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Infrastructure Investments and Resource Adequacy in the Restructured US Natural Gas Market – Is Supply Security at Risk?

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Abstract

The objective of this paper is to analyze the development of US natural gas infrastructure over the last two decades and to discuss its perspectives. In particular, we focus on the relationship between the regulatory framework for the natural gas sector and the development of investment in LNG terminals, interstate pipelines, and storage facilities. We also discuss some cross-sectional investment issues related to financing (cost of capital, financial markets) and regulation (price caps, siting). We conclude that while some improvements in the regulatory framework might enhance investments in the US natural gas sector, there is no reason to be overly concerned about infrastructure investments, resource adequacy, or supply security.

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Infrastructure Investments and Resource Adequacy in the Restructured US Natural Gas Market – Is Supply Security at Risk?

"*There is no inherent conflict between the liberalization of electricity and gas sectors that meet reasonable supply security goals as long as the appropriate market, industry structure, market design, and regulatory institutions are developed and implemented*."

Paul Joskow, Beesley Lecture, London, October 25, 2005, p. 2

1 Introduction

The issue of security of supply is back on the policy agenda in ways not seen since the 1970/80s. Since the first period of natural monopoly restructuring in the 1980s, policy-makers and economists have been seeking optimal incentives for infrastructure investment in the context of restructured markets (Helm and Thompson, 1991). In the last several years, however, this question has again risen high on the policy and research agenda due to the series of electricity blackouts in the summer of 2003, the intensified debates on cost-based vs. incentive-based regulation, and renewed supply security concerns.

The supply security discussion often focuses on electricity generation and transmission (Joskow, 2006), but there is also an emerging discussion on natural gas supply security on both sides of the Atlantic (see Joskow, 2005a, for the US, and Helm, 2005, for the UK and Europe). This debate is driven by the globalization of natural gas markets and the increasing role of natural gas in the carbon-constrained energy world of the future. In fact, two different aspects of supply security need to be distinguished: i) the physical supply of energy resources to a country or a region, which may be threatened by supply disruption, cartelization of upstream producers, and so on. Although this is an important issue, we will not deal with it here and refer to Linde and Stern (2004) and Stern (2006) for recent discussions of geopolitical issues in natural gas, and to Adelman, et al. (1986) for a similar analysis from two decades ago; ii) supply security with respect to adequacy of investments in (natural gas) infrastructure, such as terminals receiving liquefied natural gas (LNG), transmission pipelines and storage facilities. One can also distinguish between short-term operating reliability and <u>longer-term resource adequacy</u> of infrastructure (Joskow, 2005a). In the following, we focus on this latter issue.

There is an ongoing policy debate about the relationship between industry restructuring (referred to as "liberalization" in Europe) and investment incentives. Industry representatives generally claim that industry restructuring in an unstable institutional environment places infrastructure investments that ensure supply security at risk. Market proponents, on the other hand, argue that a laissez-faire approach is the best way of stimulating efficient investment. Economic theories of investment in infrastructure do not provide clear indications of the conditions under which "efficient" levels of investments can be achieved and what factors lead to over- and underinvestment. Institutional and transaction cost oriented approaches insist on the need for appropriate institutional settings to assure long-term investment, e.g. Joskow (1987) for the coal industry. The real-options approach suggests that under uncertainty, delaying investments may be beneficial even though these projects may well cover their capital costs (Dixit and Pindyck, 1994). Among the regulatory approaches, the Averch-Johnson (1960) approach of *over*investment in a rate-of-return regulated natural monopoly contrasts with theories of *under*investment due to the discretionary power of the regulators (Baumol and Klevorick, 1970) or because the effect of sunk costs is not adequately taken into account in the rate setting (Hausman and Myers, 2002). Helm and Thompson (1991) have suggested that the social costs of underinvestment are higher than the social benefits of overinvestment. The literature also deals with externalities, issues of ownership and corporate governance, and investments in service quality. Hirschhausen, et al. (2004) provide an overview of the literature.

Some of the theoretical work has been helpful in identifying the effects of regulation on investment, and also in pointing out the need to take sector and technology-specific aspects into account. However, the models fail to provide unambiguous results, and a case-specific assessment is still needed to derive concrete policy conclusions.[3] This is particularly true for the US natural gas market, on which little research has been carried out in the last years.

The objective of this paper is to analyze the development of US natural gas infrastructure over the last two decades, and to discuss its perspectives, and to draw policy lessons. In particular, we focus on the relationship between the regulatory framework in the natural gas sector (vertical separation, open access, etc.) and the investment behavior of companies. Our working hypothesis is that a restructured and vertically unbundled natural gas market <u>can</u> provide the right investment signals to the market if it is accompanied by the appropriate regulatory framework.

The paper is structured as follows: the next section briefly surveys the US natural gas market, its regulation and recent price trends. Stagnating or even declining domestic production and increasing consumption have led to a dramatic rise in imports, and this tendency is likely to continue in the future. Section 3 looks at the development and perspectives of LNG-receiving terminals: here, although the “boom” forecasted several years ago has not materialized, terminal expansions and newbuilds are proceeding steadily, supported by a favorable regulatory framework. We then turn to the relationship between regulation and investment in interstate pipeline transmission, an industry characterized by a peculiar regulatory setting but a strong investment record (Section 4). Section 5 looks at regulation and investment in natural gas storage. This sector is currently undergoing a structural change from being a “cost-plus” industry to being more market and finance-driven, and although investment requirements are substantial, we find no reason for concern about the resource adequacy. Section 6 discusses some cross-sectional investment issues related to financing (cost of capital, financial markets) and regulation (price caps, siting). We conclude that while some improvements in the regulatory framework might enhance investments in the US natural gas sector,

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[3] Take the controversial debate on the UK experience of energy market restructuring: whereas Helm (2005) suggests that the recipe for privatizing and regulating utilities since the early 1980s in the UK and other Anglo-Saxon countries favored a short-term perspective and may have put insufficient emphasis on longer-term aspects such as investment and quality, Pollitt

there is no reason to be overly concerned about infrastructure investments, resource adequacy, or supply security.

2 The US Natural Gas Market

The US is the second-largest gas producer in the world (526 bcm in 2005), and the largest gas consumer (634 bcm). In 2005, gas accounted for 23% of total primary energy supply; about 84% of domestic consumption was covered by indigenous supply. Although only 3% of world total natural gas reserves are located in the United States, the country produced about 20% of world natural gas in 2005 (BP, 2006). Indigenous production is concentrated mainly in the lower forty-eight states, with Texas and Louisiana producing 34% of total dry gas output. There are 8,000 major natural gas wells representing 86% of total production with the rest coming from associated oil production. Currently, the largest undeveloped reserves are in Alaska, expected to come on-stream by the end of the next decade. At present, the reserves over production ratio is about 10 years. Imports are increasingly important. Imports from Canada contributed to 13% of consumption (102 bcm in 2005), and imports of liquefied natural gas (LNG) tripled between 2002 (6.5 bcm) and 2005 (18.5 bcm, or 3%). By 2020, it is expected that LNG will increase further to about 20% of total consumption (of a total of 760 bcm).

About 27% of natural gas is used to generate electricity (utilities and IPPs), 22% in industry, 13% in transportation, and 23% and 15% by the residential and the commercial sectors respectively. Some power plants are equipped with dual-fuel equipment and are therefore able to switch back and forth from gas to other fuels relatively easily. Some of them have interruptible contracts and can be switched off in particular peak hours.

Regulation has a long tradition in the US natural gas sector: it began in the 1930s with an attempt to curb the abuse of market power in the interstate pipeline business (see IEA, 1998, and Makholm, 2006, for details). Today, the Federal Energy Regulatory Commission (FERC)[4] regulates interstate affairs, whereas intrastate business is regulated at the state level. Significant restructuring of the industry started with the removal of wellhead ceiling prices in 1978 (Natural Gas Policy Act). In 1984, Order 380 released local distribution companies (LDCs) from long-term take-or-pay contracts. Vertical unbundling was the objective of Order 436 (1985), which also suggested that interstate pipelines offer open access to their transportation infrastructure.

The “final restructuring rule” (FERC Order 636, 1992) was a milestone in moving from “simple” non-discriminatory third-party access (TPA) towards a fundamental vertical unbundling of transportation and sales activities. It created competition among gas sellers and reduced the market power of the incumbents. Pipelines were obliged to publish “electronic bulletin boards” (EBB) to provide shippers with information about the availability of services. The rule also required pipeline companies to

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(2002, 71) finds no evidence that privatization and restructuring have hurt investment, an assessment shared by Joskow (2005, 47).

expand access to interstate storage capacity. FERC Order 637 (February 2000) introduced more flexibility for shippers in accessing pipelines, while FERC maintained its regulation of pipeline tariffs. The Energy Policy Act of 2005, considering the increased demand for natural gas, has made provisions to ease investment in infrastructure, e.g. in LNG receiving terminals.

