# Value chain analysis of the natural gas industry–
# Lessons from the US regulatory success and opportunities for Europe

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ABSTRACT

The aim of any value chain & network analysis is to understand the systemic factors and conditions through which a value framework and its firms can achieve higher levels of performance. The upstream oil & gas business is increasingly stimulated for growth by federal legislation (e.g. tax credits unconventional gas plays), while the corporate earnings in the US midstream and downstream energy segments remain strictly regulated and constrained by FERC and state regulators. This study concisely describes the physical and the financial value chains of the US natural gas business in a systemic fashion. The value chains of the natural gas industry are governed and interconnected by a regulatory decision-making framework. Legislation and regulation by the US Congress for the upstream energy value chain traditionally aim to facilitate the development of domestic natural gas fields. Likewise, FERC regulation maximizes access to the midstream gas transmission segment and provisions for fair tariffs for all shippers. State regulators protect the end-consumers in the downstream value chain by providing guidelines and rulings in rate cases. Corporate energy development decisions are critically impacted by such energy policies and regulations. Long-term, mid-term and short-term measures are distinguished based upon the duration of their impact on the performance of the US natural gas market. The present analysis of the physical and financial value chains and the regulatory framework that governs the US natural gas market provides new insights on appropriate policies and regulatory strategies that could improve both the liquidity and security of supply in the European gas market. Strategic and tactical instruments for maximizing returns on investment for regulated energy utilities are also formulated.

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## 1. Introduction

The concept of value chain analysis as a generic business management tool was introduced by Porter (1985). Numerous studies on value chain analysis and value networks have been published since (e.g., Allee, 2003; and review in Weijermars, 2008). Industry stakeholders commonly benefit from a systemic value network analysis because it identifies key areas in the value network where constraints occur and opportunities for improvements arise. The global oil & gas industry is under considerable pressure to meet the world's demand for affordable and secure energy supply. Environmental concerns have intensified the inter-fuel competition and this battle can be prolonged in favour of optimum utility for the remaining global reserves of oil and gas.

In spite of the differences in regulatory regimes, inter-fuel competition tends to converge the prices for oil and natural gas into a narrow band. Fig. 1 shows the oil and gas price correlation over

the period 2002–September 2009 (this study's closure), at which time the USD price per Mcf of natural gas stood at roughly 1/10 the USD price paid for 1 bbl of oil. Oil has historically been priced at a premium to gas, trading on the spot market about one-and-a-half times on a heat-equivalent basis since 1993. Oil is usually priced at a premium because it is globally traded commodity, many inexpensive options exist for transportation and storage, and its chemical constituents are a valued feedstock to the petrochemical and refining industry. The heat-equivalence of 6 Mcf natural gas is about 1 bbl of oil (or boe) and that correlates their caloric price volumes as indicated in Fig. 1. The price elasticity range for each fuel source is controlled by different dynamics, where regulatory issues can play a large role in the price-setting for natural gas, but less so for oil. Oil prices, unlike natural gas, are not regulated and broadly follow global supply and demand cycles.

To many oil and gas professionals the natural gas value chain is foremost a physical supply line of natural gas connecting production centers (wellhead) and end-consumers (burner pit). The global expansion of natural gas production has interconnected what were originally local markets into a global network of energy supply and

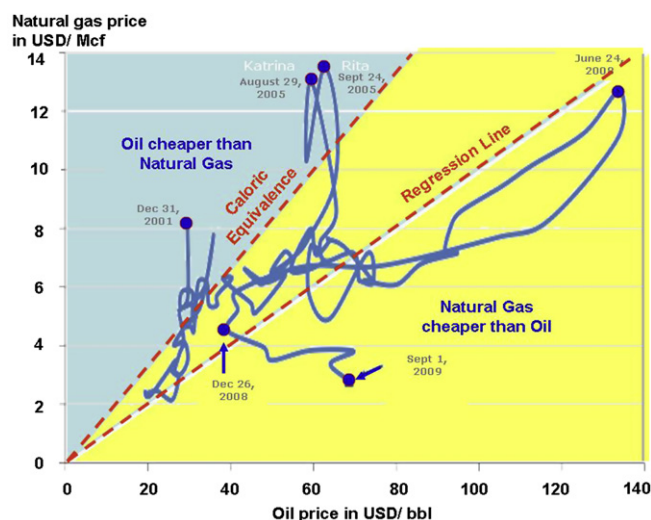*E-mail address:* r.weijermars@tudelft.nl

**Fig. 1.** Development of daily averaged Henry Hub spot market prices versus western crude as of December 2001 till September 2009 (All data from DOE/IEA).

demand. Most professionals are aware that the further development of natural gas infrastructure networks is also subject to political agenda's, complex legislation and strategic directioning (e.g., Economides and Wood, 2009). The natural gas value chain analysis summarized in the present study provides a basis for enhanced competitiveness and formulates hints for policy and strategy optimization, as well as operational performance excellence.

Large sections of the US natural gas industry are tightly regulated. The aim is to provide ground rules for the economic decision-making process in the energy industry. This paper outlines the decision-making and rate-making frameworks that govern and integrate the physical and the financial value chains of the natural gas business. The value adding and earning potential along the value chain within the interconnected decision-making framework are analyzed. The analysis reveals how regulatory and energy policy instruments have supported and - at times - depressed natural gas prices (both wellhead & retail prices). Different measures may effectuate an impact on natural gas price-making at different time-scales. The relationships between regulatory, policy and corporate investment decisions on one hand, and the price of natural gas on the other hand, provide room for tactical instruments to enhance earnings in the natural gas business.

This paper is organized as follows: Section 2 briefly outlines the emergence of the global market for natural gas. Sections 3 and 4 then depict the physical and financial value chains, respectively. The governing economic and liberalization principles are summarized in Sections 5 and 6. Decision-making steps and the critical role of regulations and policy measures for the natural gas value chain are discussed in Section 7. Examples of corporate portfolio strategies are detailed for US energy utilities in Section 8. Implications for Europe and recommendations and conclusions are formulated in Sections 9 and 10.

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This paper expresses US natural gas prices in concise USD/ Mcf notation. Henry Hub prices are formally posted in USD/ mmBtu. The alternative price measure for 1 USD/mmBtu is 1 USD/Mcf, where mmBtu stands for a caloric value of million British thermal units and Mcf for a volume of thousand cubic feet. The caloric value of 1000 cf (1 Mcf) natural gas is about 1 mmBTu. More detailed examples of the fractional variations in caloric values of natural gas resources are included in a recent review by Foss (2007).

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## 2. Brief historical outline

Natural gas resources are unevenly distributed around the world, which means that pipelines and LNG shipping routes connect production regions with consumption markets (Fig. 2). In 2009, the US holds 278,000 miles of major transmission pipelines (Miesner, 2009) and Europe 18,542 km (equivalent to 11,521 miles; Makholm, 2007). The growing imbalance between local demand markets and local production regions requires major increases in global transport capacity (Hartley and Medlock, 2006a, b; Berkel and Roodhart, 2008). Natural gas sourced from multiple sources is transported via a dedicated global network toward the world's principal market regions. Within these market regions, local distribution companies grid into the end-consumer locations (households, offices, factories, and power plants).

The natural gas market has grown fast from an early market for methane that was created first in the UK by heating locally mined coal, producing so-called manufactured gas for lighting factories and cities in the 1800s. The US pioneered long-distance natural gas transmission systems with a 40 km pipeline at Rochester in 1870, and the first high-pressure transmission system was built in 1891 over 198 km from an Indiana natural gas field to Chicago (Busby, 1999). Long-distance interstate gas transmission began to become profitable in the 1920s and by 1931 several long-distance transmission systems had been constructed across the US (Hilt, 1950).

Crucial in determining the cost of new transmission pipelines is the relative capital outlay on building, operating and maintenance cost of the pipe and of the compressor stations. It is necessary to account for the costs of construction of the line and the compressor stations, as well as the cost of running all the equipment. Models for efficient gas transmission focus on the two basic capital inputs for the asset: pipes and compressors (e.g. Chenery, 1949). Compressors are required to provide pressure for the gas transport, which decreases gradually due to frictional losses of energy when gas is moved along the pipe. The energy loss in the pipe due to friction in transmission is a decreasing function of pipe size. It follows that greater pipe diameters require less compressor capacity to pump any given amount of gas over a specific distance. The conclusion is that cost optimization uses a substitution between pipes and compressors, based on calculations of energy loss and the effect of equipment's capacity size in reducing this loss (Robinson, 1972).

Since the mid-1950s experimentation began with LNG plants and liquefied natural gas was shipped over distances that made pipelines uneconomic. The LNG market is still under development and has gained global momentum since the turn of the Millennium. A further, massive expansion of the global LNG transport infrastructure is nearing completion, with the bulk of delivery capacity coming
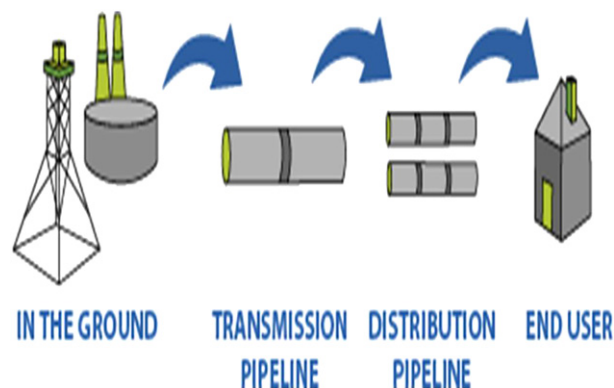


**Fig. 2.** Typical cartoon for value chain of natural gas business is replaced in this study by a more sophisticated workflow breakdown in Fig. 3.

onstream by 2011. For example, the US has approved LNG capacity plans that could land upto 70 Bcf/d from 2012 onward (Foss, 2007). However, it remains uncertain what portion of the approved capacity plans will actually be built. In 2008, the operational US Gulf Coast receiving capacity was 8 Bcf/d and the US East Coast receiving capacity amounted to nearly 5 Bcf/d (DOE/EIA, 2009). In 2008, only 7.5% of the available LNG landing capacity was actually used in the US, which can be inferred from the fact that LNG imports had declined to a mere 352 Bcf which equates to daily average LNG landings of 0.96 Bcf/d in 2008. What is more, some 14% of the 2008 LNG US imports (i.e. 49 Bcf of the total 352 Bcf imported, DOE data) were re-exported and resold either at a loss or forwarded at net import prices to customers abroad (see DOE-EIA LNG import/export balance sheets, 2009) due to the depressed domestic prices and demand in the 2nd half of 2008.

At present, Earth's proved ultimate recoverable reserves of conventional oil and gas amount to 2000 Gbbls and 12,000 tcf, respectively (Laherrere and Wingert, 2008). Oil reserves from conventional sources can satisfy our oil consumption rate trend for the next 20 years and can be extended by unconventional oil reserves for at least an additional decade or more. Natural gas reserves last for another 80–100 years at the present consumption rate trend. In 2008, the world consumed oil at a rate of 85 million bbls/d (30 Gbbls/y) and natural gas at a rate of 315 Bcf/d, corresponding to 115 tcf/y (DOE/EIA, 2009).

Ultimately, it is the demand of end-consumers who must pay for all engineering efforts by natural gas producers, shippers, transmission providers and retailers, which determines whether regional natural gas markets can develop successfully. Essentially, the physical value chain of natural gas that has been built around our planet is supported by a financial value chain, and vice versa. This paper analyzes the key relationships between these two value chains, and concentrates on the decision-making framework crucial for success in the natural gas business.

## 3. Physical value chain for natural gas

The physical workflow architecture for the natural gas business is built around a capital-intensive asset base. Fig. 2 shows a simple cartoon as is commonly used to depict the natural gas value chain. This study proposes a more detailed breakdown of the physical value chain as shown in Fig. 3. The assets of each of the three principal business segments are held by E&P companies (Upstream), gas transmission providers (Midstream) and Local Distribution Companies (Downstream), the latter often owned by utility providers. Liberalization of the US natural gas market in the late 20th Century has led to a situation where end-users can built dedicated pipelines in joint ventures with midstream (and sometimes upstream) transmission providers which bypasses the LCD tariff zones. In the US, 60% of the retail gas is delivered through LDCs, and another 40% is bypassed by mainline pipeline systems (Tobin, 2008). The trend is that more and more end-users will bypass the LDCs in order to save on tariffs.

