The dynamics of natural gas supply coordination in a New World
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Chapter 5
Interregional gas market structure, trade and pricing patterns

5.1 Introduction
The international gas market is essentially interregional in nature, with on the one hand important fundamental changes occurring in terms of market structure and trade and (interregional) pricing on the other. From a market where relatively isolated gas suppliers and buyers were once regionally, and even locally, captive to one another, local markets have become more regional, and regional markets have in turn become increasingly interlinked. This has in large part been due to the advent and tremendous growth of LNG and, in particular, the evolution of economies of scale in the LNG value chain during the 1990s and 2000s. Increasingly, where pipelines have enabled gas trade within regional markets, LNG has facilitated long-distance gas trade between these regional markets and more distant suppliers. The overall mismatch between the location of gas resources and demand centres, and their growing import-dependence, has in recent years increased the need for further and greater LNG flows.

At a regional level, the various regional gas markets, the US, Europe and the Asia-Pacific region are import-dependent to diverging degrees and on different combinations of suppliers and exhibit diverging pricing and trade patterns, this aspect is covered in Section 5.3. The increasing level of import-dependency of the various regional gas markets and policy uncertainties are covered in Section 5.4. Gas trade, especially in the LNG industry has always been underpinned by fixed long-term contracts with oil indexation. Patterns in regional and interregional gas trade are shifting, however, proving to be quite dynamic as suppliers seek to benefit from interregional price imbalances through new business models. Interregional LNG flows have increasingly begun to act as price bridges between the various regional markets through shorter-term trading, parallel to long-term, oil indexed LNG flows. Section 5.5 is a brief discussion about the rapidly evolving world of LNG and how it is being trade in more flexible ways than has traditionally been the case.

5.2 World gas production in 2008
As a result of the asymmetric distribution of reserves as described in Chapter 3, the international gas market, regardless of how it actually functions in terms of trading and pricing, is naturally predisposed to an oligopolistic market structure. Particularly so when one takes into account that since the late 1970s, natural gas reserves have been primarily exploited by na-
tional government companies. The supply side of the international gas market is therefore characterised by a limited number of very large—and potentially very large—suppliers and many smaller, heterogeneous players. Just as is the case for gas reserves, gas production is highly concentrated. Rather than being a market where thousands compete to buy and sell, the natural gas market is often dominated by a small number of firms or a powerful consortium, which determines the bargaining relationships in an increasingly regional and interregional gas market [Davis 1984].

Russia is the biggest gas producer of the world (657 bcm in 2008), whereas most of its gas is consumed in Russia. For its export, Gazprom has a monopoly over export flows. According to Gazprom’s data, Gazprom’s gas export sales in the CIS were 83 bcm and in Europe 170 bcm in 2008 [Gazprom 2009a]. Other major producing countries are the US (583 bcm in 2008), Canada (175 bcm in 2008) and Iran (121 bcm in 2008). Canada exports 58 percent of its production to the US and the remaining production is for internal use. The US consumes most of its gas domestically. Iran could potentially become a major exporter; yet in 2008 it became a net-importer of gas (1.7 bcm). Besides Russia and Canada, Norway and Algeria are major exporters (and producers) of gas. Norway produced 103 bcm in 2008 and exported a large share to Europe by pipeline, and in the near future also by LNG. Algeria consumes a larger share, 31 percent, of its production (82 bcm in 2008) domestically. The Netherlands is a traditional exporter of gas to European countries, which produced 85 bcm in 2008, of which 62 bcm was exported to other European countries [IEA 2009a].

Figure 5.1 Historical export volume development of gas exporting countries: 1998-2008

Source: own analysis, based on IEA [2003]; IEA [2008]; IEA [2009]
The UK and Saudi Arabia consume most of their produced gas (respectively, 73 bcm and 70 bcm in 2008) domestically. Other major producers are China (76 bcm in 2007), Mexico (52 bcm in 2008) and Argentina (45 bcm in 2008) [IEA 2009a]. The upstream gas sectors in other upcoming exporters – mainly the Caspian region, Iran, Iraq and Qatar – are relatively under-developed. The Central Asian countries play an important role in Russia’s current gas export flows, but ever since the mid-1990s they have been in search of alternative pipeline export routes. Qatar called for a moratorium in 2005 on the North field; halting further investment decisions on new projects while it is bringing to fruition some massive, committed LNG projects [CIEP 2008]. In the Asia-Pacific markets, Indonesia, Malaysia, Australia and Brunei play an important role in LNG exports. The internationalisation of on the one hand Russia, as a pipeline gas exporter to Europe and Asia, and its LNG-exporting counterpart, Qatar, on the other, is likely to have a long-lasting and deep impact on the interregional gas industry. The other major gas exporters (and producers) are outlined in Figure 5.1 above and Map 5.1 below.
5.3 Regional markets and pricing

While the overall market structure of the natural gas industry is highly oligopolistic from a global or interregional perspective, the import-dependencies of regional markets and of separate countries diverge widely, taking into account figures for 2008. In order to appreciate the real significance of the various suppliers and their potential impact on market conditions it is useful to perceive the suppliers through a regional prism, particularly because the regional gas markets in question differ immensely in terms of not only primary energy mixes, but also in terms of import-dependency and thus also gas market structure. The structure of the market will make its effects felt on an increasingly global scale, and regional developments are likely to shape global ones in turn.

Expectations have been raised of further globalisation of the gas business, with different market structures, more fragmented value chains, more flexibility in supplies to markets and shorter-term contracts [De Jong et al. 2010]. The three major regional gas markets for natural gas, the US, Europe and the Pacific region, all trade gas with different types of contracts, each market functioning with its own pricing mechanisms, i.e., spot versus oil- or oil product indexation. This has a direct impact on trade and pricing in the two major LNG trading basins, the Atlantic and Pacific basins, which separate an interregional market for LNG into two distinct sub-markets (refer to Map 5.1 above).

The geography of the interregional gas market will change markedly in the 2010s, towards 2020 and beyond. By 2020, Russia will continue to be an important supplier in the European market, while Russia itself becomes a more global player. Russia will do so by commencing exports to Asian markets through (long-term) pipeline gas supplies, and by venturing into the LNG industry with its own proper LNG projects. At the same time, considerable amounts of LNG (for which liquefaction capacity is either under construction or planned) will become available to many of the same areas in which Russian gas is likely to play a role, from Nigeria, Australia, Qatar and the other Persian Gulf LNG producers, amongst various others (see also chapters 6 and 7). While traditionally the Pacific Basin drove LNG demand in the past, future

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123 While LNG is traded mainly in two different major trading areas: the Atlantic and Pacific basins, pipeline gas volumes still dominate international trade by size of yearly volumes. The Atlantic Basin, where LNG trading takes place west of the Suez Canal, consists of the US and Western and Southwestern Europe, where exporters include Trinidad and Tobago, Egypt, Algeria, Libya, Nigeria and Norway. The Pacific Basin, ‘east of Suez’, consists of Japan and South Korea, and newly emerging gas importers such as China and India on the importing side while LNG exporters include Malaysia, Brunei, Australia and Indonesia. Three other LNG exporters, in the Persian Gulf, include Qatar, Oman and the UAE. These LNG exporters in the Pacific basin are officially east of Suez, but are within economically viable distances of the US and European markets as well. As such, they act as exporters of LNG to multiples markets in both basins. Rising demand in Middle Eastern countries should also be taken into account since much gas is to come from this region, especially from the Persian Gulf region.
LNG demand is already influenced by Atlantic Basin gas demand as well. The Atlantic Basin has become comparatively more important in this regard.

