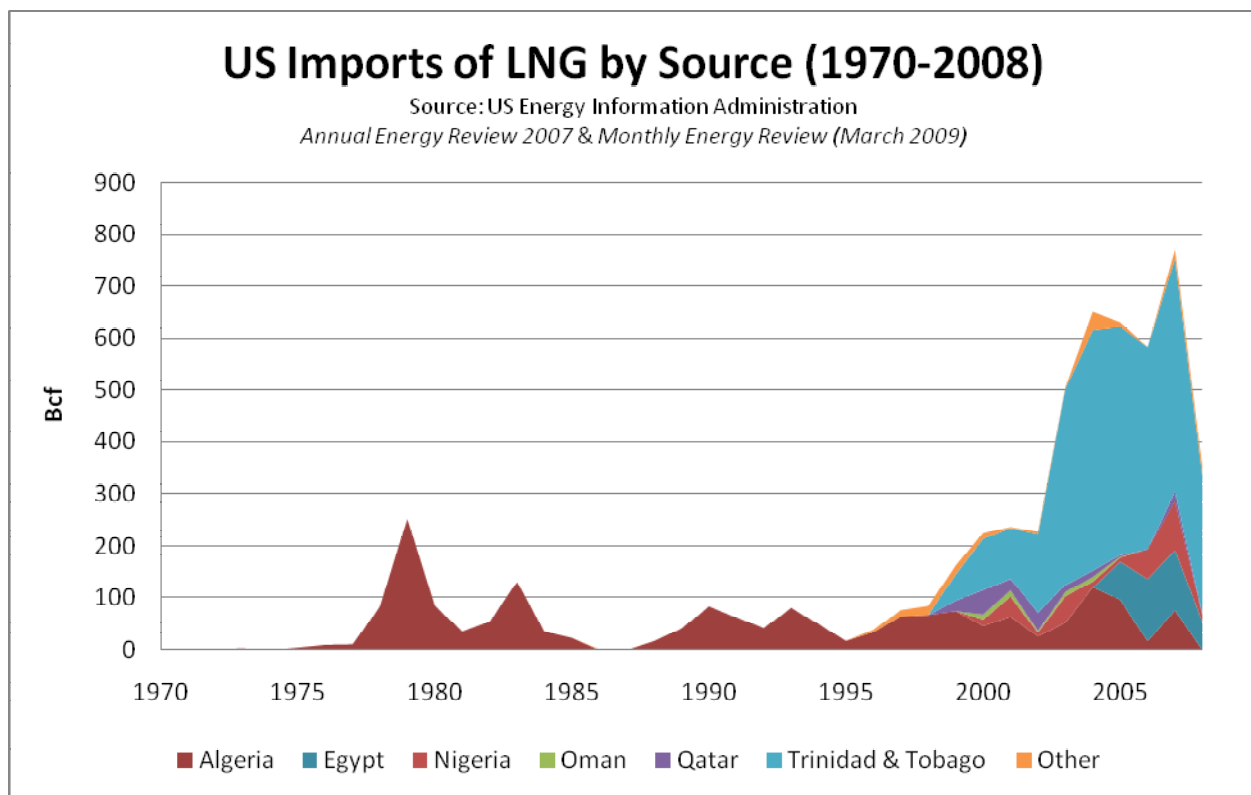


Contemporaneously with these projects, federal regulatory initiatives began to change the fundamentals of the U.S. natural gas industry². These broad structural reforms precluded a utility's ability to pass-on the costs of more expensive contracted-for supplies when lower-cost supplies were available for purchase on the spot market and could be transported reliably under the newly-minted expedient of "open access". Since financial support for LNG projects of that era was typically underwritten by long-term, take-or-pay arrangements, the new rules of the game proved to be "game changers" for future import projects.

Exacerbating the situation were contractual disputes over price with Algeria’s Sonatrach, the sole producer/supplier of LNG for these projects as well as national security concerns about relying too heavily upon foreign suppliers of energy for U.S. consumption. The experience of lengthy gasoline lines as the result “oil crises” – the OAPEC embargo of 1973 and dislocations caused by the Iranian Revolution in 1979 – was fresh in the minds of American consumers and reflected in the era’s energy policies and planning. In 1980 the facilities at Both Cove Point and Elba Island were mothballed and the terminal at Lake Charles was shut-down shortly after its completion in 1982.