The Shippers and Traders are crucial institutions that link the Upstream and Downstream business segment. These marketers buy gas at the wellheads and sell to utilities and end-users. Their service is warranted by the volumes booked on transmission providers of interstate pipelines that transport gas pursuant to FERC regulations. The regional natural gas transmission companies control the portion of the network between the gas supply and production sources. The local gas distribution company is responsible for delivery of the gas between the local city gates and the customer base (commercial and residential). The shippers and traders act as liaisons between the production companies and between the transmission and local distribution companies (Gabriel et al., 2005; Murry and Zhu, 2008).

The US natural gas market has been strongly affected by regulations of the US Federal Energy Regulatory Commission (FERC). For example, FERC Orders 436 (1985) and 636 (1992) mandated that
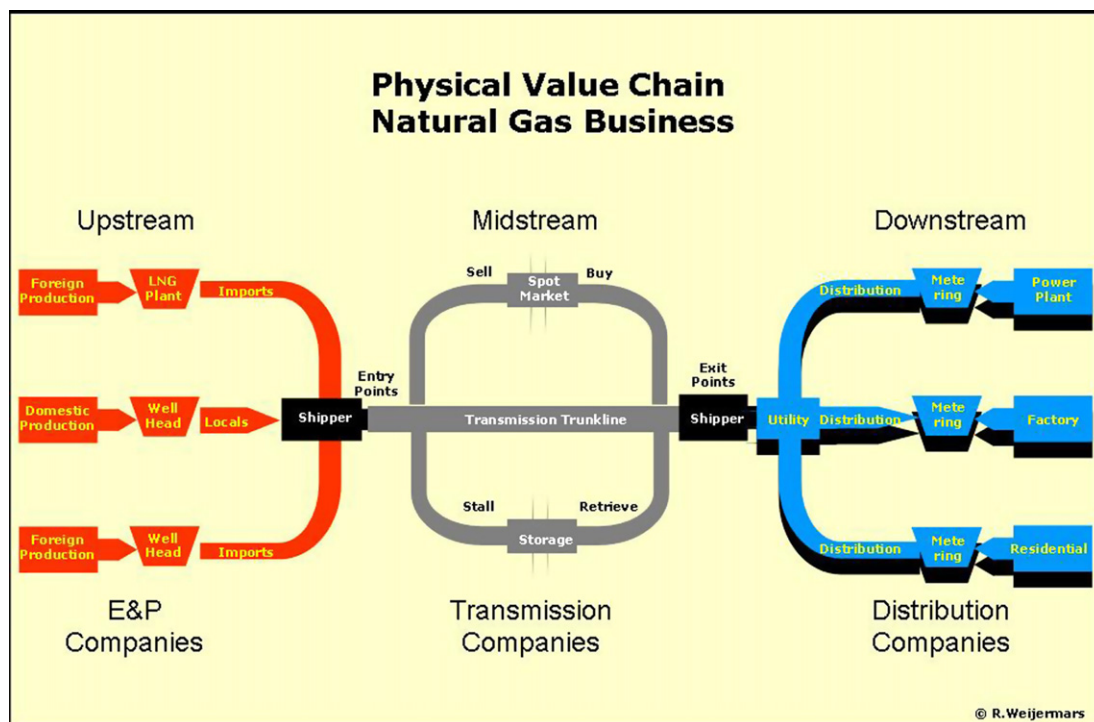
**Fig. 3.** Physical value chain for natural gas trade. Natural gas produced by the upstream business segment is sold by shippers and traders to end-users in the downstream segment. The transmission and storage segment (Midstream) provides transport capacity to shippers. In the US model, the returns of Utility companies and Natural Gas transmission companies are regulated, principally by state regulators and a federal regulator, respectively. The black path behind the blue fork illustrates that shippers and in some cases, producers, can sell gas directly to the retailers, and can bypass the LDC network when a dedicated pipeline serves the end-consumer.
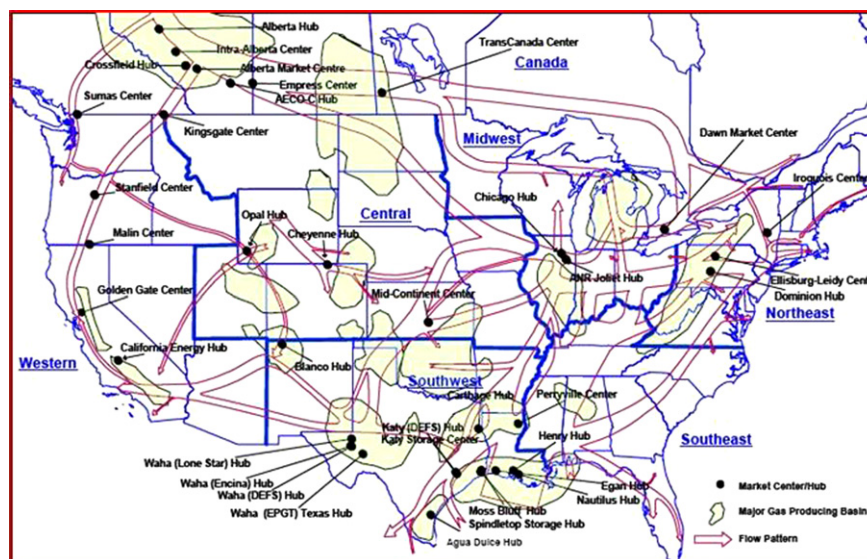
**Fig. 4.** Major US and Canadian Market Centers (Hubs), gas production basins and interstate pipeline flows [from Tobin (2003)].

interstate natural gas pipeline companies transformed themselves from buyers and sellers of natural gas into on one hand strictly physical gas transmission providers and on the other hand strictly trading companies for gas sales. US gas marketers and traders have emerged after FERC order 436, and accelerated when voluntary TPA (third party pipeline access) was initiated by FERC order 636, and enforced in 1993 (Dahl, 2004). There were only 50 US marketers (shippers) in 1986 that purchased gas for resale, to increase to some 260 companies in the 1990s. Market centers ('hubs') evolved rapidly since the 1990s to provide marketing services that are in part linked to physical gas movements. Originally, the number of cross-links between major pipelines remained limited and were mainly designed to ensure security of supply (emergency inter-connects) and not primarily for gas trading purposes. That situation has been reversed by the FERC regulations which promoted market liquidity and the market center concept was favorably supported by regulations to increase the interchange and trading of gas across pipeline systems and to foster competitive efficiencies among market centers (see Johnson et al., 1999).

Trading occurs physically at major hubs, of which the Louisiana Henry Hub is the most important intersection point of interstate pipelines (Fig. 4). A 2003 market center review (Tobin, 2003) concluded that 37 hubs operated in North America, located in the US (28 hubs) and Canada (9 hubs). Although the number of hubs had not changed significantly since 1996 (39 hubs; 30 US; 9 Canada), their scale of operations had expanded significantly by 2003. Of the 37 operational hubs, some were entirely dedicated to producer services, and 28 hubs had web-based trading and nomination platforms, providing purposeful price transparency and trading volumes (i.e. liquidity in the market). In the period (1996–2003) 8 US hubs were de-activated and 6 new ones emerged. Also, 12 US hubs changed ownership (Tobin, 2003). The number of pipeline interconnections had also effectively expanded after FERC Order 636 (see Table 1, described in Section 6).

The successful market centers that remain have large transaction volumes and minimize the shippers' transaction costs. Some centers continue under FERC regulation with a maximum rate but with permission to trade at discount (below the maximum) when applying transparency of discount rules. The 2001 collapse of ENRON, which operated two hubs that closed upon bankruptcy, dented confidence and liquidity of the gas market, but in 2003 trading volumes were back to 'pre-ENRON collapse' levels (Tobin, 2003).

The market centers or Hubs provide transportation of gas from one interconnected pipeline to another, either via 'wheeling' in a dedicated market center pipeline; or via a direct header exchange between major interstate pipelines. The hubs can store and park gas quantities in linepack or in underground storage facilities (e.g., salt caverns) and balance short-term interruptible supplies for customers. Gas storage capacity has significantly expanded after Order 636 of 1992; at the end of 2008 there were 398 UGS facilities in the US with an aggregated capacity of 3.9 tcf (Tobin, 2005, 2006, 2009). UGS space together with linepack and LNG storage capacity sums up to a total working gas capacity of 4.3 tcf, which corresponds to 20% of the US total annual natural gas consumption of 2008.

The market hubs commonly provide shippers with administration services of gas (title) transfers and nominations, and additional price risk management and hedging services. 'Hub-to-hub transfer' is also possible, whereby trading occurs when the cost of physical shipping of gas between hubs is higher than trading volumes at distant locations to provide the shipper with delivery capacity. Market centers also provide a focal point for spot market transactions and gas trading, and this provides sellers with a platform to reach those buyers who are willing to pay the most attractive commodity price.

The US 2008 natural gas consumption of 22 tcf amounts to a theoretical average network-load minimum of 62.5 Bcf/d. However, gas moves and trades many times over, so that minimum transport need is overtaken by traded transport; the physical loops between production and demand regions, and the intermediary trading hub lead to much higher daily transmission volumes. For example, in 2001, the top 20 US marketers jointly moved nearly 170 Bcf/d, which translates to 62.4 tcf/y (Dahl, 2004). Natural gas currently accounts for 23% of the US primary energy demand (DOE/EIA, 2009).

The next section details some of the financial transactions that occur between the various business partners involved in the natural gas value chain.

## 4. Financial value chain for natural gas

What US retail customers must pay for their natural gas commodity is the result of a complex process of negotiation between utility companies, state regulators and consumer advocacy groups. Lower wholesale prices translate over time to lower

**Table 1**
Major regulations for US Gas Industry by US Congress, FERC & Court Rulings.

| Date | US Congress Energy Acts | Principal objective |
|---|---|---|
| 1978 | Natural Gas Policy Act | Provide for gradual phase-out of producer rate regulation and incremental pricing guidelines for industrial gas sales; led to upscaling of cogeneration of electricity in major industrial heat producers in conjunction with Public Utility Regulatory Policies Act (PURPA) |
| 1989 | Natural Gas Wellhead Decontrol Act | Complete deregulation of wellhead gas prices |
| 1992 | Energy Policy Act | Reduce US dependence on foreign oil (federal bodies should use natural gas engines and utilities) and provide funding for research to recover more natural gas from conventional and unconventional resources |
| 2005 | Energy Policy Act | FERC obtained Penal Authority to penalize company's that do not abide to FERC Code of Conduct and Regulation Orders |
| | **FERC orders no.** | **Principal objective** |
| 1985 | 436 | Third Party Access (TPA) to gas transmission pipelines encouraged, activate discounts for shippers and producers |
| 1987 | 500 | Open access to gas transmission pipelines further regulated and shift cost of long-term obligations to producers and shippers in case of no-take of gas volumes |
| 1988 | 497 | Separate operating employees of interstate natural gas pipelines from their marketing affiliates to function independently of each other |
| 1992 | 636 | Mandate full Third Party Access (TPA) to gas transmission pipelines |
| 1996 | 889 | Enforce that employees of the transmission providers engaged in transmission system operations function independently of marketing employees |
| 2000 | 637 | Provide full transparency about tariffs and capacity via Open Access Same-time Online Information Platform; daily auctions |
| 2003 | 2004 | Corporate separation of marketing & title transfer services to shippers and gas transmission services, overruled by landmark court ruling in 2006 and CFR 18 revision in 2008 |
| 2008 | 712 | More efficient pipeline capacity release standards |
| 2008 | Revision CFR 18 part 358 | Revision of Order 497, 889 and 2004 based on 2006 Court ruling to allow integrated planning and competitive solicitation of and transmission capacity; limited to a strict functional separation of transmission function employees and marketing function employees |
| | **Landmark court rulings** | **Principal outcome** |
| 1954 | Phillips decision | Federal Power Commission must enforce wellhead price control and use authority to regulate E&P industry |
| 2006 | Ruling in National Fuel Gas Supply Corporation versus FERC | Court rejects the treatment of Energy Affiliates in FERC order no. 2004, implying FERC's corporate separation between Energy and marketing affiliates is not required as long as functional no-conduit rule is fulfilled |

consumer prices. The US wholesale price for natural gas is set at the Henry Hub, the largest centralized point for natural gas spot and futures trading in the United States. The New York Mercantile Exchange (NYMEX) uses the Henry Hub as the point of delivery for its natural gas futures contracts, which began trading on April 3, 1990. The monthly and annual spreads of the wellhead and spot market price are graphed in Figs. 5 and 6. The US wellhead prices are reported in EIA's Natural Gas Monthly as received from natural gas producers for marketed gas. [Marketed natural gas includes ethane, butane, propane gas liquids, typically making up 5% of US natural gas production when 95% methane ('dry' natural gas) is produced (Budzik, 2002)].