5.3.1 The balance between LNG and pipeline gas

Inter- or intra-regional trade consisted of some 201 bcm worth of LNG (or 52 percent of total trade) compared with almost 185 bcm for pipeline gas (some 48 percent of total trade) [IEA 2009b]. With the increase in interregional gas trade due in large part to rising import-dependencies, the growth rate for LNG trade is likely to remain high compared to the growth rate in pipeline gas. A total global liquefaction capacity of 256 bcm existed at the end of 2007; an additional 146 bcm is being constructed, which will take total liquefaction to 400 bcm by 2012 alone [IEA 2009b]. A note of caution should be taken with regard to the demand-side impact of the 2008-2009 international financial and economic crisis.

5.3.2 The European gas market(s)

Market Structure

Looking in more detail at the current major regional gas markets for exporting countries – the US, Europe and Asia-Pacific - Europe is by far the most exposed to both pipeline and LNG flows and imports and is already heavily import-dependent. When seen as a major regional market, Europe traditionally relies on indigenously produced gas as well as pipeline gas from Russia, Norway and Algeria, but now it also imports LNG from a number of other sources outside Europe. Of the three main regional markets, Europe is by far the most exposed to both pipeline and LNG flows for its imports. European consumption totalled 581 bcm in 2008, of which 372 bcm were imported (64 percent) [IEA 2009a]. Europe enjoys the luxury of some intra-European supply, with a mature producing area centred on Northwestern Europe (NWE) and the North Sea. The NWE region includes the most important off-take market for net-exporting suppliers within the EU, mainly the Netherlands and the UK. Other relative major production areas within the EU are located in Germany, Romania, Denmark

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124 In this research, references to ‘Europe’ and the ‘European market’ correspond with the inclusion of the EU member-states, Norway, the Balkan non-EU member-states, Switzerland and Turkey while it excludes the CIS member-states.
125 In this study, Asia is defined by all LNG importing countries in Asia in 2008 – the traditional importing countries: Japan, South Korea, and Taiwan, and the emerging gas markets: India and China.
126 The non-OECD gas producing countries are also large consumers of gas (for example, the CIS, Middle Eastern and North African countries). This study focuses primarily on the export strategies towards gas-importing countries. Combined with the fact that these countries are more or less self-sufficient, these off-take markets will not be taken into account in an in-depth analysis.
127 The NWE gas market is defined by Ireland, the UK, Denmark, Germany, the Netherlands, Belgium, Luxembourg, and France.
Figure 5.2 below provides a graphical overview of Europe’s pipeline and LNG supplies in 2008 [IEA 2009a].

The most important non-EU pipeline gas suppliers to Europe include mainly Norway, Algeria and Russia. Norway supplies the UK and Northwest Continental Europe (75 bcm to 84 bcm in 2008). Algeria supplies the Iberian Peninsula (Spain and Portugal as well as Italy (36 bcm in 2008 by pipeline), and Russia is an important supplier to the continental northern, central and southern European markets (160 bcm in 2008). Other pipeline suppliers, including Libya, Iran and Azerbaijan supply small volumes, although more may be available from these countries in the near future. In 2008, the European gas market relied to some extent on LNG supplies, mainly with supplies from Algeria (18 bcm in 2008) and Nigeria (14 bcm), only covering only 9 percent of total European gas consumption. In recent years Qatar has also established some market share in the European gas market (8 bcm) with its recent LNG exports. Northern, central and eastern Europe thus rely more on pipeline gas, while Southern and South-western Europe are traditionally dependent on LNG imports, as well as some pipeline imports from North African producers.

Figure 5.2 Gas supply to the European countries by type and source in 2008 (in bcm)

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Other EU gas producing member states – such as Poland, Hungary, France, and Austria – have a very mature gas system with declining production (less than 5 bcm/y) and limited remaining resources [CIEP 2008].
Pricing in the European gas market

The European market really consists of two markets when it comes to gas pricing: a spot or spot-oriented gas market centred on the UK on the one hand, with its own hub, the National Balancing Point (NBP), and long-term contracts centred on intra-European trading and imports from outside the European market on the other. The NBP, Title Transfer Facility (TTF), Zeebrugge and the Central European Gas Hub (CEGH) at Baumgarten are just some of a number of European gas trading hubs where buyers and sellers can use to buy and sell gas on short-term basis [Cronshaw et al. 2008]. Their levels of development and liquidity diverge enormously. The yardstick for hub pricing is the replacement value of the gas rather than the market value principle; contractual prices for natural gas are always geared to the energy content of the gas involved [Dickel et al. 2007; IEA 2008a]. A new trend is for pipeline gas suppliers to reserve capacity for short-term supplies to the wholesale markets and via hub markets, notably producers from Norway and Gazprom, though volumes are still small [CIEP 2008].

The bulk of Europe’s gas is traded under long-term, take-or-pay contracts often lasting between 20 and 30 years, often matching the duration of investments. These oil and oil product-indexed contracts cover the required long-run marginal costs of the gas. Thus the long-run marginal production costs at one of Norway’s most expensive fields acts as a price setter for the European gas market in long-term contracts. The long-term contracts in Europe mostly act as sources of base-load volumes with a high load factor, with little variation or flexibility in delivery. The NBP day-ahead prices reflect regional gas prices in the UK, on a more spot-oriented basis while the German Border Price is an indicator of the oil-indexed gas price on the European continent [IEA 2008a]. The European market is thus a hybrid market involving both short- and long-term trading, with an important gas trading pattern between hubs and long-term contracts arising as such:

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129 The NBP hub saw physically traded volumes rise to 67 bcm and 903 bcm worth of traded volume in 2007 [IEA 2008a]. The TTF and Zeebrugge each reached a level of roughly 10 bcm of physically traded gas and traded gas 25 bcm and 40 bcm, respectively [Cronshaw et al. 2008]. The CEGH reached physical trade occurring at a level of 6.9 bcm in 2007, a 46 percent rise form the previous year while traded volumes rose to 17.7 bcm [IEA 2008a].

