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Developing a Natural Gas Trading Hub in Asia

Obstacles and
Opportunities



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Warner ten Kate
Lászlo Varró, Anne-Sophie Corbeau

INTERNATIONAL ENERGY AGENCY

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75739 Paris Cedex 15, France

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Acknowledgements

The author of this report would like to thank all the contributors and reviewers for their input and comments.

Significant contributions, valuable comments and feedback were received from within the International Energy Agency (IEA), and from a panel of external industry reviewers. In that regard, I offer special thanks to Thijs van Hittersum, Karel van der Lingen, Colin Lyle, Julie Jiang, Jonathan Sinton, and Doug Wood for their careful review and challenging comments that have considerably improved the quality of this paper.

Warner ten Kate (formerly IEA) is the lead author of this report, produced under the supervision of László Varró and with contributions by Anne-Sophie Corbeau. At the IEA Gas, Coal and Power Division (GCP) I would like to thank László Varró, Head of the Gas, Coal and Power Markets Division, for his valuable advice, unrelenting support and extensive discussion on the topic. My colleagues of the GCP gas team Ichiro Fukuda and Hideomi Ito, who, as LNG experts, showed me the way through the liquid maze. Special thanks go to Alexander Antonyuk for rigorously attacking my assumptions, making them either stronger or irrelevant. Finally, nothing would have come together if not for the inspirational gas team leadership of Anne-Sophie Corbeau.

I am grateful to Janet Pape for editorial work.

Cheryl Haines, Bertrand Sadin, Astrid Dumond, Muriel Custodio and Angela Gosmann at the IEA Communication and Information Office (CIO) provided essential support in terms of editing, production and publication.

Executive summary

Natural gas has the potential to improve energy security and economic and environmental performance in the Asian-Pacific economies. However expanding its role will depend on regional market conditions that allow gas to compete autonomously in energy markets which are themselves connected to global energy markets. The future role of gas in Asia will depend on whether natural gas pricing is tied more closely with supply and demand fundamentals in the region.

The Asian natural gas market is the fastest-growing gas market worldwide, and is expected to become the second-largest by 2015, with 790 billion cubic metres (bcm) of natural gas demand. The market for natural gas in Asia is dominated by long-term contracts in which the price of gas is linked, or indexed, to that of oil. Developing countries might require long-term contracts to ensure security of supply for their fast-growing economies, and producers will look to secure return on their considerable infrastructure investments.

In recent years, this has helped keep Asian gas prices much higher than those in other parts of the world, leading to competitiveness concerns and serious questions about whether such a system can last. In order to expand its market share, natural gas has to be competitive within the energy mix of the region or country where it is delivered. In Asia, however, current constraints include the region's lack of both a trading hub to facilitate the exchange of natural gas, and the development of a transparent price signal to steer investments in natural gas infrastructures.

The confidence in the legitimacy and transparency of natural gas pricing generated on a natural gas hub is crucial for investment decisions in such a capital-intensive industry. This confidence can be derived to a large extent from the institutional and structural requirements put into place, but ultimately it lies in the long-term resolve of government to allow markets to determine natural gas prices with minimal interference from short-term political considerations.

To successfully develop a reliable natural gas price in the Asian-Pacific region would require a competitive national/regional market, which would then need to meet a set of institutional and structural requirements to create the market confidence to attract new participants (namely financials) and to encourage market players to use a trading hub for the balancing of their portfolios.

A "hands-off" government approach is necessary. This would involve separating transport from commercial activities, price deregulation at the wholesale level, sufficient network capacity and non-discriminatory access, and a competitive number of market participants with the involvement of financial institutions.

Prospects for a competitive wholesale natural gas market in Asia are limited. Even in the most mature Asia-Pacific markets, the basic requirements for a wholesale market are missing, as governments continue to emphasise security objectives over economic ones. Of the Asia-Pacific economies reviewed in this paper, Singapore seems the candidate best suited to develop a competitive natural gas market and trading hub in the medium term.

A unique characteristic of the natural gas trade in Asia-Pacific is the limited amount of natural gas that is traded via pipelines, and the region's growing dependence on the global liquefied natural gas (LNG) supply chain. That global LNG market has become decidedly more short-term oriented and flexible over the past decade – a result of the expansion of global LNG production, the emergence of global portfolio players and enhanced competition in the Atlantic Basin.

And yet these Atlantic Basin developments have had a limited impact on supply flexibility in the Asia-Pacific region. A competitive natural gas market in Asia would need an even more flexible LNG supply than is currently in place. This will require a continued expansion of shipping

availability and third-party access (TPA) to regasification terminals in the Asia-Pacific region. Furthermore, it would involve relaxing destination clauses in LNG supply contracts that allow for market segmentation and stiffen the overall supply chain. Any such modification of the contract structure must properly incorporate aspects that preserve investment security.

In the Asia-Pacific region, competitive natural gas markets and a reliable gas price will not develop overnight, and will not necessarily lead to lower prices. However, such a development will allow market players in Asia-Pacific economies to increase portfolio flexibility as natural gas markets in this region continue to mature.

Governments in the region will need to signal their willingness to facilitate competition further downstream. Singaporean efforts to develop a competitive natural gas market and complementary trading hub might be considered small relative to the size of the entire Asia-Pacific natural gas market. However, the example of an alternative market model which is able to adapt global supply changes to the regional market would be a powerful one.

Introduction

Global natural gas demand is expected to continue to grow rapidly, outperforming all other fossil fuels. Global demand is fuelled by the economic growth of emerging economies (aided by air quality concerns), notably China, and to a lesser extent India. In the short to medium term, regional gas demand is also boosted by the aftermath of the Fukushima Daiichi nuclear accident, as gas is one of the key available energy sources to replace nuclear power generation in the Japanese electricity mix.

In recent years, significant revisions in global natural gas resource estimates have alleviated concerns about the long-term availability of natural gas in both developed and developing economies. As a result of the exponential growth of United States' shale gas production, new global LNG liquefaction capacity and the impact of lower demand due to the economic crisis, a gap emerged in 2009 between spot prices (the prices at which the gas can be bought or sold at a specified time and place) in the United States and United Kingdom on the one side, and oil-linked gas prices prevailing in Asia Pacific¹ and Europe, on the other.

As of 2012, natural gas prices in the United States remained at low levels of around USD 3 per million British thermal units (MBtu); European spot prices, albeit three to four times higher than those in the United States, are still at a discount to European long-term contract prices, while prices in Japan peaked at a level considerably higher than those in Europe. This is raising the question, both in Europe and Asia, of the appropriate way to price natural gas.

The European Union has sought to answer this question through the development of alternative pricing mechanisms via gas-to-gas pricing on gas trading hubs. Europe has a liquid trading hub in the United Kingdom, the National Balancing Point (NBP), and more recently developed some trading hubs in continental Europe, notably the Title Transfer Facility (TTF) in the Netherlands and Net Connect Germany (NCG) in Germany. However, no such developments have taken place in the Asia-Pacific economies so far.

A key change for many individual natural gas markets in Asia-Pacific is the growing reliance on imports, in particular, LNG imports. Aside from Japan, the Republic of Korea and Chinese Taipei, importing LNG is a relatively new phenomenon for Asian countries: India started in 2005, China in 2006, Thailand in 2011, and Indonesia and Malaysia in 2012. Additionally, a few other Asian countries are expected to become LNG importers this decade.

To grow and consolidate the role of natural gas in the Asia-Pacific region, natural gas will have to be competitive on price, notably against coal. Simultaneously, countries should continue to attract new sources of supply, which are likely to be more expensive. Asia-Pacific natural gas exporters have historically relied on long-term, oil-indexed contracts to sell their production. This makes natural gas prices in the Asia-Pacific region largely dependent on oil market factors.

Expanding the role of natural gas, and thereby improving the energy security, economic and environmental performance of these economies in the long run, will depend on market conditions. These must allow gas to compete autonomously in local energy markets connected to the global market through a pricing system in Asia that is compatible with regional gas supply and demand.

This paper will focus on the obstacles and opportunities for the Asia-Pacific economies to establish natural gas trading hubs that allow for natural gas prices to reflect local demand and supply. In the first chapter, pricing mechanisms for natural gas are explained and current regional

¹ Asia-Pacific in this Information Paper is defined as Non-OECD Asia, China including the Hong Kong area, and OECD Asia Oceania minus Israel. Alphabetically, these are as follows: Australia, Bangladesh, Brunei Darussalam, Chinese Taipei, India, Indonesia, Japan, Korea, Malaysia, Myanmar, New Zealand, Pakistan, China, the Philippines, Thailand, Vietnam, and "other".

trends are set in a global perspective. The outlook for the natural gas market in the Asia-Pacific region is discussed in Chapter 2. In Chapter 3, the process of developing a trading hub and a transparent natural gas price is set out. This chapter explains basic requirements needed to create a competitive wholesale natural gas market, the subsequent role of a hub in such a competitive market, and the respective roles for government and market parties in such a transformative process. Finally, Chapter 4 analyses the perspectives for selected natural gas markets in Asia and the global LNG supply chain to create and support a competitive natural gas market.

1. Natural gas pricing in Asia-Pacific

Pricing natural gas

Broadly speaking, there are two ways to establish a wholesale price level for natural gas: either via market-based pricing or through price regulation.

The market-based way implies that the price of natural gas is determined by supply-demand forces in a market that is not necessarily the natural gas market. In fact, indexation to another commodity (oil, coal, oil products or electricity) will allow supply/demand factors in other markets to set the wholesale price of natural gas. The exact wholesale price of natural gas varies by contract, since contract conditions can set a floor, cap, time lag or none/all of the above for the price of natural gas for a period of delivery. Most important, however, in pricing the “economic” way is that the price development of natural gas over time is being determined by market participants rather than government regulation.²

The International Gas Union (IGU) has identified three major market-based pricing mechanisms, covering OECD and non-OECD markets (IGU, 2012). These mechanisms are:

- **oil (product) indexation**, whereby gas prices are linked to other fuel prices (mostly oil or refined products, sometimes coal);
- **gas-to-gas competition**, indicating an indexation to spot prices that reflect supply and demand for natural gas in a market; and
- **netback from final product**, which refers mostly to contracts where the gas price is linked to the price of ammonia.³

Government regulation is able to set natural gas prices (price regulation is possible at every level of the natural gas value chain: wellhead, wholesale, city gate or differentiating between various segments of consumers) at a level required to suit the government’s domestic policy objectives. Inherently, price regulation of natural gas to meet desired political, social, economic or environmental outcomes will lead to less transparent price signals and an unstable investment climate for the future, as government policy objectives can (easily) change.

Frequently, but not necessarily, gas price regulation will lead to below-cost prices for certain segments of consumers. This is most likely to occur in natural gas producing countries. In such cases, it is very difficult (if not undesirable for a regulator) to regulate price levels to accurately reflect gas’s value in a national economy. This mismatch frequently results in (unintended) distortions in the usage of natural gas, which limit efficient economic development. A clear consequence of below-market pricing of natural gas is the inefficient use of the resource. This potentially limits export revenues (through increased domestic demand) for a producer country; or, it could increase import expenditures for a consumer country through higher domestic demand.

The IGU has identified five major government-regulated pricing mechanisms, covering OECD and non-OECD markets (IGU, 2006). These mechanisms are:

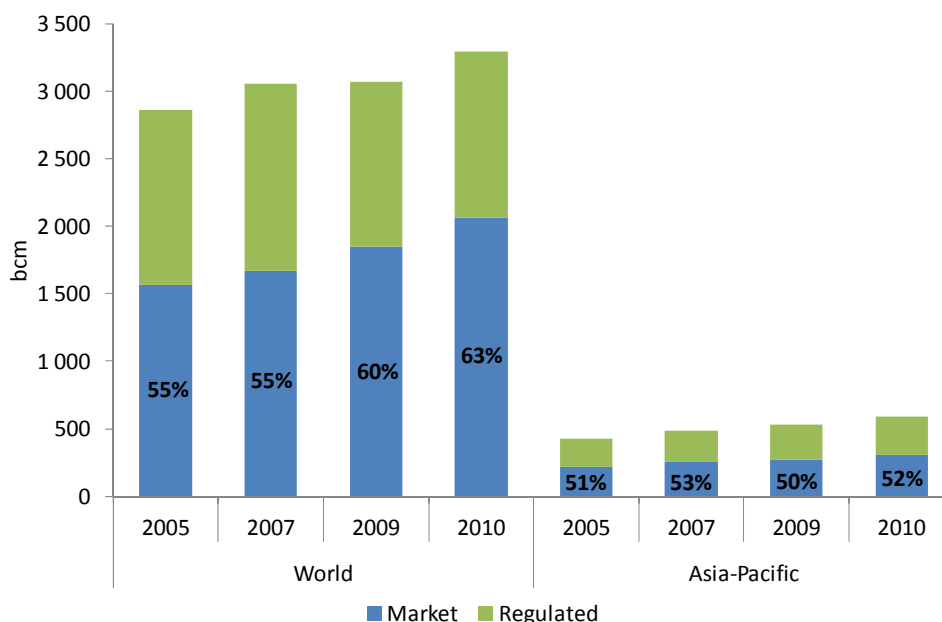
² Governments can influence price levels by regulating the natural gas markets as a whole, but the price level that will derive from these regulations is not as easily determined as through direct price regulation.

³ Netback pricing of natural gas of a final product (such as ammonia) is perhaps the most straightforward way to couple price developments of natural gas to price developments in another market, but completely disregards developments in the natural gas market itself. This is frequently the case when costs of natural gas (feedstock) represent a considerable share of the cost of the end product, thereby guaranteeing a profit margin on the sale of the end product. Alternatively, the netback approach can be used to determine the price level before indexing it to other products.

- **Regulation cost of service (RCS)** covers the price of service, including investment and a fair return. Such prices would be published by the regulator or ministry and aim at recovering the wellhead price.
- **Social and political regulation (SPR)**, whereby the price is set by ministries on an ad-hoc basis depending on perceived social needs, supply/demand balance or government revenue needs. This means natural gas prices can increase (or decrease) very sharply, independently of any specific development in the gas market.
- **Regulation below cost (RBC)**, where the price does not cover the basic production and transmission price, reflecting subsidies. This generally happens only when the gas company is state owned, and is more likely when natural gas is associated with oil production that provides the bulk of the government's revenues (in effect oil provides a subsidy on gas consumption).
- **Bilateral monopoly (BM)**, referring mostly to bilateral agreements within former Soviet Union countries, where prices are agreed on a yearly/multi-year basis between the governments of two countries.
- **No price (NP)**, occasionally used by producers for internal consumption.

This paper will focus on the perspectives for market-based price formation in the Asia-Pacific region; it is therefore relevant to compare the share of market-based price formation with that of other regions. Research by the IGU has shown that through the period 2005-10, global natural gas pricing was slightly dominated by market-based gas prices. In 2010, the price level of 63% of all wholesale natural gas sold globally was determined by market forces. This dominant share for market-based price formation is primarily the result of the dominance of gas-to-gas pricing in the North American natural gas market, which comprised 25% of global gas demand in 2010.

Figure 1 • Price formation of natural gas consumption in the world and Asia-Pacific, 2005-10



Sources: IGU, 2006; IGU, 2008; IGU, 2010; IGU 2012.