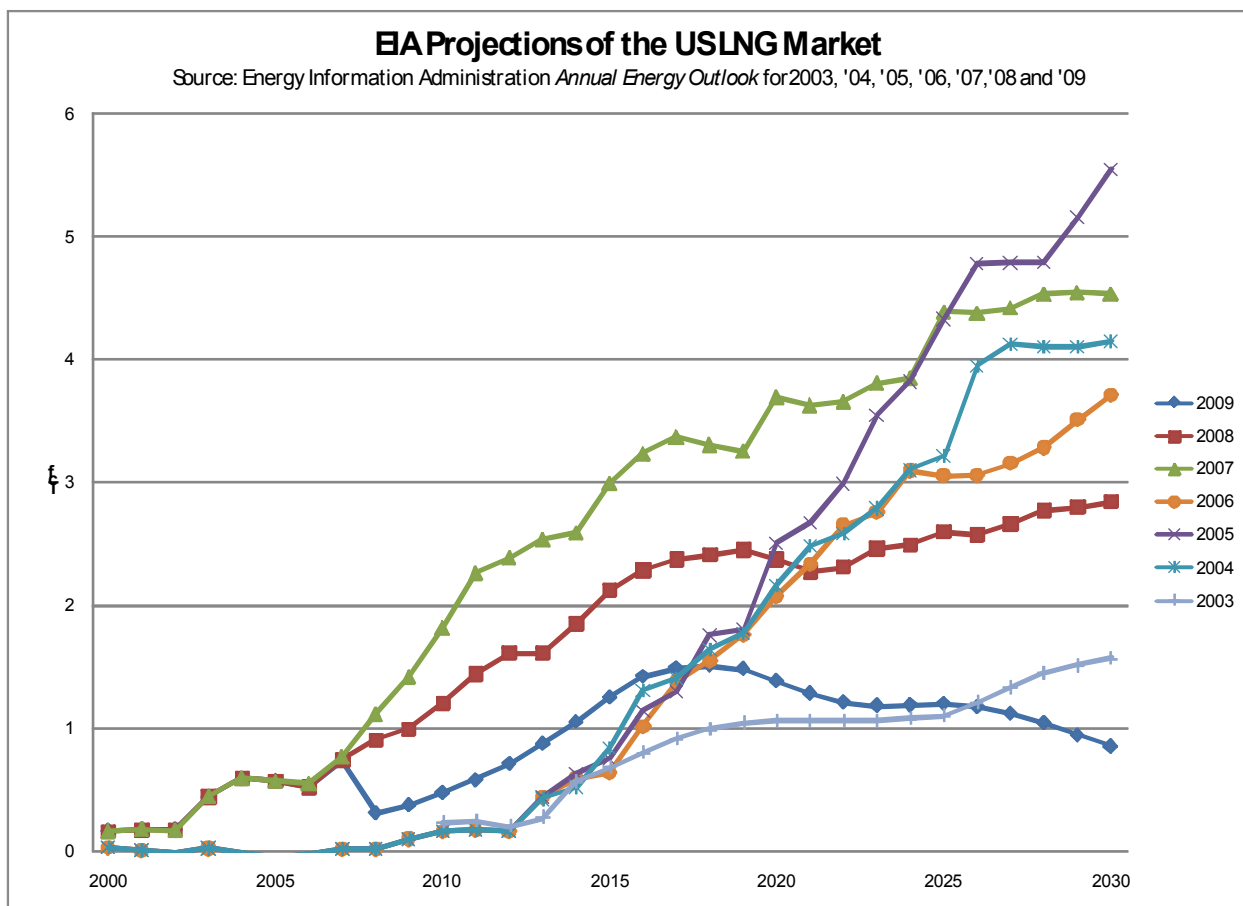
As illustrated in Figures 1 and 2, interest in bringing imported LNG to U.S. markets was rekindled in the early years of the current decade by the confluence of projected growth in the demand for natural gas and rising prices for North American-sourced supplies. Total imports in 2002 were 4.0 Tcf of which 3.8 Tcf were delivered by pipeline from Canada and 0.2 Tcf were imported LNG, primarily from Trinidad and Tobago (151 Bcf).

Figure 2



In 2002, the U.S. Energy Information Administration (“EIA”) forecast that “LNG imports are expected to increase, but they are not expected to become a major source of U.S. supply through 2020.”³ In the following year, however, and reflecting the optimism that accompanied this “second phase” of U.S. LNG imports, EIA forecast that U.S. natural gas consumption would increase from 22.5 Tcf in 2002 to 26.1 Tcf in 2010 and 31.4 Tcf by 2030.⁴ (See Figure 3 for a comparison of this forecast with forecasts issued in 2004 through 2009.)

Figure 3



Underpinning this forecast was the assumption that domestic gas production was not expected to keep pace with increasing demand. At the time of that forecast (2002), the shortfall of 3.5 Tcf was met primarily by pipeline supplies from Canada. Canadian imports were expected to decline from 2010 onward with the maturation of Canadian fields and the growth of Canada’s own internal demand for natural gas. Accordingly, EIA forecast that by 2015, LNG would

become the USA's largest source of imported gas, rising from 5 percent of imports in 2002 to 39 percent in 2010.⁵

In 2004, EIA expressed considerable optimism about the future for importing LNG to the U.S. market. In an update to its January 2003 report, *U.S. LNG Markets and Uses*, it noted that

LNG has become an increasingly important part of the U.S. energy market. ... All U.S. LNG import terminals were operational in 2003 for the first time since 1981, resulting in record high LNG receipts, more than double the previous high in 1979. Proposals for more than 20 new import facilities are currently before regulatory authorities and many more are being planned.

Indeed, by June 2004 there were 27 new regasification terminals in various stages of investor and governmental approval for a combined capacity of 31 Bcf/day⁶ – which was far in excess of the expected demand.⁷ (Presently there are 40 LNG terminals in North America that are either before FERC or being discussed by the LNG industry. Of these, 7 import terminals are in operation on the U.S. East Coast, the Gulf Coast and in Puerto Rico. An additional export is in Alaska.⁸)

Within a few years, however, economic conditions were causing this optimism to be revisited. In 2007, EIA had revised its forecast of domestic consumption to a target of 26.1 Tcf by 2030. This was a considerable reduction from the 31.4 Tcf that had been forecast for 2025 only four years earlier. LNG was, however, still seen as a promising growth opportunity. EIA's 2007 forecast saw LNG imports growing from .6 Tcf in 2005 to 4.5 Tcf in 2030. Other industry forecasts were at least similarly optimistic.⁹

By the end of 2008, that optimism had turned to pessimism and EIA commented that

Strong global demand, supply constraints, and lower relative U.S. natural gas prices have all contributed to the decline in U.S. imports of LNG, which are expected to fall from 770 Bcf in 2007 to 350 Bcf in 2008, a reduction of 55 percent. LNG imports are expected to total about 410 Bcf in 2009.¹⁰

In its *Annual Energy Outlook 2009*, EIA projected that the gap between domestic supply and consumption would be 3% (.8 Tcf) by 2030. This compares with a 14% gap (3.2 Tcf) that had been forecast in its *Annual Energy Outlook 2008* and which expressed a logical rationale for the long-term expansion of a U.S. LNG market.¹¹

2007 proved to be the peak year for LNG imports to the USA with deliveries of 771 Bcf accounting for 16.7% of natural gas imports and 3.3% of U.S. natural gas consumption. Table 1 compares the change in imports from 2007 to 2008 and shows that the volume of imports in 2008 was only 352 Bcf, 54 per cent less than in the previous year. Notably, the resulting level of imports is less than half of the 1.11 Tcf that EIA had forecast for 2008 as recently as 2007.