Fig. 5 shows that average wellhead prices over the period 1995 to 1999 stood at a modest 2 USD/Mcf, spiked in 2001 with a monthly averaged wellhead price high of 6 USD/Mcf (but annual price averages ranging between 3 and 4 USD/Mcf for 1999−2002),
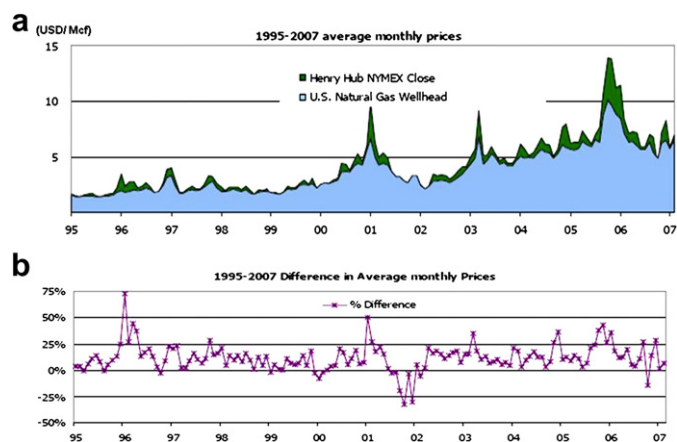


**Fig. 5.** (a) Monthly averaged wellhead price of US Natural Gas versus Henry Hub spot market price. (b) Difference in monthly averaged wellhead and Henry Hub spot market price. The annual average US gas price is graphed in Fig. 8 [compilation by Ontario Power Authority, 2007].
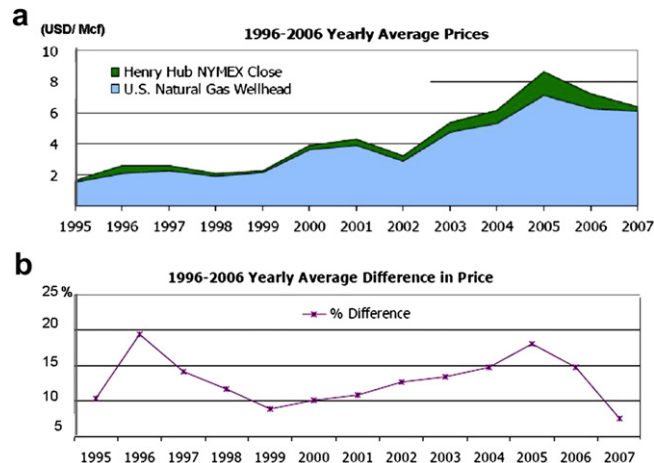


**Fig. 6.** (a) Annually averaged wellhead price of US Natural Gas versus Henry Hub spot market price. (b) Difference in annually averaged wellhead and Henry Hub spot market price [compilation by Ontario Power Authority (2007)].
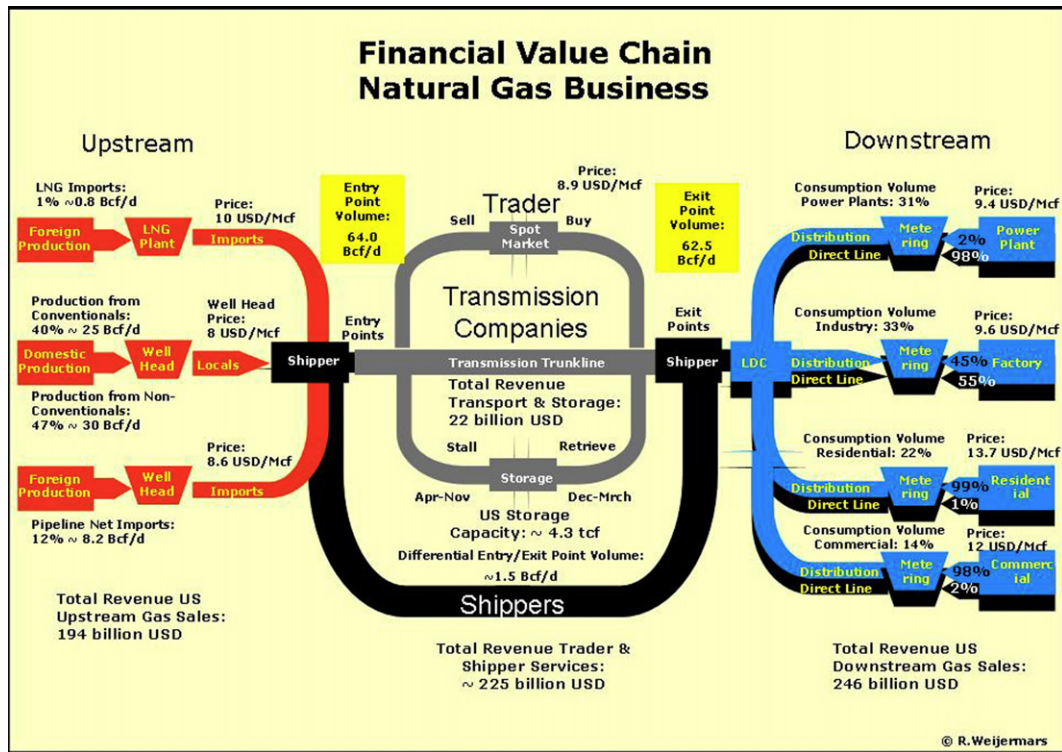
**Fig. 7.** Financial value chain for natural gas trade. Rates of return on investments by utility companies and natural gas transmission companies are regulated, principally by state regulators and federal regulators, respectively. The prices and revenues indicated are annually averaged values for the US natural gas market in 2008 (data inferred from Reports and Tables by DOE Energy Information Administration; ratio between LDC and direct distribution lines are from Tobin, 2008).

and gained a firm monthly wellhead price floor of 5 USD/Mcf from 2003 onward (with a peak wellhead price of 10 USD/Mcf at year-end of 2005).

The difference between the wellhead and spot market price is a coarse measure of the efficiency in bringing natural gas from wellhead to the wholesale clients that need the gas in order to match pre-set contractual quantities for end-consumers with real physical volumes. Over the period 1995–2007, the difference between wellhead and wholesale prices has ranged between 12% (monthly) and 13% (yearly), with standard deviation of 13% and 5%, respectively (Figs. 5 and 6). Over the period August 1996 to December 2000, the monthly averaged price differential was 10.4% (Budzik, 2002).

Comprehensive analysis of the price elasticity of the US gas market by Foss (2007) indicates that, over the coming decade, 6 USD/Mcf represents an effective cap on natural gas priced while 3 USD/Mcf represents a floor, and that this 'price deck' provides fierce competition for LNG imports. This price scenario converges with the price scenarios modeled by the US National Commission on Energy Policy (2003). The US gas price study by Foss (2007) also demonstrates the close relationship between ultimate recoverable gas reserves and wellhead price that makes such recovery economic. In any case, the combined US and Canadian domestic natural gas production in 2007 stood at 70 Bcf/d, with 40 Bcf/d coming from conventionals, and 30 Bcf/d from unconventionals. The US alone produced 55 Bcf/d in 2008, with 25 Bcf/d from conventionals and 30 Bcf/d from unconventional resources: i.e. tight gas — 17 Bcf/d, coal bed methane — 5 Bcf/d, and shale gas — 8 Bcf/d (DOE/EIA, 2009).

The US natural gas value chain system (producer, marketer — i.e. shippers & traders —, transmission and local distribution apparatus) has been transformed significantly over the past decades. Fig. 7 details some of the major transactions that occur between all parties involved in the natural gas value chain. US natural gas transmission rates depend upon type of contract (fixed, interruptable, etc.). A typical shipper agreement pays transporters a tariff of 14% of retail price for transmission and storage, amounting to approximately 1 USD for each Mcf of gas delivered, commonly across 4 or 5 tariff zones (Rextag, 2009). The US natural gas consumption of 62.5 Bcf/d in 2008 means the US energy industry transmitted daily a natural gas volume of $62.5 \times 10^6$ Mcf with an overall wellhead worth (at 6 USD/Mcf) of 375 million USD/



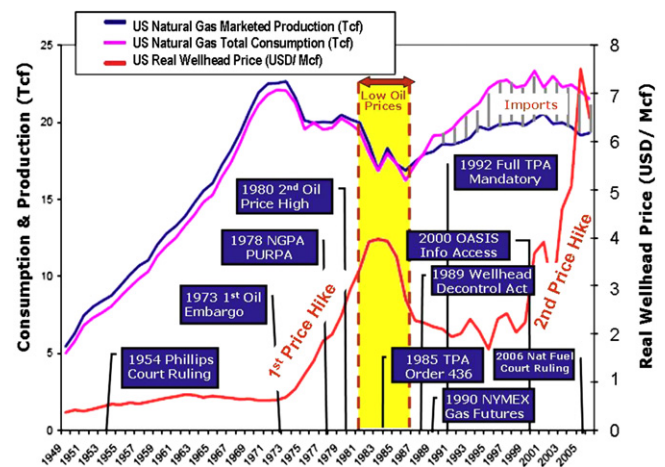**Fig. 8.** Long-term real wellhead price for natural gas and spread between total consumption an production. A 15 year consumption decline that started in 1973 bottomed out in 1988. The recovery fell slightly back in 2005 and 2006 in response to rising natural gas prices, but turned up again in 2007 as prices hikes settled. 'Real' wellhead prices implies that historic wellhead prices have been inflation-adjusted.

d. The daily US transmission volume of $62.5 \times 10^6$ Mcf at an average 1 USD tariff amounts to a natural gas pipeline intake of 62.5 million USD/d or 22 billion USD/y. This converges with an estimate of 20 billion USD for the 2008 revenue of the US natural gas transmission industry (Miesner, 2009).

The US federal and state regulators have played a major role in the development of liquidity in the natural gas market (and corporate strategies). Because the natural gas industry has been subject to rather complex regulations, the principles of market liberalization for the natural gas business are briefly reviewed in the next section.

## 5. Economic liberalization principles

The US Congress laid the basis for a Keynesian regulation (Keynes, 1936) of the utility industry by the Natural Gas Act of 1938, but regulation of the wellhead price for US natural gas was not enforced until the US supreme court's Phillips decison of 1954, which ordered the Federal Power Commission (FERCs pre-deccesor) to establish price control over the E&P gas industry (e.g., Sturm, 1997). The result was that the wellhead price for natural gas stayed stable for two decades, below 1 USD/Mcf in the period between 1954 and 1973 (see Fig. 8). Over the same period, the US natural gas consumption grew steadily from a mere 8 tcf in 1954 to a robust 22 tcf in 1973. The 1973 OPEC embargo led to major revisions of the US Federal Natural Gas Policy Acts (NGPA) in 1978 and 1992. The Natural Gas Policy Act of 1978 reversed the Phillips decision and in anticipation of the Court's decision wellhead prices were steadily climbing in the period between 1973 and 1983, with a temporary peak value of 4 USD/Mcf in 1983.

The steady climb of the natural gas price in the decade of 1973–1983 was accompanied by a decline in consumption that continued till 1988, when the annual US natural gas consumption bottomed out at 17 tcf (marking a 23% consumption decline from 22 tcf in 1973). The consumption decline reached its deepest contraction in volumes between 1981 and 1987, when global oil prices were so low that North Sea oil production was partly shut-in. Inter-fuel competition clearly led to a shift from natural gas to oil in the period 1981–1987.

The US Congress Energy Policy Act of 1992, in its aim to further reduce US dependency on foreign oil, provided federal funding for research into development of natural gas from both conventional and unconventional resources. The 1992 EPA aided the recovery of the natural gas market that had already begun in 1988, and by 2003 had finally regained the 22 tcf consumption level of 30 years earlier. Security of Supply was the principal incentive for US Congress Energy Policy Acts. Given the recovery of the gas market to 22 tcf after 30 years, the US federal energy policy must be concluded as successful. The annualized gas wellhead price, which had declined from its 1983 peak of 4 USD/Mcf to 2 USD/Mcf in 1996, has since risen in step with the market's recovery in consumption volume (Fig. 8), prior to the global financial crisis of 2008/2009.