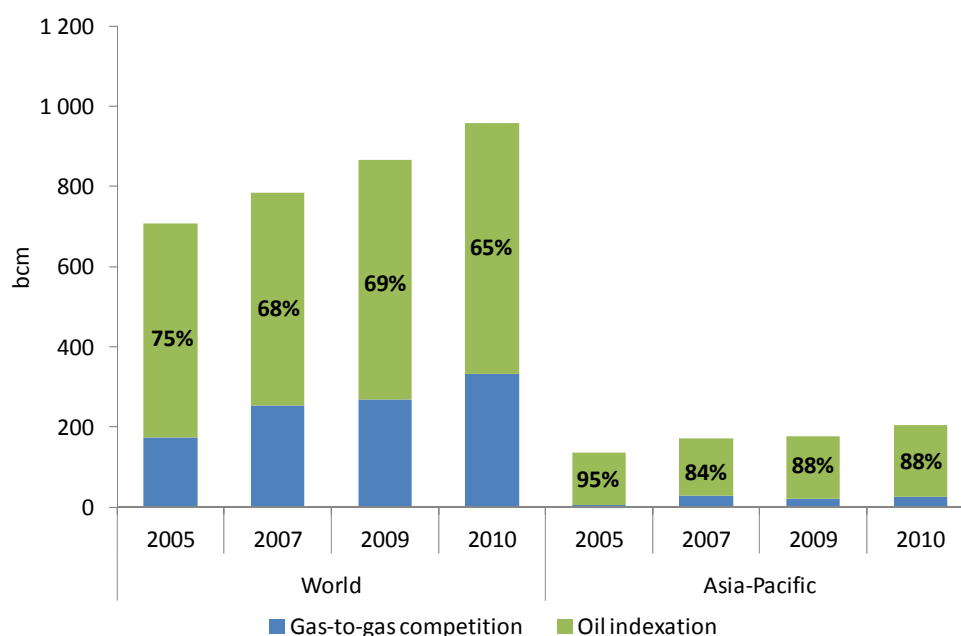
In other markets, most notably the Middle East, Africa and the Former Soviet Union (FSU), price formation was dominated by regulatory preferences throughout 2005-10.

In the Asian-Pacific region government regulations to a large extent continue to determine natural gas prices.⁴

Globally, market-based pricing mechanisms are based on oil indexation or gas-to-gas competition. The “netback from final product” price mechanism is used for less than 1% of global gas consumption, and is not used in interregional natural gas trade. Participation by market parties in international gas trade (either by pipeline or LNG) exposes market areas to different price concepts and signals. This gives both consumers and producers an incentive to adapt price mechanisms in response to pressure to align domestic prices with import prices (IGU, 2012).

Over the period 2005-10, the global trade of natural gas, both transported by pipe and LNG, was predominantly priced on the basis of oil indexation. Although oil indexation has continued to decline as a pricing mechanism in natural gas trade, the price of 65% of global gas trade in 2010 was still indexed to oil.

Figure 2 • Pricing mechanisms in global natural gas trade, 2005-10

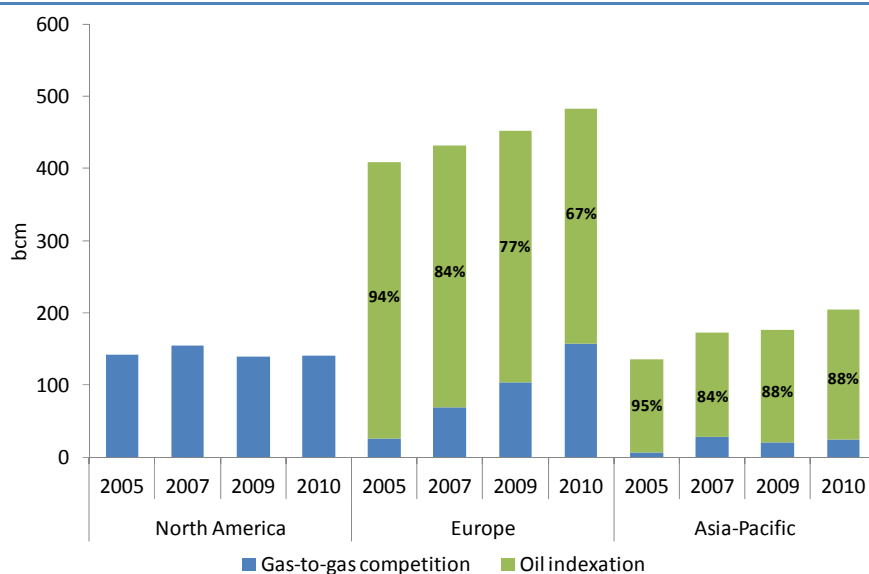


Sources: IGU, 2006; IGU, 2008; IGU, 2010; IGU, 2012.

In Europe and Asia-Pacific (and indeed, globally), oil indexation is the dominant price mechanism for traded gas, although Europe continues to shift towards more gas-to-gas based prices. Yet all North American gas is priced on a gas-to-gas basis, and in 2010 North America comprised 14% of global natural gas trade. European markets are also moving in this direction, owing to a continued increase in trade through continental European gas hubs, as market confidence in the price-setting ability of these hubs has increased. Moreover, the European long-term supply contracts (from Russia, Norway and the Netherlands) are being adjusted to index part of the volume on gas-to-gas competition rather than oil (CERA, 2009b).

Traditionally, natural gas trade in Asia has been dominated by oil-indexed pricing, with a share of 88% of natural gas traded in the region in 2010. No significant changes in this trend can be observed throughout 2005-10.

⁴ In the IGU’s *Wholesale Gas Price Formation*, the Asia-Pacific region consists of the combined IGU Asia and Asia-Pacific regions encompassing: Afghanistan, Australia, Bangladesh, Brunei, China Hong Kong region, Chinese Taipei, India, Indonesia, Japan, Myanmar, Malaysia, New Zealand, Pakistan, China, the Philippines, Singapore, Korea, Thailand, and Vietnam.

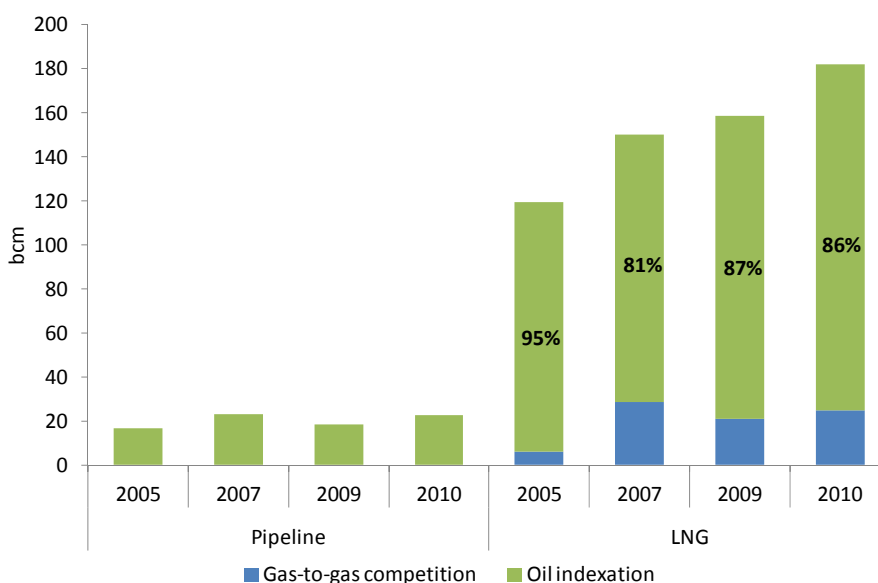
Figure 3 • Market-based pricing in gas trade in North America, Europe and Asia-Pacific

Sources: IGU, 2006; IGU, 2008; IGU, 2010; IGU, 2012.

Pricing natural gas in Asia-Pacific

In 2010, just over half (52%) of the natural gas consumed in the Asia-Pacific region was priced on market-based price formation mechanisms. The majority (67%) of this market-based gas was imported (pipelines or LNG), while 33% was domestically produced.

Natural gas trade in Asia-Pacific is priced through either oil indexation or gas-to-gas competition. All pipeline-traded volumes of gas are priced with a link to the oil market, while some gas-to-gas competition has started to emerge in LNG trading in Asia (Figure 4).

Figure 4 • Asia-Pacific pricing mechanisms for natural gas trade (pipeline and LNG)

Sources: IGU, 2006; IGU, 2008; IGU, 2010; IGU, 2012.

Most gas-to-gas competition pricing in Asia-Pacific is LNG spot trade. However, one can argue that the price for spot cargoes in the global LNG market is not necessarily set through genuine

gas-to-gas competition, as 70% of global LNG imports in 2010 were oil indexed. In addition, only a limited amount (18%) of LNG is delivered in markets with a genuine competitive wholesale gas market (*e.g.* in the United Kingdom and the United States) and priced at a level determined by supply/demand factors.

This means that the price for spot-traded LNG in Asia is not based on supply/demand in the Asia-Pacific region. Instead, the oil-indexed gas price sets a reference price level which market conditions then modify. Those market conditions are determined by the relationship between a buyer and a seller, the availability of surplus gas in the LNG supply chain, and the buyer's need for the gas. These market conditions shift the LNG spot price above or below the oil-indexed level.

In this regard, the LNG spot price in Asia is not one that is realised through market competition in the Anglo-American sense. As Asia has no trading hub to facilitate gas-to-gas competition, the term "spot purchase" signifies the purchase of a single cargo that can vary in size, and that will be "lifted" in a relatively short timeframe, usually less than one year in the future.⁵ While in North America there are no oil-indexed volumes that influence the spot market.

The sale of an LNG spot cargo is frequently negotiated without reference to other sources of natural gas, because the main Asian LNG-importing economies have no connection to pipeline natural gas. Spot cargoes are generally priced above or below a long-term, oil-indexed LNG price in the importing market, the price level of which depends on global market demand for oil rather than regional supply/demand for natural gas.

As a result, spot LNG has frequently been more expensive than the oil-indexed cargoes bought under long-term contracts in the Asian region. Over the period 2007 to Q1 2012, Japan, Korea and Chinese Taipei have frequently paid a spot premium compared to their long-term supply contracts; on average, 77% of the imported spot cargoes were priced above long-term contracts (Table 1).

The current oil indexation in the Asia-Pacific gas trade is the result of historical developments and contract negotiations between suppliers and, originally, Japanese customers. In 1969 the first LNG supply contract was signed that made volumes available from Alaska in the United States. The first 15- to 20-year LNG supply contracts (Brunei and Abu Dhabi started to deliver LNG to Japan as well) adopted a fixed-price setting that valued LNG at around USD 0.5/MBtu. Initially, the LNG price was set at a premium versus crude oil; and was then progressively raised as oil prices rose during the 1970s.

Table 1 • LNG spot cargoes delivered in Japan, Korea and Chinese Taipei, 2007-Q1 2012

	Spot cargoes	Spot price		
	bcm	% LNG import	> long-term	< long-term
Japan	29.6	6%	74%	26%
Korea	32.7	20%	83%	17%
Chinese Taipei	12.3	17%	71%	29%
Total	74.5	11%	77%	23%

Note: spot cargoes for Japan originate from Algeria, Egypt, Equatorial Guinea, Nigeria, Norway, Peru, Trinidad, Yemen and re-exported cargoes from non-producing nations. Spot cargoes for Korea originate from the United Arab Emirates, Algeria, Brunei, Egypt, Nigeria, Norway, Peru, Qatar, Trinidad, the United States and re-exported cargoes from non-producing nations. Spot cargoes for Chinese Taipei originate from the United Arab Emirates, Algeria, Brunei, Egypt, Equatorial Guinea, Norway, Oman, Peru, Russia, Trinidad, United States, Yemen, and re-exported cargoes from non-producing nations.

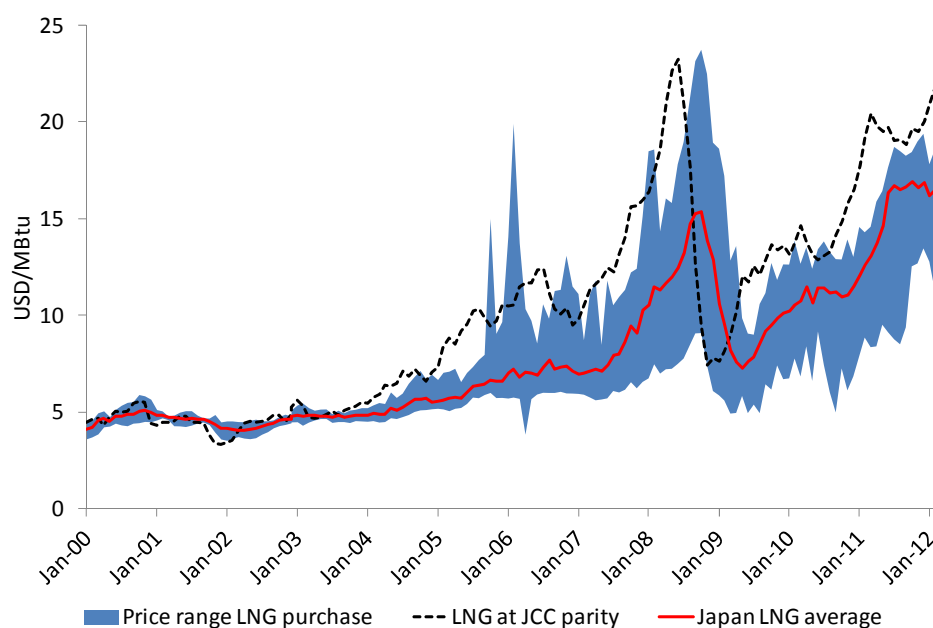
Sources: customs data Japan, Korea and Chinese Taipei.

⁵ This qualification of "spot purchase and short-term LNG trade" is derived from International Group of Liquefied Natural Gas Importers (GIIGNL).

Subsequently, the first LNG supply contract signed between Indonesia and Japan introduced oil indexation. Initially, this would establish a link with the average oil price or the government selling price (GSP) of Indonesia's crude oil sales. However, near the end of the 1980s, Saudi Arabia introduced netback pricing for its oil exports; this reduced Indonesia's GSP and consequently, the price of LNG exported to Japan. Therefore, it was in the LNG producer's interest that the oil-indexed price would be determined in the market where the LNG would be delivered; the Japanese Custom Cleared (JCC) price provided that requirement.⁶

When Korea (1985) and Chinese Taipei (1990) started to import LNG, their supply contracts were also linked to the JCC, making this the dominant oil marker in the region. The decline in oil prices during the 1980s led to the introduction of S-curve pricing formulas. S-curve formulas are usually establishing a linear relationship between the price of gas and oil as long as oil prices stay within a predetermined range. When the oil price moves out of this range, the relationship between the price of oil and the resulting gas price weakens, therefore reducing the risk of low oil prices for producers, but also introducing protection against high oil prices for consumers.⁷ As the first S-curve contracts were developed to protect producers (and their upfront investments in LNG infrastructure), at an average oil price below USD 20/bbl during the period 1985-99, this resulted in more expensive LNG than the energy equivalent in oil.

Figure 5 • Average Japanese LNG import prices and price range



Source: Japanese customs.

During the 2000s, oil prices increased significantly, but S-curves protected LNG buyers against this increase, reducing the price of LNG imports on a calorific basis in relation to that of oil. Despite the renegotiation of long-term contracts during the first part of the decade, a rapid rise in oil prices resulted in long-term LNG prices lower than their oil equivalent. However, the additional import of spot-marketed cargoes would frequently be above prices equal to the calorific oil equivalent (Figure 5).

⁶ The JCC is also frequently referred to as the Japan Crude Cocktail.

⁷ For an introduction to LNG pricing and the S-curve see: Flower (2008).

After 2004, LNG producers tried through negotiations to raise or abolish the S-curve (Miyamoto, Ishiguro and Yamada, 2009). Currently the discussion in long-term LNG supply contracts focuses on the “slope” in an LNG price formula, basically determining LNG prices at a certain percentage of the JCC price (plus or minus a constant). As a consequence of increasing oil prices, increased availability of spot-marketed LNG on global markets, the rigidity of long-term LNG supply contracts and additional gas demand shocks (primarily, the Fukushima accident in 2011), LNG spot prices have become more volatile since 2004.

Although oil and LNG prices diverged considerably, the overall movement of the LNG price is still comparable with oil prices. The increased import of spot-purchased LNG, however, has increased the price spread, making LNG an increasingly volatile commodity.

Table 2 • LNG import into Japan: at JCC parity, historical average and average spread of deliveries

USD/MBtu	LNG at JCC parity	Japanese LNG import price	Average spread	Spread
2000	4.89	4.70	1.02	22%
2001	4.27	4.61	0.56	12%
2002	4.36	4.28	0.71	16%
2003	5.05	4.79	0.63	13%
2004	6.37	5.19	1.24	24%
2005	9.02	6.02	2.51	42%
2006	11.08	7.12	6.14	86%
2007	12.30	7.74	5.02	65%
2008	16.92	12.66	11.16	88%
2009	10.92	9.04	7.23	80%
2010	13.83	10.90	6.15	56%
2011	19.07	14.78	7.36	50%

Source: Japanese customs.