130 These long-term agreements have several characteristics. The take-or-pay provisions consists of clauses in which the buyer is obliged to pay for a certain amount of gas regardless of whether he uses it or not. All major parties in Europe make use of the so-called market-value principle: the price of gas is valued vis-à-vis other alternative fuel prices for that customer in a particular (export) market, added to the long-term contracts after the first oil crisis, though it was already being used in the Dutch market. The resulting market value or price of gas is then netted back to the seller, i.e., netback values are then calculated; transportation costs and transit fees are subtracted from the price the producer receives. Destination clauses in some supply contracts ensured that gas would flow to the destined market, thus maintaining a local market value approach [Cronshaw et al. 2008].

131 These contracts use a formula that is linked to competing fuels in export markets. This formula is also linked to the highest-cost marginal field, which in the European case this is the Troll field in Norway. This pricing formula is known commonly in the industry and referred to as the Troll pricing formula [Dickel et al. 2007].

132 Base-load volumes satisfy a certain base in demand: the ‘load factor’ measures variations in natural gas deliveries. A high load factor of 100 percent, for example, has no variation while a low load factor involves higher variation.
“If long-term oil-based contract prices are higher than the gas hub prices, than it is likely that customers will buy at the hub and try to minimise purchases at the contract price. This will drive prices up to contract prices. If there is a well-functioning, deep and liquid hub, then it is possible the hub price will influence the long-term contract price. […] In this case, the long-term contract price is likely to be a floor price to the hub with players looking to buy additional gas in the traded market, driving prices up” [Cronshaw et al. 2008, p. 41].

5.3.3 The US gas market

Market structure
The US market is an entirely different story when compared to Europe, enjoying virtual self-sufficiency until recently. The US natural gas market is the largest in terms of volume in the world, consuming some 658 bcm in 2008 and importing 112 bcm [IEA 2009a]. Of these 112 bcm, it imported 101 bcm from its North American neighbour Canada and 1 bcm from Mexico in the form of pipeline gas. As for LNG, it imported 7 bcm from Trinidad and Tobago, 2 bcm from Egypt, and 1 bcm from other countries [IEA 2009a]. Thus of the 112 bcm the US imported in 2008, 91 percent came from neighbouring pipeline gas exporters and 9 percent from LNG exporters. This means gas imports accounted for only 17 percent of total gas consumption, while LNG imports as a percentage of total consumption amounted only 1.5 percent. In recent years however, the development of unconventional gas, stimulated by higher gas prices and fiscal incentives, has reduced the US call on LNG imports (in 2008, the LNG import were less than half the level of 2007) [IEA 2009b]. The ongoing economic downturn, combined with lower oil and gas prices, may result in a decline in unconventional gas supplies and lower LNG imports for the time being. Figure 5.3 shows the gas supplies to the US by type and source in 2008.

The Barnett Shale in Texas is already contributing 6 percent to total production in the lower-48 states in the US [IEA 2008a].
Figure 5.3 Gas supply to the US by type and source in 2008 (in bcm)

* Egypt: 1.6 bcm; Nigeria: 0.3 bcm; Qatar: 0.1 bcm; non specified: 0.5 bcm.

Source: own analysis, based on IEA [2009].

Pricing in the US market

In its functioning as a deep, liquid, and versatile market with hundreds of domestic producers and transmission companies, the US stands in stark contrast to the European market(s).134 The North American market is the most liquid market in the world as well as the deepest. Its liquidity is embodied by the Henry Hub, the most important gas trading hub in the US, which yields the Henry Hub spot gas price.135 The NYMEX trading platform, which provides futures trading, has proved to be highly successful for gas risk management, providing a very liquid vehicle for hedging short-term US gas market transactions.136 In view of its depth and liquidity, the US market thus remains the outlet for LNG suppliers, especially those in the Atlantic Basin. Vast amounts of storage in the US and a clear regulatory framework contribute to a well-functioning and liquid market by providing flexibility during times of high demand.137 Even

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134 The combined Canadian and US natural gas markets form the largest integrated natural gas market in the world, with Canada providing roughly a quarter of the combined gas production.
135 The prices set at Henry Hub on the Texas-Louisiana border are considered to be the primary price quotation for the North American gas market [IEA 2008a]. At Henry Hub, contracts for short-term delivery and trading are available on a day-ahead and month-ahead basis, so buyers and sellers can trade on a short-term basis (as opposed to long-term contracts). Instruments for covering or hedging against risks are available at the NYMEX exchange.
136 While the NYMEX transactions are fully transparent, the swaps market lacks the transparency of the NYMEX exchange quotations [Jensen 2004].
137 Available storage in the US is estimated to stand at 110 bcm, mostly in the form of depleted natural gas fields or oil fields, as well as natural aquifers.
LNG imports are based on short-term supplies, with only very few long-term supply contracts with buyers in the North American market in existence [CIEP 2008]. This is paradoxical, since LNG trade is supposed to be based exclusively on long-term contract: this mismatch once vindicated the view of some that the US could never become a major LNG importer [Yergin and Stoppard 2003].

A line of separation between the eastern and central US and the western US (California, etc.) is drawn by the Rocky Mountains, with both sides of the US market acting separately. Much of the eastern and central side actually consists of a set of different hubs, each representing demand in different gas consuming centres across the country. If sufficient capacity is available to transport gas between these hubs, price differentials between these hubs will represent the marginal transportation costs between the different locations and price differentials tend to give pipeline companies a clear, timely signal and incentive to build new infrastructure between hubs [Cronshaw et al. 2008]. These basis differentials are a standard element of US gas market trading [Jensen 2004]. The North American market is characterised by thousands of producers, which have an incentive to produce more when prices are high, while mid-stream marketers of gas add value by arranging transportation and storage, and even financing as well as by assuming price risk.

The predominance of spot trading and liquidity in the US natural gas market has all the characteristics necessary for ‘gas-to-gas’ competition, in which the market value for gas is determined purely by gas demand and supply factors, rather than indexation to alternative fuels. There appear to be three ranges of price relationships between gas and oil in the US: 1) a discounted gas-to-gas level where the prices of the two fuels are decoupled; 2) a higher level where

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138 There are 38 different hubs in the US and Canada. They have tended to develop at the junction of multiple pipeline interconnections, and usually have access to natural gas storage facilities, allowing the hub operator to offer balancing services, enhancing trading options for both buyers and sellers. The hubs can be located in a producing area near a gas supply basin (such as Henry Hub) or they can be market area hubs, located near a market center, characterized by numerous market participants and access to services, such as balancing and title transfer, organized by the hub operator [Cronshaw et al. 2008].