There is a general consensus that the past three decades have transformed the largest natural gas industry of the world into the most competitive one as well (IEA, 2002). Restructuring has had a substantial impact on the industry. Production and marketing have been completely deregulated. The interstate pipelines are formally subject to cost-of-service regulation by FERC, whereas in practice most of the contracts are negotiated in a fairly competitive environment. Intrastate pipelines and the 1,400 local gas distribution companies (LDCs) distributors are regulated by state utility commissions. Storage is largely provided by regulated entities (often in combination with pipelines), but some unregulated merchant investments also exist, and increasingly do. Natural gas consumers can choose to buy directly from producers, or use marketers as intermediaries. Many industrial customers and power plants obtain their gas directly from interstate and intrastate pipelines, and only use distribution companies for transport services.

Gas prices were low for most of the 1990s, and during this time people became accustomed to $2-3/MBTU wellhead prices. However, prices have climbed since the beginning of the current decade, in particular during the last few winters. The reasons include weak domestic natural gas production (despite increased drilling), colder-than-normal temperatures for a number of consecutive weeks during each heating season, and record-high crude oil prices. Currently, prices are in the range of $4-6/MBTU and futures prices confirm that “cheap gas” may be a thing of the past.

3 LNG Receiving Terminals

3.1 Market structure

Liquefied natural gas (LNG) has gone from being an expensive, “exotic” fuel traded only at the regional level to being a globally traded energy source. LNG is playing a more central role in the energy supply of all major coastal countries, including the US, South Korea, India, China, and Europe as well. This section focuses on the US LNG-receiving infrastructure[5]; a survey of the increasingly global LNG market and a discussion of LNG supply issues can be found in Jensen (2004).

Although in the past LNG was used mainly for peak-shaving purposes, the rising need for natural gas in electricity generation potentially makes it a less seasonal commodity. LNG imports have risen steadily, although capacity utilization is still modest at less than 60%. There is a general consensus that LNG imports will increase as domestic production stagnates and imports from other sources (e.g., Canadian pipeline gas) decline. The EIA (2006) Annual Energy Outlook suggests an increasingly important role for LNG: the “high LNG” scenario sees LNG imports at 280 bcm in 2030 (EIA, 2006,

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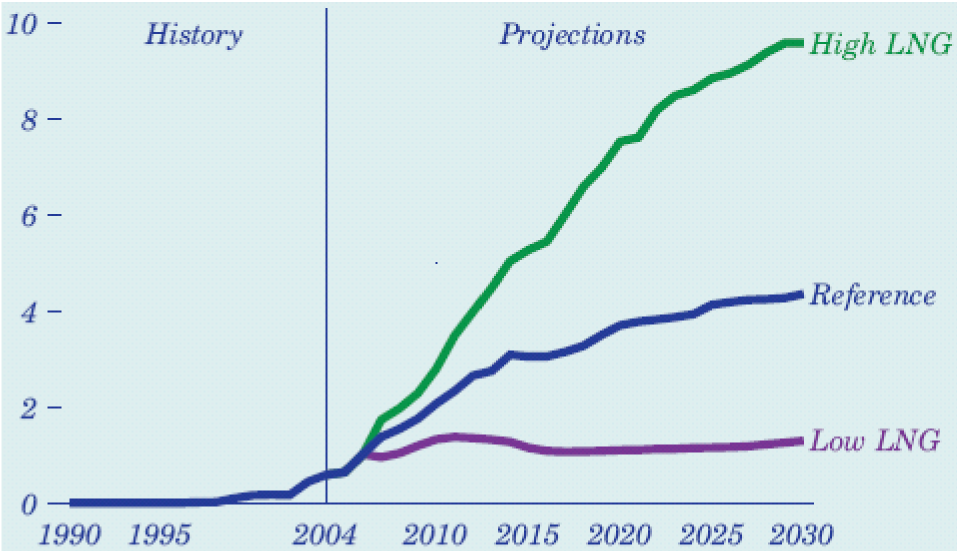
[4] FERC employs a staff of about 1,200 of whom 425 concentrate on oil and natural gas.
[5] There is also one liquefaction plant in Kenai, Alaska, delivering to Japan, which we do not deal with in this paper.

90), whereas the reference scenario predicts net imports of 110 bcm. Even the "low LNG" scenario (about 53 bcm) corresponds to almost a threefold increase with respect to 2004 imports. However, it is important to note that LNG imports are vulnerable to high energy prices. Thus, Ellerman (2003, 14) suggests that interfuel substitution, primarily switching from natural gas to coal, will determine the demand for natural gas and, thus, the role of LNG. He goes on to say that another "price threat to LNG is the world oil price level and the extent to which North American demand will/can shift to oil generation" (Ellerman, 2003, 14).

Figure 1: Net imports of liquefied natural gas in three supply scenarios, 1990-2030 (trillion cubic feet)



Source: EIA (2006, 90)

Traditionally, Algeria was the dominant supplier of LNG to the US, albeit at a low level. Since 1999, the mix of supply sources shifted to include facilities in Trinidad and Tobago, today accounting for over two-thirds of imported LNG; additional deliveries come from Nigeria, Qatar, Oman, and Malaysia. Negotiations with other suppliers are underway, some of which are greenfield operations.

In the wake of high oil prices in the 1970s, four LNG-receiving terminals were built in the US: Everett (MA, currently 7.3 bcm/a sendoff capacity), Cove Point (MD, 12.2 bcm/a), Elba Island (GA, 4.5 bcm/a), and Lake Charles (LA, 10 bcm/a). Cove Point and Elba Island were mothballed in the 1980s; Lake Charles was also closed down for a significant period. However all three terminals have recently been reopened, and all four, including Everett, are currently undergoing substantial expansion. The first newly built terminal in the "new world" of global LNG was finished in 2005, with total investments of about $700 million. Excelerate's "Gulf Gateway Energy Bridge" is located about 116 miles off the Louisiana coast; the natural gas reaches the Louisiana shore near the Henry Hub.

3.2 Regulation

For many years, LNG terminals were considered to be part of the transportation chain and thus subject to open-access service under Section 7c of the Natural Gas Act. Three of the four terminals built two and a half decades ago are subject to open access regulation; only the Everett (MA) terminal was exempt from that regulation and has always operated as a dedicated terminal. Given increased demand for LNG imports and a supposedly unfavorable framework for investment, FERC decided to make a policy shift in 2002. In its “Hackberry Decision”, FERC terminated open access requirements for LNG import terminals. LNG import facilities are now generally treated as “supply sources” rather than as part of the transportation chain and thus no longer fall under Section 7c but under Section 3 of the Natural Gas Act. FERC specifically stated that it hoped the new policy would encourage the construction of new LNG facilities by removing some of the economic and regulatory barriers to investment (EIA, 2005a).

Jensen (2004, 83) suggests that the Hackberry decision “has shifted the balance of power in terminal projects at the integrated majors and away from the merchants.” Waiving open access restrictions may in fact have favored investments by integrated groups with a large share of capacity covered by upstream and downstream contracts or even physical control rights. However, as argued below, the Hackberry decision has not eliminated all merchants from the business. Nor is it evident that waiving open access was really necessary to induce investment, or clear whether or not this investment would have taken place in any event.

3.3 Investment

Recent investments and outlook

A case-by-case analysis of investment projects indicates that there is no need to be overly concerned about investment incentives in US LNG terminals. The five existing LNG regasification terminals today have a total nominal capacity of 48 bcm/a; with imports at 18 bcm in 2004. In addition to the new terminal built in 2005, significant expansions are underway in the four “traditional” terminals:

- Suez’ Distrigas facility in Everett, MA, has been operating continually since 1971, supplying peak gas to the Boston area. Distrigas added a second unit to the Everett site, bringing its capacity to about 7.3 bcm/a. Plans have been announced to add another 3.6 bcm/a. The company relies on long-term contracted supplies from Trinidad, and in exceptional cases also from Algeria;
- Dominion’s Cove Point terminal, located on the Chesapeake Bay, MD (50 miles south of Washington, D.C.), was reopened for LNG imports in 2003, and provides peak-shaving facilities. Cove Point has two unloading berths and can receive two tankers at a time; both terminals are run as open access. Dominion finished its first terminal expansion in 2005 and is adding another terminal in 2008, tripling its storage capacity and doubling its annual daily peak sendout capacity from 0.028 bcm to 0.06 bcm.
- El Paso’s Southern LNG Terminal, located at Elba Island, GA, was reopened in 2001. The facility receives contracted gas as well as short-term loads. Southern LNG doubled its sendout capacity with the construction of a new terminal, from 6.1 bcm/a to 12.2 bcm/a. The recent

contracting of the terminal to the BG Group is expected to increase the utilization rates of the terminal, BG having plans to bring LNG in the coming years from Trinidad and Tobago.