On average, the price spread between monthly LNG imports during a year has increased since 2004. As a consequence of the financial crisis, spreads between various LNG supplies for Japan peaked at USD 11.16/MBtu in 2008. This equated to around 85% of the average import price for Japanese LNG that year. Although the differential in price between various LNG imports has decreased somewhat in the following years, it remained over 50% of the average LNG import price through 2009-11.

This does not necessary imply that spot-purchased cargoes are always more expensive than oil-indexed LNG imports (as seen in Table 1).⁸ The price formulas in long-term supply contracts generally set the average price of LNG at a level below the level of the oil equivalent, but are responsive to the relative changes in the oil price through time. Asian long-term contracts for natural gas traded via pipelines have a similar oil-indexed price mechanism, although the overall price level is generally lower than LNG.

Currently, then, the lack of a competitive natural gas market in the Asia-Pacific region hinders the development of a price reflecting appropriate supply and demand criteria.⁹ Consequently, the price of natural gas in the Asia-Pacific region is set by LNG buyers and based on a different market (oil). Oil-indexed LNG contracts set a price benchmark, while spot LNG is imported at increasingly diverging prices relative to the oil-indexed benchmark. Under these circumstances it

⁸ In 2011, the volume imported as spot cargoes in Japan was generally priced below oil indexed long-term contracts (IEA, 2012a).

⁹ An alternative Japan/Korea Marker does exist and is discussed in Box 2 in Chapter 4.

is difficult if not impossible for both long-term LNG and spot LNG prices to reflect the accurate market value of natural gas in the various developing and developed economies in Asia.

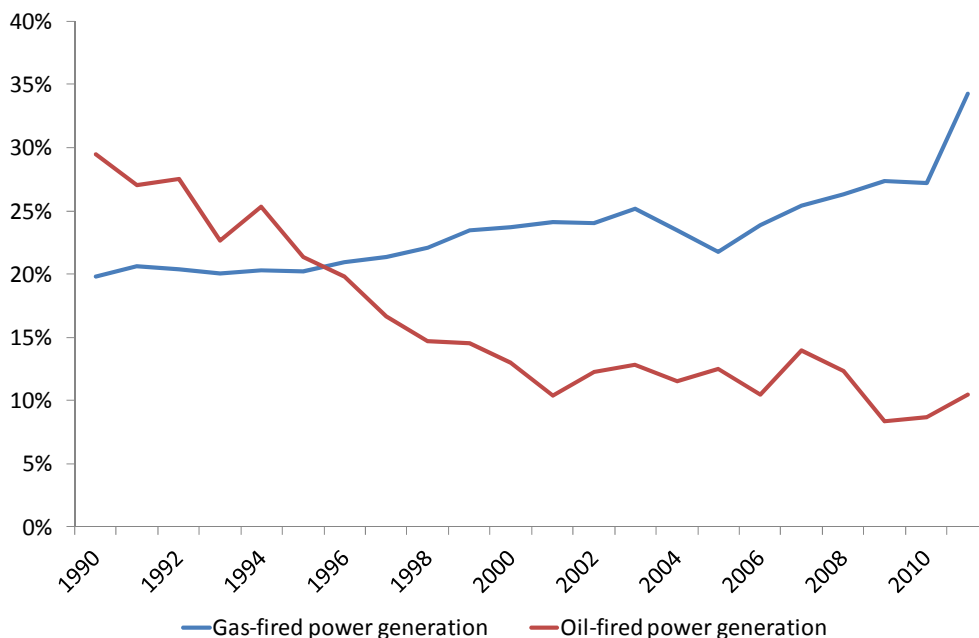
The rationale for gas-to-gas pricing in Asia-Pacific

As LNG did not have a “market” in Asia, the original rationale for oil indexation in Asian LNG contracts, much like in the European gas market, was to look for its replacement value. In Japan, LNG was seen as an alternative for oil that was still prominently used in power generation. On the supply side, the Organisation of Petroleum Exporting Countries (OPEC) agreed in 1980 on an LNG export policy that explicitly aimed at calorific parity with oil prices. More recently, in 2011, the Gas Exporters Country Forum (GECF) also endorsed oil indexation as the preferred pricing scheme to trade natural gas (GECF, 2012).

A link to a globally traded commodity such as oil gives investors in LNG liquefaction plants and transport infrastructure the ability to hedge revenues over longer periods of time and therefore provides a secure flow of revenues. The global oil market is generally perceived with a high degree of confidence with regard to its lower probability for price manipulation and lower volatility compared to natural gas (G20, 2011). On the downstream side, most of the initial LNG buyers were regulated utilities, which enabled them to shift market risk to their end consumers (Jensen, 2004). Oil indexation was therefore initially readily accepted by both producers and consumers as one of the key principles underpinning long-term LNG supply contracts.

Times have changed, however. Although further investment in LNG production capacity needs to be properly facilitated, natural gas also needs to be competitive within the end-user market. Oil is less and less the primary competitor to natural gas in the Asia-Pacific region.

Figure 6 • Share of oil and gas in electricity generated in Japan, 1990-2011



Note: unless otherwise stated, all material in figures and tables derives from IEA data and analysis.

Source: IEA, 2012c.

Take the following as an example: in the Japanese energy mix, oil has lost its dominant share in power generation to natural gas, coal and (until the Fukushima accident) nuclear power. This

development has significantly redressed LNG's competitive environment in power generation from oil-dominated to directly competing with oil, coal and nuclear power. Oil has maintained its dominant share in Japan's total primary energy supply through its role in transport (currently also strengthened by the use of oil to replace nuclear power generation, but this is likely to be temporary), a development not specifically Japanese, but global.

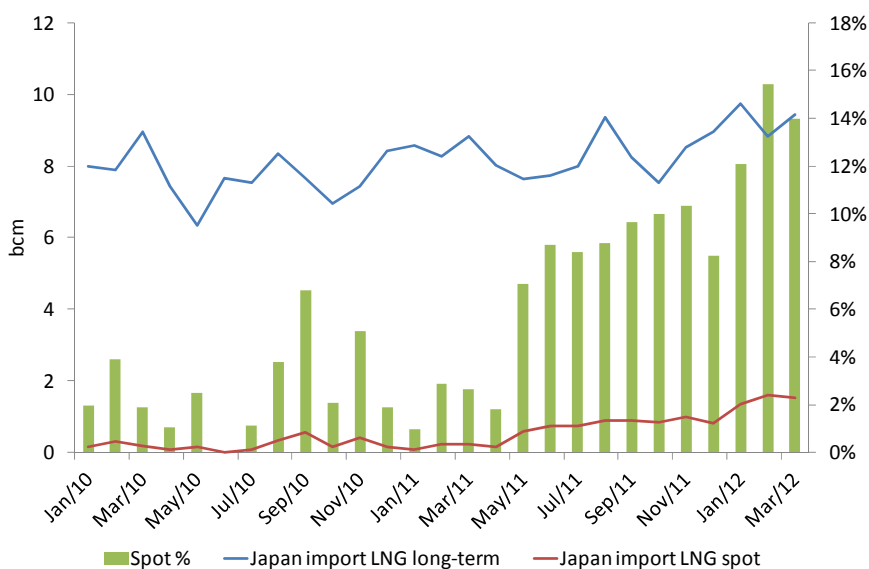
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Linking the price of natural gas to oil on account of end-user competition makes little sense when oil does not directly compete with natural gas (Jensen, 2011). Yet, in developing natural gas markets, oil-indexed contracts have been the backbone for market development (as described above). These contracts are likely to continue to dominate in the developing economies in Asia, as considerations other than price (environmental factors and security of supply) are frequently more relevant for companies and policymakers, and an alternative natural gas price is generally not available in these economies.

However, for mature natural gas markets, the limits of oil indexation as a price-setting mechanism for LNG became clear in 2011, when Japan needed an increasing amount of LNG to satisfy power demand after the Fukushima accident. Japanese spot cargo purchases increased to record levels, and although average LNG import prices did the same, this was not an immediate consequence of supply and demand on the global LNG market.

Most of the additional volume of spot LNG purchased between January 2011 and April 2012 was priced below long-term, oil-indexed volumes (and long-term LNG exporters that benchmark spot cargoes to oil) (IEA, 2012a). As a consequence, these lower priced spot supplies (from, among others, Nigeria and Equatorial Guinea), reduced the average price of a cubic metre of LNG, despite record demand. Consequently, the rise in LNG prices was mainly caused by the simultaneous run-up in oil prices during 2011 (as a consequence of the Arab Spring in North Africa and issues with Iran) rather than the increase in Japanese demand.

Figure 7 • Japanese long-term and spot volumes import, 2010-12



Source: Japanese customs.

While consuming nations might see a need for long-term contracts to ensure supply security (although this ultimately depends on the physical availability of gas), producers generally use these contracts to secure financing and a return on investment. For developing natural gas markets, oil-linkage is frequently readily accepted by both producers and consumers as a pricing

mechanism, for lack of a reliable alternative. A developing gas market is initially unable to generate a reliable natural gas price, as the infrastructure investments required to develop a market will set these at an uncompetitive level.

However, in mature natural gas markets, oil price linkage is a weak instrument for generating a competitive price. Since the initial infrastructure investments in many mature gas markets have depreciated, governments might wish to introduce more competition through the separation of networks and supply activities in the natural gas sector. This process separates procurement costs from distribution costs in the wholesale natural gas price, allowing infrastructure investments to be financed on the basis of a service fee for delivery of the commodity to customers.

Simultaneously, the natural gas price resulting from competition will increase transparency in the gas market because commodity and transport capacity are priced separately, at levels reflecting their respective supply/demand balance. When a natural gas market is properly set up, the resulting price will reveal inefficiencies or bottlenecks in the supply chain (which beforehand were only known to vertically integrated monopolies), allowing for efficient accommodation of these bottlenecks through financial incentives. The introduction of competition thus allows for more efficient procurement and distribution of natural gas by companies throughout the value chain.

Oil indexation simply cannot deliver the increased transparency and information required in a mature natural gas market. As price incentives to generate investments (or change consumer/producer behaviour) are generated in a market that has very limited interaction with the gas market, it will be increasingly difficult for natural gas companies to efficiently supply customers as a market matures.

Introduction of competition in natural gas markets will generate price signals different from those generated by the oil market. A competitive natural gas price will not mean that natural gas is automatically priced lower than equivalent oil-indexed volumes. When properly set up, it will mean that a natural gas market will price natural gas at its relative value in a specific energy mix, providing customers with a reliable, flexible and low carbon source of energy. However, before turning to the ways in which a competitive natural gas trading hub can be created, the next chapter will focus on the outlook for the Asia-Pacific natural gas market.

2. The Asian-Pacific natural gas market

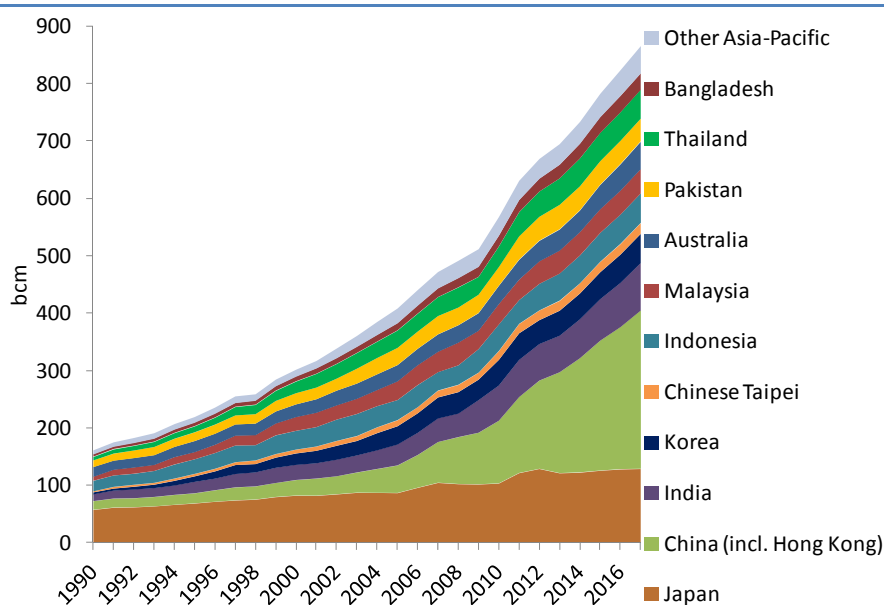
The Asian-Pacific natural gas market is complex and fragmented. It is certainly not a geographically defined market: it is not highly interconnected by high pressure pipelines, like the European and North American natural gas markets. The main natural gas-consuming countries in Asia-Pacific are: China, Japan, India, Korea, Thailand, Indonesia, Malaysia, Pakistan, Bangladesh Australia and Chinese Taipei. These countries each consumed over 10 bcm of natural gas in 2011.

The region has three separate markets with have their distinct dynamics. First there are the mature, well-established markets of Japan, Korea and Chinese Taipei, which are isolated, mainly supplied by LNG and have limited scope for further growth.¹⁰ Second, the “emerging giants”, China and India, which will develop considerable natural gas demand supplied through both pipeline and LNG.¹¹ Third, the area of South-East Asia, which consists of several large LNG producers (Malaysia, Indonesia and Brunei) and rapidly growing economies interconnected to a limited extent by pipelines.

Asia-Pacific supply-demand balance

Since 1990, the natural gas market in the Asia-Pacific region has undergone remarkable growth, to about 560 bcm in 2010. Natural gas consumption has grown by more than 250% since 1990, representing an average year-on-year increase of 6% for over two decades. Japanese consumption represented the mainstay of Asian natural gas demand, especially in LNG, until 2010, when China surpassed Japan as the largest natural gas market in Asia.

Figure 8 • Natural gas demand in Asia-Pacific, 1990-2017



Note: “Other Asia-Pacific” in this graph consists of: Brunei Darussalam, Mongolia, Myanmar, Nepal, New Zealand, Korea, the Philippines, Singapore, Sri Lanka, Vietnam, and other.

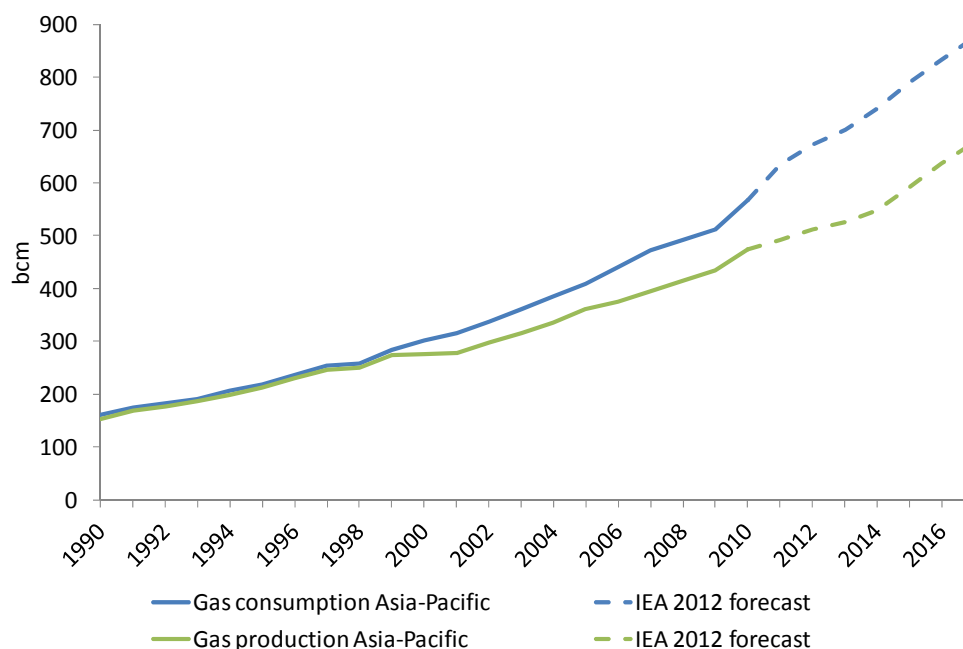
Sources: IEA, 2011b; IEA, 2012a.