Table 1

Change in Imports by Source – 2007 to 2008¹²

<u>Source</u>	<u>2007</u> <u>(Bcf)</u>	<u>2008</u> <u>(Bcf)</u>	<u>Change</u> <u>from 2007</u>
Algeria	77.3	0	-100%
Egypt	114.6	54.8	-52%
Nigeria	95.0	12.0	-87%
Qatar	18.4	3.1	-83%
Trinidad & Tobago	447.8	264.2	-41%
Other	17.8	17.5	-2%
Total Imports	770.8	351.7	-54%

Prospects for the Future

The precipitous decline in imports from 2007 to 2008 reflects the adverse effects of four inter-related situations:

- a. Declining domestic demand for natural gas as a result of the current economic recession;
- b. Non-competitive pricing for domestic natural gas vis-à-vis Asian and European gas markets;
- c. The near-term shortage of liquefaction capacity; and
- d. The rapid increase in domestic production largely related to un-conventional gas production as an alternative to imported LNG.

Declining Domestic Demand for Natural Gas

The U.S. has been in an economic recession since December 2007 and among its effects has been a decline in the demand for natural gas. At the beginning of 2008, EIA projected that domestic consumption would rise year-over-year by over 3%. However, consumption actually increased by just 0.8%.¹³ In its *Short-Term Energy Outlook* of 14 April 2009, EIA projects that domestic consumption will decline by 1.8% in 2009 and remain at approximately that level through 2010.¹⁴ The main contributor to this decline is the industrial sector, where the

consumption of natural gas is expected to fall by 7.4% during the current year. These projections sharply revise downward EIA's December 2008 projection of a 2.4% decline in the industrial sector's consumption of natural gas for 2009.

We cannot speculate about when the current recession will end or the impact that its recovery will have upon the development of U.S. LNG markets. It is likely, however, that these adverse economic conditions have sharply lessened the need – whether real or perceived – for even the most prudent of utilities to be concerned at present with acquiring supplemental low cost supplies for the near- to intermediate term.

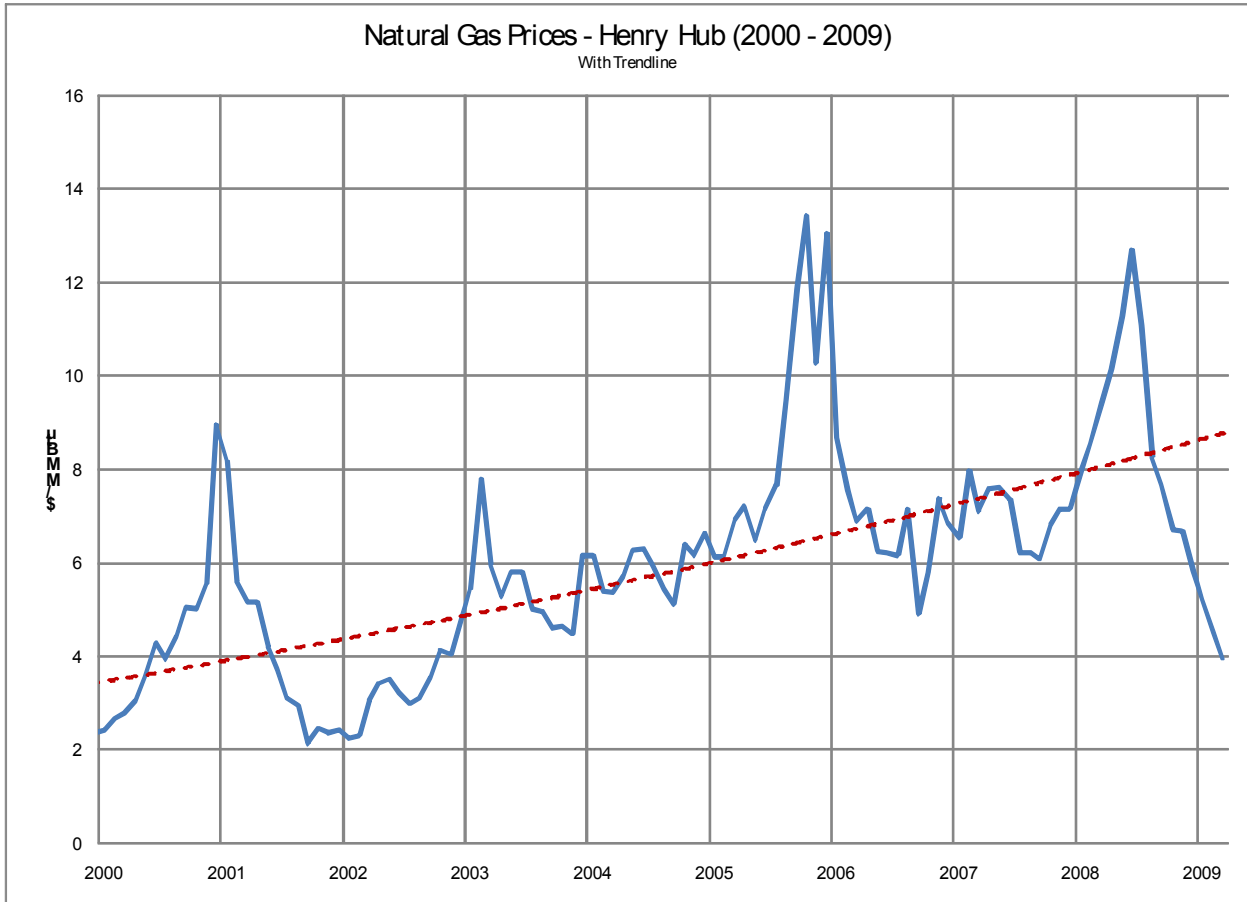
Non-competitive Pricing

Most of the world's LNG is still sold under long-term contract, however, an increasing share of that business is transacted on the spot market or under contracts for less than 12-months' duration. Under these shorter-term arrangements, U.S. buyers must compete with other importers from countries, particularly in Asia and Europe, where natural gas prices are typically linked, formulaically, to the price of oil. U.S. natural gas prices, although somewhat correlated to the price of oil, are linked to prices at Henry Hub on the Louisiana Gulf Coast, the delivery point for natural gas futures contracts on the New York Mercantile Exchange (NYMEX).