Another important incentive for the US exploration success for natural gas was based on the earlier 1978 NGPA. The 'old' wellhead price regulation of 1954 was completely reformed by the 1978 Natural Gas Policy Act, which laid the basis for deregulation of the Phillips wellhead price control and thereby stimulated the E&P industry into improving security of supply. The 1978 deregulation dramatically accelerated domestic exploration drilling and production, which eventually led to a recovery of the US natural gas market in the next decade.

The 1978 deregulation, while embracing Milton Friedman's free market concept (Friedmann, 1962), required strong federal regulation to force pipelines to open access to gas sellers into the pipeline grid via a series of FERC regulation orders, starting with Order 436 in 1985. The aim of the FERC orders was to bring liquidity in the gas market and increase trading volumes to bring the gas price and volume into market equilibrium. FERC orders led to the effective unbundling of transmission services and title transfer administration services associated with the market place. Prior to the FERC orders, gas shippers were charged a 'bundled' service package at a standard cost that accounted for all cost incurred by the pipeline in procurement, transportation and delivery of the gas. While the majority of shipper contracts were 'firm' and long-term in the early days of the US deregulation, the majority of the shipper contracts have now become 'interruptible' and short-term.

## 6. FERC's 2008 revised ruling on corporate separation of transmission companies

The US Federal Energy Regulatory Commission (FERC), based in Washington D.C., carries out its responsibilities under the Natural Gas Act to monitor and regulate activities of the US natural gas industry to ensure its competitiveness and assure improved efficiency of the industry's operations [FERC, 18CFR (Code of Federal Regulations)]. FERC regulations focus on standardized business practices and communication methodologies of interstate pipelines in order to create a more integrated and efficient pipeline grid; this effectuates implementation regulation for the US Congress Energy Policies (Table 1). FERC also possesses civil penalty authority granted by US Congress in EP ACT 2005, which provides the full panoply of statutory remedies to address violations of its statutes (FERC NOPR, 2008a,b).

The 1992 FERC order 636 regulated full Third Party Access (TPA) to gas transmission pipelines. The separation of ownership of shippers and transmission services was completed in FERC Order 2004 (issued in 2003), but that was overruled by the US Court of Appeals in a landmark ruling of 2006 and led to a major revision in FERCs deregulation policy (see below).

The landmark 2006 litigation ruling in the US Court of Appeals for the D.C. Circuit in National Fuel Gas Supply Corporation versus FERC rejected the treatment of Energy Affiliates in Order no. 2004. FERC's Notice of Proposed Rule Making (FERC NOPR, 2008a) explicitly states that it is no longer appropriate to retain the corporate separation approach adopted earlier in Order No. 2004. FERC now adopts an "employee functional" separation approach, rather than a "corporate functional" separation approach. The new ruling intends to pinpoint precisely which employees need to function independently from one another. Each transmission provider must appoint and post the name of the Chief Compliance Officer, who is responsible for enforcing the FERC Standards of Conduct, including measures and written procedures in book of account and records available to FERC's inspections. Corporate separation as purported in Order 2004 is no longer required as per Order of 2008. The new ruling requires a strict functional separation of transmission function employees and marketing function employees and combines key elements of Orders 497, 889, and 2004 to provide improved regulation transparency.

The original Order No. 497 (1988) required that interstate natural gas pipelines, to the maximum extent practicable, ensure that their operating employees and the operating employees of their marketing affiliates function independently of each other. Order No. 889 (1996) required that, except in emergency circumstances, the employees of the transmission provider engaged in transmission system operations must function independently of its employees who engage in wholesale merchant functions, or the employees of any of its marketing affiliates (i.e., wholesale sales and purchases of electric energy). Thus, the prohibition keyed off the job function of the employee, rather than by whom he or she was employed. The functional separation between transmission and

merchant personnel for natural gas transmission providers established in Orders no. 497 (1988), and 889 (1996) was subsequently extended into a corporate separation in Order No. 2004 (2003). This impacted the industry's corporate structure, because all major pipeline operators in US have marketing affiliates that handle gas trading and shipping (Dahl, 2004). However, the revision of FERC's 18CFR (and its reformulation of Orders 497, 889 and 2004), FERC now explicitly avoids the impeding of legitimate integrated resource planning and competitive sollicitation. FERC conceded that difficulties could arise when planning employees of a marketing affiliate are prohibited from receiving transmission information. FERC also recognized that vertical integration can produce efficiencies of operation and advantages to an affiliate; having energy or marketing affiliates is not improper if they do not amount to exercises of market power. FERC further understands that planning of new transmission capacity requires consideration of planning employees in the marketing affiliate to ensure the provision of services to customers on a reliable and least cost basis.

The revised Standards of Conduct abandons the separation of energy affiliates and marketing affiliates of transmission providers (FERC, 18CFR): *"Executives should not be impeded to make business decisions by assessing needed data and assess the merits of potential investments; it is unnecessary to 'balkanize' employees from one another by erecting barriers to the free flow of information that could thwart perfectly legitimate efficiencies, which would disadvantage consumers in the form of higher rates."* And: *"If a company finds it is more efficient to have fewer subsidiaries and combine multiple functions in a single affiliate, it need not avoid doing so simply to shield the affiliate's non-marketing employees from the restrictions set by the Standards "* (FERC NOPR, 2008b, p. 27). In other words, integrated gas transmission providers may bundle employees in single companies, as long as the Standards for functional separation of transmission and marketing function employees are respected and enforced by the Chief Compliance Officer.

Attorneys, accountants, risk managers and rate designers do not fall within the scope of the independent-functioning rule but remain subject to the no-conduit rule and may not pass on non-public transmission function information to marketing function employees.

## 7. Decision-making and rate-making in the natural gas value chain

The exploration, production, trading, transportation, distribution and consumption of natural gas is supported by a capital-intensive asset base. The prospect of reasonable and fair returns on investment in its asset base justifies growth of the natural gas industry. The financial value chain of the US natural gas business, schematically represented in Fig. 7, generates an totalized annual revenue of 687 billion USD. The returns on investment tied to those revenues in the upstream sector are generally outperforming the S&P index (see ROCE study by Weijermars, 2009a). However, the returns in the midstream and downstream segments are strictly regulated and cannot outperform the market as the maximum returns are determined by the concurrent market rates authorized by the regulators (see Section 8).

While returns in the oil production business are not directly constrained by regulatory issues, the physical constraints of the natural gas value chain imply that downstream bottlenecks directly affect the wellhead prices. That means that natural gas markets can be either made (or broken) by a combination of the right (or wrong) policies and regulatory measures.

Table 2 lists the crucial elements of the physical value chain and of the interconnected financial value chain. At each stage in the value chain, the connection between the physical and financial

value chains is maintained by a decision-making process. Decisions at each stage in the value chain are impacted by vertical connections in what is here termed the decision-making value chain. There is a critical role for regulations and policies in creating specific circumstances (i.e., market situation, regulatory complexity and speed, profit potential, geopolitical stability, etc.) that jointly determine whether a corporate investment decision will be in favour or against the further development of a specific physical asset in the natural gas value chain.

For example, favorable license policies may either stimulate or defer exploration activities for natural gas. Once discoveries are made, the corporate hurdle rate for field development project approval can be positively impacted by a favorable tax regime. At each subsequent step in the value chain, corporate decisions determine whether or not any new assets will be developed. The discussion of Sections 3—6 has outlined how the US natural gas industry has developed under strong federal control and how a range of stimulus packages has led to investments in the development of new fields and technologies. For example, horizontal drilling techniques became play openers for the unconventional natural gas resources. Therefore, the regulators of transmission, storage and LNG capacity (FERC in the US) and the regulators of LDCs and utility services (State Public Utility Commissions) jointly control the authorized returns on investment related to the asset base of these companies. That means that the federal and state regulators play a key role in determining which incentive premiums they grant for both new projects and innovative projects.

Long-term, mid-term and short-term measures are distinguished based upon the duration of their impact on the performance of the US natural gas market. Some of the major measures (see Table 2) are discussed for each category, in turn, below.

### 7.1. Short-term measures

Intermediate rate adjustments (either upward or downward) by regulators can help to dampen volatility in wellhead and wholesale prices. Industry on the other hand, must be quick to react to oversupply situations to prevent excessive price drops. The margins on earnings by retail and transmission companies are regulated in most countries. This sets a ceiling for return on investments, but no floor for natural gas prices. In the course of 2009, wholesale prices for natural gas around the world have been tumbling off their mid-2008 highs. Fig. 9a shows in detail how the US wellhead and spot market prices have slipped during the economic recession of 2008/2009. Oil reached its lowest price level in December 26, 2008, and has since steadily regained ground to resume reasonable price levels. US wellhead and spot market prices for natural gas, however, have continued to decline and Henry Hub wholesale natural gas reached a lowest daily average of 1.84 USD/Mcf on September 4, 2009. Retail prices for natural gas have been raised by utilities since May 2009, in line with the earlier progressive recovery of the oil prices (Fig. 9a, rise of residential gas prices). But the seasonal rise in natural gas retail prices since May 2009, controlled by the utilities, also ceased its recovery in September 2009. That is because the persistent decline of natural gas wellhead and wholesale prices in the first half of 2009 has led gas utility companies in September 2009 to seek permission from Public Utility Commissions in their respective states for downward correction of their retail prices. These rate cuts for retail gas, with the effect of lowering customer bills, are substantial, e.g., 21% for Avista Utilities in Oregon, 17% for Pudget Sound Energy in Washington, 20% for Questar Gas in Utah, and 22% for Intermountain Gas in Idaho (SNL Energy Natural Gas Weekly, September 2009).

Fig. 9b shows the US seasonal storage cycle, and how storage volumes in the fall of 2009 climbed rapidly as compared to previous years. The aggregate peak capacity of US underground natural gas

**Table 2**
Decision-making steps and critical role of regulations for the natural gas value chain (from wellhead to burner-tip).