- Last but not least, Southern Union's Lake Charles terminal on the Calcasieu River, reopened in the late 1980s, feeds its gas into the Henry Hub and its surrounding 16 pipelines. Most of the cargoes received are short-term or "spot". The facility not only withstood hurricanes Katrina and Rita, but also continued its two-step expansion from 0.17 bcm to 0.25 bcm storage capacity, and from 10 bcm/a to 21 bcm/a annual sendout capacity.

In addition to significant investments at existing sites, a large number of additional terminals are under construction and others are under consideration. Figure 2 shows all existing and proposed LNG terminals in North America, i.e. the US, Mexico, and Canada.[6] One peculiar pattern emerges: the advanced new-build projects are either located in the Gulf of Mexico (Louisiana, Texas, or offshore) or not on US territory, but feeding into the US pipeline system (Mexico, Bahamas, and Canada). The former projects rely on the fact that Texas and Louisiana are two major gas-producing states in the US, and that local governments are familiar with industrial projects, facilitating the approval process. The region is also attractive due to the proximity to the Henry Hub, a liquid market hub. FERC has recently granted permits to three facilities on the Gulf Coast.[7]

The latter projects (Mexico, Bahamas, Canada) are clearly driven by the NIMBY ("not in my backyard") attitude that still prevails in California and the Northeast. It is difficult to assess the probability of success for individual US projects outside the Gulf of Mexico (Jensen, 2004, Frisch, 2005). Environmental opposition facing the construction of new terminals is intense, and developers regularly have to delay or cancel projects. This leaves significant room for "outsiders", who have proven more than willing to occupy these market niches. Thus, Baja California, Mexico, has granted two licenses for LNG terminals.[8] Natural gas from the two Baja terminals will be shipped into Southern California, whereas the Gulf Coast terminal will reduce the shipments from Texas into Mexico, which remains a net importer of natural gas. Likewise, the Bahamas have two advanced terminal projects.[9] Last but not least, the Canadian government has given permit to the Canaport terminal in New Brunswick, which already is under construction.

Overall, another additional 30 terminals have been proposed. Based on own estimates, we have attached probabilities of success to each of the projects, and therefore report an expected capacity: Nominal LNG import capacity is likely to increase to about 125 mtpa in the US (173 bcm/a) by the year 2012, and to 144 mtpa (198 bcm/a) in North America including the East Coast of Mexico and

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[6] This list should be considered with care, since it does not provide reliable information about whether these projects will be realized. We have obtained additional information on realization through expert interviews and field studies. For an extended list of "potential" North American terminals see http://www.ferc.gov/industries/lng/indus-act/terminals/horizon-lng.pdf .

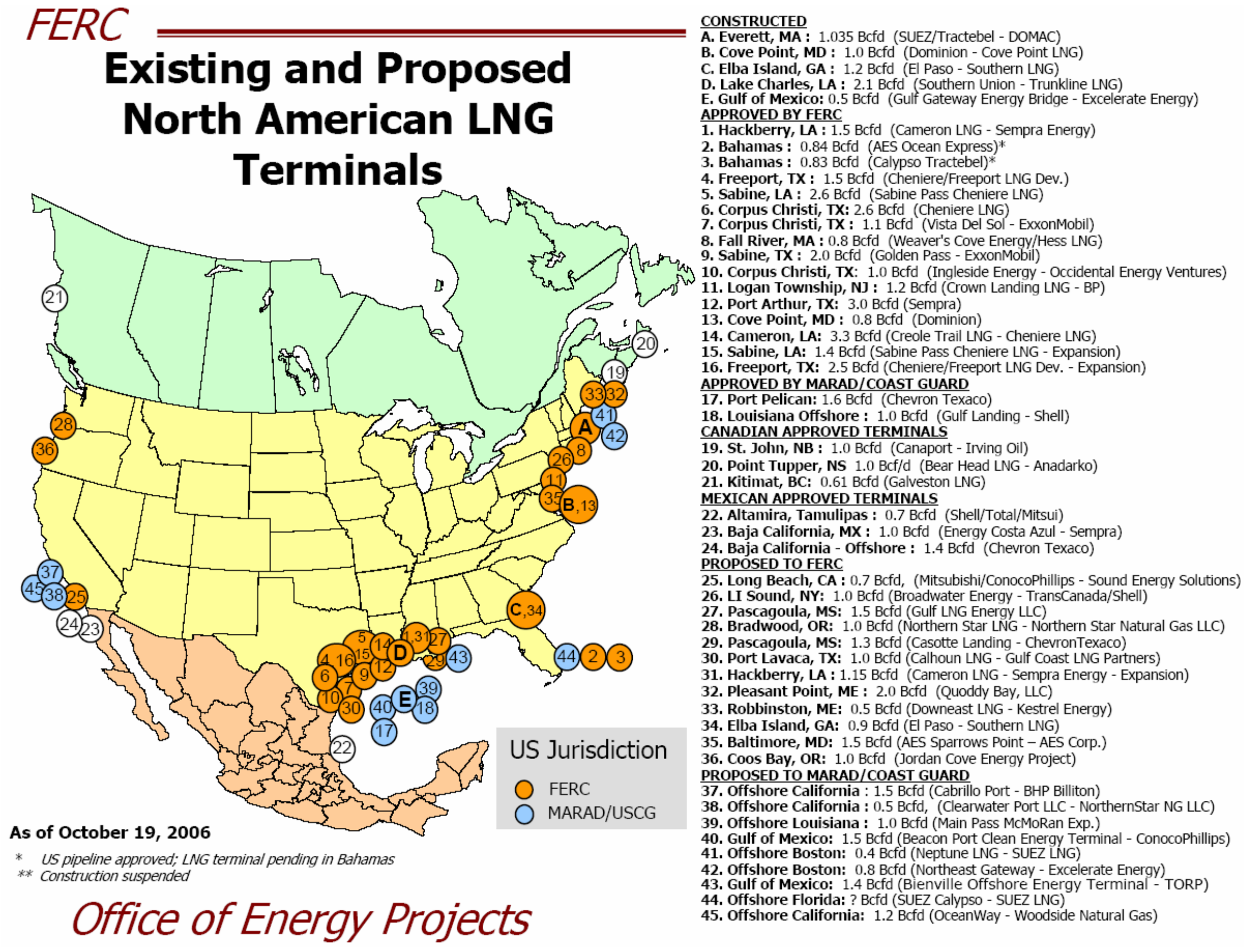
[7] Sempra Energy's Cameron terminal near Hackberry, Louisiana, the Freeport LNG Development's terminal near Freeport, Texas, and Cheniere LNG's Sabine Pass terminal in Cameron Parish, Louisiana.

[8] Sempra Energy at Costa Azul, 1 (10 bcm/a), and Chevron Texaco, offshore (14 bcm/a); one additional terminal is currently under construction at Altamira on the Gulf Coast of Mexico (Shell/Total/Mitsui (7 bcm/a)).

[9] The Tractebel Calypso project (8 bcm/a) and AES' Ocean Express (8 bcm/a). A third terminal, El Paso's Seafarer (5 bcm/a), has been proposed to FERC; the gas is supposed to be shipped into Florida by pipeline.