As shown in Figure 4, "Henry Hub" prices have been trending upwards for most of the current decade. This upward momentum suggested that the U.S. natural gas market would be able to compete successfully for LNG supplies as new liquefaction projects came on line around the world. As shown in Figure 5, U.S. prices were, indeed, higher than Japanese prices until 2002, and higher than European prices until 2005.

From 2005 until 2008 the price of crude oil – to which Asian and European natural gas prices are linked – increased dramatically. (On 11 July 2008, NYMEX prompt month crude futures hit an historic intraday high of \$147.27/bbl.¹⁵) As crude prices rose, the historic linkage between U.S. oil and natural gas prices became disconnected. (See Figure 6.) During the period 2000-2005, the ratio between a barrel of crude oil and an MMBtu of natural gas was 7.1. From 2006 through 2008, however, that ratio increased to 10.5 and in 2008, the ratio was 11.1. This disconnect meant that the formulaic prices of Asia and Europe were higher than U.S. prices and, as such, the U.S. natural gas market was at a competitive price disadvantage in bidding for international LNG. The pricing environment was further stressed when, in January 2008, a combination of cold weather and an extended nuclear generation outage in Japan increased that country's demand for replacement gas generation. Under those condition, the LNG spot market price approached \$20/mmbtu.¹⁶

Figure 4¹⁷



The collapse of crude prices since the last months of 2008 brought the oil-to-gas relationship toward a more normal level, which, if sustained, would favor a more competitive domestic LNG market in 2009. However, while the ratio for the 4-month period from November 2008 to February 2009 was down to 8.1; the ratio for March 2009 was a decidedly uncompetitive 12.2.

Furthermore, as shown in Figure 7, natural gas futures as of 24 April 2009 suggest that the Henry Hub price will remain significantly below the NBP price at least into the first months of 2010.