| Business segment | Physical value chain | Decision-making steps | Financial value chain | Critical role of regulatory policies & gas prices effects |
|---|---|---|---|---|
| Upstream (E&P companies) | Exploration<br>Gas reservoir discovery | Acquisition exploration license & expenditure<br>Translation of discovery of reserves (GIP) into P90 volumes | Exploration cost<br>Appraisal drilling cost | License fees & policies on national access<br>Tax regime can stimulate small and new field development<br>(e.g. Dutch small field policy, US tax incentives for unconventionals) |
| | Project appraisal | Drop or develop decision based on NPV of proven (P90) reserve volume. | Corporate budget covers appraisal work | GIP P90 volume multiplied by long-term wellhead price minus cost of gas recovery facilities (CAPEX), operational expenditure (OPEX), tax and depreciation |
| | Field development | Portfolio & risk analysis; hurdle rate for IRR, corporate strategy and discount model conclusive for project development | Project CAPEX goes into work executed by field development contractors | Corporate hurdle rate use long-term natural gas price equivalent of long-term oil prices (see Table 2) |
| | Production | Production upon project completion 2–3 yrs after decision for field development | Cash flow from gas sales at wellhead starts to pay back field development's CAPEX & covers OPEX; company can pay shareholders and invest in new development projects | Production continues unless wellhead price drops below hurdle rate assumption or production costs exceed sales proceeds. |
| Shippers & traders | Gas Shipper measurement of gas volume at transmission entry point | Shipper buys gas from wellhead (or from trader at spot market) when profit margin exists between wellhead price and utility company price; needs to book transmission capacity to enable sales to utilities | Differential between wholesale price and wellhead price (plus cost of transmission and storage) pays for shipper's services | Sales margin must justify buying & selling; degree of unbundling & deregulation determines TPA & competition |
| Midstream (Transmission Companies) | Transmission (pipeline/LNG) | Transmission company holds open seasons to determine future need for transmission capacity (pipeline or LNG terminals & fleet); portfolio & risk analysis; hurdle rate for IRR, corporate strategy and discount model conclusive for project development; delays from land-use permits may incur extra costs | Transportation tariffs translate into Net Operating Income (NOI) that covers Cost of Capital for project (WACC) | Regulator authorizes bandwidth for NOI and sets transmission tariffs. Transmission income drops when sale volumes of shippers in short-term and flexible contracts decline. |
| | Storage & buffer (UGS, linepack, etc) | Storage capacity built when shippers indicate need in open seasons; hurdle rate for IRR, corporate strategy and discount model conclusive for project development | Storage tariffs translate into Net Operating Income (NOI) that covers Cost of Capital for project (WACC) | Regulator authorizes bandwidth for NOI and thus sets storage tariffs. |
| Shippers & traders | Gas Shipper measurement of gas volume at transmission exit point | Shipper sells gas to utility when needed or diverts to storage for later use when price differentials are more attractive | Differential between wholesale price and Wellhead price (plus cost of transmission and storage) pays for Shipper's Services | Margin justifies buying & selling |
| Downstream (utility companies) | Distribution Pipeline | Utility company builds distribution capacity when end user-demand justify project cost | Retail price translates into Net Operating Income (NOI) that covers Cost of Capital for project (WACC) | State Regulators authorize bandwidth for NOI. |
| | End-users & retail metering services | Residential users (Choose most practical & economic fuel source for heating & cooking at home)<br>Industrial users (use most economic fuel – fierce inter-fuel competition)<br>Power stations (choice between hydro, wind, photovoltaic, geothermal, nuclear, coal, gas or combined cycle sources) | Differential between wholesale price and utility price pays for the LDC services.<br>End user consumption volumes determined by seasonal temperatures (summer-winter cycle, industrial activity (economic recession versus growth), inter-fuel competition and environmental issues. | Pricing of alternative fuel sources |
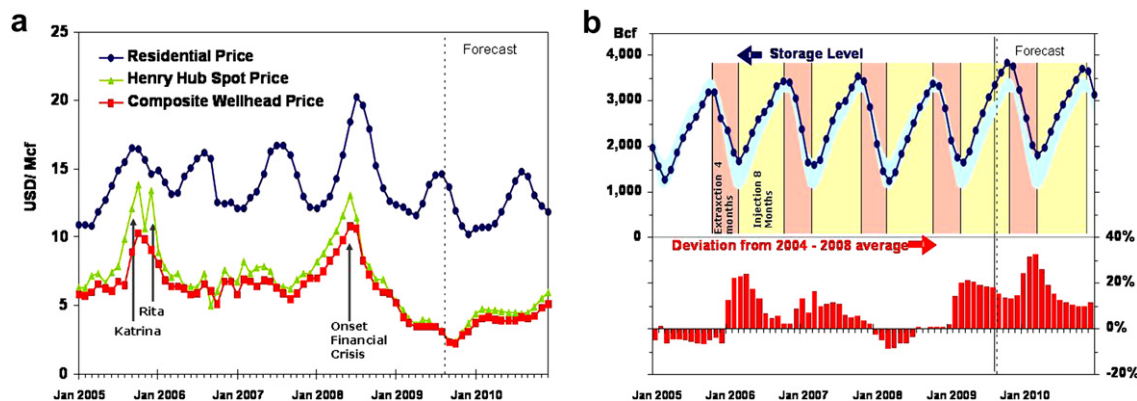
Fig. 9. (a) Seasonal cycle of residential retail prices for natural gas is mostly affected by slowing demand in summer and rising demand in winter. Wholesale price (at Henry Hub) is affected by hurricanes (Katrina and Rita in 2005) and the financial crisis starting July 2008. Contemporary wellhead and spot market prices have followed the recessional market in a downward trend. (b) US Storage capacity is in 2009 utilized more and faster than in previous years, due to slower demand and sustained domestic production. All data and forecasts for 2010 are by DOE/EIA (2009).

storage reached 3889 Bcf and the US total 2009 working gas design capacity was 4313 Bcf (DOE/EIA, 2009). As storage and working gas design capacity become more rapidly filled by steadily growing domestic production and delayed consumer demand, price-induced shut-ins have started to occur. For example, the low gas prices of September 2009 led analysts to conclude that September 2009 price levels, ranging between 2.60 and 3 USD/Mcf, threaten price-induced shut-ins for 2 to 6% of the US domestic production (analyst report by Kristin.Friel@BarclaysCapital.com, Sept 2009).

Fig. 10a documents the price development in the US natural gas market as the onset of the 2008/2009 financial crisis occurred. The 2009 glut in natural gas supply was compounded by a steady success in the US domestic natural gas production increase (6% up in 2008), whereas consumer demand lagged behind due to the economic recession. The decline in natural gas prices was not triggered by a domestic oversupply in natural gas. Prices peaked in July 2008 (Henry Hub noted a daily average wholesale gas price high of 13.32 USD/Mcf on July 3, 2008) in step with oil price highs as the global economy boomed, but began a year long decline when the first signs of the financial crisis came to the forefront later in July 2008 (Fig. 10a). The effect of the US success with the development of its unconventional gas plays was that a slight oversupply in 2009 continues to depress concurrent prices for natural gas.

Price drops across the natural gas value chain in the period July 2008 to September 2009 are not limited to the US alone. Fig. 10b plots the UK wholesale price for natural gas at the National Balancing Point against the annually averaged price for Brent Blend.

While crude oil has reached bottom prices in December 2008, a steady recovery has occurred for oil prices in 2009. This is not so for natural gas, which continued its price decline since the onset in July 2008 until mid 2009 (Fig. 10b).

### 7.2. Mid-term measures

Socialization of the cost for certain innovations may help to hedge risk and speed up hesitating companies to move in and start building certain assets rather than waiting for future solutions. An example may be the new American Clean Energy and Security Act of 2009, also known as the Waxman–Markey cap-and-trade bill after its prime senatorial backers, which passed the US House of Representatives on June 26, 2009. The impact of this new US legislation may lead to fuel switches from pollutive coal to cleaner natural gas and carbon emission cap prices of 12–50 USD per metric ton. The outlook for the US is a sustained and growing dependency on natural gas. Electricity generation is now fueled by 18 Bcf/d of natural gas, a usage that could double by 2020. Inter-fuel competition also favours renewables such as wind and solar.

The anticipated switch toward power generation using cleaner natural gas over the next two decades implies further growth in the US domestic production of natural gas is required by some 18 Bcf/d as compared to 2009. Such a growth does not immediately follow from the current modest growth path for US natural gas production. That is because production of unconventionals increased 12 Bcf/d from 2000 to 2008, but conventionals already declined by



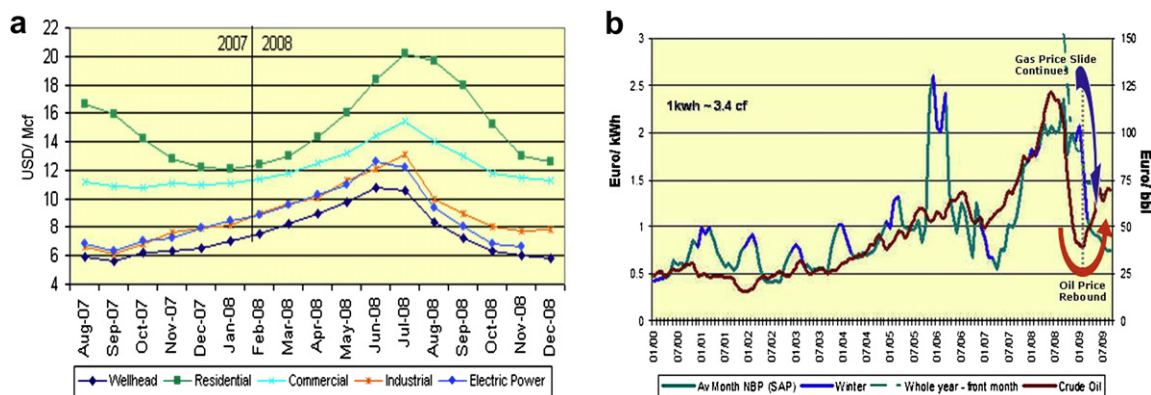Fig. 10. (a): Retail prices peaked ahead of their seasonal cycle in July (and not winter) and started to slip as the economic recession due to the financial crisis evolved. US Wellhead prices follow the demand market in a downward trend. (All data from DOE/IEA.) (b) UK wholesale price for natural gas (left hand scale) against Brent Blend (right hand scale). (Gas data from NPBA; oil from Bloomberg.)
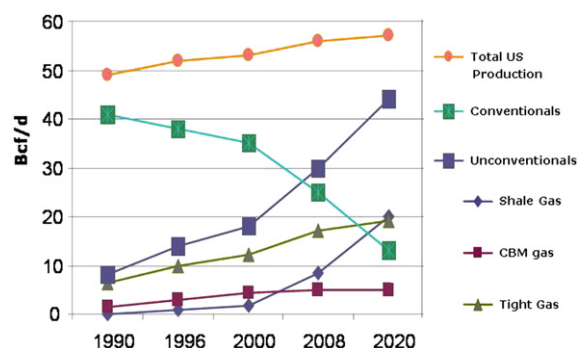
**Fig. 11.** Production from unconventional resources (shale gas, CBM, and tight sands) accounts for more than half of the US natural gas production. Conventionals are in decline and barely balanced by production increases from unconventionals [data from DOE/EIA (2009)].

10 Bcf/d over the same period, allowing for a net increase of only 2 Bcf/d. The US natural gas production from conventionals will further decline and drop to 13 Bcf/d by 2020 (Fig. 11). Recent estimates indicate that shale gas output is expected to more than double to 20 Bcf/d by 2020. But that is only just enough to maintain US production at its current level. Production of CBM has remained flat since the early 2000s when interest shifted to shale gas; production from tight sands is also leveling off, according to EIA projections. If domestic production cannot grow in step with the anticipated rise in demand for natural gas, imports from Canada and LNG from overseas must fill the gap. Nonetheless, in 2008 some 14% of the LNG imported by the US was resold either at a loss or forwarded at net import prices to customers abroad due to the depressed domestic prices and the suppressed demand (see DOE/EIA, 2009, LNG import/export balance sheets).

### 7.3. Long-term measures

Ultimate natural gas reserves in the US have doubled to 2,000 tcf in the last 25 years, thanks to tax incentives to stimulate the development of natural gas production from unconventional reservoirs: shales, CBM, and tight sands. Europe could learn form the US success in the development of a natural gas industry with an aggregate revenue of 687 billion USD in 2008 (Fig. 8), that seemed already past its life-cycle peak in the early 1970s (see Fig. 9). One example is the 1980 section 29, addition to the US Tax Code, which continues to provide credits for drilling and production from CBM plays. Of course the state itself is benefitting too, because the estimated annual tax intake in the US on natural gas profits amounts to some 14 billion USD (using 10% margin assumption on revenues and tax rate of 20%). The aggregated revenue value of the European natural gas industry has not been assessed here, but US numbers are indicative for Europe, as the European consumption of natural gas is comparable to that of the US. European upstream (natural gas) revenues are lower than those in the US due to its lower indigenous production, and this leads to a rough estimated of annual revenue of some 500 billion Euro for the European natural gas business, and taxation on profits (at 30% rates) amounting to 15 billion Euros.

## 8. Portfolio strategies and rate-making by US energy utilities

The major US integrated energy utilities and natural gas transmission companies have chosen various portfolio strategies, whereby corporate alignment is sought between natural gas transmission services and other assets and services in their corporate portfolios. For example, five firms (identified here concisely by NYSE symbols: EP, SE, WMB, KMP and BWP) are
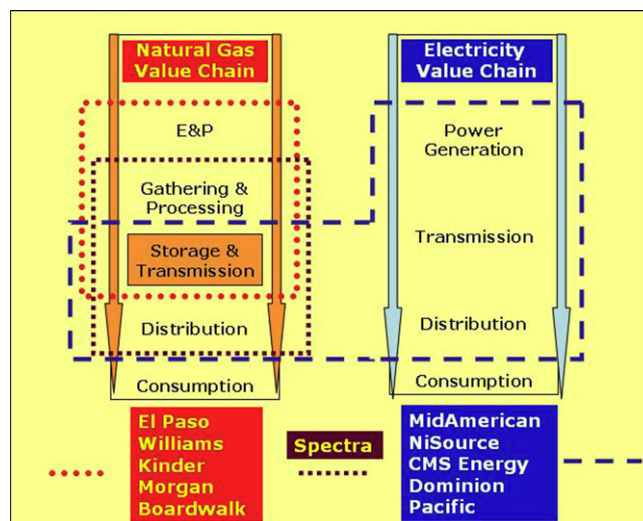


**Fig. 12.** Major US Energy companies with natural gas storage and transmission core assets.

exclusively dedicated to the natural gas value chain, and five other firms (MidAmerican, Ni, D, CMS and PGE) have substantial holdings in both the electricity and natural gas value chains. This includes MidAmerican Energy Holding Corporation (MidAmerican), which holds a major US natural gas pipelines, but is not itself listed on NYSE (only via a Berkshire Hathaway Incorporated [BRK.A]).