139 These players are thus often active on the short-term (spot) and long-term (futures and forwards) market on the NYMEX exchange, where risks can be covered through direct contracts with other counter parties for delivery at a certain hub [Cronshaw et al. 2008]. The debt service on the investment is protected, not in the form of take-or-pay obligations for combined transportation and commodity, but in the form of a ‘ship-or-pay’ obligation [Dickel et al. 2007].

140 For a graphic illustration of this relationship, refer to Figure 27 in [Dickel et al. 2007, p. 121]. However, even Henry Hub prices show a reasonably strong correlation with WTI oil prices at times while at others they follow their own patterns. This linkage weakens and strengthens depending on the relative pricing in the US of gas versus fuel oil, amongst other factors. During the 1990s, gas prices seemed to decouple from oil linkages after restructuring in the North American industry and so “during an extended period when gas supplies were in surplus – the gas ‘bubble’ – that indeed appeared to be true. […] But the gas shock of the winter 2000/2001 eliminated the assumption that oil pricing was no longer relevant in North American pricing. During shortage, buyers quickly bid up gas prices, until dual-fired power generation users found it economical to switch from gas to residential fuel oil. Thus an indirect linkage between gas prices and oil prices was re-established” [Dickel et al. 2007, p. 120].
the gas prices are linked to residual fuel oil and 3) a still-higher level where the gas price linkage is to distillate fuel oil. In the coming years, gas prices in the US market will be set in essence by competition between LNG and unconventional gas production [IEA 2009a].

### 5.3.4 The Asia-Pacific markets

Turning to the Asian-Pacific market, i.e., the Pacific Basin for LNG, a completely different market structure than can be discerned from the ones in the US and European gas markets described above. Traditional gas markets in the Pacific Basin include Japan, Korea and Taiwan, and these three countries have been the driving forces behind LNG trade in the Pacific since the 1960s and 1970s. Since the mid-2000s, China and India have become important new LNG-importing markets in the Pacific Basin, though they have yet to make their joint impact felt in the Pacific Basin (in absolute volume terms). Total gas consumption in the Asia-Pacific region was 267 bcm in 2008. The share of indigenous supply in total Asian gas consumption (excluding intra-regional gas trade by pipeline and LNG) is around 60 percent, due to a few large producing countries in South-East Asia (for example Indonesia, Malaysia and Brunei) [De Jong et al. 2010]. When accounting for gas-importing countries, as shown in Figure 5.4, the share of LNG imports is much higher (60 percent).

#### Japan, South Korea and Taiwan

Japan and South Korea have traditionally been powerful LNG buyers in the Pacific Basin. Japan has long been and still is the world’s largest LNG buyer, accounting for some 67.7 percent of Pacific Basin trade. Japan boasts the most diversified gas import market in the world through its multiple LNG import commitments. Some 70 percent of Japan’s LNG was sourced from just four countries: Indonesia, Australia, Malaysia and Qatar in 2008, by contrast, Atlantic Basin suppliers such as Egypt, Algeria, Nigeria, Equatorial Guinea and Trinidad and Tobago provided almost 5 percent [IEA 2008b]. South Korea and Taiwan accounted for much of the incremental rise in Pacific Basin LNG imports from 1995 onwards. Together, Japan and South Korea are the world’s largest LNG importers, importing 95.4 bcm and 36 bcm, respectively, in 2008, with Taiwan following suit at 12 bcm. Collectively, all three countries imported LNG from traditional LNG exporters such as Indonesia, Malaysia and Brunei. Other suppliers to these three important LNG markets include Oman, Australia and Qatar. Japan, South Korea and Taiwan are set to remain important LNG buyers in the Pacific Basin.

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61 For a graphic illustration of this relationship refer to [Jensen 2004, p. 28]. Gas is responsible for almost 20 percent of power generation in the North America energy scene.

62 In 1985, the Pacific Basin accounted for 40 bcm worth of LNG trade, with Japan in the lead, while by 2000 this figure had risen to nearly 100 bcm, and some 130 bcm in 2006 [Chabrelie 2007].
China and India

China and India have only just made their début during the last few years as gas importers, primarily in the form of (relatively small) small LNG imports. These two countries, given the rates of economic growth and their desire to increase their use of gas in their energy mixes, are likely to have a long-lasting structural impact on the LNG market in the Pacific Basin and ultimately also in the Atlantic Basin. For now, gas plays a only a marginal role in these countries’ energy needs (4-5 percent in 2008) [IEA 2009b]. China has had sufficient domestically produced gas volumes until 2005 to satisfy domestic demand, after which time it began to import LNG, thus joining the ranks of the Pacific LNG buyers. China produced 73 bcm in 2008, but consumed 77.6 bcm in the same year [IEA 2009b]. China is a newcomer to the natural gas market as far as gas imports are concerned when compared with South Korea or Japan (in the Asia-Pacific region), importing 4 bcm worth of LNG from Australia, Algeria, Egypt, Equatorial Guinea and Nigeria in 2008. Recently, China is reported to have begun importing pipeline gas from Turkmenistan with the opening of a pipeline connecting both countries (also see Chapter 6). India produced 29 bcm in 2008, consuming 39 bcm and importing 10 bcm worth of LNG. In 2008, India’s LNG imports came from Qatar, Nigeria, Oman, and minor amounts from Australia, Equatorial Guinea, the United Arab Emirates (UAE), Algeria, Egypt, Malaysia.
Pricing in the Asia-Pacific market

As mentioned earlier in this chapter, the Japanese market is characterised by an almost exclusive reliance on LNG imports, which come primarily from the Pacific Basin (including the Persian Gulf). With Japan as the leading LNG buyer in the region, LNG prices there are logically tied to the Japanese crude oil price. In traditional long-term Asian LNG contracts, pricing is linked to the import prices of a basket of prices, including the Japan Crude Cocktail (JCC), as Japan is the largest buyer of LNG by volume in the Pacific Basin [IEA 2008a].

Japan’s gas base load deliveries as well as peak load requirements are all satisfied with LNG imports. Japan’s LNG imports are all tied into long-term contracts as Japan does not enjoy the luxury of hub trading. The tradition of long-term contracts in the Asia-Pacific Basin originates from one of the first Japanese-backed projects, namely the Arun project, resting on the willingness of the Japanese government – through the Ministry of International Trade and Industry (MITI) and Japan’s Export-Import Bank (J-EXIM) – to set up the purchase of the gas and the timely construction of an infrastructure for using it [Barnes et al. 2006].

5.4 Growth opportunities for gas-exporting countries

In the period stretching to 2015 and beyond, the OECD markets, i.e., the US and Canada, OECD Europe, Japan and Korea will remain the world’s deepest markets by volume, while demand in emerging gas markets such as China and India rises fastest in relative terms. The historic intra-regional supply growth of the Pacific basin is expected to slow, while the Middle East, Africa and to a lesser extent Latin America emerge as more important incremental exporters [Jensen 2004]. Much demand uncertainty has arisen with onset of the financial and economic crisis of 2008-2009. In the mean time, most of the major regional gas-importing markets are expected to continue to become more import-dependent, due to higher gas demand and lower indigenous supplies.