Figure 5

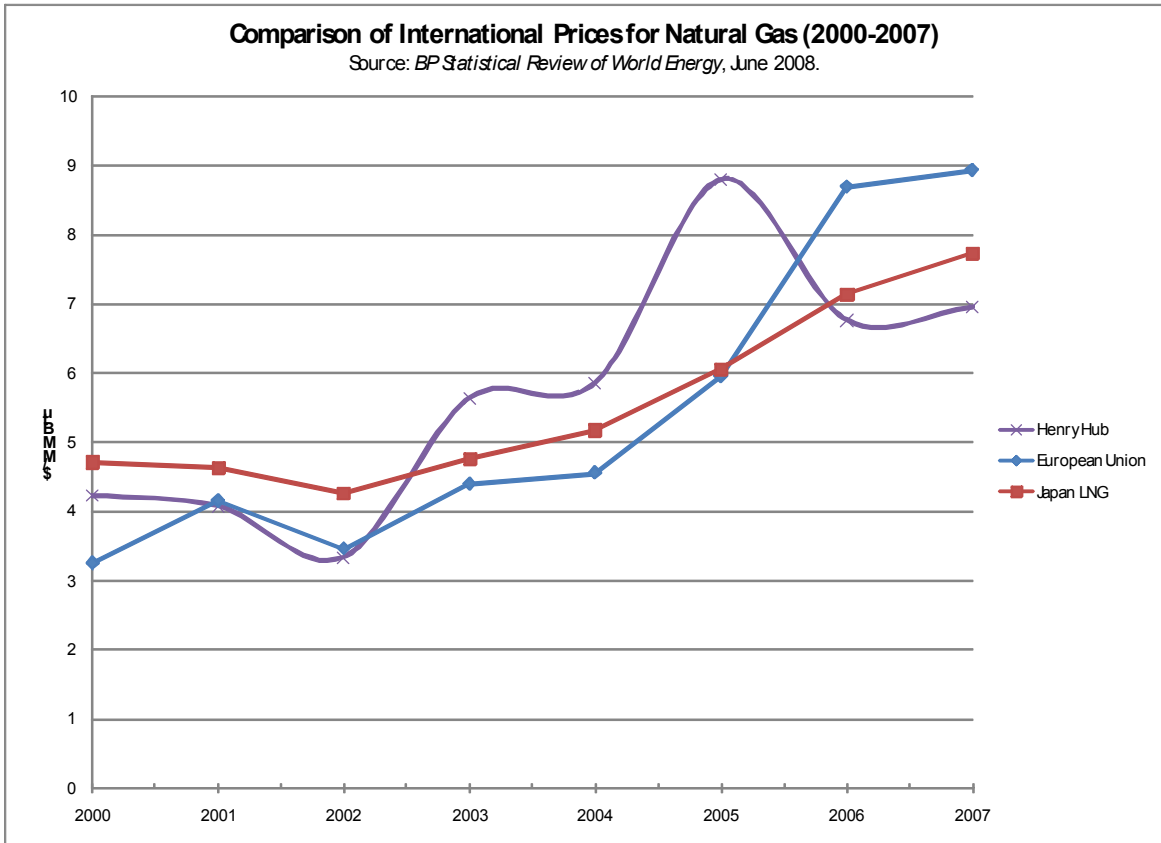


Figure 6¹⁸

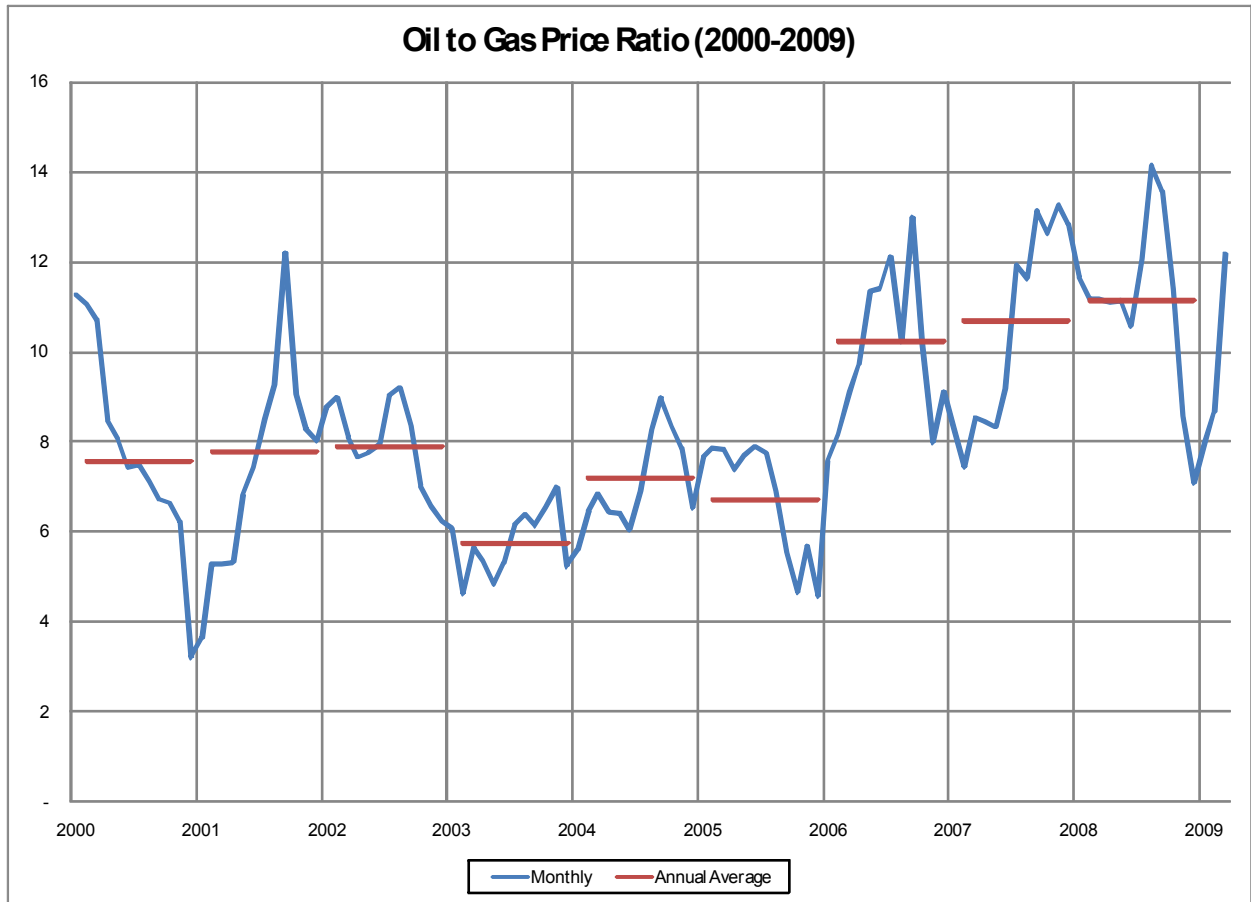
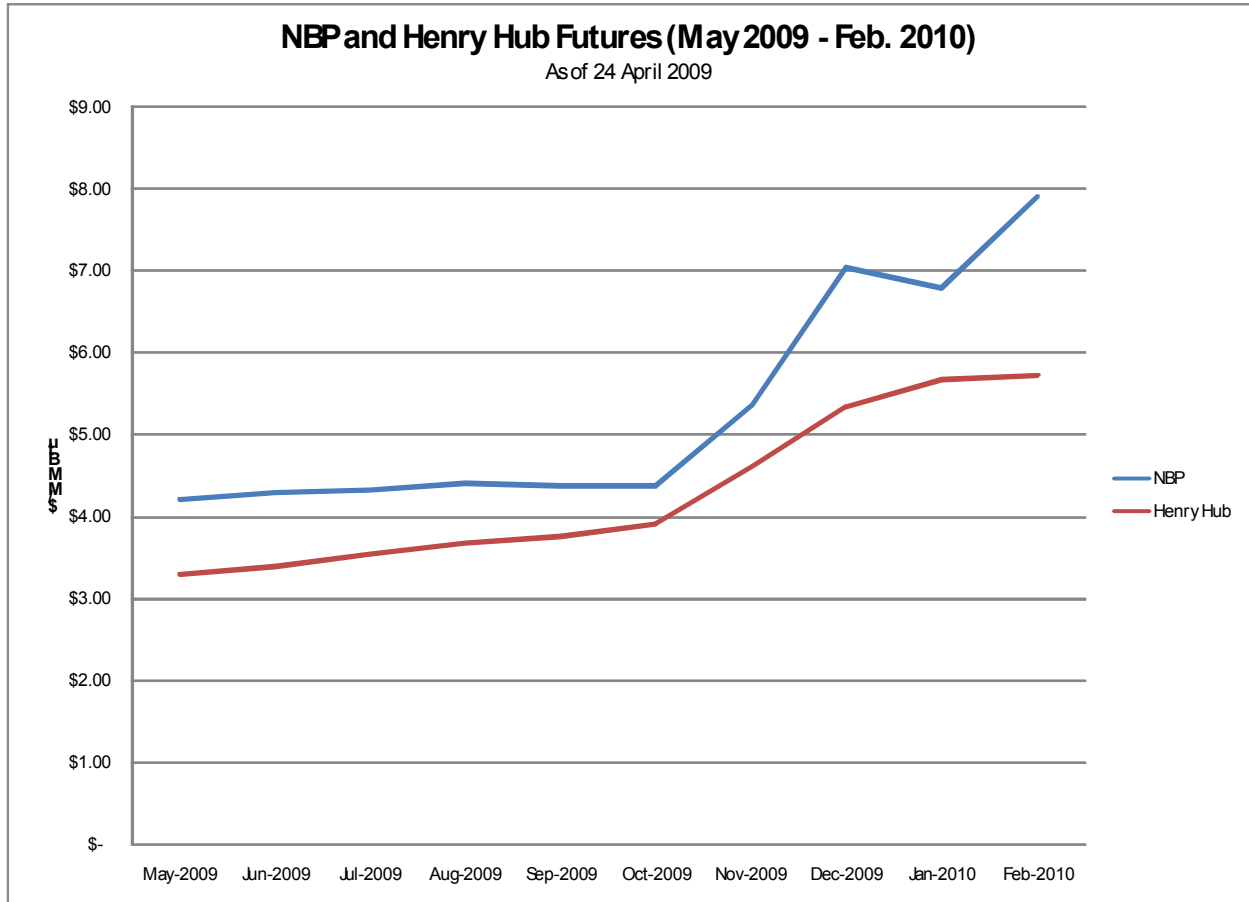