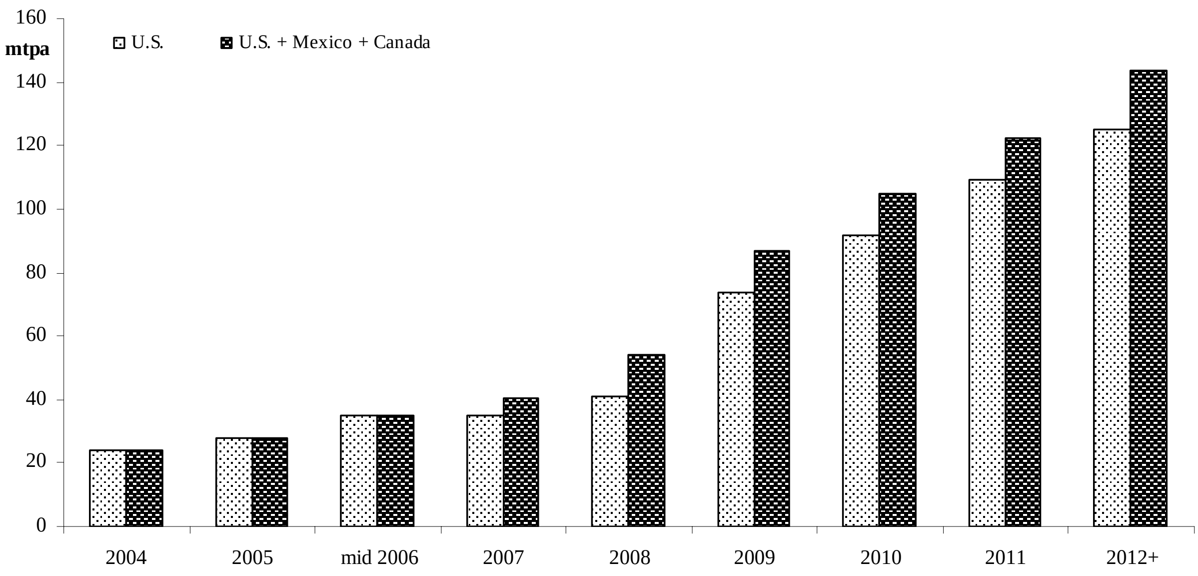
Canada. Figure 3 shows the increasing capacities, based on existing terminals and projects on the Atlantic coast that have already been approved.

Figure 2: Existing and proposed North American LNG terminals



Source: FERC (2006); download http://www.ferc.gov/industries/lng/indus-act/terminals/exist-prop-lng.pdf

Figure 3: Development of regasification capacities in North America



Source: Author's estimates

Corporate strategies: integrated companies, tollers, and hybrids

When looking at investment strategies at the corporate level, one observes a striking diversity; investment strategies vary between strong vertical integration and significantly less integrated structures. In fact, one can distinguish two stylized corporate strategies on the North American LNG market (see Nissen, 2004, 2006, for a more in-depth categorization, and Ruester and Neumann, 2006, for a survey of strategies in the international LNG business):

- Players vertically integrated along the LNG value-added chain. This is the classic case of a company that owns upstream gas and/or liquefaction capacities, perhaps ships or chartered tankers, and downstream commercial marketing activities. The integrated LNG player treats the LNG terminal as part of its value added chain and does not have any incentive to rent out spare capacity to potential competitors. An example of an integrated LNG player is the SUEZ Group, owning upstream liquefaction capacity (Trinidad and Tobago), importing regasification capacity (Everett, MA), and downstream gas-consuming power plants;
- Private "merchant" entrants in the LNG terminal business, many of them newcomers to LNG markets. This strategy consists of developing LNG terminals as a service provided to industry. The merchant company may develop its own upstream and/or downstream facilities, but is ready to offer LNG-receiving capacity for rent to the market ("tolling"). An example is Cheniere Energy, which is currently developing four natural gas importing "tolling" facilities. The re-emergence of such quasi-open access regimes at several terminals suggests that exclusive rights for the upstream business of the investing party are not necessarily a condition for investment.

3.4 Conclusions

Given the current LNG terminal "rush" in North America, there seems to be no reason for concern about supply security with respect to LNG infrastructure. We have not detected any major market failure or state failure that would need to be rectified for more LNG terminals to be developed. The five existing terminals are expanding their capacities significantly and at least ten promising projects are underway that will further increase send-out capacity by 2010. Given the uncertainty surrounding the future of LNG in the North American natural gas market—mainly due to high prices—there may even be too many projects for importing terminals.

While there do exist upstream constraints—that is, difficulties tapping LNG supplies in an increasingly tight world market—these problems are economic rather than institutional in nature. Global competition for LNG has indeed emerged, but the basic rules of supply and demand still hold, suggesting that LNG is available to North American importers at internationally competitive prices. Insufficient pipeline capacity to feed the regasified LNG into the interregional pipeline grid has not been a major constraint so far either.

The major remaining obstacles are siting issues that have delayed and even impeded LNG terminal developments in regions other than the Gulf Coast. While FERC generally approves LNG projects quite rapidly, state and local authorities are often hesitant if not outright opposed to these terminals.

Some legal issues remain to be resolved, in particular the different roles of federal, state, and local regulators in siting (Wolak, 2005). Current public awareness campaigns and the series of "LNG conferences" mandated by the Energy Policy Act will help to promote public support, but intensified political efforts will be required for LNG to continue its growth in the US market.

4 Interstate Gas Transmission Pipelines

4.1 Market Structure

The US high-pressure interstate natural gas pipeline transmission network has evolved quite organically over the last few decades, and today corresponds fairly well to the structure of demand. The system carries gas from the main supply areas in the South and the Gulf of Mexico to the main consumption areas in the Northeast, the Midwest and California (Figure 4). The total network length is somewhere below 300,000 miles and there do not appear to be obvious bottlenecks.

Figure 4: Principal interstate natural gas flow summary, 2004

Source: EIA (2005), Natural Gas Annual 2004

Under current regulations, the pipeline business is structurally unbundled from the upstream producers and the downstream consumers (open access). Primary transportation services are formally subject to cost-of-service regulation, but free market-based trading exists for secondary capacity, i.e. resold primary capacity.[10] Local distribution companies (LDCs) rely mostly on primary service in direct

[10] Note that the FERC has done an attempt to cap the secondary market to the level of the regulated price of the primary auction; however, this turned out to be unsuccessful: "There is little hard empiric evidence on how extensive the delivered

bookings with pipeline companies because of state regulations obliging them to guarantee their customers a given supply. Likewise, large industrial users and electricity users generally also prefer to hold firm primary capacity, but they also rely on interruptible and released capacity because of the potential for short-term fuel switching (IEA, 1996, 87). Furthermore, marketers play an important role as intermediaries between the upstream producers and large downstream customers; thus they generally provide a diversified mix of services, of which interruptible and released capacity account for about two-thirds of their total capacity needs (IEA, 1996, 87).

4.2 Regulation

The interstate pipeline industry has gone through several waves of restructuring and re-regulation over the last century. Makholm (2006) provides a detailed account of the historical development of the US natural gas interstate pipeline system.[11] Structural regulation led to unbundling and gas-to-gas competition, whereas price regulation has remained virtually unchanged, based on a traditional cost-of-service approach to transportation fee setting. Order 636 (1992, "Restructuring Rule") has obliged interstate pipelines to unbundle their marketing activities, thus becoming mere transporters of natural gas. Pipelines now must offer all other market players equal access to their transportation infrastructure ("open access"). This allows marketers, producers, LDCs, and even end-users themselves to close contracts for transportation of their natural gas via interstate pipelines on an equal and unbiased basis. Since interstate pipelines serve only to transport natural gas, vertical coordination is assured by contracts and trading rather than by vertical integration.

Contrary to Europe, where pipeline companies have a high degree of market power, the pipeline business in the US is competitive in many of the regions. Most destination markets are served by several competing pipelines. Thus, pipelines compete for shippers, and rates are negotiated in a competitive environment. On the other hand, there remains a formal cost-of-service regulation of interstate pipelines. Transportation rates are set under the Natural Gas Act, 15 u. S. C. §717, similar to the setting of rates for local gas distribution and telephone exchange companies.[12] However, in a more competitive framework, these regulated tariffs are hardly applied. Thus, "special contracting" between pipeline and shippers is allowed using negotiated rates, and this is frequently employed (the customer

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market is, but the existence of delivered gas transactions during peak periods suggests that, due to the price cap, capacity holders with available capacity will choose to use that capacity to make delivered transactions, where the profit opportunity is greater, rather than releasing the capacity, where the price is capped." (Docket No. RM98-10-000, p. 25)

[11] In essence, he distinguishes three periods of development: i) pre-1935 with no federal regulation and a high degree of vertical integration; ii) post-1944, when all prices in the industry were federally regulated; and iii) post-1984, when—after a transition period—pipeline regulation was considerably decreased, leading to more competitive markets and investment decisions. See also MacAvoy (2000).