Fig. 12 classifies the eleven major integrated energy companies based upon their portfolio type. One firm (KMP) also holds unique $CO_2$ extraction, transmission and injection business related to Texan oil field production flooding — amounting to 1.75 Bcf/d — in addition to its natural gas transmission activities. A capacity inventory of the US natural gas transmission industry (Table 3) reveals that five leading players in the US natural gas transmission business (EP, SE, WMB, BRK.A & NI) hold 45% of the pipeline mileage and account for 70.2% of the actual natural gas transmission volume.

The total US interstate pipeline capacity (for 2007) stood at 153 Bcf/d with a time-averaged throughput of 62.5 Bcf/d (Table 3), which means the overall US natural gas system utilization is 41%. This capacity utilization is confirmed by systems statistics annually published by Rextag (2008, 2009). Clearly, companies like KMP (85% utilization), BRK.A with Northern Natural Gas Company (75% utilization), EP (71% utilization) and WMB (54% utilization) outperform the market in utilization of their pipeline asset capacity (Table 3).

For a quick comparison, Europe's pipeline utilization of the total constructed transmission capacity of 57.3 Bcf/d with 48.4 Bcf/d consumption throughput (taking 500 bcm/y or 17.67 tcf/y, for 2007) stands at 84.5% — more than double that of the US average capacity utilization and throughput load. The top three US energy companies jointly hold 1/3 of the total US interstate pipeline mileage and account for 56% of the domestic volume throughput (Table 3). In another view, the first seven US companies listed in Table 3 jointly hold 45% of the national interstate transmission pipeline mileage, and jointly transport 51 Bcf/d or 81.6% of the average daily consumption.

### 8.1. Business drivers

Business drivers for most energy utilities are on one hand improving the quality of services to customers with rising expectations (open access, open seasons, volume balancing across borders, volume advanced metering, flexible contracts at

**Table 3**
Interstate pipeline mileage and throughput by the major US interstate gas transmission companies (2007 data).

| NYSE | Company | Miles Interstate Pipeline 278,000 | Percent of US Total Mileage 100% | Peak Capacity & [Actual Through-put] 153 Bcf/d [62.5Bcf/d] | Percent of US Total Capacity & [Through-Put] 100% [100%] | Storage Capacity [UGS] |
|---|---|---|---|---|---|---|
| EP | El Paso Corporation | 42,000 | 15% | 24.5 Bcf/d [17.5 Bcf/d] 71% utilization | 16% [28%] | 230 Bcf |
| SE | Spectra Energy Company | 18,000 | 6.5% | - [9.9 Bcf/d] | [16%] | 265 Bcf |
| WMB | Williams Energy Services | 15,000 | 5.4% | 13.7 Bcf/d [7.4 Bcf/d] 54% utilization | 9% [12%] | 216 Bcf |
| BRK.A (*) | MidAmerican Energy Holdings | 16, 9 00 | 6% | 7.1 Bcf/d [5.3 Bcf/d] 75% utilization | 4.6% [8.5%] | 73 Bc f |
| NI | NiSource Incorporated | 16,000 | 5.8% | - [4.5 Bcf/d] | [7.2%] | 637 Bcf |
| KMP | Kinder Morgan Energy Partners | 8,700 | 3.1% | 5.2 Bcf/d [4.4 Bcf/d] 85% utilization | 3.4% [ 7%] | 400 Bcf |
| D | Dominion Resources Incorporated | 7,800 | 2.8% | - [2.0 Bcf/d] | [3.2%] | 975 Bcf |
| CMS | CMS Energy | 1,669 partly intrastate | 0.6% | - [0.6 Bcf/d] 'local' | [1%] | 143 Bcf |
| PCG 'PG&E' | Pacific Gas & Electricity Corporation | 6,136 partly intrastate | 2.2% | - [3.09 Bcf/d] 'local' | [5%] | 47 Bcf |
| BWP | Boardwalk | 14,000 (includes laterals) | 5% | 7.6 Bcf/d [4.8 Bcf/d] | 5% [ 7.7%] | 160 Bcf |
| Totals | | 1 4 6 , 2 0 5 | 52.2% | [59.5 Bcf/d] | [95%] | 3.15 tcf |

(*) Privately held in Berkshire Hathaway.
Highlighted companies outperform the market in utilization of their pipeline capacity.

competitive prices, storage capacity, LNG re-gasification plants, optimum security and integrated services) and on the other hand the maximizing of shareholder return in uncertain regulatory environments. Finding a proper and beneficial balance between the two 'utility' functions (i.e., customer service & shareholder returns) requires active direction-setting and strategic management. Table 4 summarizes the business portfolios of El Paso and Williams Energy Services. Both companies landed into problems in 2002 after the ENRON collapse and have successfully recovered.

El Paso was involved in the 2001 ENRON induced energy crisis and hit by litigation, which dropped the stock price, and also resulted in the loss of the company's investment-grade rating. Too much risk was loaded onto the company by engaging in overly speculative (if not fraudulent) trading practices in 2001. As a result the El Paso's asset value declined. The workforce needed to help the company's recovery but with reduced numbers in a downsized company; El Paso laid off 2/3 of its employees (from 15,000 to 5,500) in 2002. In 2003, a new CEO (Dough Foshee, formerly at

**Table 4**
Business portfolios of El Paso Corporation and Williams Energy Services (2007 data).

| NYSE | Company | Major business units | Major assets, products & services | Asset value billions USD | Asset value (%) | Operating net income EBIT millions USD | Net Income (%) |
|------|---------|---------------------|-----------------------------------|--------------------------|-----------------|----------------------------------------|----------------|
| EP | El Paso Corporation 5344 employees | Gas pipelines | 42,000 miles 17.5 Bcf/d | 16.8 | 46.3 | 1273 | 73.4 |
| | | E&P | 289 Bcf prod; 2.8 tcf reserves incl. int. operations Brasil & Egypt | 19 | 52.3 | 909 | 55.2 |
| | | Gas marketing | | | | (202) | (12.3) |
| | | Power (divested) | 549 MW Brasil & Pakistan | 0.5 | 1.4 | (37) | (22.5) |
| | | Corporate | | | | (283) | (17.2) |
| | | Others | | | | (15) | (0.1) |
| | | Total | | 36.3 | 100 | 1645 | 100 |
| WMB | Williams Energy Services 4319 employees | Gas pipelines | 15,000 miles 7.4 Bcf/d | 9.5 | 41.7 | 622 | 33.4 |
| | | E&P | 360 Bcf prod 4.1 tcf reserves | 7.7 | 33.8 | 731 | 39.2 |
| | | Midstream gas & liquids | | 5.3 | 23.2 | 1011 | 54.2 |
| | | Gas marketing | | 0.06 | 0.3 | (337) | (18.2) |
| | | Corporate | | 0.25 | 1.0 | (161) | (8.6) |
| | | Others | | – | – | (1) | (–) |
| | | Total | | 22.8 | 100 | 1865 | 100 |

Halliburton) took over and helped the company's turn around toward solvency. In his 2008 summary report, the CEO of El Paso emphasized that under the global recession an unprecedented (but reminiscent of the 2002 restructuring) need arose for leading the company in real-time, while maintaining maximum flexibility to respond to the near-term events. For example, such responses included cutting the cost of long-term investment projects where margins thinned but maintaining CAPEX investments in markets that are 'hot', and deliver those projects on-time and on-budget.

Williams was also affected by the ENRON collapse in 2001, but mostly by 2.14 billion USD obligations loaded onto the company by bankruptcy of its telecommunications subsidiary. Natural gas trading losses also compounded for Williams the problems in the difficult power market of 2002. The lowering of Williams' credit-rating to non-investment-grade triggered several hundred million USD in additional collateral requirements, in conjunction with its eliminated access to capital markets. Divesture of assets (the selling of 3.5 billion USD of assets, including Kern River Natural Gas Pipeline to Mid-American) and drastic reduction of the workforce (by half, from 9800 to 4800 employees) led Williams out of insolvency. Apparently, too much business risk was loaded onto the company by engaging in the competitive telecommunications business. As a result the company's asset value declined. The workforce was reduced to cut OPEX and the downsized company was readjusted to bring the company's productivity in line with the new strategy back to solvency.

### 8.2. Tactical responses

*Four tactical instruments emerged* in the course of a detailed study of competiveness in the US natural gas transmission industry (Weijermars, 2010). The latter study focused on industry clockspeed and did not discuss the optimum use of these tactical instruments, which are critical for natural gas transmission and energy utility companies to achieve optimized performance. These four tactical instruments occupy key roles in the strategic investment decisions by company boards. These tactical instruments are:

- Bound versus unbound M&A options
- Portfolio balancing of low and high margin assets
- Rigorous management accounting to optimize ROI in spite of the GRC
- Corporate restructuring to reap equity return from stretched WACC in subsidiaries

These tactical tools are concisely outlined below:

#### 8.2.1. Bound versus unbound M&A options

Unbound M&A options are available to companies that transmit natural gas but without distribution networks to the end-consumers (see Fig. 12 for major value chain choices and up- and downstream emphasis). Such companies without LDC assets can easily divest low throughput pipelines and instead acquire (or build) profitable high volume throughput pipelines elsewhere. In contrast, vertically integrated gas distribution companies must feed their LDC networks and thus are "anchored" to serving their downstream end-consumers even when volumes in their midstream transmission pipelines are relatively low. In general, companies dedicated to natural gas transmission (EP, WMB and KMP) have actual throughput volumes that utilize pipeline design capacity much better than that of most distribution companies (Table 3). An exception is MidAmerican, which is a retailer in both the natural gas and electricity value chains (Fig. 12), but still holds two very profitable natural gas transmission companies (i.e., Northern Natural Gas Company and Kern River Gas Transmission Company).

#### 8.2.2. Portfolio balancing of low and high margin assets

Portfolio choices are made to balance low margin and high turnover business activities (e.g. distribution) with high margin and lower asset turnover business activities (e.g. natural gas transmission). The RONOA for gas transmission assets is generally much higher than for other assets of integrated energy companies. This fact can be concisely illustrated by considering the trade-off between margin and asset turnover when these factor into the RONOA (Table 5, examine 2nd row for relationship of ratios in RONOA, Margin and Asset Turnover, e.g., Lumby and Jones, 2003):

$$RONOA = Margin \times Asset\ Turnover \qquad (1)$$

The plots of Figs. 13 and 14 show the relationship between RONOA, Margin and Asset Turnover of the Corporate and Gas Transmission Business segments for the peer group companies. This reveals a peer group average *margin* (excluding CMS Energy) of about 40% for gas transmission activities, versus 10% margin for all total corporate assets. The corporate *asset turnover* averages 40%, versus 20% for the gas transmission business segment.

Table 5 illustrates the portfolio leverage between margins and asset turnovers. Table 5 includes the implied margin and turnover

**Table 5**
Corporate portfolio effects on RONOA, margin and asset turnover from different business segments

| Business Activity | RONOA<br>EBIT/Net Operating Assets | Margin<br>EBIT/Revenue | Asset Turnover<br>Revenue/Net Operating Assets | Portfolio percentage |
|---|---|---|---|---|
| Corporate Portfolio | 4% | 10% | 40% | 100% |
| Gas Transmission Business Segment | 8% | 40% | 20% | 33% |
| Other Business Segments (e.g. distribution, etc.) | 2.5% | 5% | 50% | 66% |

of the other assets in the corporate business portfolio, which have a relatively low margin of only 5% at an average asset turnover of 50%. This typically applies to distribution assets of utilities that serve end-consumers. Table 6 provides the portfolio profiles of Spectra, NiSource, Kinder Morgan and Dominion; MidAmerican and CMS Energy were excluded for economy of space.

#### 8.2.3. Rigorous management accounting to optimize ROI in General Rate Cases (GRCs)

The US General Rate Case (GRC) policy for regulated utility services constrains utility companies' return on investment of their regulated asset base (RAB). Such assets may only generate a rate of return (ROR) that compensates the company's WACC. The WACC (*Weighted Average Cost of Capital*) is the cost of each capital component multiplied by its proportional weight in the company's RAB financing, and then is summed (e.g., Lumby and Jones, 2003):

$$\text{WACC} = \frac{E}{V} \times R_e + \frac{D}{V} \times R_d(1 - T_c) \tag{2}$$

where $R_e$ is the cost of equity; $R_d$, cost of debt; $E$, market value of the firm's equity; $D$, market value of the firm's debt; $V = E + D$; $E/V$, percentage of financing that is equity; $D/V$, percentage of financing that is debt; $T_c$, corporate tax rate.