In a ‘post-Kyoto’ world, gas is seen as the transition fuel towards more renewable energies, because: (1) gas is much cleaner than other fossil fuels, especially in the area of power generation; and (2) gas is an appropriate source to balance intermittent renewable sources, such as

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143 Included in Japan’s long-term LNG import contracts is the so-called ‘S-curve’ to help alleviate, for both LNG sellers and buyers, the effects of sudden, severe oil (or JCC) price swings by establishing ceilings and floors in the movement of the LNG price relative to the oil price. For a graphic illustration of this relationship and further explanations, refer to Figure 28 in [IEA 2007a, p. 111]. Also refer to [Flower 2008a].

144 Vertically integrated regional companies form the basis of the city gas industry and by the end of March 2007 there were 213 general gas utilities in Japan, of which three major LNG purchasers, Tokyo Gas, Osaka Gas and Toho Gas share some 75 percent of the market in Japan (36 percent, 27 percent and 11 percent, respectively) [IEA 2008a].

145 Normally, with the functioning of the ‘S’ curve, the LNG price is above crude oil (JCC) parity at low oil prices but the premium erodes as the oil price increases and is eliminated depending on the size of the constant in the LNG pricing formula [Flower 2008a].

146 Of great significance, in addition, is the absolute rise in consumption in net-exporting regions and countries such as the Middle East and Russia, putting pressure on their export capacity [IEA 2009b].
wind energy. In the IEA’s ‘green’ scenario, for example, world gas demand in 2030 is 17 percent lower than in the reference scenario, though demand is still higher in 2030 than in 2007. Relatively low lead times and capital costs for Combined Cycle Gas Turbines (CCGT) gas-fired plants are expected to be important contributors to demand for gas in power generation, both in OECD and non-OECD countries [IEA 2009b]. However, long-term gas demand forecasts in the world’s most important gas consuming regions are prone to great uncertainties due to various reasons. More than ever, one can observe that analysts and institutions are offering diverging views on the future demand for gas [CIEP 2008]. Below, some of the main gas demand uncertainties are listed below, largely based on [IEA 2009c; CIEP 2008]:

1) In most of the countries the current economic decline has resulted in a reduction in demand and may affect gas demand from 2015 onwards. Depending on the length and depth of the crisis, expected however that demand will rebound, largely driven by the power generation sector IEA [2009];

2) government policies (including security of supply and environmental policies), surrounding the use of gas in its energy mix, such as the 20/20/20 EU targets, could affect especially the amount of gas imports (either for political or economic reasons) [CIEP 2008];

3) the relative (oil and) gas price (volatility) development vis-à-vis its substitutes, such as coal and renewables;

4) Carbon Dioxide (CO\textsubscript{2}) emission costs and Carbon Capture and Storage (CCS) developments. For instance, with high CO\textsubscript{2} emission costs (and high coal prices) power generation plants will focus on gas;

5) different (price) regulatory uncertainties could have an impact on the role of gas and its demand.

According to the reference scenario of the IEA [2008b], primary energy demand is set to rise by 1.6 percent per annum between 2006 and 2030, an increase of 45.3 percent. The power generation sector is expected to take up much of the demand in this regard as it rises by 2.4 percent per annum between 2006 and 2030, amounting to a 57 percent rise.

5.4.1 The European gas market

According to the Reference scenario of IEA [2009c], OECD Europe will increase its import dependency to 77 percent by 2020 and 85 percent in 2030 (excluding Norway). The growth of gas imports will be substantial in some regions. In Northwestern Europe (NWE) the growth of gas imports is mainly due to lower indigenous supplies from the gas fields in the

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147 The EU adopted an integrated energy and climate change policy in December 2008, including targets for 2020. These targets include: (1) cutting greenhouse gases by 20 percent (30 percent if international agreement is reached); (2) reducing energy consumption by 20 percent through increased energy efficiency; and (3) meeting 20 percent of EU’s energy needs from renewable sources.

148 The much higher level of gas prices, in absolute terms and relative to coal prices is the main reason for the downward revision in projected demand growth by the IEA [2008b].
North Sea and in other markets also as a result of higher expected gas demand. The total gas demand will increase by 20 percent from 2007 (544 bcm) to 2030 (651 bcm), according to the Reference scenario (see Figure 5.5). In IEA’s ‘green’ scenario, gas demand will decrease by 3 percent from 2007 to 2030 (525 bcm), although the level of imports will still rise due to declining indigenous production. Apart from the already mentioned uncertainties, the main uncertainties for future European demand are found in policies surrounding the use of gas in the power generation segment (e.g., the role of renewables, the effectiveness of the CO\textsubscript{2} emission trade, the fuel choices as a result of security of supply reasons, and the prospects of CCS), including the potential for energy savings. Other specific uncertainties in regard to European gas demand are undeveloped gas (transit) networks in some sub-regional markets [expert interviews; Correljé et al. 2009].

Figure 5.5 OECD Europe gas market: import dependency (reference scenario in bcm)

For example, European gas imports could vary substantially by 2020 depending on EU policy on 20/20/20 and oil price developments. These policies are the result of a desire to decrease import dependence, particularly from Russia. The resulting bandwidth is 170 bcm in 2020 (312 to 482 bcm). One scenario expects a decrease in EU’s gas imports from 316 bcm in 2010 to 312 bcm in 2020. See Chapter 10 for a scenario analysis on aggregated European gas demand (and supply).
5.4.2 The US gas market

The US is likely to remain only modestly dependent on LNG imports. The EIA [2010] takes into account the significant contribution of unconventional gas production in that region, affecting US demand for LNG imports, which may stabilise indigenous supplies. The future unconventional gas production is the main specific uncertainty in the US (and global) gas markets, especially under currently low Henry Hub gas prices [IEA 2009b]. Another consequence of the surge of unconventional gas production is that the further internationalisation of the gas market, in which the US was expected to become a major buyer of LNG, is not developing as perceived, making a continuation of more regional based gas flows more likely.

Figure 5.6 The US gas market: import dependency (reference scenario in bcm)

According to the Reference scenario of the IEA [2009c], the US is projected to consume some 635 bcm by 2020, and 649 bcm in 2030, which results in a small demand reduction between 2007 and 2030 [IEA 2009c]. According to the green scenario, the demand reduction is slightly higher (4 percent between 2007 and 2030). In absolute terms, over the course of the next decades, with pipeline imports from Canada en Mexico combined with some LNG supplies from Latin America, the Middle East and Africa, it will remain a possible important mar-
ket for exporting countries. Figure 5.6 provides an overview of the import dependency of the US market in IEA’s Reference and green scenario.