¹⁰ The full impact of the Fukushima accident on future power sector demand in the mature gas market of Japan (but also Korea and Chinese Taipei) is still unclear. Natural gas is generally well placed to speedily replace generation capacity if needed, as it has considerably lower capital expenditures than coal-fired generation and offshore wind generation.

¹¹ Indian pipeline connections with either Iran or Turkmenistan have been discussed in the past, but prospects for these pipeline connections remain very unclear because of geopolitical tensions and uncertainties over economic viability.

Since 1998, total natural gas production in Asia-Pacific has lagged behind regional consumption. A few countries, such as Indonesia and Malaysia, were net exporters providing LNG for import-dependent countries such as Korea and Japan. In 2010, natural gas production in the region fell around 93 bcm short of consumption, a shortfall that is expected to increase to about 200 bcm in 2017, despite a considerable increase in regional production.

Figure 9 • Asia-Pacific natural gas consumption-production forecast, 1990-2017



Sources: IEA, 2011b; IEA 2012a.

Dependence on natural gas imports from outside the Asia-Pacific region increased by 12% annually throughout 2000-10. It is expected that this import dependency will grow by 5% annually over the period 2011-17. The relatively moderate increase reflects increasing gas production projected for China and Australia. Overall demand in the Asia-Pacific region is expected to follow global demand trends, growing at around 3% per annum to reach 875 bcm in 2017.

Natural gas demand by sector in Asia-Pacific

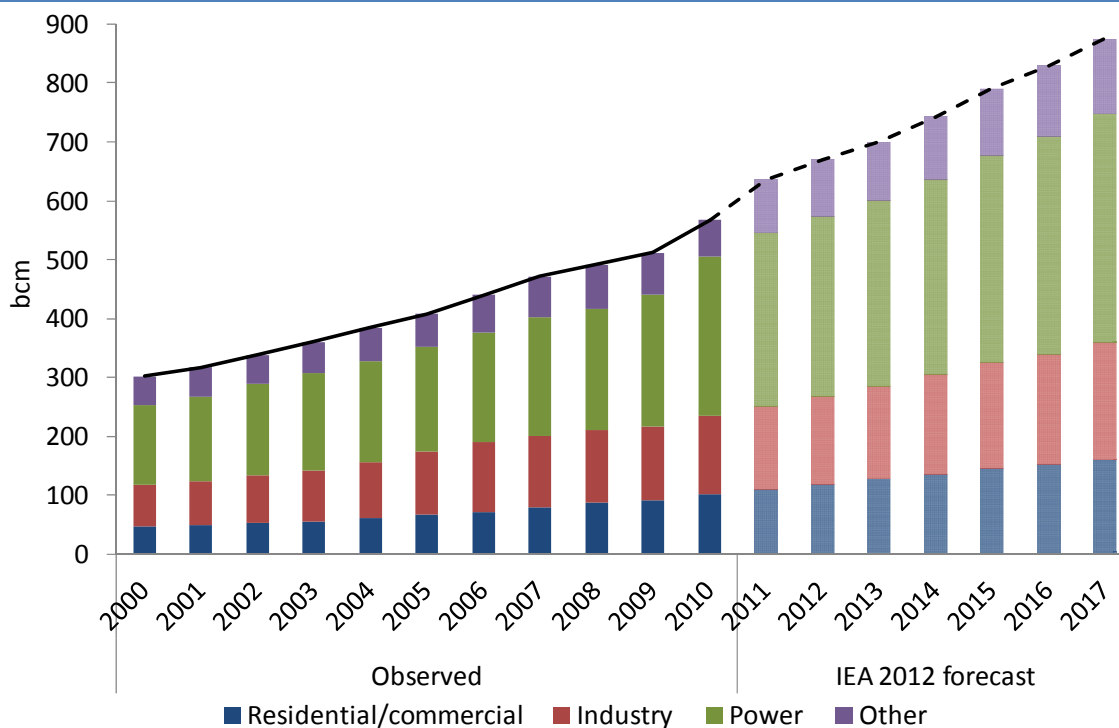
Fast-growing demand for natural gas will lead to growth in every natural gas-consuming sector in most of the Asian-Pacific economies. The power and industrial sectors predominate, with 71% of the region's natural gas consumed in these sectors in 2010. Natural gas consumption in the power sector is set to be dominant throughout the period 2011-17, with 44% consumed in 2017, down slightly from 47% in 2010.

The residential/commercial sector in Asia-Pacific consumed around 110 bcm in 2011, which made its overall share around 17% of total natural gas consumption. Although this represents a considerable amount of natural gas, it is a much lower share than the United States (34% in 2009) and Europe (37% in 2009). The Asia-Pacific residential sector is forecast to create about 18% of regional natural gas demand (160 bcm) in 2017 (Figure 10).

The main exemptions to this rule are Korea and the developing economy of China, where the residential sectors make up a considerable share of demand, as natural gas is used for heating in the northern parts of the countries. Although demand growth in Korea's residential sector is expected to be fairly limited (up 2 bcm in 2017), residential demand will continue to comprise around 40% of total gas demand (FACTS, 2012). Demand in the Chinese residential sector is set to

increase considerably, by 52 bcm (11% annually until 2017), increasing 2017 residential demand to around 33% of total. Such growth in demand, responsive to seasonal temperatures, would have to be accommodated through increases in seasonal flexibility in natural gas supply (both LNG and pipeline), much like that observed in other mature markets with significant residential demand.

Figure 10 • Sectoral demand for natural gas in Asia-Pacific, 2000-17



Note: other comprises use by the energy and transport industries, and losses.

Sources: IEA, 2011; IEA, 2012.

Although demand for natural gas in the residential sector is set to increase at a faster pace (6% per year) than demand in the industrial and power sector (5% and 4% per year, respectively) natural gas consumption will continue to be dominated by industry and power consumers, both of which usually require little seasonal flexibility.¹² Demand from the power sector requires more short-term flexibility, since gas-fired power generation is frequently used to balance the electricity network throughout the day. Industrial gas demand is primarily responsive to overall economic growth and sectoral business cycles.

Natural gas trade in Asia-Pacific

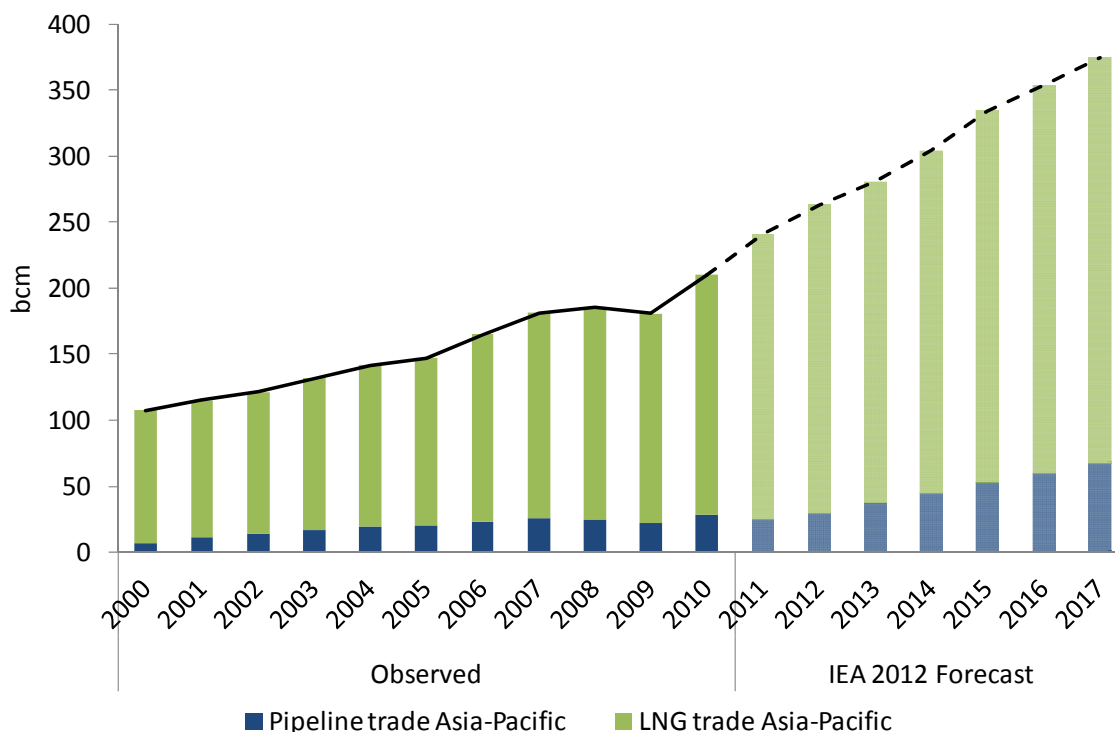
Natural gas trade in this region is growing by 6% per year, which makes it the main driver in global growth projections of 5% annually over the period 2011-17. While natural gas trade in the region is currently dominated by LNG, pipeline natural gas is set to grow by 15% per year through the period 2011-17.

The share of pipeline-traded gas is to increase to about 18% of total trade in 2017, up from 11% in 2011. Pipeline trade is mainly driven by increased imports from Central Asia and Myanmar into

¹² Seasonal flexibility is considered long term and is usually provided through storage in depleted natural fields with considerable working volume that can accommodate seasonal temperature-related swings in natural gas demand in the residential sector. This contrasts with short-term flexibility (*i.e.* within day, within week) which usually involves storage in salt caverns or aquifers with limited working volume, but high send-out capacity that can accommodate short-term swings in demand/supply.

China, as no other new pipeline interconnections or expansions in the region are under serious consideration in the region at the moment.

Figure 11 • Pipeline and LNG trade in Asia-Pacific, 2000-17



Sources: IEA, 2011a; IEA, 2012b.

LNG trade in Asia-Pacific

The two most mature natural gas markets in the Asia-Pacific region are Japan and Chinese Taipei; coincidentally, both markets are nearly exclusively supplied by LNG, as local production is practically non-existent. In 2011, these two mature markets consumed 87% of all LNG delivered into Asia. A marked shift in demand for LNG is expected, as mature markets such as Japan have limited potential for an increase in LNG demand, while demand growth in China and India is likely to be considerable.

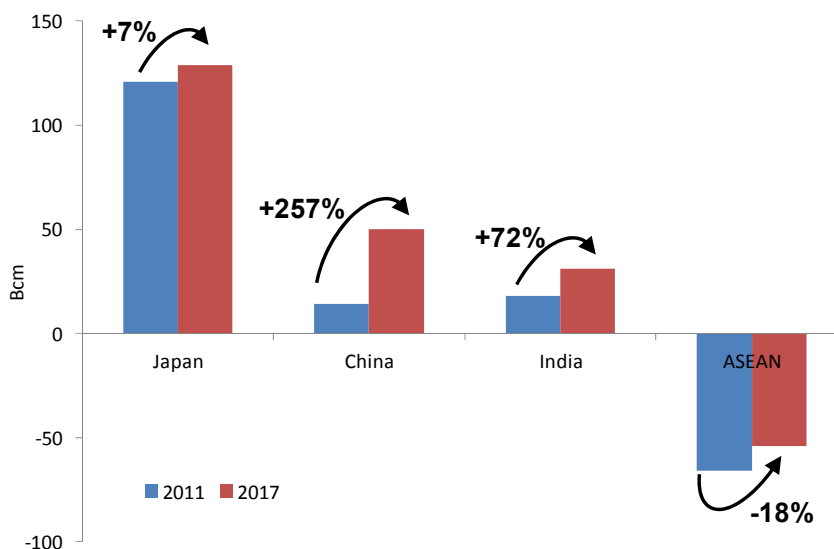
The ASEAN nations that currently function as a large source of regional LNG production, supplying about 66 bcm of LNG to satisfy broader Asia-Pacific demand, will see a marked change in their net export position.¹³ In the medium term, the net export position will decline as LNG production decreases and regional consumption increases. Thailand started to import LNG in 2012, while Singapore, Vietnam, and the Philippines are expected to start importing LNG within this decade. Overall, LNG export capacity of the ASEAN region to supply the Asia-Pacific market is projected to decrease by 18% by 2017.

Traditionally, the Asia-Pacific demand for LNG was satisfied by regionally produced LNG, from Australia as well as ASEAN countries. In the first quarter of 2012, 47% of Asian-Pacific LNG imports originated from the Asia-Pacific region, a level not seen since the 1970s. Despite the forecast increase in Asian-Pacific gas demand, a considerable increase in Australian LNG production

¹³ Member states of the Association of South East Asian Nations (ASEAN) comprise: Brunei Darussalam, Cambodia, Indonesia, Laos, Malaysia, Myanmar, the Philippines, Singapore, Thailand and Vietnam. Within the ASEAN, Malaysia, Indonesia and Brunei Darussalam are net LNG exporters.

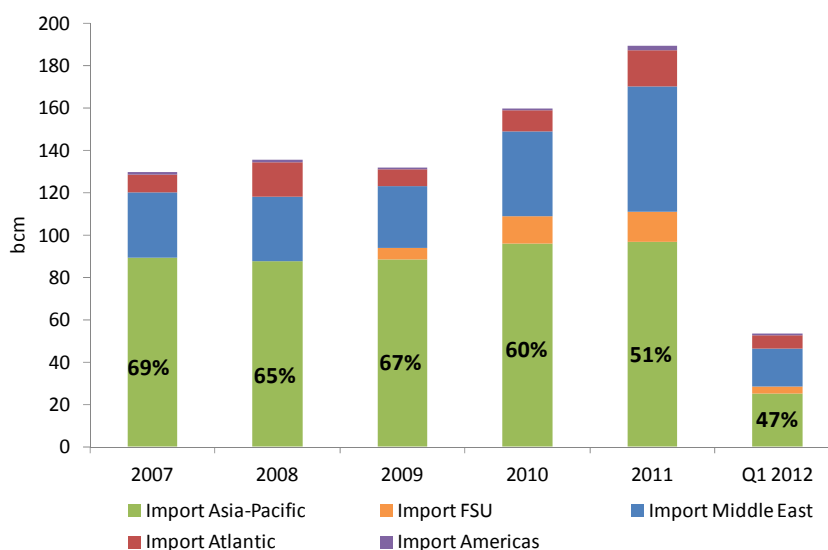
will maintain Asia-Pacific LNG production around 52% of total regional LNG demand. Total Asian-Pacific LNG import from other regions is estimated to be 147 bcm by 2017, an increase of about 62% from 2011 levels.

Figure 12 • Forecasted growth in LNG trade in Japan, China, India and ASEAN nations, 2011-17



Source: IEA, 2012b.

Figure 13 • LNG import into Japan, Korea, China, Chinese Taipei and India, 2007-12



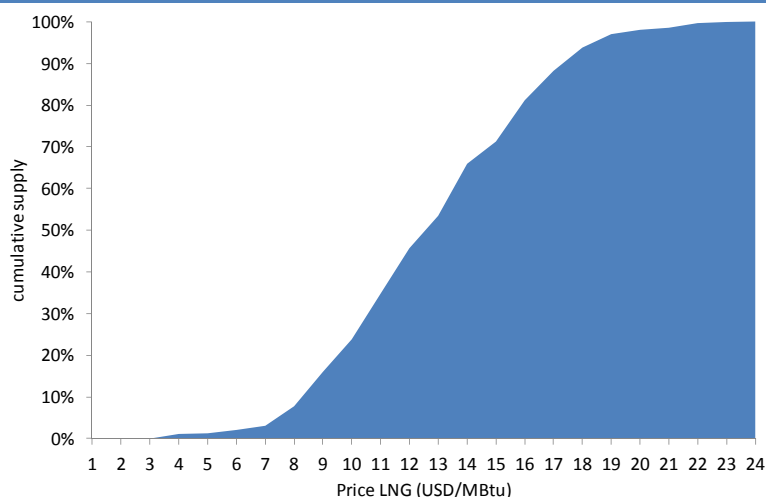
Sources: customs agencies of Japan, Korea and Chinese Taipei (plus China and India when available).