The tax rate already discounts the debt financing so that cash flows in the WACC are charging fully the cost of equity capital but only part of the debt cost that is not already compensated for by the tax break.

Utilities are unpopular to have a high equity ratio (say 75%) because that would let them make higher ROEs factoring into the ROR ruling. A higher debt-ratio is nearly mandatory because that makes the overall ROR lower (less risk in debt financed capital as
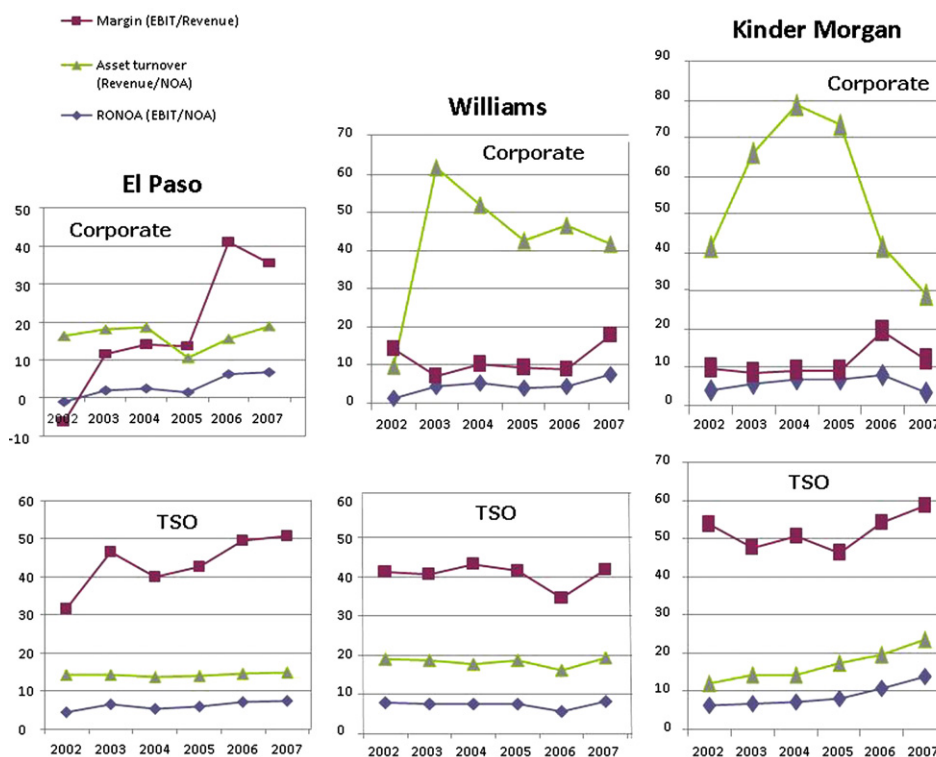


**Fig. 13.** Margin, turnover and RONOA (all as percentage ratios) for corporate and gas transmission assets of El Paso, Williams and Kinder Morgan. These companies are exclusively active in the natural gas value chain (see also Fig. 12). Data abstracted from K-10 SEC Filings.
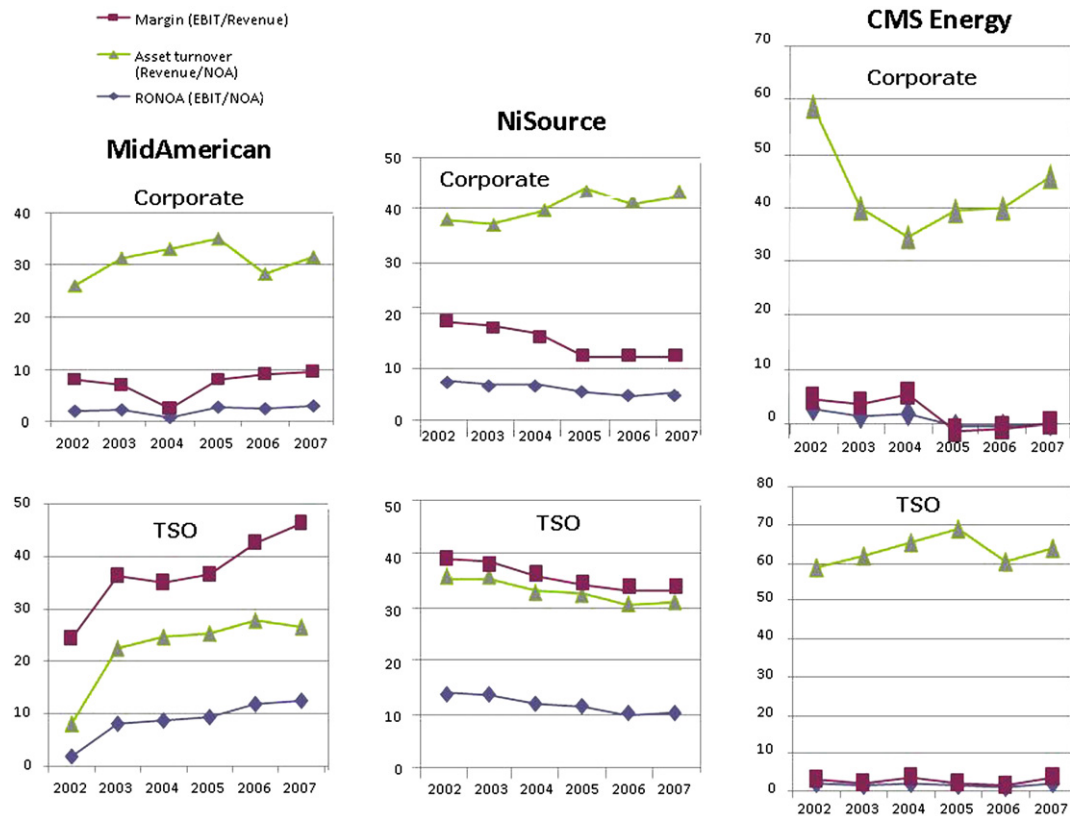
**Fig. 14.** Margin, turnover and RONOA (all as percentage ratios) for corporate and gas transmission assets of MidAmerican, NiSource and CMS Energy. These companies are active in both the electricity and natural gas value chains (see also Fig. 12). Data abstracted from K-10 SEC Filings.

market rates for debt financing are lower than equity financing). Utility bills will be lower when equity financing of the utility company is lower. The amount of risk involved leverages the type of financing, risky projects may need a higher equity stake.

Typically, the State Regulator (Department of Public Utility Control) authorizes a WACC based return on investment, whereby the banks set the rate of return on debt capital. However, the State regulator sets the Return on Equity (ROE) investments that is part of the WACC for the utilities that operate in their state. The ROE three-year average for a peer utility group of 15 US power companies over the period 2004 to 2006 yields an ROE of 11.39% after removing the two lowest and highest ROE outliers.

The GRC is not allowing for a full risk premium. For example, the Pacific Gas & Electricity Company (PG&E) reports in its 2008 SEC 10-K filing (p. 20) that its corporate WACC was disputed by the Californian Public Utility Commission (enforcing FERC guidelines). The authorized overall rate of return of its WACC at 8.79% was based on 6.05% long-term debt, 5.68% for preferred stock and 11.35% for common stock and a capital structure of 46% debt, 2% preferred stock and 52% equity. Table 7 shows the capital structure, authorized ROR and WACC structure resulting in an overall WACC of 8.79%.

Strictly speaking, regulated utility companies are not supposed to add true 'economic value', that is to outperform capital markets, which only occurs when ROI > WACC. A company would be adding true 'economic value' (EVA) as long as its ROI is larger than its WACC:

$$EVA = (ROI - WACC) \times TCE \tag{3}$$

with EVA for economic value added, ROI for return on investment, WACC for weighted average cost of capital and TCE for total capital employed. The regulator also requires that the ROR on the company's net assets (RAB) may not exceed the WACC. The authorized annual net operating income (NOI) is given by:

$$NOI = ROR \times RAB \tag{4}$$

Interestingly, a company's WACC 'stretches' and gets close to capital markets returns (ROIs) when capital is predominantly raised from equity sources. For example, PG&Es 2008 WACC is as high as 8.79% because it includes 52% equity financing with an allowed rate of return of 11.35%. The higher the equity stake, the higher the WACC permissible under the negotiated GRC agreements. Corporate restructuring can reap the full benefit of equity financing for the parent company (see below).

### 8.2.4. Corporate restructuring to reap equity return from 'stretched' WACC in subsidiaries

The General Rate Case (GRC) agreements reached in negotiations by regulated utility companies with FERC and state regulators (Fig. 15) sets the return rate for their regulated natural gas and electricity utilities. For example, the Californian Public Utility Commission sets the GRC for a 4-year period based on a forecast of costs from the first ('test') year (e.g., 2007 till 2010). Attrition or upward rate adjustments are allowed when the capital investment structure of the company (i.e., the company's WACC) changes. According to FERC ruling, the company's WACC must use return rates that represent a fair return on capital in the concurrent markets (e.g., 6.05% for long-term debt, 5.68% for preferred stock and 11.35% for common stock, in the 2008 example of PG&E quoted above).

**Table 6**
Business portfolios of spectra, NiSource, Kinder Morgan and Dominion (2007 data).

| NYSE | Company | Major business units | Major assets, products & services | Asset value (billions USD) | Asset value (%) | Operating net income EBIT (millions USD) | Net income (%) |
|---|---|---|---|---|---|---|---|
| SE | Spectra Energy Company 6350 employees {formerly Duke Energy} | Gas pipelines | 18,000 miles 9.9 Bcf/d | 8.8 | 45.2 | 894 | 42.3 |
| | | Gas distribution | 37,000 miles; 1.3 million customers | 5.0 | 25.6 | 322 | 15.2 |
| | | Field services | Joint venture Conoco; 58,000 miles gathering lines | 1.1 | 5.6 | 533 | 25.2 |
| | | Canada W | | 4.6 | 23.6 | 366 | 17.3 |
| | | Total | | 19.5 | 100 | 2115 | 100 |
| NI | NiSource Incorporated 7607 employees | Gas pipeline & St | 16,000 miles 4.2 Bcf/d | 3.5 | 19.3 | 362 | 38.9 |
| | | Gas Distribution | 58,000 miles; 3.3 million customers | 7 | 38.7 | 333 | 35.7 |
| | | Power | 2,907 MW; 457,000 customers | 3.4 | 18.8 | 262 | 28.1 |
| | | Corporate | | 2.8 | 15.5 | (33) | (3.5) |
| | | Others | | 1.4 | 7.7 | 8 | 0.8 |
| | | Total | | 18.1 | 100 | 932 | 100 |
| KMP | Kinder Morgan Energy Partners 7600 employees | Natural gas transmission pipelines & gathering | 8,700 miles 4.4 Bcf/d 16,800 miles | 4.4 | 29.1 | 600 | 32.8 |
| | | $CO_2$ Transport | 1300 miles of $CO_2$ pipelines delivering 637 Bcf to 10 Texan Oil Fields | 2.0 | 13.3 | 537 | 29.3 |
| | | Products pipelines | 8,300 miles refined product pipelines; Including Plantation 51% KMP/49% Exxon | 4.0 | 26.5 | 569 | 31.1 |
| | | Terminals | 108 Liquids & bulk load facilities | 3.0 | 19.8 | 416 | 22.8 |
| | | Trans mountain | 700 miles of common carrier pipelines | 1.4 | 9.3 | (294) | (16.0) |
| | | Corporate | | 0.3 | 2.0 | | |
| | | Total | | 15.1 | 100 | 1829 | 100 |
| D | Dominion Resources Incorporated 17,000 employees | Natural Gas Transmission & Storage | 7,800 miles 2.0 Bcf/d 14,000 miles | 5.0 | 18.9 | 387 | 15.2 |
| | | Gas distribution | 28,000 miles; 1.2 million customers | 8.3 | 31.3 | 765 | 30.0 |
| | | Power | 26,500 MW | 10.2 | 38.5 | 415 | 16.3 |
| | | Electric transmisison | 6,000 miles; 2.4 million costumers | | | | |
| | | E&P | 1 tcf reserves | Sold | | | |
| | | Others | | 3.0 | 11.3 | 981 | 38.5 |
| | | Total | | 26.5 | 100 | 2539 | 100 |

Particularly, the allowable rate for return on equity (ROE) can be a matter of dispute between the regulator and the company. For example, MidAmerican's SEC 10-K filing for 2008 reports a FERC ruling against its use of 12.5% rate of return on equity investment in the Kern River Gas Transmission Company. FERC only allowed 11.55% ROE, which is notably still 0.2% higher than the 2008 rate of return on common equity capital that CPUC allowed to PG&E. In another ruling, the Ohio regulator authorized (after legal settlement) a 8.49% return rate as per the compounded WACC (ROE plus cost of discounted debt, see Eq. (3)) to Dominion East Ohio, a subsidiary of Dominion Resources Incorporated (SEC 10-K filing 2008).