Figure 7¹⁹



Shortage of Liquefaction Capacity

Global liquefaction capacity has been slow to come online – with only a 1.9% increase during the first half of 2008 compared to the same period in 2007. This slow growth is due both to delayed completion of in progress projects, and the cancellation of new projects.

There were significant project completion delays in 2008, including include Tangguh, Sakhalin 2, Yemen LNG, Qatargas 2's train 2 and RasGas 3's train 1²⁰. Project delays are being caused by vendor manufacturing capacity being stretched too thin resulting in longer delivery times. Also, governmental and lender requirements have become more onerous which has extended the time for permitting and financing closure. Detail engineering with less experienced personnel is also extending project timelines. Qatar actually shutdown some of its gas-to-liquids

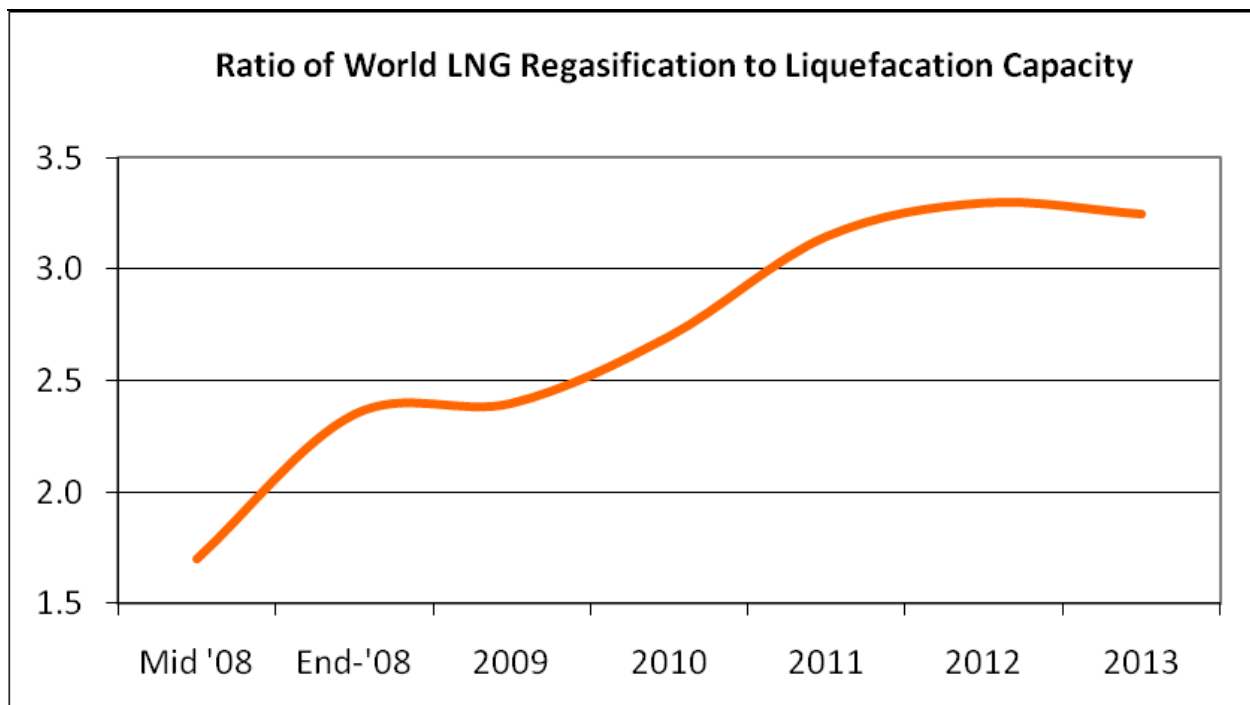
projects due to the limited manufacturing and engineering worldwide capacity being stretched too thin.

As for new projects, there are a few reasons for the slower entry of new LNG liquefaction projects. The first is the cost of the capacity which has increased from previous levels of \$200/metric ton to over \$600/metric ton in most cases. This is reflected in higher engineering, manufacturing and construction costs than before. Secondly, oil companies have been cautious making investments based on gas prices which they were concerned would not be sustainable.

Finally, Some projects that were being developed, but have stalled or been delayed due to government intervention such as Russia-Sakhalin (delayed), Iran-South Pars (cancelled), Algeria- Arzew and Skikda (delayed) or Bolivia – Pacific (cancelled).

As illustrated in Figure 8, regasification capacity, which is less expensive and less time consuming to construct than liquefaction capacity, has substantially outstripped the availability of new supply.