In absolute terms, the Asia-Pacific region will increasingly depend on global LNG suppliers, a trend that has intensified over the period 2007-11, when a near doubling of Qatari supplies strengthened Asia-Pacific dependency on other producing regions (primarily, the Middle East). Producers located in the Middle East (Qatar) are geographically well positioned to be the swing suppliers to both the Asian and Atlantic basins (Jensen 2011). Volumes from the United States (Alaska) and the Former Soviet Union (*i.e.* FSU, Shakalin II, Russia) are effectively destined for the Asian market.

The prevailing differential between the oil-indexed LNG price in the Asia-Pacific region and European prices has at times attracted considerable volumes from the Atlantic Basin, namely in

2008 (due to high oil prices) and 2011 (due to high oil prices, the Fukushima accident and a lack of demand for LNG in the Atlantic Basin). More than 75% of volume delivered from the Atlantic Basin into the Asia-Pacific region in 2007-12 was priced at over USD 10/MBtu (Figure 14). In 2011, cargo diversions and an increasing number of re-exports boosted supplies from the Atlantic Basin to Asia to around 17 bcm (equivalent to roughly 200 large cargoes).¹⁴

Figure 14 • Atlantic LNG delivered into Japan, Korea and Chinese Taipei at import price, 2007-12



Sources: customs agencies of Japan, Korea and Chinese Taipei.

Natural gas pipelines in Asia-Pacific

Pipeline trade within the Asian-Pacific region is minimal compared to LNG trade, because of the limited pipeline infrastructure connecting South-East Asia's net exporters with net importers. Similarly, the largest consuming natural gas markets of Asia-Pacific are internally fragmented as a result of a still developing gas infrastructure (China) and a dependence on LNG supply with limited domestic interconnection (Japan).

In the ASEAN region there is a long-standing goal to expand the regional pipeline system into a trans-ASEAN gas pipeline system (TAGP) connecting eight ASEAN nations by 2020.¹⁵ Despite progress on some interconnections, several key infrastructure projects have so far not materialised. ASEAN has set completion of the Trans-ASEAN Energy Network as a strategic goal, and the development of the offshore East-Natuna natural gas field is considered the main critical factor in achieving it. So far, the high carbon dioxide (CO₂) content of East-Natuna gas (nearly 70% of the deposit is CO₂) has driven up the cost to develop the resource and consequently pushed back the start-up date (now believed to lie beyond 2022). The development of any Trans-ASEAN gas infrastructure is likely to be postponed beyond a similar date, even if commercial viability is proven (a point also recognised by ASEAN) (ASEAN, 2009).

The area of South-East Asia consists of several large natural gas producers (Malaysia, Indonesia and Brunei) of which Malaysia has the most developed internal transmission system connecting producers with consumers and other producers. The Peninsular Gas Utilisation (PGU) project, completed in 1999, spans more than 1400 kilometres and connects Malaysia with Thailand and Singapore. Thailand supplies Malaysia with natural gas from the Joint Development Area (JDA) in which both countries have a share (through their national gas companies), while Malaysia supplies natural gas to the city state of Singapore.

¹⁴ Based on customs data and assuming an average LNG carrier of 140 000 m³ LNG.

¹⁵ Indonesia, Malaysia, Singapore, Vietnam, Myanmar, the Philippines, Brunei Darussalam and Thailand.

Singapore is supplied through four pipelines developed over the period 1991-2007, connecting Singapore with Malaysia (two pipelines) and Indonesia (two pipelines), with a total annual supply capacity of around 9.6 bcm. Although Singapore has no transit facilities, it can be considered as an interconnection between Indonesia and Malaysia (and Thailand). Thailand is also connected to Myanmar and takes natural gas from the Yadana and Yetagun deposits through two pipelines with total capacity of 7.4 bcm. In addition, Thailand is (technically) connected with Vietnam through a pipeline that connects a shared offshore gas field (PM3 deposit) with the Vietnamese mainland at Ca Mau. In the near future, Myanmar will be connected with China, as the Myanmar-China pipeline, with an annual capacity of 12 bcm, is scheduled to be completed in 2013.

Table 3 • Intra- and interregional pipeline(s) in Asia-Pacific

Intraregional	Pipeline	Operational (year)	Capacity (bcm/yr)
Myanmar-China	Myanmar-China Pipeline	2013	12.0
Myanmar-Thailand	Yadana-Export Pipeline	1998	5.4
	Yetagun-Export Pipeline	2000	2.0
Thailand-Vietnam	PM3-Ca Mau Pipeline	2007	2.0
Thailand-Malaysia	Trans-Thailand-Malaysia Gas Pipeline (TTM)	2005	7.7
Malaysia-Singapore	Peninsular Gas Utilisation Pipeline System (PGU)	1991	1.5
	Peninsular Gas Utilisation Pipeline System (PGU)	2007	1.1
Indonesia-Singapore	West-Natuna Transportation System	2001	3.4
	Grissik-Singapore Pipeline	2003	3.6
Interregional			
Turkmenistan-China	Central Asia Gas Pipeline (CAG)	2011	30.0

Sources: IEA, 2012a; APERC, 2000; APERC, 2012; various company websites.

Interregional pipeline trade is so far limited to the Turkmenistan-China pipeline, which connects Turkmen gas production with the centres of natural gas demand in eastern China. The pipeline is currently being upgraded to facilitate the transport of around 40 bcm of natural gas annually. In addition, spurs of the pipeline in Kazakhstan are under consideration to be able to farm more natural gas from the region, with a possible 65 bcm of total capacity for the pipeline being discussed.

It is unlikely that any of the gas from Central Asia (including possibly Russia in the future) will reach other markets in the Asia-Pacific region (Hong Kong being considered as an integral part of the Chinese supply system). As Malaysia has one of the most extensive natural gas pipeline networks in South-East Asia, it connects Thailand and Singapore through its PGU system. However, that is all the intra-regional transit capacity that exists. Other connections in the ASEAN region are dedicated upstream pipelines connected to centres of demand, without the transit capabilities observed in more well-developed natural gas networks.

Expansion of the number of interregional pipelines connecting the Asian-Pacific with other producing areas, such as the Middle East and Central Asia, seems highly unlikely. Despite decades of speculation, the geopolitical obstacles to natural gas pipelines through Afghanistan and Pakistan seem as intractable as ever. Beside geopolitical obstacles, interregional pipeline transport is frequently uncompetitive with LNG transport, as this is usually more cost-effective over longer distances (Jensen, 2011).

The most likely development might be a natural gas pipeline between China and Russia. Despite many high-level political agreements over the past decade, a final investment decision between commercial parties is still considered to be years away. The issue of the natural gas price has proven to be an insurmountable obstacle. In addition, China has developed its own energy bridge with Central Asia, supplying China with adequate volumes of attractively priced natural gas for the time being (Henderson, 2011).

As natural gas consumption in the Asia-Pacific region continues to grow and interregional and intra-regional transit capacity remains limited, nations look increasingly at seaborne LNG to supply their economies with natural gas. A growing number of countries in the Asia-Pacific region are considering building regasification terminals.

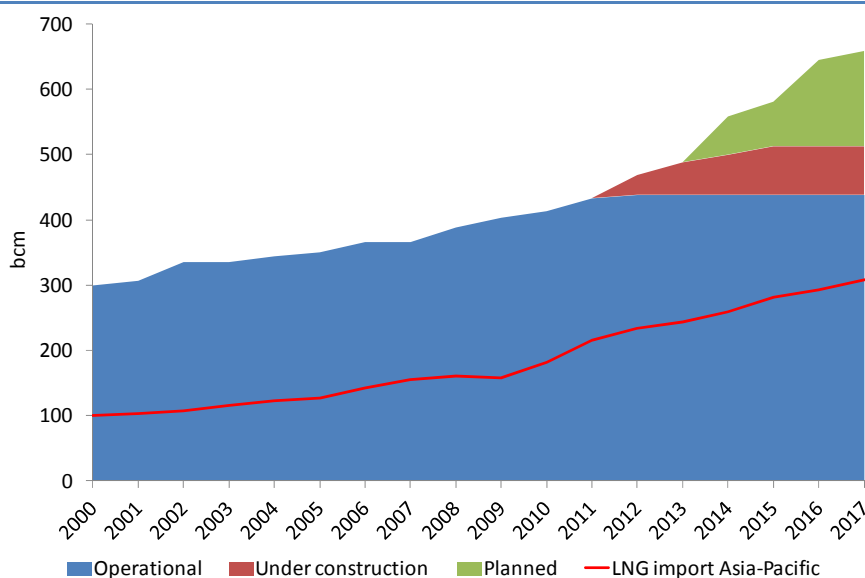
LNG supply chain flexibility in Asia-Pacific

LNG supplies need to be delivered in a way that assures flexible and reliable supply for customers. They must be located in areas serviced by LNG regasification terminals and be part of a complete LNG supply chain.¹⁶ This must accommodate short-term demand fluctuations from (large) individual consumers, seasonal demand changes, and demand that follows economic cycles while maintaining economic efficiency.

Regasification terminals

Regasification terminals are a crucial part of the LNG infrastructure, not only for the access to global LNG supplies they provide, but also as suppliers of downstream flexibility.

Figure 15 • Regasification operational, under construction and planned in Asia-Pacific, 2000-17



Sources for data on Bangladesh, China, Chinese Taipei, India, Indonesia, Japan, Korea, Malaysia, New Zealand, Pakistan, the Philippines, Thailand and Vietnam: IEA databases; various company websites.

Traditionally, there has been ample capacity in the Asia-Pacific region to receive and despatch the annual LNG total (Figure 15). However, this should not be seen as overcapacity. Regasification terminals are built to accommodate political and economic as well as technical requirements of the market. These requirements include: the forecasted peak demand of the area that is supplied by the terminal, the number of alternative sources of supply (*i.e.* the interconnectedness) of the supplied market which is frequently determined by geographic constraints. In addition government regulations (such as the required reserve margin to ensure security of supply or TPA requirements) and supply contract characteristics also influence terminal capacity choices of the user(s) of the terminal.¹⁷ The yearly capacity utilisation in Asia-Pacific is estimated to have been 34% in 2000, slowly rising to around 50% in 2011 and projected to stabilise around this level as new and

¹⁶ LNG liquefaction, LNG carriers, regasification terminals and downstream distribution infrastructure.

¹⁷ Such as cargo size, seasonality requirements, swap arrangements, LNG quality specifications, etc.

planned capacity comes on stream. In addition to China, India, Japan, Korea and Chinese Taipei, which already had regasification terminals, Thailand came on stream in 2011 and several other countries are building or considering building terminals.

Newcomers such as Singapore, Thailand, Pakistan, Bangladesh, Vietnam, New Zealand and the Philippines have announced plans to construct regasification terminals or are in the process of doing so. In addition, the traditional big LNG exporters, Malaysia and Indonesia, have constructed LNG regasification terminals that allow them to import LNG to supply their domestic market, as domestic pipeline distribution has so far not materialised.

Seasonal flexibility through LNG supply

Asian-Pacific economies generally have limited needs for seasonal flexibility in gas, because of the pre-eminence of natural gas usage for power and industry sectors. The two exceptions, as discussed above, are China and Korea.

At first glance, China has a considerable number of options to supply seasonal flexibility compared to other Asian-Pacific markets. These options consist of domestic production, underground gas storage (UGS) and access to pipeline supplies from other suppliers (allowing LNG to supply seasonal flexibility, as it is generally not the baseload supply option). However, as the Chinese natural gas market is rapidly developing, these options need to be fully explored and utilised to keep up with demand.

Due to isolation from pipeline supplies and limited geological options for underground storage (either seasonal or short-term), Korea increased the flexibility of its LNG supply chain to meet domestic demand. This has involved the expansion of high-cost storage onshore in regasification terminals, additional spot purchases on the global LNG market (national gas company KOGAS is the largest spot cargo purchaser in the world to ensure winter supplies) and equity participation in LNG upstream projects.

LNG upstream infrastructure flexibility

Despite considerable regasification capacity that can service the flexibility requirements of the individual economies, overall flexibility in the LNG supply chain is limited by infrastructural rigidities in the upstream sector. LNG liquefaction plants are frequently producing baseload, as they are very capital-intensive ventures that need to recoup these investments. This limits their availability to provide “flexibility” for gas markets that rely on LNG for their supply (*i.e.* ramping up and down when required).

Therefore, in order to limit the extensive usage of high-cost LNG storage, flexibility in the LNG supply chain will frequently come through portfolio management. Companies will combine various upstream sources into the required downstream supply profile for the overall economy (while regasification terminals ultimately provide short-term supply flexibility to the customers in the area supplied by the terminal).

LNG carrier capacity

A considerable barrier to engaging in short-term portfolio management is the restriction of LNG carrier capacity dedicated to upstream projects on a long-term basis and destination clauses that prevent reselling cargoes to third parties. As a result of the global economic crisis and shale gas development in the United States (which freed up tanker capacity originally destined for the United States’ market), free tanker availability increased until the first quarter of 2011. Subsequently, the Fukushima accident reduced the mid-term availability of LNG carriers, as Japanese parties contracted available tankers to transport spot purchases (Poten, 2012). This has resulted in

significantly increased short-term tanker rates throughout 2011 and the first quarter of 2012 (IEA, 2012a).

As of mid-2012, the number of LNG carriers under construction that are not dedicated to long-term projects comprises 37 out of 81 carriers globally until 2016. Although independent ship owners might opt to lease out their carriers under long-term contracts (which might limit any increase in short-term availability of LNG transport capacity), this shows that more ship owners see an attractive business in operating LNG carriers. With more parties willing to provide LNG transport services, LNG supply is likely to become more flexible in the medium term.

The impact of government policies on market structure

The rigidity of the LNG supply chain has traditionally provided considerable impetus to governments to secure long-term security of supply through state owned natural gas companies. These organisations can match supply and demand for LNG through the vertical integration of their activities along the value chain, especially through long-term supply contracts and acquiring equity in upstream development. Regasification terminals are generally developed to accommodate long-term supply contracts concluded by state-owned enterprises and, without unbiased third party access, further limit LNG supply flexibility to consumers.

In addition, the natural gas market structure in most Asian economies limits competition as a result of strong national organisations, which are generally regulated monopolies. These aim to maximise revenues on their long-term, oil-indexed LNG contracts in their respective home markets (Rogers, 2012). The continued state involvement of various Asian-Pacific economies in the natural gas sector is also visible in the regasification terminals' ownership of state-owned enterprises. Nearly 79% of the terminals in operation, under construction or planned until 2017 are owned and operated by vertically integrated, government-owned entities.

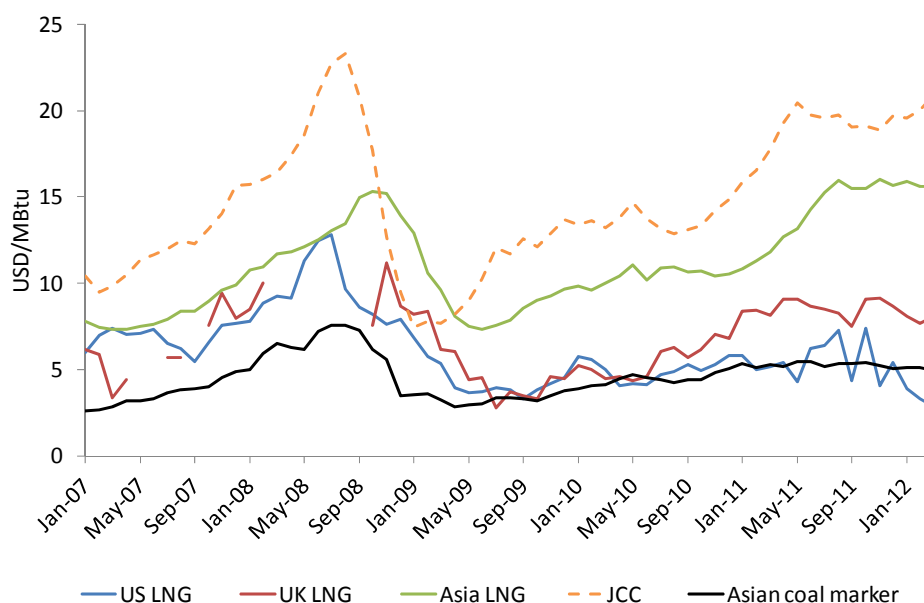
Despite the increase in regasification capacity, the current infrastructure of the LNG supply chain limits the ability to respond to changes in demand or supply. Even with an increase in the number of LNG carriers available short term, the current LNG contracting structure is dominated by long-term contracts that limit the availability of spot LNG on world markets (see Chapter 4). This means LNG supply cannot respond cost-effectively to changing demand patterns in downstream Asia-Pacific markets.