[12] FERC allows pipelines to recover costs of prudent operation, depreciation, taxes, and a return on the capital invested, subject to an overall rate of return (Loeffler, 2004); companies can require rate cases when they feel that regulated rates do not cover their costs sufficiently. In an attempt to promote the expansion of existing pipeline capacity, FERC at some point in time had adopt the "rolled-in" rate-setting principle, whereby the additional cost incurred was included in the overall cost base for calculating minimum revenue needs and rates; thus, existing pipeline customers shared the costs of providing capacity to new customers (whereas in the incremental-rate principle, the costs of pipeline expansion are allocated solely to new customers). However, FERC has abandoned this approach and is now favoring incremental pricing; see Policy Statement on Determination of Need; 1902-AB86, FERC Docket No. PL-3-000.

can choose to return to cost-based rates).[13] Rate cases are often settled by the parties directly, so little public information is available about what formulas are applied.

There is a debate about the underlying reason for the low level of congestion on the natural gas pipeline network. On the other hand, the competitive character of the industry, coupled with a high growth of demand, has generated a significant amount of incremental pipeline capacity, independently of the regulatory regime. On the other hand, it has been argued that FERC uses the allowed rate of return as an instrument to attract investments in pipeline infrastructure.[14] In determining the appropriate rate base, the traditional "used and useful" approach is applied. The average weighted cost of capital is determined by estimating the appropriate rate of debt, the cost of equity and the capital structure ("gearing ratio"). Based on the representative sample of investment projects quoted by Loeffler (2004) and our own calculations, we estimated the weighted average cost of capital (WACC) for interstate pipeline projects (newbuilds and extensions) between 1996 and 2003 at 11.6%, which is higher than one would generally expect.[15]

Thus, the industry is characterized by an institutional setting that "works in practice, but not in theory."[16] Competition between pipeline operators and network extension go hand in hand, even though the prices necessary to attain the regulated rates of return may not be achieved. There is an interesting parallel to regulation of network expansion in other infrastructure sectors that operate under competitive conditions, such as railroads or telecommunication.[17] Thus, Hausman (1998) and Hausman and Myers (2002) suggest that traditional regulation trying to establish "competitive prices" may lead to adverse effects on innovation and new investment. The reason is that this approach may neglect the significant sunk costs by an incumbent, and the value of the "real option" offered to a new, merchant competitor that only has to pay the regulated "competitive" price.[18] There is an emerging discussion on these issues applied to natural gas, both in academic and in the FERC, but it is to early to draw any conclusions for regulatory policy.

4.3 Recent investments and outlook

Although the pipeline system has gone through periodical investment cycles ("boom and bust"), on average the system has grown at a considerable rate (Makholm, 2006). After the implementation of

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[13] FERC has also started to test incentive regulation schemes such as performance-based ratemaking (PBR), in which pipeline companies have to share efficiency gains with customers via lower prices.

[14] Thus, Joskow (2005a, 20) has suggested that the "high rates of return chosen by FERC were intended to stimulate investment, reduce congestion, and increase reliability (…) this is one reason why investment in natural gas pipeline capacity has preceded reasonably well in the liberalized US market and there is little congestion on the natural gas pipeline network."

[15] Values range up to 12.64% for the Shell Gas Pipeline Co. (1996, 82% equity financed), with a lower bound of about 8.4% for the Questar Southern Trails Pipeline (1999, 70% debt financed).

[16] Quote by Paul Joskow.

[17] I am thankful to Paul Joskow for pointing out this issue and the recent literature.

[18] Hausman (1998) analyses the „total service long-run incremental cost" rule (TSLRIC) for incumbent local exchange carries (ILEC) and concludes that "failure by regulators to recognize the sunk cost character of much network investment leads to the grant of a free option to the competitors of the incumbent"; "the adoption of TSLRIC as a cost basis to set the prices for unbundled elements has negative economic incentives effects for innovation and for new investment in telecommunication (p. 17). Along similar lines, Hausman and Myers (2002) analyze the regulation of US railroads and conclude that the "simulated competitive rate benchmark is too low because it fails to account for the sunk and irreversible nature of many investments in railroads…. We find that required return calculated from the STB model that ignores these factors is too low by between 30% and 84.4%" (p. 308).

Order 636 (1992), the natural gas pipeline system went through another investment boom. The rather generous rates of return offered to pipeline companies have led to an expansion of the system throughout the period. Between 2002 and 2004, the average annual expenditure for natural gas pipeline development was $3.5 billion, corresponding to approx. 2,000 miles or 100 bcm/a of added capacity per year. The focus of recent investments was on expanding the import capacity from Canada. Within the US, priority is given to expanding capacities between the regions of increasing production (Gulf of Mexico, Central Region) and regions of increasing demand (Southwest, Northeast, Midwest, West). Thus, among the major projects undertaken was a new deepwater pipeline system in the Gulf of Mexico (18 bcm/a), the Cheyenne Plains Pipeline (5.6 bcm/a) extension of the Colorado Interstate Gas system, which provides shippers greater access to Midwestern markets, and several pipelines reaching from Texas to Arizona and California; also, the connections from the Rocky Mountains will be strengthened by the expansion of the Kern River Pipeline and the newly built Ruby and Coronado Pipelines. Pipeline expansions are likely to continue. Proposed investments for 2006 and 2007 are in the order of $2.7 billion and $3.2 billion, respectively. A list of pipeline projects contains more than 10,000 miles of new pipelines, or 500 bcm/a (Court, 2006). This suggests that significant bottlenecks in the US transmission pipeline system are not to be expected.

Another type of investment is currently taking place in what has sometimes been considered a bottleneck to LNG development: the construction or extension of pipelines needed for large-scale development of LNG import facilities and the interconnecting laterals. A significant amount of new pipeline capacity has been proposed on those portions of the interstate and non-interstate pipeline grid to which LNG developers plan to transport their supplies. LNG terminal builders themselves have proposed to build downstream pipeline capacities to connect the terminal to the grid (e.g. Cheniere). Alternatively, the incumbent pipeline operators should have sufficient incentives to invest in these potentially lucrative segments. As more LNG projects are announced, interstate pipelines have also started to sponsor open-season exercises, with LNG shippers as the main target group. Until now, no binding pipeline constraints seem to have hindered LNG terminal developments. Three interstate pipeline companies have announced plans to expand parts of their system to accommodate additional LNG sources, and six pipeline (lateral) projects in association with proposed new LNG import facilities along the Gulf Coast have been announced for 2007.

An investment project of this type is the Cheniere Sabine Pass Pipeline Company’s construction of a natural gas pipeline connecting the proposed Sabine Pass LNG terminal in Louisiana with interstate and intrastate natural gas transmission pipelines in the southern part of the state. In 2003, the company filed a FERC application to construct and operate the pipeline (60 bcm/a, 16 miles long, 42 inch diameter, $90 million) and related facilities to transport natural gas on an open access basis. The whole project (LNG import terminal & pipeline) received FERC approval in December 2004. Both the beginning of construction and the start of operations are scheduled for 2007. Cheniere is also planning two other pipelines linked to LNG receiving terminals (Corpus Christi, TX and Creole Trail, TX).

4.4 Conclusions

Throughout the recent debate on supply security, concerns have been raised about potentially insufficient investments in the transmission pipeline infrastructure.[19] Our analysis of pipeline regulation and investments does not support this hypothesis. Given that the US natural gas market today is open and competitive, infrastructure investments have not been impeded. The current institutional and regulatory setting in the US poses no serious structural obstacles to natural gas pipeline developments and no particular cause for worry regarding medium-term resource adequacy. Fairly generous rate-of-return regulation has led to significant growth of the US natural gas pipeline infrastructure over the past two decades. Rising demand for natural gas and high prices are favorable to further pipeline expansions and newbuilds. Also, in the "competition" between LNG terminal expansion and pipeline expansion, pipelines have an advantage because they can rely on marginal expansions of existing routes for which administrative procedures (right of way, siting, etc.) have already been carried out to a large extent. Moreover, bottlenecks are unlikely even where the planned expansion is based on LNG import projects, or in regions where pipeline density is low (such as California).

To what extent the solid growth of investment in the pipeline infrastructure is due to the competitive nature of the industry, to cost-of-service regulation, or to "accident" is a question that can not be resolved here. The FERC is currently reviewing its policy in the wake of the upcoming discussion of supply security. This also includes a discussion whether the formal regulators process should include more incentive-based elements, or PBR (performance-based regulation).