Figure 8²¹

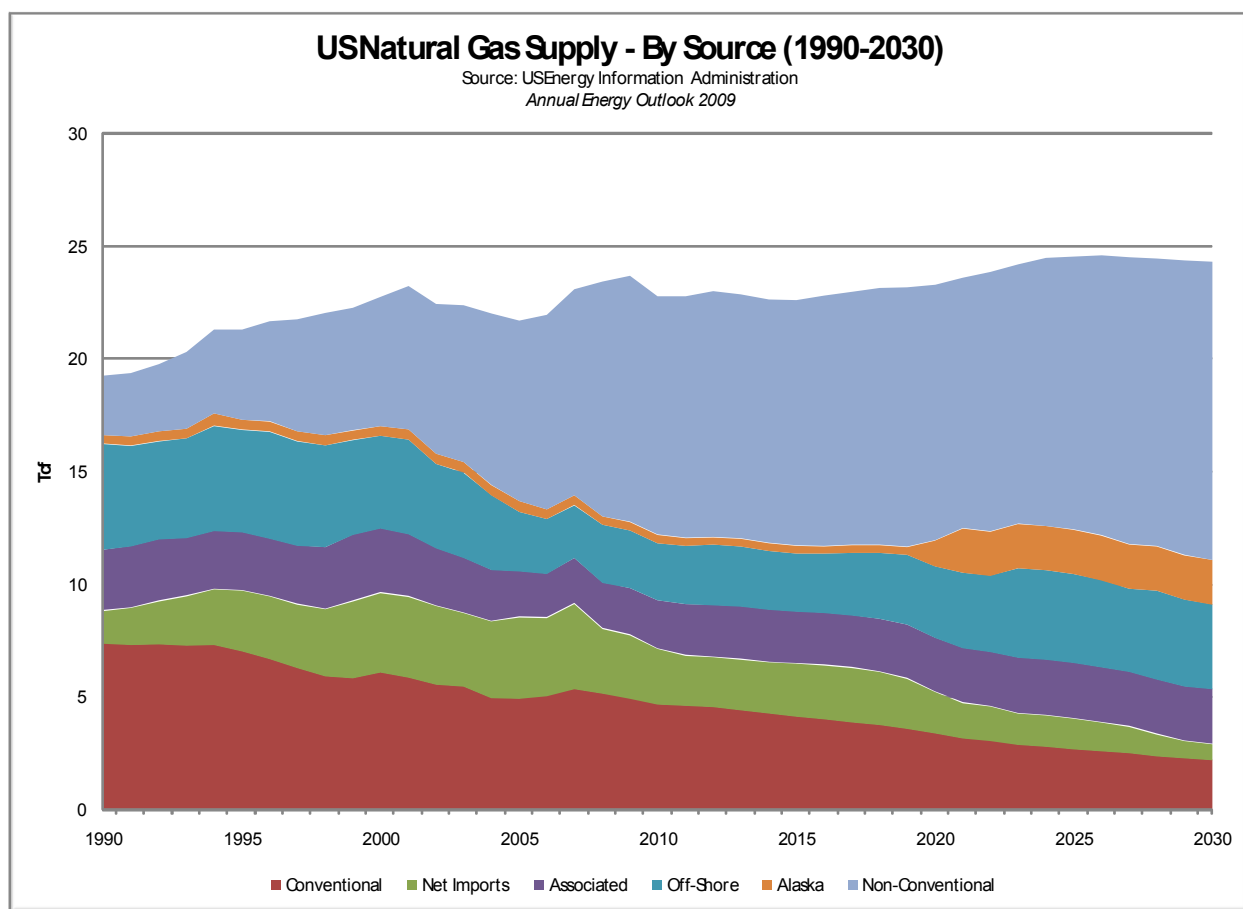


Competitive Alternatives to Imported LNG

While the gap between U.S. and international gas prices was exacerbated by the historic disconnect between oil and gas prices that was just one side of the equation. On the gas side of the equation, a spike in unconventional gas production increased U.S. domestic production to a twenty year high of just over 20 TCF²².

As shown in Figure 9, the greatest contribution to U.S. natural gas supply over the long term is expected to come from non-conventional production. Natural gas in tight sand formations sources is expected to account for 30% of total production in 2030. Production from shale formations is, however, the fastest growing source of supply and is expected to increase from 1.2 Tcf in 2007 to 4.2 Tcf (18% of total production) in 2030.²³

Figure 9



The combination of sustained higher gas prices and break-throughs in production technology has opened up vast new U.S. natural gas reserves that are economically feasible to exploit.

Unconventional gas production comprised about 50% of U.S. domestic production in 2008, and is expected to grow rapidly. Estimates of future unconventional gas production are invariably bullish; but vary widely. Consensus estimates from leading forecasters expect shale production to grow at 10% a year through 2015, with all sources of unconventional gas accounting for about 65% of total U.S. production²⁴. Most of this new supply was not anticipated when the flood of U.S. regasification terminal projects were planned in the mid 2000's, and is sure to displace once planned LNG imports. Some forecasters have suggested that the unconventional base is substantial enough to nearly eliminate the necessity to bring LNG to U.S. shores through 2030²⁵.

While the full cycle costs of importing LNG are less than U.S. domestic unconventional gas production -- U.S. LNG import full cycle costs estimated to range \$3.50-\$4.50/mmbtu^{26, 27} and U.S. shale production costs range, depending on basin, from \$4.25 - \$7.50/mmbtu²⁸ -- the substantial imbalance of global regasification to liquefaction capacity and international pricing dynamics addressed above, left the U.S. the market of last resort for spot LNG cargoes in 2008.

Conclusion: The Investor's Perspective

It may be argued that the downturn of LNG imports in 2008 is cyclical and will, therefore, be of relatively short duration. Notwithstanding the uncertainties of economic recovery that will adversely affect the development of an LNG market, the factors that emerged in 2008 to cause this bearish year for the U.S. LNG industry -- price, supply, and demand -- are fundamental and seem, therefore, to be of more pervasive concern to potential investors.