Natural gas price development in Asia-Pacific

The fact that Asian LNG-importing economies are mainly supplied through long-term, oil-indexed contracts has driven natural gas prices in the Asia-Pacific region to record highs. Historically (before 2004), LNG prices between the three major centres of consumption were linked through the oil price movement. However, shale gas development in the United States and increased liberalisation of natural gas markets in Europe have set the global wholesale gas prices at three distinct levels between 2009 and 2012.

Since 2011, Asia-Pacific LNG prices are back at pre-crisis levels for the mature Asian gas markets Japan, Korea and Chinese Taipei. Indian and Chinese LNG import price levels have been markedly lower than those of other Asian economies due to different contractual arrangements. China in particular negotiated favourable long-term price formulas at the start of this century for its Australian supply contracts. This made Chinese LNG import prices competitive with coal import until January 2011. But as imports from other LNG suppliers have increased, Chinese LNG imports have become less competitive with coal (IEA, 2012a).

Figure 16 • Regional gas prices and Japan Crude Cocktail, 2007-12



Note: the interruptions in the UK LNG curve signify that no LNG cargoes landed in the UK during those periods, resulting in no price information.

Sources: IEA databases; US Energy Information Administration; UK customs; Japanese customs; Korean customs; and Chinese Taipei customs.

Despite the dominance of oil indexation in import contracts for both LNG and pipeline supplies, other indexation models are sometimes considered, *e.g.* coal indexation in the negotiations between the Russian and Chinese administrations for long-term natural gas imports. On the basis of market value (natural gas is priced at the level of the fuel it replaces in the energy mix), it could be argued that natural gas is primarily in competition with coal, as this is the predominant fuel in China.

The inclusion of a link to the coal price in long-term gas contracts has proven to be unacceptable for the Russian gas company Gazprom (IEA, 2011a). For this exporter the link to coal prices is a significant risk to investment recovery, as coal prices are generally lower than oil-indexed natural gas prices. In addition, the linkage to the coal market is a risk to the price-setting mechanism as Chinese (frequently state owned) coal producers have considerable sway over international coal prices, thus presenting a threat to market-based pricing. However, despite these initial developments new benchmarks for indexation are likely to be used in the future in commercial negotiations between supplier and consumer.

The Asian-Pacific market broadly comprises three areas of market maturity (see Introduction to this Chapter):

- the well-established markets of Japan, Korea and Chinese Taipei have end-user natural gas prices that reflect the dominance of oil-indexed supplies at a cost-plus basis: oil-indexed commodity plus services for consumers;
- the emerging giants, notably China, have substantial domestic production and regulated end-user prices across various economic sectors; these are set at a level to provide energy for the growing economy (IEA, 2012b); and
- the area of South-East Asia where end-user prices are regulated at a level frequently below cost of service, namely in economies with considerable domestic production, leading to a subsidy for consumers (IEA, 2011c).

Wholesale prices in the Asian-Pacific region are set at a cost-plus basis from oil-indexed natural gas prices or at a regulated level, depending on the economy and sector where natural gas is consumed. Apart from the isolated market of Australia¹⁸ and the Japan/Korea Marker (JKM) from Platts (discussed in Chapter 4) there is no Asia-Pacific wholesale price for natural gas that reflects the fundamentals of demand and supply.

Towards a regional interconnected market?

Although the overall dependence of Asia-Pacific on natural gas imports from other producing regions will stabilise at roughly 50% over the next decade, the overall volume of imported natural gas in the region will continue to increase, to around 200 bcm in 2017. However, as the largest individual natural gas markets (Japan and China) suffer from a lack of interconnectedness, a physically interconnected regional natural gas market is unlikely within this time frame.

Currently, the pipelines connecting different centres of demand in the region are generally dedicated to upstream developments. A considerable expansion of the intra-regional PNG (pipeline-supplied natural gas) trade (with Russia) of natural gas remains unlikely for the time being. Limited progress on pipeline infrastructure (even within domestic markets) has led to a surge in regasification terminals to connect the national gas markets to the global LNG supply system.

In principle, there are no technical barriers that would hinder the emergence of a regionally interconnected Asian-Pacific market with LNG trade as its backbone. However, the current structures of the LNG supply chain (liquefaction and transport) offer limited flexibility. In addition, the importing gas markets are frequently dominated by a few vertically integrated organisations that with supply infrastructures that suit their specific long-term, oil-indexed contracts, but do not promote flexibility or competition.

Finally, there is currently no effective regional cooperation between large natural gas markets (both developing and mature) that would support a more interconnected gas market in the Asia-Pacific region. Although ASEAN has proposed ambitious objectives for further cooperation, progress is limited. As a result of differing national policies, most not related to energy, cooperation that could lead to a regional natural gas market similar to that (still to be completed) for the European Union is unlikely for the time being.

Development of a natural gas price reflecting regional supply/demand in an LNG-dominated supply system does not necessarily require political and economic cooperation on a level such as the European Union's. Transparent national gas prices derived from local supply and demand can provide incentives to direct LNG flows across the region, facilitate further investment infrastructure and generate a representative regional price level. This would be similar to the pipeline based natural gas market in the United States.

The first steps to create a supply/demand-responsive natural gas price would involve governments restructuring their national gas markets so as to allow an alternative price signal to develop. The steps needed by governments to develop such a transparent pricing signal are outlined in the following chapter.

¹⁸ Technically, Australia does import natural gas from the shared development with Timor-Leste, but it remains a geographically isolated net exporter.

3. Creating a liquid natural gas trading hub

As governments try to create a competitive, sustainable and secure natural gas market, increasing competition in the gas market is seen as a way to deliver all three of these policy targets at a minimum cost to society. In general, this process will involve three interlinked trends.

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- a move from public ownership in the energy sector to a more private one;
- a move to less vertically integrated energy companies; and
- less government interference in the natural gas market (Ming-Zhi Gao, 2010).

A monopolistic market structure is fairly common in the take-off phase of natural gas market development, due to the need for a capital-intensive infrastructure and the subsequent low returns on investment in the development stage (IEA, 1998). In general, pressure for a more competitive natural gas market starts to build when a gas market has developed into a mature market.¹⁹ In this stage, infrastructure investments have depreciated and returns start to increase in relation to further investment requirements as existing infrastructure can be utilised at low marginal cost.

Although the starting point of various national natural gas markets may differ, governments generally need to take a number of steps to allow markets to open up and then to continue to function. A government needs to guarantee a set of institutional and structural requirements to (further) open a market: access to infrastructure, introduction of consumer choice, reduction of wholesale price regulation and application of competition policy. These steps should initially create the confidence for consumers and producers to start using the market place as the primary platform to facilitate the exchange of ownership of natural gas in the market.

Requirements for a functioning natural gas market

This chapter will look at ways to create a functioning wholesale natural gas market, which can be defined as: “a single price zone accessible to incumbents and new entrants on equal terms and where trading is liquid, so that it creates a reliable price signal in the forward and spot markets which are not distorted” (Dengel, 2011).

The primary goal of a deregulation process is to increase competition among natural gas suppliers and consumers in a market. In general, a move away from a monopolised natural gas market will lead from a non-competitive market, via a developing market stage to a mature, functioning market with full retail competition. IEA has identified two market models that serve as an alternative to the monopoly market structure: the pipeline-to-pipeline competition model and the mandatory third party access to the network model.

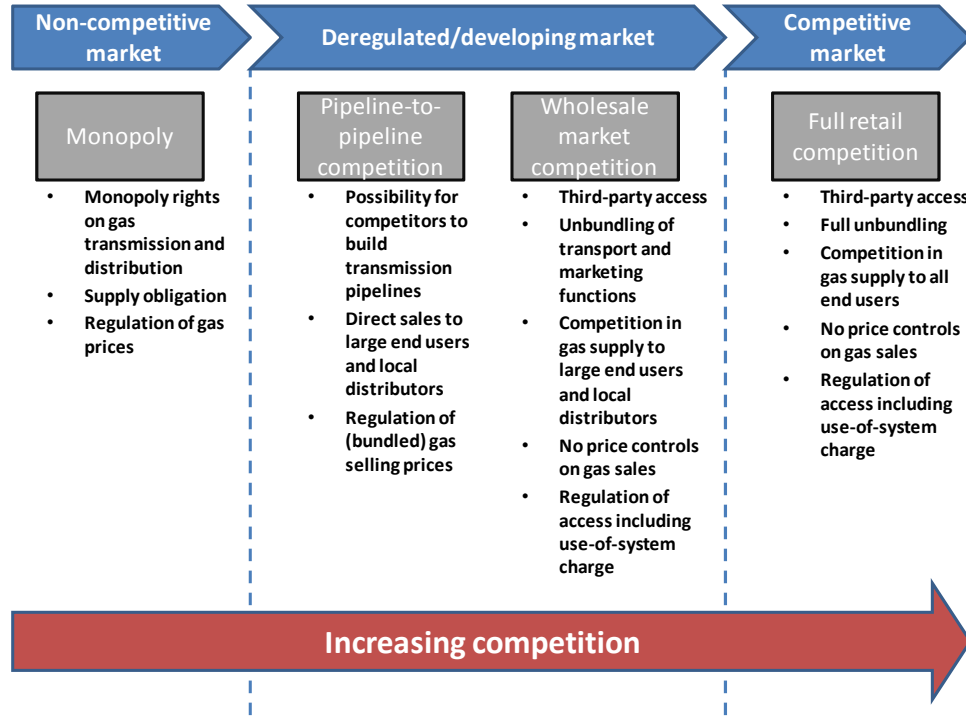
Any functioning market will have a degree of competition among suppliers, either at the beginning of the value chain or through the entire value chain down to the retail level. In the pipeline-to-pipeline model, competition is organised between suppliers who build the infrastructure to deliver to customers. In mandatory access to network, a distinction can be made between a market with wholesale competition and a market with full retail competition; in the latter case, competition is introduced into the final part of the value chain, while wholesale competition stops short of the retail segment.

As governments start to deregulate their natural gas markets, they will embark on a complex process to meet their respective social, economic and supply security objectives for this sector and the energy supply as a whole. However, new parties that will enter the natural gas sector as

¹⁹ Mature market: a market that has reached a state of equilibrium marked by the absence of significant growth.

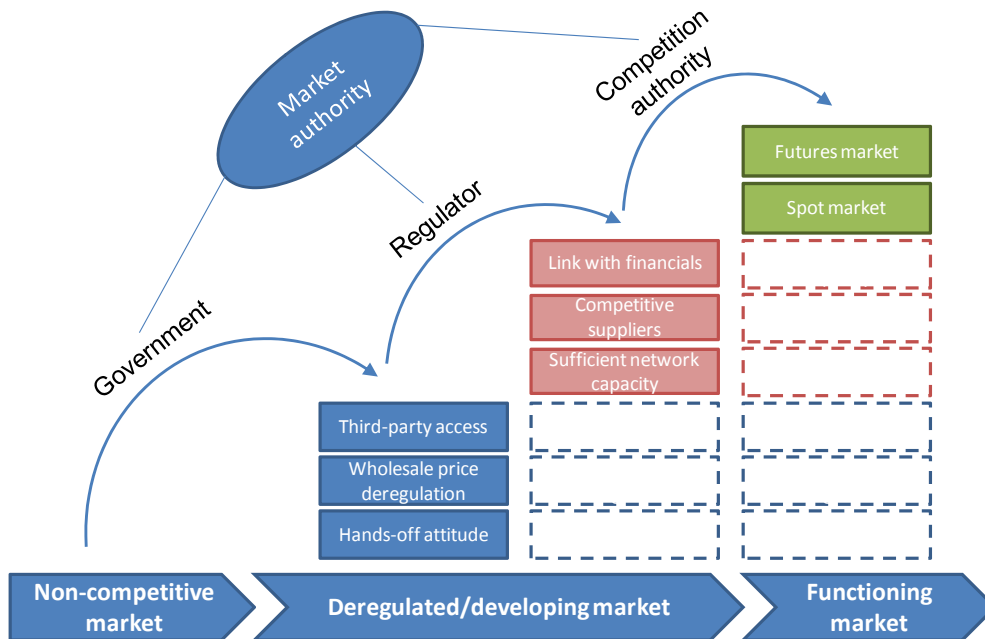
a result of deregulation will influence the ongoing process in a way that might require further changes in the rules set by the government. It is therefore a continuous reciprocal process between a government and market parties, with outcomes that will never be entirely clear from the onset.

Figure 17 • Increasing competition in a natural gas market



Sources: IEA (1998); author.

Figure 18 • Creating a competitive wholesale natural gas market



A functioning wholesale market ultimately delivers a reliable price signal that accurately reflects the supply/demand balance, now and in the future. Each country will have a different point of

departure and a different objective when implementing policies to support a competitive natural gas market. Government action is necessary to create a transparent and level playing field that increases competition between suppliers and consumers.

Increasing competition in the natural gas market is a process usually set in motion by the government, but ultimately needing to be self-sustained by the market in which the government has a supervisory role (e.g. through a competition authority). This will mean that the government's role itself will shift during this process from being the market (through a state company or other entity) to a regulator that effectively monitors and sets the rules, to finally a role similar to that of a competition authority.

The establishment of a gas exchange with a spot and futures market that provides a reliable price signal is considered to be a key attribute of a competitive natural gas market. The institutional and structural requirements for a deregulated wholesale natural gas market that is the foundation of a natural gas exchange are set out below.²⁰

Institutional requirements to create a wholesale natural gas market

To support competition in a natural gas market, first some institutional requirements need to be met. Governments must actively create the foundations of a natural gas market, dismantling old institutions while building new ones. The way these requirements are met can vary from government to government, depending on the respective state of the natural gas sector in a country, among other factors.

In general, a successful attempt at increasing competition will meet the following institutional requirements (in no specific order):

- **A hands-off government approach to natural gas markets:** this implies a governmental mindset that will be carried on through the respective natural gas market governing entities. It also implies a shift from direct policy making and market involvement to market monitoring through an independent anti-trust agency. However, the particular institutional arrangements to withdraw direct government influence from the market may differ significantly among countries.
- **Separation of transport and commercial activities:** the natural gas industry is known for its tendency to behave as a natural monopoly, since the high costs of infrastructure investments prohibit the development of parallel infrastructures to supply the same customers (especially at retail level). It is widely recognised that these vertically integrated supply systems need to be broken up. Whether this break-up is established through full ownership unbundling or through financial separation (from the mother company) is immaterial, as long as commercial and transport activities are run as separate entities.²¹ Subsequently, the independent transport entity will levy a fair and indiscriminate transmission fee on a proportional basis for all shippers.
- **Wholesale price deregulation:** part of the governmental hands-off approach would involve letting the market set the wholesale price level for natural gas. This would immediately break the former bundled, regulated, natural gas price into a transmission price (through unbundling) and a wholesale price that includes commodity, services and a profit margin. It would allow large customers to seek the supplier that can deliver the product that suits their need at the least possible cost. Eventually, this freedom of choice can also be offered to individual households, but it is not strictly necessary for a functioning wholesale market to emerge (although it would spread the social-economic benefits of greater economic efficiency to these customers).

²⁰ Based on: R. Haas and H. Auer (2006), pp. 857-864. Although electricity markets are decidedly not the same as natural gas markets, both are heavily dependent on infrastructure access and therefore allow for a similar market development.

²¹ There is ongoing debate on what would be required to guarantee unbiased third-party access. In the light of market confidence, it might be advisable to consider full ownership unbundling as a measure to increase confidence that network and commercial activities are truly run separately.