5 Storage

5.1 Market structure

Natural gas storage connects the supply side and the demand side, and is therefore an important link in the supply security chain. Underground storage provides capacities to meet peak demand such as daily or winter peaks. In general, storage facilities are filled during the summer in times of "cheap" gas and released in the winter when prices are high. Storage can thus provide a supply and demand cushion when market participants react to price differences between forward prices and spot prices (which need not always be the case, see Simmons, 2000, 2). There are three different types of storage facilities: i) depleted reservoirs in oil and/or gas fields, (ii) aquifers, and (iii) salt cavern formations. These three types differ in their physical and economic characteristics but above all in their capacity to hold natural gas and send-out rates (or deliverability rates).[20] Salt dome storage is more expensive but offers considerably more flexibility in terms of higher withdrawal and injection rates relative to

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[19] See, i.e., the Commission's Conference on the State of Natural Gas Infrastructure on October 12, 2005. http://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=2181&CalType=%20&Date=10%2f12%2f2005&CalendarID=116

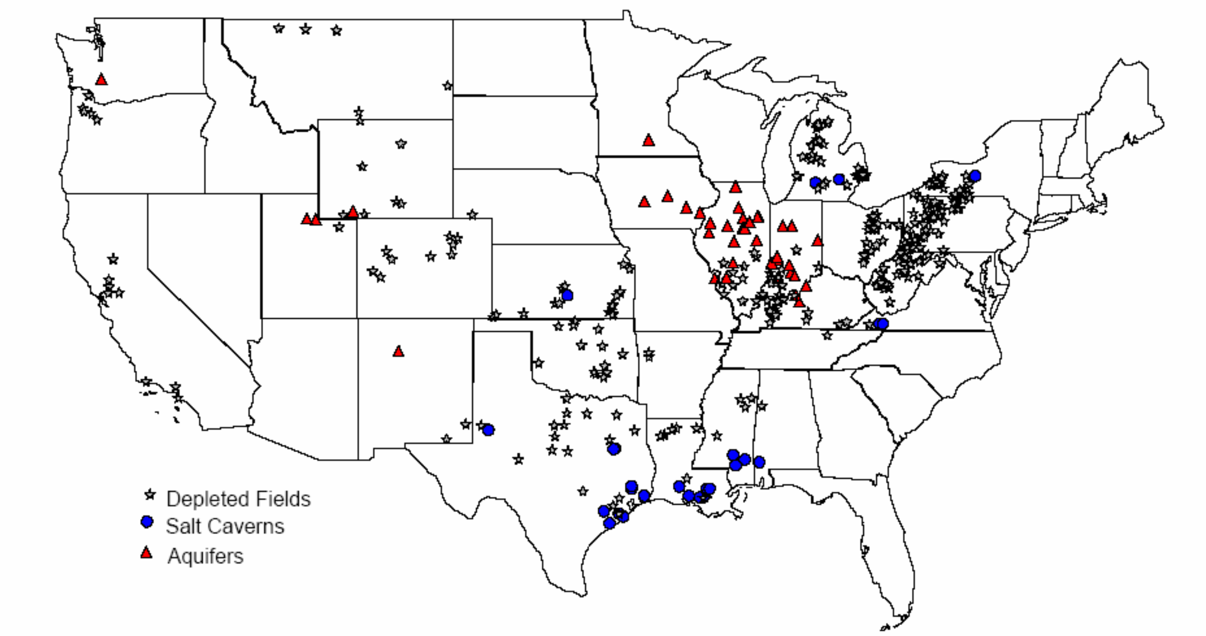
[20] See Simons (2000) for details, and for definitions of the technical terms used. LNG is also stored in above-ground tanks, but is generally not accounted for in the statistics on storage.

working gas capacity; base gas requirements are relatively low.[21] The majority of working gas is kept in depleted oil and gas reservoirs, which is less expensive but significantly less flexible than salt dome storage. The geology of aquifers is similar to depleted production fields, but the use for gas storage usually requires more base (cushion) gas and greater monitoring of withdrawal and injection performance.

In the US, there are about 430 storage sites (operated by about 120 companies), amounting to a working capacity of 120 Bcf. Eighty-seven percent of this capacity resides in depleted fields, 9% in aquifers, and only 4% in salt caverns. While large storage capacities exist in the gas-producing states of Texas and Louisiana, and—to a lesser degree—in the Midwest, the gas consuming Northeast and California have little storage capacity (Figure 5). The majority of salt cavern storage facilities have been developed in salt dome formations located in the Gulf Coast states. In some areas, most notably the Midwestern United States, natural aquifers have been converted to gas storage reservoirs. The East Coast is characterized by depleted reservoir and aquifer storage, and the West has primarily depleted reservoir storage.

The principal owners/operators of underground storage facilities are (1) interstate pipeline companies, (2) intrastate pipeline companies, (3) local distribution companies (LDCs), and (4) independent storage service providers. Owners/operators of storage facilities are not necessarily the owners of the gas held in storage. Indeed, most working gas held in storage facilities is under lease by shippers, LDCs, or the end users that own the gas. Energy marketers lease storage capacity both to increase the flexibility of products for customers and to enhance profitability (Simmons, 2000, 8).

Figure 5: **Locations of existing natural gas underground storage fields in the United States, 2004**



Source: EIA (2005), Natural Gas Annual, p.30

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[21] The typical number of cycles per year is 4 to 5 for salt dome storage, but only 1 to 1.5 for reservoir storage. Salt dome storage also has the flexibility to withdraw during the day and inject at night in order to serve peaking power generation

The very nature of storage has changed significantly over recent years with natural gas utilities changing the way they use storage to hedge summer injections and minimizing storage refill costs. No longer a simple backup inventory or seasonal supply source, storage has become a carefully managed asset. Marketers have emerged that move gas into and out of storage as changes in price levels present arbitrage opportunities. This change of attitude goes hand in hand with changes in inventory management and storage utilization. The deregulation of underground storage and the growth in the number of gas-fired electricity generating plants have lead to a premium on high-deliverability storage facilities. The independent storage service providers, often smaller and more focused companies started by entrepreneurs, are focusing on salt formations and other high deliverability sites. The merchant storage sites are almost exclusively used to serve third-party customers who can benefit most from the characteristics of these facilities, such as marketers and electricity generators. The intensification of LNG imports further increases the strategic role of storage and the magnitude of seasonal arbitrage spreads.

Storage can be used as a real hedge and/or as a financial instrument, and over the last few years, the NYMEX has developed a liquid futures and options market for natural gas storage inventories. The cost of storing should be less then the differential between cost of natural gas in the withdrawal period and the refill period. According to Simmons (2000), a seasonal contango between the summer and the winter months of $0.50/MBTU or better allows companies to cover storage costs including a rate of return. Seasonal storage price spreads have widened in recent years. Whereas in the period 2001–2003, monthly average premiums for the following January contracts ranged between $0.23 and $0.92/MBTU, prices have increased considerably since. The current NYMEX off-peak-to-winter (seasonal) storage price curve is in contango through 2010. These developments imply favorable conditions for new investment in natural gas storage, both regulated and merchant gas storage.

5.2 Regulation

If a storage facility serves interstate commerce, it is under the jurisdiction of the FERC; otherwise, it is state-regulated. Traditionally, interstate pipelines and storage facilities are subject to FERC cost-based regulation. There are currently 14 larger regulated storage companies (of which 12 are integrated with pipeline operators, and two are independent). FERC Order 636 required pipeline companies to operate their storage facilities on an open-access basis. This means that a large part of working gas capacity (beyond the quantity required for load balancing) at each site must be made available for lease to third parties on a non-discriminatory basis.

There have also been recent explicit attempts to make regulation more investment-friendly. Throughout the 1990s, investments in storage capacities were not considered a particularly important policy issue. However, with the California price spike of 2000/01, high gas prices since 2004 and general political concerns about supply security, public awareness of limited storage capacities increased. One obstacle to storage investment has been identified in FERC's narrow interpretation of

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facilities that only run during the peak electricity demand hours of the day.

market power, leading to storage operators being prevented from applying market-based rates. Complex administrative requirements and procedures have also been cited as entry barriers (FERC, 2004, 27). Reacting to these challenges, the Energy Policy Act of 2005 implemented provisions to favor storage investments. Companies are now allowed to set their own rates based on open season and market characteristics before handing them to FERC, which then either accepts or changes these rates accordingly. The Gas Storage Pricing Notice of Proposed Rulemaking (NOPR)[22] i) expands the definition of the relevant product market to include close substitutes for gas storage services for the authorization of market-based rates;[23] and ii) implements the new Natural Gas Act Section 4(f), which permits the Commission to authorize market-based rates even where an applicant has market power. Current rate policies thus provide higher flexibility to design cost-based rates, negotiated rates and market-based rates. This move corresponds to a loosening of FERC's stand on market power issues.