5.4.3 The Asia-Pacific gas markets

According to the IEA’s Reference scenario, demand in the Asia-Pacific countries will stand at 592 bcm in 2030. The OECD Pacific market (i.e., Japan, South Korea, and Australia/New Zealand) grows from 170 bcm in 2007 to 218 bcm in 2030, while China’s consumption may rise to 242 bcm in 2030 (up from 73 bcm in 2007) and India’s consumption to 132 bcm (up from 39 bcm in 2007). This boils down to 1.1 percent per annum for OECD Pacific countries versus 5.3 percent per annum for China and 5.4 percent per annum for India between 2007 and 2030 [IEA 2009c]. According to IEA’s green scenario, gas demand is expected to increase, but less than in the case of IEA’s Reference scenario (for OECD Pacific a change of 12 percent in 2030; for China 18 percent; and for India no change) [IEA 2009c].

Figure 5.7 LNG importing Asian countries: import dependency (reference scenario in bcm)

For China and India, coal is expected to dominate their energy mixes, although environmental policies may change the composition of their energy mix [IEA 2009c]. Most of its growth in
gas needs to be fulfilled by imports, although production is expected to rise. The demand growth differs substantially in the medium-term by regional market, according to the reference scenario of the IEA [2009c]. However, the call on imported gas is expected to increase in all above-mentioned regions. In Figure 5.7 the demand growth and the import-dependency is graphically displayed.

Specifically, China’s regulatory landscape, combined with increasing domestic production (the government plans to double its domestic production to 160 bcm by 2015), uncertainties about price reforms, and other market uncertainties, may hinder an additional call on import gas [IEA 2008a]. Future flows to Japan and South Korea, the traditional LNG imports of the Asia-Pacific region, are likely to continue coming from Pacific Basin suppliers such as Brunei and Malaysia as well as Australia and from Middle Eastern suppliers such as the UAE, Oman and Qatar. Future flows for China and India may perhaps materialise in the form of both LNG imports from similar sources as mentioned above for Japan, etc., and pipeline gas imports from the Middle East and Central Asia. China was interconnected by pipeline to Turkmenistan in December 2009, and could possibly be interconnected with Myanmar in the future, Kazakhstan and Russia as well (with Russian supplies reaching other Asian markets as well, see Chapter 7) [IEA 2009b]. Depending on a number of uncertainties, India may be import pipeline gas from Iran and perhaps Turkmenistan by pipeline, although this seems unlikely to occur before 2015 [IEA 2009b], if at all.

5.5 The flexibility of LNG and new business models
The main causes for increased flexibility in the LNG value chain is due to a combination of a number factors [Stern 2008; Jensen 2004], namely the following: Advances in technology and flexibility of different physical components in the LNG chain; the need for buyers to access flexible supplies at short-notice; changing business models and the entry into LNG markets of commercial players oriented towards short-term trading and profitability; the growing influence of price arbitrage between Henry Hub (the US), NBP (the UK) and the JCC; economies of scale in shipping; import-dependencies and rising demand in consuming regions and and interregional price discrepancies.

How future flows are determined depends to a large extent on LNG trade and pricing developments in the important LNG trading basins. As of yet, there thus is no globally functioning

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50 For example, in April 2008 China signed a long-term deal with Qatar for LNG to be supplied as of 2010 (see Chapter 7).
51 Though China is already active in the LNG market of the Pacific basin, it opts for diversity of imports and has strengthened ties with its Central Asian neighbors with the aim of establishing more reliable pipeline gas import routes as well. The Chinese are also in talks with Kazakhstan over a similar pipeline to be built from Kazakhstan’s western provinces to China where it will also link up with China’s West – East pipeline [MEES 2008b] and [PIGR 2008d].

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LNG market, and long-term contracts will continue to pre-dominate the nature of gas trade. Nevertheless, long-term contracts between buyers and sellers of LNG, the bedrock for investments in a capital intensive gas industry have shown increased flexibility in the face of inter-regional price differences. High demand in various markets and price discrepancies help stimulate arbitrage in a market with comparatively few sellers and many buyers, hinting at increasing interconnection between markets and a ‘shorter-term’ market for LNG cargoes. Of course, currently a situation of ‘under-demand’ or oversupply exists, which has had a considerable impact on this short-term end of the market.

The transatlantic gas markets, i.e., the Atlantic Basin for LNG, sees the strongest potential for increased hub-driven gas-to-gas flows, given the presence of important hubs such as Henry Hub, the NBP and other continental European hubs. The Pacific Basin is likely to see LNG trade mostly based on long-term contracts. A shorter-term market involves spot trading which reveals that the spot price lies above the value in long-term contracts, breaking oil-price linkages with high prices, and conversely; a long market involves spot trading which reveals that the spot price lies below the value in long-term contracts, breaking oil-price linkages with low prices [Frisch 2008]. Neither the markets nor the suppliers appear to be driving the market towards full commoditisation which might lead to a single global commodity price; nonetheless, some convergence of pricing may occur [IEA 2008a]. Much also depends on the further aftermath of the economic and financial crisis and how long the recession lasts.

5.5.1 The growth of regional hub trade in the Atlantic Basin
In the Atlantic Basin approximately 40 percent of the total trade has been made of “flexible” LNG, before the economic downturn in 2008 [De Jong et al. 2010]. The share of the UK and US markets in the LNG markets will likely continue to drive shorter-term trade in the Atlantic Basin (and beyond). The Atlantic Basin (with the US Henry Hub on the one hand and European hubs such as NBP, TTF, etc., on the other) holds much potential for continued and perhaps increased short-term LNG trade. The US market already boasts a deep and liquid market, while in Europe the rise of more flexible intra-regional supplies is boosting liquidity there as well. A new trend, for example, is for LNG and pipeline gas suppliers to reserve capacity for short-term supplies to the wholesale markets and via the hubs, notably LNG producers and from Norway and Gazprom by pipeline, though volumes are still small [CIEP 2008]. Contractual commitments downstream of the receiving terminal can be met through the purchase of gas at trading hubs, enabling the LNG to be shipped to other markets [Flower 2008b]. Since OECD Europe, for example, will see its incremental import demand satisfied by both pipeline gas and LNG, LNG imports to Europe will interact with pipeline gas sold on the basis of oil- and hub-based prices [IEA 2007a].
The result is also that gas prices can move more freely and in a more unpredictable manner than is the case in long-term contracts. These more volatile prices can fluctuate above the price level established in long-term contracts, and thus when hub indices exceed indexation in long-term contracts; sellers have an incentive to index their contracts to a stronger weighted impact of hub prices. Conversely, hub-based prices can sink below the oil-indexed level established in long-term contracts, which will encourage buyers to do the same; argue for greater spot indexation. New hedging instruments have, during recent years, facilitated short-term trade between Henry Hub and the European spot markets. In this manner, intraregional, flexible pipeline volumes in Europe, for example, can interact on a short-term basis with interregional, flexible LNG in the Atlantic Basin (and beyond). Should a number of re-gasification terminals be built on the west coast of the US, these could put additional pressures on rigid LNG through exposure to Henry Hub prices [Stern 2008]. All of the above should be seen in light of the current (2009-2010) economic recession.