Structural requirements to create a wholesale natural gas market

In addition to institutional requirements, it is generally accepted that market parties need a minimum degree of certainty that a market is actually competitive and is functioning as such. This requires structural requirements to be secured (by the government or the independent entity). The governmental role will then shift from active participant to regulator, setting rules and monitoring the sector. These structural requirements are the following (in no specific order):

- **Sufficient network capacity and non-discriminatory access to networks:** essential to a well-functioning natural gas market is its accessibility via non-discriminatory access to networks, and the availability of capacity on these networks. Non-discriminatory access will increase the number of market participants, while sufficient network capacity will ensure that no separate “islands” that behave according to their own supply/demand dynamics will exist within the natural gas networks. Essential elements to guarantee these structural requirements are an independent transmission system operator (TSO), either divested or functionally separated; and a clear and unbiased investment regime based on a well-developed network code (set of rules).
- **Competitive number of market participants:** lowering the barrier to entry through a well regulated network code should increase competition for the incumbent natural gas company. A genuinely competitive gas market requires a number of parties with competitive market shares along a non-regulated value chain (upstream and downstream). The question of how many market participants, and with what share of the market, constitutes true competition depends on market-specific circumstances and needs to be answered by the government/regulator. The regulator then needs to enforce the appropriate structure, increasingly behaving as a competition authority.
- **Involvement of financial institutions:** enabling a market to efficiently service supply and demand will require investment throughout the natural gas value chain (upstream development, transport, storage and distribution capacity). Apart from capital investments that will be recouped by operational revenues, a competitive natural gas market will also need financial parties that are willing to cover financial/operational risks for parties involved in the natural gas trade, providing tools for customers to smooth out and optimise revenue streams from their activities in the natural gas market. If a natural gas trading platform is established, a link between natural gas markets and financial institutions is needed to reduce counterparty risk and to provide a clear, long-term price signal. It is crucial that financial parties take long-term positions in the gas market and generate a long-term price signal, as financials currently do in the global oil market.

The structural requirements (available capacity with unbiased access, a competitive number of market participants and a link with financials) are essential to kick-start a natural gas market. They should be guaranteed by a regulator (ideally independent of companies *and* government) that monitors the market and can act independently, when needed (*e.g.* force an incumbent company to facilitate more competition). The existence of an independent regulator should also boost the confidence of parties in the market. However, a transparent natural gas price that reflects the current and future state of the market will not be realised unless a platform for the ownership exchange of natural gas is developed.

Creating a natural gas price: from hub to market

During a complex process such as the deregulation of a natural gas sector, the ultimate policy aim would be that the sector would sustain itself by attracting outside investments to more efficiently serve its customers. However, to allow gas supply and demand to meet in a market place, a platform for exchange is needed, more commonly referred to as a hub.

A natural gas trading hub is where the title for natural gas is exchanged between a number of buyers and sellers. Initially it has a purely administrative function to facilitate trade, but one that is crucial to enable competitive markets to function, as trade without ownership exchange is simply not possible. On the hub, both a spot market, where gas is traded for limited time into the future, and a futures market, where delivery of the gas can extend several years into the future, can subsequently be realised. Globally, two types of hubs for natural gas trading have emerged: a physical and a virtual hub.

Trading platforms: physical versus virtual hubs

A physical hub is a geographical point in the network where a price is set for natural gas delivered on that specific location. A prime example of such a physical hub is that of the United States, the best functioning and most liquid natural gas market in the world, which essentially consists of a physical trading point (the Henry Hub in Louisiana), which sets the benchmark price for the entire North American trading area. However, the United States also has many regional physical trading hubs reflecting local and regional supply/demand balances. At these local hubs, natural gas is frequently traded at a differential from Henry Hub, taking into account regional disparities and production and transport costs to that specific regional hub.

In essence, the whole North American natural gas system operates around a price set by the natural gas exchange at Henry Hub, resulting in prices across the United States that differ, albeit staying reasonably close together. Within the United States' geographical area, arbitrage opportunities between regional hub prices drive investments in transport capacity by private pipeline companies. However, for this to work in other countries' markets would probably require a regulator that can regulate access to interconnecting pipelines throughout the gas market, such as the Federal Energy Regulatory Commission (FERC) in the United States.

Henry Hub (HH) was not selected by the natural gas market regulator, but by the New York Mercantile Exchange (NYMEX), which was looking for a centrally located and sufficiently interconnected point for the exchange of natural gas ownership. A different approach was taken in the United Kingdom. When the British natural gas sector was deregulated in the 1990s, the British regulator established a network code that created the virtual National Balancing Point (NBP). This virtual trading point was established as a daily balancing tool for the entire British geographic area. The NBP price reflects the commodity price in the entire area without geographic differentials due to transport costs. Transport costs are levied separately by the TSO that runs the British gas network and are regulated by the British energy regulator (Ofgem).

Currently the European Union prefers to continue to integrate its natural gas markets through the establishment of virtual (regional) trading hubs.²² This is a pragmatic approach, since it builds on the existing arrangements of national TSOs and regulators (rather than creating one overarching European regulator) and an infrastructure built to facilitate long-term import contracts with national balancing and limited interconnections. The demise in relevance of the physical Zeebrugge hub has shown that in the current developing European market environment, a virtual hub is considered less cumbersome due to simplified entry/exit arrangements, attracting new parties to gas markets.²³

Physical and virtual gas trading hubs have different set-ups to accommodate the different structures of their industries (*i.e.* fully privatised transport activities in United States versus

²² The European Union accepted a proposal to develop competitive natural gas markets in Europe by the Council of European Energy Regulators (CEER, 2011).

²³ Consequently, the Belgian regulator CREG and TSO Fluxys have decided to develop two virtual hubs in Belgium ahead of a decision by European regulator CEER to recommend virtual hub development as the basis of the European Gas Target Model.

regulated TSO in the European Union) and purpose of the hub (to facilitate trade in the United States versus balancing in the European Union). But both platforms have proven to be able to facilitate trade, to sustain the transition towards a liquid futures market, and to generate reliable pricing signals for market participants.

Merging physical and virtual natural gas trade

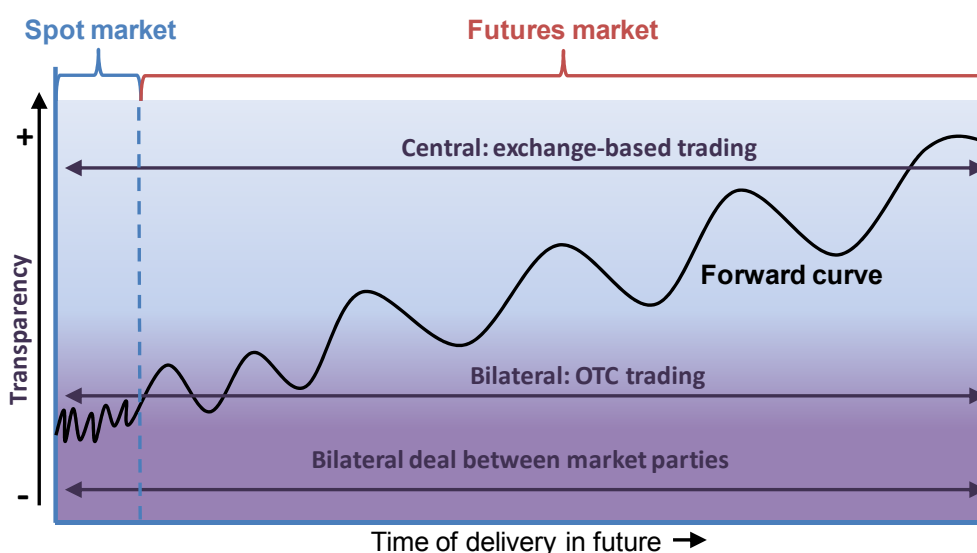
Regardless of the hub is physical or virtual, when moving from physical balancing on the spot market to a liquid futures market, the physical gas supply and the virtual gas supply will meet at this hub. The natural gas hub will then bring together market participants that use the same natural gas market for different aims. This has consequences for the way that natural gas is traded, for the type of market participants active in the market, and for the products that are traded in the market.

Market trading: bilateral versus centralised trading

In a non-competitive market, the ownership exchange of natural gas would be arranged in a bilateral fashion between the end-consumer and the (regional) supplier. As wholesale markets increase competition between suppliers and between consumers, other arrangements open up. In wholesale markets, natural gas is traded either bilaterally between market parties and over-the-counter trades (OTC, frequently through brokers) or centrally on an exchange operated by a marketing organisation, such as NYMEX, APX/Endex (Anglo-Dutch energy exchange) or Intercontinental Exchange (ICE).

Bilateral trade involves trading not only in standardised products, but also customised products that are widely used by suppliers to accommodate a consumer's specific requirements for timing, flexibility, volume, etc. These bilateral trades can be closed both in the futures market and spot market; however, these will be delivered on the hub, as it is a platform facilitating ownership exchange.

Figure 19 • Bilateral, OTC and central trading and transparency on spot and futures markets



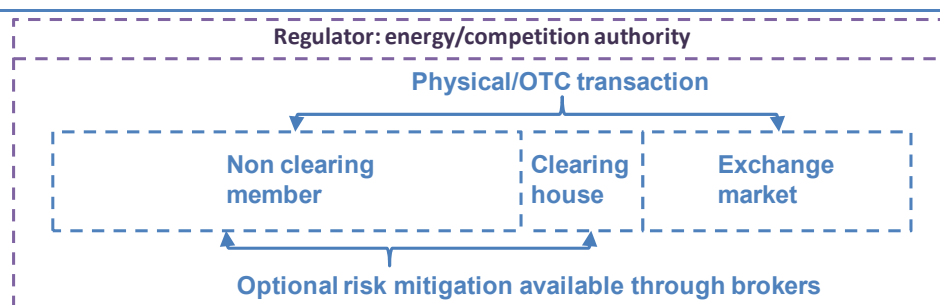
A perceived benefit of exchange-based trading is that transactions take place on exchanges that facilitate transparent, centralised trade in standardised products, with the gas hub as delivery point. This centralised trade through the exchange will increase transparency in the natural gas market through the price signals and indices that these transactions will provide. In general, trading through centralised exchanges is considered to be more transparent by regulators, since OTC trading does not take place “on screen”.

Although this transparency argument is viable, it does not necessarily mean that OTC trading limits the functioning of a natural gas market, since all market parties involved in OTC trade have equal access to this information.²⁴

An important factor in choosing how to trade natural gas on a hub is the way counterparty risk is managed. To a large extent, this reflects the merger of the physical natural gas industry with the financial industry, with increased “financialisation” of the natural gas trade as a wholesale gas market develops.

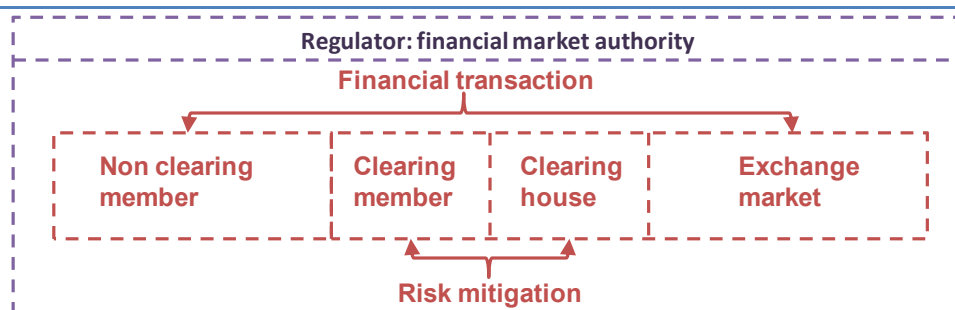
In bilateral (or OTC) transactions, counterparty risk will to a large extent rest with the parties involved in the transaction. The primary advantages considered for these transactions are the lower costs (*e.g.* clearing fees and other services) and the fact that OTC transactions allow parties to buy and sell customised products. Customised products can decrease the need to set up portfolio management structures and trading desks. Generally, companies that engage in OTC transactions reduce their counterparty risk by internal corporate regulations that assess credit worthiness, which sometimes results in bilateral clearing agreements. If a market party wishes to insure itself against counterparty risk, this is still possible through clearing houses, but this reduces the cost advantage of an OTC trading transaction versus an exchange-based transaction, where transactions are always cleared and so safer.

Figure 20 • A schematic OTC transaction



Part of the cost of using a clearing house (CH) is incurred by the CH carrying the risk of settlement failures. A CH (frequently part of the marketing organisation that operates the exchange market) facilitates risk mitigation between the clearing member (CM, frequently a financial institution) and the market counterparty. Counterparty risk, both financial and legal, is then isolated from the non clearing member’s (NCM, a market participant) trading on the future and spot market.

Figure 21 • A schematic financial transaction on a natural gas exchange



²⁴ This is a debate that frequently resurfaces as politicians blame invisible speculators for high commodity prices (frequently crude oil, but also staple foods and other strategic commodities). They frequently refer to the OTC market as “the market”. In fact, both OTC and exchange-based transactions increase the functioning of a natural gas trading hub, as both provide specific services to market participants and so attract market participation.

An important distinction is that the transaction described here as a “financial” transaction on an exchange does not necessarily involve physical natural gas exchanging hands; natural gas has become an energy derivative. Consequently, the government’s regulatory authority that will be most likely involved is the financial market authority (FMA), since this type of transaction generally fits well within the competence of such a regulator. Usually, a physical transaction through OTC trades on the spot market will fall under competency of the energy market regulator or competition authority.

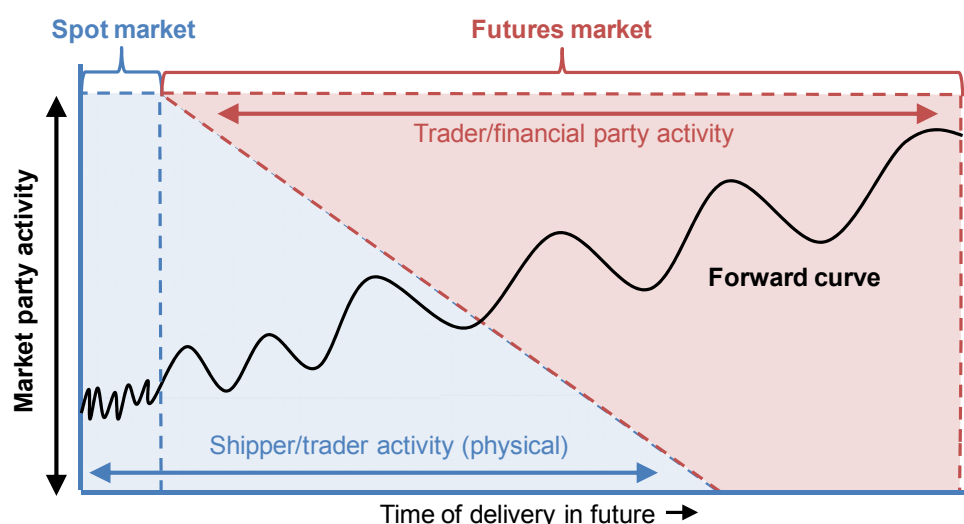
This shift in regulatory regime through the merger of the physical and financial trade on an exchange hub exemplifies the deregulation process. As a consequence, financial parties will come to recognise market mechanisms and regulatory frameworks, creating increased confidence in the market which will encourage them to integrate natural gas trading into their mainstream activities. As a result, financial markets will provide real-time-priced natural gas derivatives to all market parties, thereby further increasing transparency and confidence in the market. This will ultimately drive the process of creating a competitive wholesale market forward.

Market participants: physical versus financial players

As explained above, involvement from financial parties is critical to developing future pricing, as these parties are willing to take risk exposure to create a margin. The entry of financial entities in a market tends to increase competition, and involvement in the futures market. Physical parties (shippers) that deliver gas to consumers use the spot market as a balancing tool for their portfolio and will be considerably less active on the futures market.