5.3 Investment

Recent projects and outlook

Restructuring of the natural gas industry has also changed the fundamental understanding of the role of storage in the value-added chain and the corresponding investment patterns. Today, not only interstate storage sites but also state storage facilities owned and/or operated by large LDCs, intrastate pipelines, and independents operate on an open-access basis, especially those sites affiliated with natural gas trading hubs. Storage is used in conjunction with various financial instruments (e.g. futures and options contracts, swaps, etc.) in attempts to benefit from changing market conditions.

In the "new" world of commercial storage, different investment strategies are pursued by different players. Independent storage operators are more interested in high deliverability rates, and therefore invest mainly in salt caverns and high deliverability sites. The largest growth in daily withdrawal capability has been from high deliverability storage sites, which include salt cavern storage reservoirs as well as some depleted oil or gas reservoirs. The largest investment projects of recent years have been concentrated in the Southwest/Gulf Coast area (EIA, 2004a). This trend is favored by the existence of a large natural gas pipeline infrastructure and the presence of a rich salt formation geology on the Gulf Coast of East Texas, Southern Louisiana, Mississippi, and Alabama.[24] During the past years, average additions to withdrawal capacity have been about 20 bcm/a.

At present, investment in storage is high. Since the beginning of 2000, FERC has approved 49 storage projects. There are 14 storage projects pending. Potential projects total about 107 Bcf of capacity and have a deliverability of 5.3 Bcf per day. The majority of these projects are located in the Gulf Coast region. Further development of storage will also depend on the amount of gas supplies from potential LNG terminals in that region.[25]

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[22] Docket Number RM05-23-000, and AD04-11-000; Rate Regulation of Certain Underground Storage Facilities (December 22, 2005) 74 FERC ¶ 61,076 (http://www.ferc.gov/whats-new/comm-meet/121505/C-1.pdf).
[23] Close substitutes for storage, such as spare pipeline capacity and LNG imports, are recognized as being competitive.
[24] In 2003, this area of the United States accounted for 26 percent of the new pipeline capacity, and 55 percent of the combined working gas storage capacity additions installed in the Southeast and Southwest regions.
[25] Updates can be found at FERC's website: http://www.ferc.gov/industries/gas/indus-act/storage.asp

The changing nature of natural gas storage, which has gone from being a regulated, “boring” industry to a dynamic, market-oriented industry, in combination with increasing natural gas demand, has led to an upward revision of forecasts for future gas storage requirements. Official FERC projections assume new gas storage requirements in the range of 650 Bcf until 2020 (FERC, 2004, 15). 210 Bcf are required by 2008, and another 440 Bcf by 2020. Currently, the average size of the approved projects is “only” about $50 million.[26] This indicates that the barriers to entry are relatively low, and that merchant investment in storage has become a feasible alternative to traditional investment.

Corporate strategies between full integration and independents

Two different examples show the wide range of corporate strategies between traditional, integrated and cost-based investment, and the new approach to independent, more merchant-oriented investment:

- KeySpan, the largest distributor of natural gas in the Northeast United States, is an example of a vertically integrated utility operating and investing in storage on a traditional cost-of-service basis. The core of the company consists of regulated natural gas and electrical utilities and some unregulated subsidiary companies engaged, for example, in exploration and production of oil and gas, and investments. KeySpan Energy Development Corporation has investments in electricity generation, exploration and production of natural gas, natural gas pipelines and gas storage in the Northeast region of the United States and the United Kingdom. Upstream, the company is engaged in the exploration, development and production of domestic natural gas and oil properties (Appalachian Basin). KeySpan's wholly owned subsidiary, KLNG, owns and operates 600,000 barrels of LNG storage and receiving in Rhode Island. In a joint venture with BG LNG Service, KeySpan plans to upgrade this facility to accept marine deliveries and triple vaporization capacity. Downstream, the company owns electricity generation facilities powered by natural gas. Within this portfolio, natural gas storage facilities are being expanded continuously.
- Situated at the other end of the scale, Falcon Gas Storage represents the “new generation” of gas storage owners and operators, both in its financing and in its technical approach to gas storage management. Falcon is a greenfield start-up, founded in 2000 with $5 million in investment fund capital (Energy Spectrum Partners). Within only six years, Falcon has become the largest independently owned developer and operator of high-deliverability multi-cycle (HDMC) natural gas storage capacity in the US, offering firm and interruptible services at market-based rates. Falcon started out with the purchase of the Worsham-Steed (TX) depleted oil and gas reservoir in 2000, which was turned into a storage facility capable of providing storage services from two to six inventory cycles. Additional equity investment was raised in 2001 to acquire the Hill-Lake (TX) storage facility (10 Bcf working gas storage, operating since 2002, and fully subscribed in the very first year). The third project, MoBay Storage Hub (AL), was acquired in 2002, and henceforth developed to become the largest,

[26] Source: FERC Office of Energy Projects.

most southeasterly HDMC storage facility in the US, directly connected to the Gulfstream natural gas system.

5.4 Conclusion

The US storage market is well developed and there are no evident shortages that would endanger supply security. FERC Order 636 has provided a new structure for the storage market. "Interstate" storage capacities—those regulated by FERC due to their use for interstate trade—are subject to cost-of-service regulation. However, price caps as defined above are often not reached, as storage companies negotiate "market-based" rates. Prudent investors are assured of recovering capital costs at almost no risk. This setting, using regulation to provide a "safety valve", has worked well to spur storage investment.

Restructuring has also changed the perception of storage by the market actors, and led to the emergence of independent, merchant-oriented storage operators. Although the ownership of storage capacity remains largely with the interstate pipelines and gas utilities, natural gas marketers now control about one-fourth of underground storage capacity through contracts and gas supply asset management agreements. The market has become transparent, favoring further investments by independent companies.

Despite the sector's rapid growth, concerns have been expressed recently as to whether future requirements for natural gas storage will be met. FERC predicts that up to 2020, storage requirements will increase to approximately 650 Bcf. The issue is addressed by FERC's NOPR on rate regulation of certain underground storage facilities, easing price regulation and market power control. FERC assumes that the market has become more competitive and is now focusing more on investment than on market power issues.

6 Cross-Sectional Policy Issues

Our discussion on natural gas infrastructure has shown little concern about the adequacy of LNG terminals, interstate pipelines, or storage facilities. This does not imply, however, that there are no important policy issues to be considered in this area. The following section highlights some cross-sectional policy issues that may play a role in the further reform process.

6.1 Appropriate cost of capital

One concern regards the cost of capital calculated by FERC to determine regulated rates—a key issue in any cost-of-service regulation. On several accounts it seems that the allowed rates of return in the US gas sector are high, some argue perhaps too high. From a theoretical perspective, a firm will undertake investments if the discounted present value of net revenues equals (or exceeds) its capital costs. The central question is how to estimate an appropriate, risk-adjusted cost of capital. While rate-of-return regulation has sometimes been criticized for triggering overinvestment and an inefficient use of capital and labor, it has also been argued to secure long-term investment. FERC may have used the cost-of-capital estimations as an instrument to encourage companies to invest both in the pipeline and in the storage business. Joskow (2005a, 20) and Loeffler (2004) have suggested that investment in the natural gas pipeline system has proceeded fairly smoothly due to the FERC's generous interpretation of the real cost of capital. On the other hand one has to acknowledge that pipelines and storage get built mainly because there is a functioning market for the construction of additional capacity (Makholm, 2006).

There is a recurring debate about the appropriate method to estimate capital costs. Since 1998, FERC has been using the discounted cash flow ("DCF") formula.[27] This is a forward-looking approach, as opposed to the backward-looking capital asset pricing model (CAPM), used dominantly in Europe. It has been argued that the discounted cash flow approach overestimates the cost of capital, since financial markets are generally (over-)optimistic about future dividend and growth rates. However, as Makholm (2003) argues, CAPM and DCF tend to yield similar capital costs; thanks to its solid, straightforward theoretical base and because it can capitalize on the depth of the US capital markets, it is "hard to foresee abandoning the discounted cash flow method" relied upon so heavily in the past (Makholm, 2003, 12).