Whereas any gas transmission company itself may only earn back its WACC for the authorized RAB (and no more), integrated energy groups have begun to place most of their gas transmission businesses in separate corporations in which they hold sole or at least majority control. This means that the WACC for the RAB in their subsidiary transmission company is 'raised' commensurate with the amount of equity capital held by the parent company:

$$ROI = WACC \times RAB \tag{5}$$

The parent company itself can borrow relatively cheap debt capital to finance shares in the transmission company, which then is allowed under the GRC to return on the equity investment at
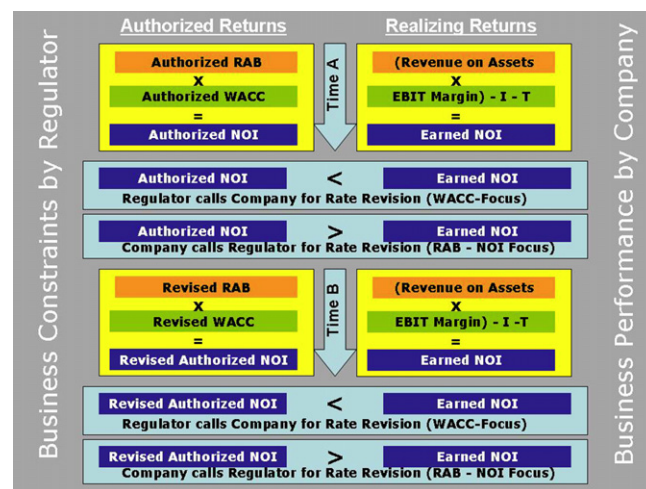
**Table 7**
Example of leverage between capital structure, WACC and authorized ROR in the gas transmission and utility industry.

| Capital structure | Ratio (%) | Authorized ROR (%) | Wt. Cost Capital (%) |
|---|---|---|---|
| Debt (long-term) | 46 | 6.05 | 2.78 |
| Preferred stock | 2 | 5.68 | 0.11 |
| Common stock | 52 | 11.35 (=ROE) | 5.90 |
| Total | 100 | – | WACC = 8.79% |



**Fig. 15.** Timeline (time A to B) for negotiations between Energy Utility Company and Regulator representatives. The net operating income (NOI) is subject to the regulator's scrutiny.

**Table 8**
Major regulations for EU gas industry.

| Date | EU Directives & Acts | Principal objective |
|------|----------------------|---------------------|
| August 1998 | 98/30/EC 1st gas directive "Regulation for an internal natural gas market" | Guarantee TPA to improve competitiveness and improve security of supply. |
| June 2003 | 2003/55/EC 2nd Ammended gas directive "acceleration directive" | Encourage legal unbundling of transmission systems operators (TSOs) from gas trading companies on a voluntary basis. Deregulate gas markets by July 2004 and have full TPA by July 2007, including TPA for storage systems. |
| 2004 | 1st Strategic Energy review | Directions on security of supply. |
| March 2005 | European Gas Regulatory Forum | Guidelines on services and rules for TPA compiled by the Forum |
| Oct 2007 | EU Commission Report "An Energy Policy for Europe" | Diverging views within EU; France and Germany favour independent TSOs as in NL since July 2005. |
| Nov 2008 | 2nd Strategic Energy Review | Securing an energy future. |
| April 2009 | 3rd Legislative Energy & Gas Package | Creation of ACER (Agency for Cooperation of Energy Regulators) and ENTSO (European Network of Transmission System Operators). |

ROEs in parity with the market rate. This way the parent company of utilities can deliver TSR to satisfy their shareholders at a rate that prudent investors would expect when (ac)-counting with CAPM returns.

The corporate restructuring to reap equity return from stretched WACC on the WACC in subsidiaries also enables utilities to earn the maximum authorized rates of return (maximizing ROE) that approach the prudent investor's CAPM returns.

Utilities claim that FERC and state regulators exclude the utility's actual costs from the revenue requirements; i.e. they are not excepting all cost of providing competitive energy. The corporate restructuring to reap equity return from stretched WACC on the WACC in subsidiaries enables utilities to earn and maximize the authorized rates of return (ROR).

## 9. Implications for European natural gas industry

The introduction of market liberalization, pioneered in the US under strong federal governance (legislation, regulation and deregulation) has only just begun in Europe. The EU gas directive of 1998 laid the basis for the liberalization and regulation process in Europe. Deregulation of previously regulated wellhead prices as in the US was not needed in the EU as wellhead prices were never regulated. Table 8 lists the major EU energy directives and rulings. Given the course for unbundling that EU is still pioneering, FERC's 2008 revision of Orders 497, 889 and 2004 (following the 2006 Court ruling) is relevant. The revised FERC Orders allow for integrated planning of transmission capacity: corporate unbundling is no longer required, only a functional separation of transmission function employees and marketing function employees (see also Section 6 and Table 1 in this study).

The EU market for natural gas is nearly as big as the US market. In 2008, the US consumed 20% of the world's total natural gas production (US domestic production accounted for 87% and 13% was imported), Europe consumed 19% of the world's natural gas (a majority importer with 50% internal production and 50% imports), while the former USSR consumed 22% (but is a net exporter), (DOE/EIA, 2009). The imbalance between internal natural gas production and consumption makes Europe vulnerable to security of supply concerns. Europe's import need totals 300 bcm/y in 2010, and grows to 400 bcm/y in 2020, and 500 bcm/y in 2030 (see Berkel and Roodhart for low, reference and high economic growth cases using EIA 2007 data). For a quick comparison between US and EU, the total US interstate pipeline design capacity was 133 Bcf/day (EIA data 2003; but already reached 153 Bcf/d in 2007, see Weijermars, 2010), nearly three times the European design capacity of 57.3 Bcf/

day for 2006 (IEA, 2007). The US capacity reflects a much larger transmission network for similar final consumer throughput volumes but also serves a US natural gas market with much higher liquidity (trade and reselling) than in Europe.

The further development of true liquidity in the EU natural gas market is hampered by the dwindling of its internal production capacity, which has not yet been reversed by a still weak and ineffective federal governance system as compared to the US. The EU's third legislative energy package of 2009 has laid a further basis for improved federal cooperation between energy regulators of the EU member states in ACER (see Table 8 for explanation). It is absolutely essential to remove impediments in the natural gas value chain and streamline the decision-making process. In Europe, the natural gas industry's clockspeed (cf. Weijermars, 2009a, b) will slow down if regulatory issues remain unsolved or drag on, or remain unclear. Such issues cannot be settled by industry itself but reside in external factors such as regulators and legislators.

Table 9 lists some major differences between the US and EU natural gas markets. Individual companies must continue to work with both their state and federal EU regulators to solve issues that are crucial for decision-making improvements. They must continually act to solve this question: "How can external forces be influenced to optimize our strategy and improve our competitiveness?" Some of the peculiarities of the EU's energy market have been highlighted in recent work (Brunekreeft and Guliyev, 2009; Dyrland and Roggekamp, 2009; Hasegawa et al., 2007; Holtz et al., 2008; Huygen et al., 2009; Jamasb et al., 2007, 2008; Neuhoff and Hirschhausen, 2005; Pollitt, 2008; Sagen and Aune, 2004). From the point of view of competitiveness, within the constraints of regulation, US energy utilities still are competing for investors' money to ensure their highest return on investment. In the US,

**Table 9**
Major differences between US & EU natural gas markets.

| Federation | Principal state |
|------------|-----------------|
| US | • Many domestic gas producers <br> • Many effective hubs <br> • Many interstate pipelines <br> • Many well integrated energy companies, market players <br> • Strong federal Regulator |
| EU | • Dwindling & limited domestic production <br> • Few hubs <br> • Limited number of true interstate pipelines <br> • Few integrated market players <br> • Landscape dominated by National regulators, not Federal regulator |

returns are regulated sternly by the FERC (midstream) and the Public Utility State Commissions (downstream). Given the considerable tax revenue generated by energy utilities in the US (some 14 billion USD per year) and EU (some 15 billion USD per year), see section 7.3, it remains important to support the natural gas business with rules and regulations that improve the industry's performance.

## 10. Recommendations and conclusions

Europe faces a steady indigenous production decline, with import needs amounting to 300 bcm/y in 2010, and 400 bcm/y in 2020. In a way, this situation resembles the steep production decline that the US experienced when domestic production peaked at 60 Bcf/d in the early 1970s and then dropped to 43 Bcf/d in the early 1980s. Tax incentives for the development of unconventional natural gas resources (shale gas, CBM, tight sands) provided since the mid 1980s have delivered results. Production of unconventionals increased from 8 Bcf/d in 1990 to 30 Bcf/d in 2008, accounting for more than half of today's US natural gas production of 55 Bcf/d.

What Europe needs to do is find means to slow down, or even better, reverse the decline of its indigenous natural gas production. Exceptional policies are needed to juggle the many variables in the security of supply equation, including the geopolitics of the overseas suppliers. Security of supply can by improved in part through measures (policies and regulations – laws and rules) previously tested and proven successful in the US market. The major measures that could improve competitiveness and efficiency of the natural gas market in Europe, and therefore need serious consideration, are as follows:

- Provide tax breaks for production from unconventional natural gas resources (shale gas, CBM, tight gas).
- Increase liquidity in the natural gas market by enforcing TPA pipeline access, *everywhere*, in Europe.
- Provide incentive regulation that will increase market liquidity by building physical hubs between major European pipelines (to make ENTSO into a success).
- Encourage the construction of dedicated pipelines to serve major end-users without LCD intermediaries. This will improve the position of natural gas in inter-fuel competition (e.g. natural gas versus coal in power plants, and versus oil in heating systems for greenhouses).
- Provide incentive regulation to build long-distance infrastructure that can bring new gas volumes from abroad to Europe (Long-distance pipeline, LNG terminals).
- Provide raised rates of return (in the authorized WACC) for new infrastructure investments to stimulate timely delivery of such projects.
- Build export capacity to relieve short-term excess supply, for example, when warm winters would fill storage capacity to the brim, as occurred in the US in fall 2009. Remember that in the US a state like Texas exports natural gas to Mexico, while on the other hand Michigan is 66% dependent on Canadian imports (accounting for the bulk volume of the US national average of 13% imports for 2008.) Therefore, the building of export capacity in Europe should not be overlooked. Such a capacity would help to improve global market liquidity for natural gas, and therefore provides a mechanism to stabilize prices in times of over- and under balancing between demand and supply regions.

Ultimately, the estimated annual tax contribution of some 15 billion Euros by the European natural gas business represents a capital asset that should be jointly nurtured by industry,

governments and end-consumers. These stakeholders need to engage in intelligent discourse leading to effective measures and investments to ensure longivity of the asset base and the energy services provided. As for the US, the 2009 price shocks documented for the US natural gas market are due to the depressed demand for energy associated with the economic recession of 2008/2009. Oversupply of natural gas in the US compounded the 2009 price slide. The time-scale of field development in unconventional gas plays is much longer than that of the instantaneous and unanticipated recession triggered by the 2008 financial crisis. In spite of short-term chokes in commodity price, the US domestic natural gas supply still needs to increase in order to ensure the long-term energy security.

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## List of abbreviations

*CAPM:* Capital asset pricing model
*DOE:* Department of energy
*EBIT:* Earnings before interest payments and taxes
*EIA:* Energy information administration
*EU:* European Union
*EVA:* Economic value added
*FERC:* Federal energy regulation commission
*GRC:* General rate case
*HSE:* Health, safety and environment
*IRR:* Internal rate of return
*LDC:* Local distribution company
*LNG:* Liquefied natural gas
*M&A:* Merger and acquisition
*NOI:* Net operating income
*RAB:* Regulates asset base
*RF:* Risk-free rate of return
*ROCE:* Return on capital employed
*ROE:* Return on equity
*ROI:* Return on investment
*RONOA:* Return on net operating assets
*ROR:* Rate of return
*SEC:* Security and exchange commission
*TCE:* Total capital employed
*TSR:* Total shareholder return
*US:* United States
*USGS:* United States geological survey
*WACC:* Weighted average cost of capital