5.5.2 The persistence of long-term contracts in the Asia-Pacific Basin
The trade in LNG in the Pacific Basin is characterised mostly by LNG trading involving oil price indexation (see Section 5.4.3 above). The share of flexible LNG in the Asian market may thus be considerably lower than the Atlantic Basin. Only a small share of LNG is traded on a true spot basis, the prices paid for spot cargoes tend to reflect the current market situation (such as power outages and sudden demand expansion) [IEA 2008a, p. 23]. With the 2008-2009 global economic and financial crisis, prices in this ‘short-term’ market have fallen substantially below oil parity as the market shifted form a seller’s to a buyer’s market. Japan’s integrated gas utilities have generally been able to buy exceptionally expensive spot LNG cargoes in the Pacific Basin and beyond because they have purchase portfolios large enough to absorb the high price of these individual cargoes; and seller’s arguments for price increases, especially in higher oil price ranges [IEA 2007a]. The converse now holds for buyers in a buyer’s market: low short-term prices encourage a downward price review in these contracts. In addition, these utilities form purchasing consortia in order to collectively increase their clout and purchasing power. During 2008, the outage of a nuclear power plant in Japan created additional demand for individual LNG cargoes, making room for diversions of cargoes from as far away as the Atlantic Basin.

Another example involves a Qatari diversion of LNG in November 2006. One of Qatar’s first diversion deals was concluded when Korea Gas agreed to a long-term contract for 2.6 bcm at prices which are understood to be above crude oil parity at an oil price of $60/bbl, which is a significant premium over the prices in Korea’s other long-term purchase contracts [Flower 2008b]. While the S-curve has been the mechanism of choice in these contracts, Japan was reported to be prepared to use new term contracts for Indonesia involving a full exposure to the JCC price, i.e., parity-based, from 2010 onwards [PIGR 2008c]. The impact of the economic recession is undoubtedly serious enough to force a review of these price terms.
5.5.3 Newly emerging LNG business models and downside risks

Economies of scale, interregional price differences (e.g. arbitrage opportunities), the opening of the US market, high energy prices in this decade and a sellers’ market have together combined to create new business models for LNG which diverge significantly from the traditional long-term contract [CIEP 2008]. Downstream integration into re-gasification assets occurs in three forms: 1) an integrated, bi-lateral model where the buyer pays for re-gasification, 2) self-contracting, which is a second generation model and 3) a third-party construction of a re-gas terminal where either a seller or buyer buys capacity on a long- or short-term basis (e.g., such as the Gas Access To Europe (GATE) terminal in the Netherlands). Self-contracting also occurs in the European pipeline gas markets and increasingly occurs in a similar manner for LNG. The new business models for LNG include allocations of output for short-term deals, self-contracting and aggregation [IEA 2008a; CIEP 2008; De Jong et al. 2010]:
1) Producers reserving part of their liquefaction capacity for short-term deals.
2) Producers and mid-streamers contracting their own production: Upstream stakeholders purchase planned liquefaction output, and in turn market it by themselves, either through capacity and/or equity acquisition at re-gasification terminals downstream in consuming countries or even direct sales to willing buyers. Various pockets of liquefaction output, or equity liftings, are thus allocated to different markets by either a consortium or joint venture or by one single player, achieving supply diversity and optimal revenues through the attainment of re-gasification assets downstream. This strategy may be pursued by LNG producers already established in the market with assured cash flows from earlier investments or by new LNG players, to the extent there is sufficient cash flow from supplies committed under long-term contracts.
3) The emergence of LNG aggregators buying LNG long-term and selling it in a mixed portfolio (though few companies have actually ventured on with this business model): So-called aggregators make sales commitments at LNG receiving terminals in emerging LNG consuming countries. Often, long-term supplies are bought by an aggregator and then sold on a short-term basis in different markets as described above; this aggregates supply and demand and interlinks regional markets still further. This has given rise to so-called ‘market-or-pay’ agreements between upstream equity lifters or aggregators, in which liquefaction output is bought by the aggregator, often an IEF, regardless of whether the output is marketed or not. They hereby clearly intend to move LNG through their own integrated systems much as they might earlier have done with third-party contracting.

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153 For an extensive description of gas supply business models and financing, refer to Chapter 2 in [Smeenk 2010].
154 Pipeline suppliers to the European market, notably those from Russia, Norway and Algeria, also appear to add “flexible supplies”, not committed to their markets by means of long-term contracts, in their supply portfolio for Europe, for purposes of direct marketing and sales in the wholesale spot market [De Jong et al. 2009; CIEP 2008]. For example, Gazprom M&CT has already contracted pipeline capacity in the Nord Stream pipeline (see also Case study 3, Chapter 9).
Yet, the movement away from oil-linked price clauses in long-term contracts to short-term or spot market purchases or even term contracts with gas-linked pricing poses a substantial challenge, costs and risks to gas sellers [Jensen 2004]. At the value chain level, some consequences of self-contracting (and other forms of flexibly marketing LNG) are [De Jong et al. 2010]:

- The need for producers to secure re-gasification capacity in different markets (or overcapacity in case of a pipeline system) in order to realise the potential of arbitrage. In addition, this is done so as to maintain shipping capacity such that a supplier remains capable of reaching the markets included in its arbitrage portfolio;
- the need for producers to develop the tools and capabilities to sell gas directly in markets of their choices without long-term supply contracts for flexible gas.

These business models may lead to chronic surpluses in shipping and re-gasification, which would result in higher risks and costs for producers (and aggregators). This enabled LNG (and pipeline gas) to become more flexible, fostering the impression that interregional gas-to-gas competition may decouple this flexible LNG from long-term, take-or-pay, oil-indexed contracts. The downside risks of the new business models are both revenue- and volume-related. When the current sellers’ market transforms into a buyers’ market, short-term and spot gas prices may well be less desirable than the prices realised under long-term contracts and it may even prove difficult to place LNG in markets which are already well supplied. According to De Jong et al [2009], for these reasons the self-contracting producers and aggregators often exploit at least one “haven” of last resort for their LNG via firm’s re-gasification capacity. In many cases this lies in the US as it offers the most liquid market, with the most capacity to absorb surplus LNG even in an oversupplied global market. Obviously, with the impact of the rise of the production of unconventional gas in the US, this situation has fundamentally changed.