6.2 A "missing money" problem?

Another issue is the structure of price regulation and its connection to infrastructure investments, in particular the regulation of peak prices in times of capacity shortages (congestion). The "resource adequacy" question, discussed at length in electricity generation and transmission has also been mentioned in the natural gas sector, although natural gas infrastructure is less subject to "pig cycles" than electricity generation. To some extent, the situation in natural gas pipelines and storage may resemble the "missing money" phenomenon currently enlivening the debate over the adequacy of resources for electricity generation.[28] The quest of pipeline and storage operators for "market-based" rates assumes that by applying prices that are based on utilization rates and thus (very) high in times of shortages, the necessary financial conditions for investment are created. In recent years, FERC has indeed suggested a more intensive use of market-based rates in all three infrastructure sectors. It may be difficult to distinguish peak prices due to congestion from artificially increased prices due to abuse of market power. The obligation to convey real-time information about the physical state of the infrastructure (available capacity, utilization, ratios, maintenance schedules, etc) is useful to increase transparency in this sector. However, due to the high level of competition prevailing already in the sector, the "missing money" problem may be less important in natural gas than it is in electricity.

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[27] Opinion No. 414-A, 84 FERC ¶61.084 (1998). The formula for the Discounted Cash Flow Method is $K = d/p + g$, where K = cost of equity (the expected return on equity investment); d = current dividends per share; p = current market price per share; and g = anticipated growth rate (the expected annual growth in dividend or market price of stock). For more details, see Loeffler (2004, Appendix B).

[28] In essence, the "missing money" problem (Hogan, 2005) refers to the fact that capped prices for a partially congested infrastructure do not allow the investor to recover the fixed costs. As a solution, Hogan (2005) has argued for abandoning the price cap on wholesale markets, so that generators can obtain a (scarcity) rent to cover their fixed expenditure (the "missing money"). Opponents of this mechanism insist on the political infeasibility of skyrocketing prices, and suggest combining a price cap with a forward capacity market (Crampton and Stoft, 2006). It has also been argued that bankers would be unlikely to provide large sums of investment if they are to rely on scarcity rents for returns.

6.3 Deepening and widening of financial markets

The success of industry restructuring is closely linked to the intensified use of financial instruments. These have, to a large extent, taken the place of traditional risk-hedging strategies such as vertical integration. Thus, financial market growth has helped to ensure supply security. The futures market now offers contract periods up to seven years and is liquid for at least a two to three-year period. Henry Hub is an ideal point for physical delivery, being situated at the crossroads of 16 natural gas pipelines and close to producing fields, LNG terminals, and storage facilities.

In recent years, new financial products (such as swaps) and more widely used clearing services have been introduced successfully (FERC, 2005). There are now more than 40 delivery points available for basis swaps, compared to 20 three years ago.[29] Likewise, index and swing swaps have been extended as hedges against daily price volatility.[30] The NYMEX also introduced a hedge against last-day changes in futures prices (the "penultimate" swap). Calendar spread options on the price spread between two specified months that are used to hedge the value of storage have been added between April and October, and between October and January. NYMEX has also extended the range of the financial products in the clear port-trading system, which is a purely financial market without physical delivery (FERC, 2004, 146). Further expansion of financial markets would stimulate gas markets, and there is evidence that the market would welcome new financial instruments.

6.4 Coordinating natural gas and electricity markets

Ultimately, a large part of the supply security debate and the interest in natural gas prices is driven by concerns of the electricity industry about secure and reasonably priced natural gas. The large majority of the 250 GW of electricity generation capacity added to the system since 1997 uses natural gas as fuel; however, many gas plants did not survive, and recently the trend has re-shifted towards coal.[31] Given the recent increases in gas prices, it is particularly important that the natural gas market be structured as competitively as possible.

Apart from the California energy crisis, there are no particular signs that the structure of the US natural gas market is not competitive. Market power abuse does not seem to have occurred at a significant level. The recent rise in electricity prices is largely due to demand-driven increases in fuel costs and (possibly) to limited generation capacities. Electricity generators have been able to hedge much of their natural gas price risk through financial risk management instruments.

A convincing example of an efficient interplay between natural gas and electricity markets could be studied in a situation of tight supply during "New England cold snap" of January 15-16, 2005, the coldest two-day period in the Northeast US since 1943. Although both the electric and the natural gas systems were under stress, the markets worked successfully, leading to (high) clearing prices without

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[29] "Basis swaps" allow market participants to hedge the risk of transportation costs between Henry Hub and their preferred point of physical delivery.

[30] Index swaps let a market participant hedge exposure to daily price changes by locking in a monthly index at a given physical point; swing swaps let customers hedge against changes in daily price changes without being tied to a monthly index.

unscheduled curtailments of load (FERC, 2005, 140). Prices were driven to record highs by the high demand, as customers had a high willingness to pay in order to avoid the, even costlier, consequences of disruption of supply. However, prices decreased rapidly as soon as the cold snap came to an end, signaling the proper functioning of the markets.

One possible reform measure would be to improve the natural gas-electric interface timeline, so that the operations of natural gas-fired generation can be made consistent with both natural gas and electricity business timelines. In some cases, generators must purchase and schedule pipeline transportation before day-ahead power schedules are announced.[32] Also, the flexibility of pipeline transportation services could be increased to help match power and gas scheduling (e.g. hourly flexibility of pipeline services).

6.5 Siting

The most severe obstacle to resource adequacy and supply security may not be economic but political: the issue of siting. At present, the greatest difficulty in establishing new natural gas infrastructure in the US is the problem of obtaining the necessary siting permission. This is most extreme for LNG receiving terminals, where siting problems are more severe than other technical, financial, and economic issues; but it is also a determining factor for pipeline expansion, and, to a lesser extent, for underground storage. Resistance against siting of infrastructure is partially driven by concerned individuals, but it is also used as a bargaining instrument by interest groups to obtain a larger share of the profits that the new infrastructure is likely to generate. Therefore, finding appropriate mechanisms for negotiating between stakeholders is key.

Siting issues are now being addressed more systematically by federal and local policymakers. The Energy Policy Act of 2005 explicitly addresses appropriate siting procedures as a major step towards developing an adequate, reliable, reasonably priced and diversified energy supply. The National Commission on Energy Policy has developed guidelines to address the barriers that currently hamper the siting of new, and the extension of existing infrastructure. The best practices that currently exist in state-level siting processes should be implemented across the country.[33] While this can help to ease the technical framework for siting, more determined political support at all levels will be required if natural gas infrastructure is to be expanded significantly.

7 Conclusions

Natural gas is a strategic element of the US energy supply. Although prices have risen significantly and may stay high in the years to come, the role of natural gas as a clean and flexible energy source is

[31] From 2009, future capacity additions will be from coal (additional capacity of about 15 GW in 2009) rather than from natural gas (~ 8.5 GW).

[32] Thus, the gas operating day in New England starts at 10:00 a.m., while the power day commences at midnight, hence power operations straddle two natural gas days, and vice-versa.

[33] These include providing clear and accessible agency rules, requiring up-front, pre-filing efforts by developers, focusing the siting approval process on the question of whether a specific infrastructure proposal at a particular place is acceptable, and providing state and federal siting agencies with sufficient resources (NEPC, 2006, 11).

likely to increase further. Given current concerns about the security of resource and infrastructure supplies, the debate about the pros and the cons of restructuring is back on the agenda.

In this paper, we have looked at the market structure and the regulatory framework in the US natural gas sector and the resulting infrastructure investments. We have highlighted the main tendencies of infrastructure investment in the three market segments LNG terminals, interstate pipelines, and storage. We have found no significant obstacles to infrastructure investment that would constrain resource adequacy and/or put supply security at risk. One new LNG terminal has been finished recently and several new LNG-receiving terminals are expected to come on stream within the next few years; there may be too many investment projects rather than too few. Interstate pipeline development is dynamic and sustainable, and further expansions are expected to improve the connections between natural gas supplying regions (Texas, Louisiana, Alaska, LNG terminals) and the centers of consumption. Investment in natural gas storage has led to significant capacity additions; natural gas storage is turning from a "cost-plus" industry into a dynamic, market-oriented industry with ample investment opportunities. The regulatory framework has so far been conducive to investments in the sector. We have pointed out where further improvements could be made in the institutional framework that would enhance the efficiency of regulation. These concern the combination of cost-based regulation with elements of incentive regulation, the use of financial markets, the coordination between natural gas markets and electricity markets, and the streamlining of siting procedures.

Over the last two decades, a competitive market for natural gas has emerged in the US without evidence of adverse effects on supply security. In the restructured market, natural gas could even increase its market share, in particular in electricity generation. There is also no evidence that the reforms undertaken in the 1980/90s were ill-founded. Could not the fact that so little academic research has been carried out on the US natural gas market — in contrast to vast amount devoted to electricity markets in the event of restructuring — be understood, in a sense, as further "proof" of this?

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