The import experience of 2008 -- and uncertain prospects for substantial near term improvement -- left a wake of U.S. LNG regasification causalities both large and small. This situation has collapsed the business model pursued by some players, like Cheniere²⁹, that depended on the availability of spot cargoes both from a tolling and marketing fee standpoint. In contrast, more successful business models took the approach of matching long term supply to regas capacity, such as Sempra/Shell's 1 Bcf/d Energia Costa Azul Terminal which has most of its supply committed from Sakhalin and Indonesia's Tangguh³⁰.

Price, supply, and demand conflated in 2008 to cause a dramatic deflation of LNG importation expectations and suggest a highly bearish environment for investment in U.S. LNG import projects over the near- to intermediate-term. The prospects for developing a large-scale U.S. LNG market have diminished over the past year due *inter alia* to a radical re-estimate of domestic demand vis-à-vis domestic supply. It must be noted, however, that the often-cited critical element in these most recent reconsiderations is the price of natural gas, which has varied widely over history and always taken on distinctly different characteristics depending

upon the geographical area in which the underlying energy competes. Price has, therefore, always been a risk to be managed by skillful competitors and to be considered by prudent investors.

We return to the question of whether the experience of 2008 was part of a developmental business cycle or was it indicative of structural change in the price, supply and demand relationships for LNG that will exert an adverse effect upon future investment in the sector. Arguably, U.S. utilities and gas marketers will always seek new sources of supply and be courted by those with supplies to sell, but having seen two disappointing cycles of interest in the concept of importing LNG, it may be prudent for investors (who are far from obliged to risk capital on energy ventures) to question whether the future role of LNG in the U.S. supply mix is compatible with a constructive investment strategy.

If the latest forecasts of a narrow gap between domestic supply and domestic consumption are correct, it seems likely that LNG's role in meeting that shortfall will be only that of a supporting player in a highly price-competitive spot market. By linking LNG deliveries to a highly-competitive, global market for natural gas will require great and uncharacteristic patience from investors in the construction of expensive LNG delivery infrastructures that aren't used under base load conditions.

We doubt that such a minor role will be sufficient to attract and to sustain the magnitude of investment that the development of a U.S. LNG market infrastructure would require.

R.E.B./D.A.F.
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¹ The authors addressed this question in the article, "U.S. LNG Imports in 2008 Signal Unexpected Role for Gas Markets," in *Oil and Gas Journal*, 9 March 2009 that reflected research conducted during the 4th quarter of 2008. This paper updates that article with additional research and final statistics for 2008.

² See, for example, the Natural Gas Policy Act of 1979 and FERC Orders No. 436 (1985), 500 (1987) and 636 (1992).

³ EIA, *Annual Energy Outlook 2002*, p. 82.

⁴ EIA, *Annual Energy Outlook 2003*.

⁵ EIA, *The Global Liquefied Natural Gas Market: Status & Outlook*. December 2003, p. 29.

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- ⁶ EIA, "U.S. LNG Markets and Uses: June 2004 Update", pp. 7-8
- ⁷ In 2004, EIA's *Annual Energy Outlook* forecast that LNG imports would grow from .2 Tcf in 2002 (an average daily volume of .5 Bcf) to 2.2 Tcf (6.0 Bcf/d) in 2010 and 4.8 Tcf (13.2 Bcf/d) in 2025.
- ⁸ Existing LNG Terminals page, FERC website (9 Feb. 2009) <http://www.ferc.gov/industries/lng.asp>
- ⁹ EIA, *Annual Energy Outlook: 2007*, p. 112.
- ¹⁰ EIA, "Short-Term Energy Outlook". 12 November 2008, p. 4.
- ¹¹ EIA, *Annual Energy Outlook 2009*, p. 78.
- ¹² Calculations by the authors based upon EIA data in their *Annual Energy Review 2007*, and *Monthly Energy Review (March 2009)*.
- ¹³ EIA, Natural Gas Consumption by End Use, 2 April 2009.
http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_dcunus_a.htm
- ¹⁴ EIA, Short-Term Energy Outlook, 14 April 2009.
- ¹⁵ <http://www.reuters.com/article/topNews/idU.S.T14048520080711>
- ¹⁶ <http://www.platts.com/Natural%20Gas/Resources/News%20Features/globalng08/index.xml>
- ¹⁷ <http://research.stlouisfed.org/fred2/data/GASPRICE.txt>
- ¹⁸ Calculations by the authors based upon EIA data at
<http://tonto.eia.doe.gov/dnav/pet/hist/rwtcd.htm>
- ¹⁹ NYMEX / ICE as of 24 April 2009.
- ²⁰ FACTS Global Energy, 10/8/2008
- ²¹
<http://www.platts.com/Natural%20Gas/Resources/News%20Features/globalng08/index.xml?S=printer&>
- ²² http://tonto.eia.doe.gov/dnav/ng/hist_xls/N9010U.S.2m.xls
- ²³ EIA, *Annual Energy Outlook 2009*, p. 77.
- ²⁴ Wood Mackenzie's Long-Term View, August 2008
- ²⁵ Gas Daily, "Economists: Shale gas boom will cut need for LNG imports", December 8, 2008. Reporting on Rice World Gas Trade Model, presented by Hartley and Medlock at the U.S. Association of Energy Economists conference in New Orleans, November 2008.
- ²⁶
http://www.riceinfo.rice.edu/energy/publications/docs/GSP_WorldGasTradeModel_Part1_05_26_04.pdf
- ²⁷ Tristone Capital Presentation, Natural Gas and LNG Outlook, March 2008
- ²⁸ Michael Godec, Tyler Van Leeuwen, and Vello A. Kuuskräa, Rising drilling, stimulation costs pressure economics, *Oil & Gas Journal*, 15 Oct. 2007, p.45-51
- ²⁹ While Cheniere has long term fixed take or pay terminal use agreements with Chevron and Total, the value of these agreements was spun off into a limited partnership – Cheniere Energy Partners LP.
- ³⁰ <http://www.sempralng.com/Pages/Terminals/Energia/default.htm>.