Whether these new business models will evolve and develop further depends on (1) the risk appetite of LNG suppliers to continue to exploit their resources on the basis of the new business models in conditions of lower and/or volatile energy prices; (2) the ability and compliance of the markets, particularly the European market players and to a lesser extent those in Asian markets, to accept and manage the supply risks associated with these business models; and (3) the preparedness of producing and consuming governments to distance themselves from LNG sale and purchases transactions. The current economic crisis might encourage gas exporting companies to go for long-term contracts instead of choosing a business model of flexible supplies [De Jong et al. 2010].

5.5.4 The tendency towards further short-term trade
The advent of new business models in the marketing of LNG, in which pockets of LNG become more flexible on the basis of short-run price fluctuations between regions – and within
these price discrepancies – the spread between price levels paid for short-term LNG and long-term contracts, means pricing issues are bound to arise in the long run. Interregionally flexible LNG supplies, i.e., ‘uncommitted’ LNG volumes, will shift in accordance with shorter-run price spreads first between regional markets, then between basins, even as ‘pockets’ of pipeline gas mainly within Europe also become more flexible. The price spreads between various regional markets for LNG feed into longer-term contracts, more adequately reflecting demand and supply patterns [IEA 2009b]. The effect of these new business models on interregional trade is to create greater connections between the various regional gas markets, to create room for shorter-term trade, where peak-load ‘optimisation’ of LNG flows as complements to flexible pipeline gas is one thinkable form of short-term trade. Indeed shorter-term trading can involve pipeline gas-for-LNG swaps, term contracts, i.e., three to five-year contracts.  

Per reference to Figure 5.8 below, the share of gas-to-gas, spot-oriented pricing remained the same between 2005 and 2007 in relative terms though in absolute terms it grew, largely as a result of the growth of spot LNG imports in traditional LNG-importing countries in Asia and in Spain, for example. The bulk of gas-to-gas pricing corresponds with Henry Hub and NBP pricing, given the fact that the US and UK gas markets are very large. The traditional netback pricing mechanism in the regional markets described above accounts for more than 50 percent of the total world’s consumption. Pricing based on regulation (e.g., cost of service, below-cost and social and political) is responsible for almost another 40 percent of the total world’s gas consumption. This pricing mechanism is largely applied in producing countries, where much of the gas production is consumed locally. Some countries where regulated prices prevail (such as in Russia and Ukraine) are investigating other pricing mechanisms. The shares of other pricing mechanisms are rather small [IEA 2009c]. The economic and financial crisis of 2008-2009 is bound to have an important impact on these aforementioned pricing patterns.

\[106\] This ‘half-way-house’ contractual model is based essentially on the idea that it provides producers with a bandwidth between long-term contracts and spot sales, possibly appealing to those LNG producers whose assets have been largely amortised and who expect a continuation of today’s seller’s market or who, like Qatar, have developed a project based on self-contracting to sell in another market when desirable. The process of term contracting and tendering in both basins has led to increased prices, shorter contract duration and, at times, reduced volumes.
Note should be taken of new technologically innovative developments and techniques for liquefaction and re-gasification and their potential impact on shorter-term trade in the long run. Floating liquefaction, for example, is a process in which liquefaction plants – specially designed for the purpose – are located offshore to develop otherwise stranded gas fields, from small to large ones. At the same time, new offshore re-gasification techniques involving ships with onboard re-gasification equipment could pave the way for yet more flexible LNG deliveries to markets as expensive re-gasification (and liquefaction) terminals and Not In My Back Yard (NIMBY) problems can thus be circumvented. It involves a quicker implementation schedule when compared to conventional land-based LNG receiving terminals because offshore re-gasification buoys are used instead [IEA 2008a].\textsuperscript{156} Such acquisitions could prove valuable assets for gas suppliers in a European market with rising dependency and increased short-term trading. Another development which favours economically feasible short-term LNG trading is floating storage.\textsuperscript{157} Various types of actors in the LNG value chain, from suppliers to buyers,

\textsuperscript{156} Excelerate Energy has been successful offshore in the US, in the Gulf of Mexico in 2005. Kuwait, for example, which has a really small harbour, is also planning to use the system. Taqa Petroleum, a subsidiary of the UAE’s Abu Dhabi National Energy Company, bought from BP a strategically located platform plus emptied gas fields known as P15/P18, just off the Dutch port of Rotterdam, for eventual offshore re-gasification and storage use [MEES 2007a].

\textsuperscript{157} For example, Qatar uses floating LNG to arbitrage between markets by maintaining liquid volumes for such trades [WGI 2009d].
are increasingly active in the floating storage market where gas is stored offshore for the summer and sold to any one regional market during the winter for a higher price [WGI 2006a].

5.6 Conclusion
The 2008-2009 economic slow down in gas demand has demonstrated that tightness in inter-regional LNG flows can easily be reversed, and that future developments in gas demand are never certain. Regional gas markets such as Europe, the US and Japan, together with ‘newer’ markets such as China and India, are likely to continue functioning as they do. ‘Flexible’ LNG will proceed to act as a source satisfying marginal needs as it interacts with base-load pipeline supplies, primarily in Europe. There is thus a globalisation of the regional gas markets as LNG increasingly acts as an interregional gas price marker.

Significant price differentials between major regional gas markets have encouraged major producers and shippers to allocate production of liquefied gas into portfolios including long-term and shorter-term sales. These developments have helped push and pull LNG from a regional and bi-lateral type of trade to a more global and multi-lateral environment. These inter-regional, flexible LNG volumes, though limited in absolute terms, move to and fro between regions at great price sensitivity, doing so on the basis of some form of spot, short-term or hub-type trade, arbitraged away from originally long-term flows. These diversion effects demonstrate the tendency towards hub-based indexation, or gas-to-gas competition on an inter-regional basis. In a buyer’s market and under conditions involving falling demand, and thus also falling shorter-term prices (and oil prices), such trading poses significant downside risks.

Along regional lines, the gas markets in the US, Europe and the Asia-Pacific region will continue to exhibit differences in market structure and import-dependency. In terms of pricing and trade these markets will continue to differ substantially as well. The US and (part of) Europe remain on the short-term side of the gas-pricing spectrum while to a large degree Europe and the Asia-Pacific region remain dependent on long-term trade. However, with the rising flexibility of LNG, particularly in the Atlantic basin, but also between both major trading basins, some interregional price convergence is likely to occur. The rise of flexible LNG, in large part owing to new business models, is likely to be an important driving force in the further globalisation of LNG trade. LNG volumes are thus likely to interact further with pipeline volumes on a gas-to-gas or short-term basis as LNG imports increasingly roll into the market on a marginal basis, even as oil and gas prices could continue to be closely linked with one another. As has been cautioned in this chapter time and again, the manner in which they do so is likely to be affected fundamentally by current conditions involving interregional gas market oversupply.