In general, financial parties would like to “get out” of the market before physical delivery takes place. Therefore, while financial parties are more present in the futures market, they sometimes depend on the spot market to unwind their positions. The relationship between shippers and financials is symbiotic. While increased trading by shippers on the spot market is essential for financials to get out of their positions, shippers at the same time depend on the financial derivatives that financial parties provide through the futures market to reduce the risks associated with shipper activities.

Figure 22 • Shipper and financial party activity on the spot and futures market



On a well-functioning trading hub, the price difference between the futures market and the spot market at the point in the future where these markets meet is zero. This creates an

uninterrupted price signal for natural gas delivered now and at any point in the future (the forward curve) (Figure 22).²⁵

Box 1 • Other parties involved in natural gas hub development

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In the previous chapter, traders and their activities are distinguished on the basis of their physical or financial transactions. Besides the parties that use a hub for ownership exchange, there are a number of other parties involved in the establishment of a hub and natural gas market. Their subsequent emergence on a hub and their individual roles and activities mirror the process set out in Chapter 3 for the establishment of a functioning wholesale market.

- **Infrastructure operator:** ensures that a system remains physically balanced, manages the capacity to and from a hub, and administers the transfer of ownership rights.
- **Broker:** mediates between market parties and thus simplifies the search for counterparties to sell/buy gas and helps create awareness of OTC deals.
- **Hub operator:** provides hub service agreements (for wheeling, parking, etc.), ensures contractual firmness through backup/down services, facilitates transfer of gas and stimulates standard product development.
- **Exchange:** stands between trades and allows anonymity, reduces or removes counterparty risk, ensures that prices are reported, and enables standard products to be cleared.

These parties all provide services for a trading hub that enable a hub to function and efficiently set a price that reflects the overall supply/demand balance of the natural gas market.

Market products: physical versus paper products

To establish a wholesale trading market, both shippers and traders need standardised contracts that enable them to trade quantities of gas labelled as a “product” by their time of delivery in the future. This is a simple necessity to make gas a tradable commodity. In turn, financial parties can more easily value these commodities and start buying and selling these products on the futures market.

As explained above, products traded on the futures market depend on an underlying liquid spot market to create trade in products in the future. The more liquid the trade in an underlying product or market, the more easily a product is traded in the future. Market parties perceive less risk as they can more easily get out of their (financial) positions. The number of products offered on spot and futures markets therefore depends on two factors:

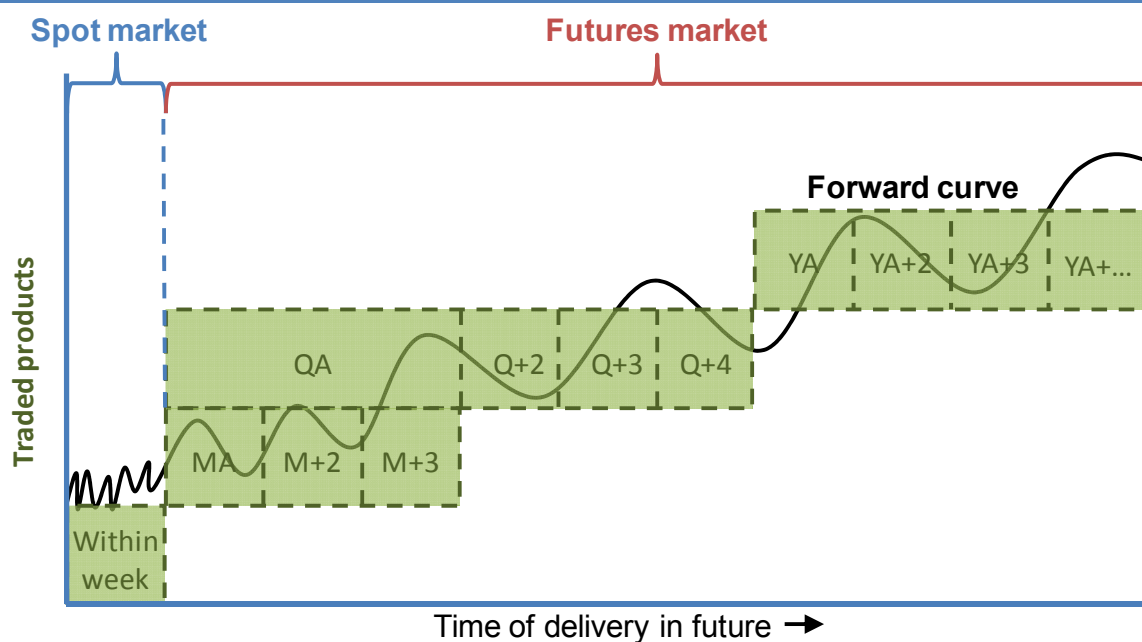
- Underlying product liquidity for short duration, close to expiry contracts (prompt of the curve²⁶) that will stimulate and “push out” trade in products for delivery in the more distant future (in short: the more liquid the prompt, the more liquid the curve).
- The demand from market parties for certain products to be introduced to balance their physical portfolio on the spot market or to hedge their financial portfolio in the futures market. This need for products is set by various market circumstances, such as regulations in the physical gas market that drive the need for new balancing tools or financial regulations that require better hedging facilities on the futures market.

²⁵ For schematic purposes in this graph and the ones below, the spot market is defined by within-week products, such as Within Day (WD), Day Ahead (DA), Weekend Ahead (WA) and Balance of Week (BOW), as these products allow for balancing purposes in the short term. How many products and how far in the future these products are traded as part of the spot market differs between markets. In this paper we consider a spot market to be the market that is used for short-term, physical balancing purposes by shippers.

²⁶ The curve is a set of prices for various products for delivery in the future, which gives a customer a price for natural gas delivered at any given time in the future (from now until the end of the curve)

New products are usually developed by the marketing organisation that operates the energy exchange in close consultation with market parties using the exchange. The market parties assess the need for new products on the spot and futures market, usually trying to develop products on the curve when tradability in underlying products is deemed sufficient. This is a delicate process involving designated market makers who will try to kick-start the trade in these new products, expanding the product portfolio offered on a hub.²⁷ A schematic set of products that mimic various market party needs in the spot and futures market is shown in Figure 23.

Figure 23 • Products traded “on the curve”



Through establishing a wholesale market for natural gas with spot and futures deals, a natural gas market will increasingly resemble a commodity derivative market. This will mean increasing the numbers of OTC and exchange-based transactions, financial and physical parties active on the trading hub, and products traded with delivery in the future. As a consequence, the resulting prices on the spot and futures market will increasingly reflect dominant supply/demand balance for a geographical area in the near future.

An exchange operator's ability to attract market parties and to support continued increase in the products and services offered on the exchange is also influenced by a number of other factors, including the strong support of the incumbent companies. The support of market makers (frequently also incumbents) in introducing products and services will reduce time-to-market and will help an exchange to meet its users' needs.²⁸ Finally, the quality and costs of the developed market model and services will determine the success of an exchange operator in relation to other operators on the same hub or in the region.

²⁷ A market maker is a market participant that agrees (with the marketing organisation) to make bid/offer spreads for certain products, within agreed parameters, in order to increase liquidity in the trade of these products for all participants.

²⁸ Time-to-market is the amount of time it takes from a product being conceived until it is available for sale; a reduction in time-to-market enables suppliers (both physical and financial) to promptly meet changes in product demand.

Contractual consequences?

The introduction of competition and trading hubs will have impact throughout the natural gas value chain, on both commercial parties and governments. Trade in natural gas is likely to increase markedly in scale and scope, as a natural gas hub's ability to balance portfolios opens up new possibilities for suppliers and consumers outside their long-term contractual obligations.

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When natural gas is introduced as an energy source into an economy, there is a considerable need for upfront capital investment, as infrastructure needs to be built to supply customers. The substantial investment risks associated with building such an infrastructure are mitigated through long-term contracts designed to guarantee an acceptable return on investment.

The volume risk in these long-term contracts is shouldered by the buyer of natural gas, who guarantees to buy a certain amount of annual contract quantity (ACQ) over the duration of the contract. Volume risk can be limited by flexibility in a long-term contract providing for a certain share of the volume not to fall under take-or-pay obligations, or certain volumes that can be consumed in the future (*i.e.* make-up gas).

In the case of physical substitution with the product (oil) that forms the basis of indexation Price risk is shouldered by the seller, who guarantees that his product would be competitive. This risk-sharing arrangement initially requires a guaranteed distribution market for the buyer, who could otherwise not meet the volume-risk obligations. The distribution market need to be subject to a restriction on supply competition for a geographic area through the obligation/commitment not to resell natural gas in other geographic markets where natural gas might have a higher value (*i.e.* final destination clause).

Long-term contracts usually provide for a mechanism to deal with major changes in market conditions, such as a sudden upswing in demand or regulatory changes that severely affect the competitiveness of natural gas in the energy market. The main mechanism is the facility to renegotiate contract conditions, to bring them into line with prevailing market conditions. As a result of these contract clauses, the natural gas industry in Europe has seen a considerable number of renegotiations in response to the collapse of demand in 2009.

Factors influencing pricing

The price formula in long-term supply contracts is intended to establish a long-term price for gas on the basis of the value for gas perceived in the (near) future by both the seller and the buyer. As markets continue to develop, the value of natural gas in the overall economy and energy mix will change; consequently, the price of natural gas needs to be adjusted to realign both price and volume risk. Generally, pricing arrangements in long-term contracts are adapted to changing market circumstances in one or more of three ways:

- the price level can be adjusted to the perceived market's value of gas (where there is no competitive market) or to the level of the market price (in a competitive market);
- the commodity to which a natural gas price is indexed can be changed to a more relevant commodity for the sectors in which natural gas is consumed; and
- the pace of the price review can be increased (or reduced), realigning a price more or less frequently to new market circumstances.

These adjustments will have to be achieved through negotiations between buyer and seller. In a competitive natural gas market, these renegotiations are considered to be a cost, as they require extensive contract reviews. This frequently involves expensive litigation, with the sole aim to bring the price of the delivered volume in line with the perceived market value of the gas, usually for only one party. Primary motivations for both parties to realign the contract price are the costs

that either party can incur from the price disparities between the long-term contract price and the market price (Sutherland, 1993).

In a competitive market, buyers will aim to reduce their procurement costs compared to those of their competitors. Long-term oil-indexed contracts will increase opportunity costs through renegotiations and risk associated with price disparities versus standardised products bought at the spot or futures market. The incentive to reduce these opportunity costs may provide a powerful motivation for consumers to reduce volumes bought under long-term contracts and opt for short-term, standardised alternatives with lower associated costs.

The existence of the two pricing mechanisms (oil-indexed and natural gas) in one natural gas market has considerable consequences for the distribution of risks between supplier and consumer in traditional long-term contracts. The supplier can no longer automatically pass on the risk of oil price indexation to end-users. As a result, from a risk management perspective it is forced to have its own import contracts repriced on a market basis as well. The only way to “redistribute” the price risk towards the supplier would involve indexing the long-term volumes on the gas market, which would require further renegotiation of contracts.

Gas consumers who directly depend for their overall competitiveness on the cost of their natural gas supply (such as electricity producers in a competitive electricity market and fertiliser producers) have a direct stake in reducing supply costs, as they cannot easily pass price risk onto their customers. These consumers are therefore usually the first movers into shorter-term, market-based natural gas contracts, as they cannot afford to price themselves out of the market in relation to their (international) competitors and need to mitigate these price risks through short(er)-term contracts. Although price volatility associated with competitive natural gas markets is a point of concern to industries (and an obstacle to moving toward hub-based pricing), a well-functioning futures market will reduce these concerns.

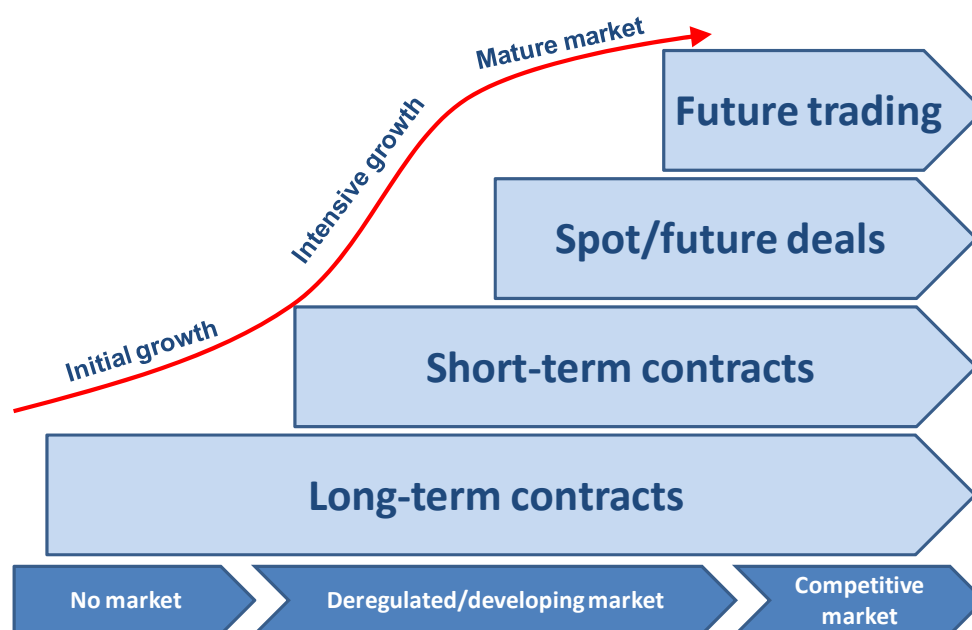
Regulated utilities with regional monopolies will be more comfortable with any price structure in long-term contracts, as they can pass price risks on to (frequently residential) end consumers. However, a regulator might impose natural gas prices in line with their (the regulator’s) perceived market value (Sutherland, 1993) or a government might enforce a certain price level. A policy of adopting market-based pricing in supply contracts will provide regulated utilities with insurance against such regulatory bias.

Producers are likely to be reluctant to change towards short-term contracting, as they will generally claim to be in need of long-term demand security for natural gas to develop capital-intensive resources to supply customers. They frequently argue that the demand for their product will be determined through inter-fuel competition in a market. However, this need not exclude market-based pricing in supply contracts, as prices determined on the basis of supply and demand should provide an incentive for inter-fuel competition.

Another explanation for producer resistance to spot-indexed pricing is a lack of confidence in the gas hub’s ability to provide a reliable price (due to a limited number of suppliers/consumers, etc.). Producers may also be reluctant to abandon well-established contract practices that may have proven reliable for many years. Finally, the current market environment with high oil prices versus lower gas prices (in Europe and the United States) does not provide an incentive for producers to change to an alternative pricing system (IEA, 2008a).

When the natural gas market becomes more competitive, consumers and producers will have the opportunity to introduce different products with a market price suited to their respective needs. This will not necessarily entail abandoning long-term contracts, because these contracts have considerable value and both buyer and seller have an interest in secure long-term supply and demand.

Figure 24 • Market development, contract duration and market maturity



Source: ECS, 2007.

Despite the impact of trading hubs on long-term contracts, it is a widespread misconception that long-term supply contracts are not possible in a competitive market. As buyers and sellers determine the contract duration, their overall objective will be to reduce associated costs. This can be done by creating a long-term contract that uses a market-based price; however, this would leave the off-take obligation with the buyer, as price risk no longer poses an issue (and is thus not a reason for renegotiations).

It is possible (and frequently preferred in fast-growing markets) for consumers to contract long-term volumes; however, this will only be advantageous if the total product (*e.g.* taking into account other contract conditions) suits the needs of both supplier and buyer. Indeed, there are attractions to a hybrid system of natural gas pricing (as is currently the case in Europe) where long-term, oil-indexed contracts continue to be the backbone of natural gas supply, while spot-indexed supplies provide a balancing role (CIEP, 2008). In a competitive natural gas market (long-term or short-term), contracts and their pricing mechanisms will have to suit the producer's and consumer's needs, since other options are always on the table.

The main consequence of an increase in competition on natural gas contracts is that the number of available contracts will increase as suppliers and consumers look for the counterparty that can provide their specific contractual need. Developments in the United States and Europe have shown that this will involve a shift away from long-term supply contracts and an increase of market-based pricing mechanisms in these contracts. The transition from a gas market that is dominated by long-term contracts with indexed pricing mechanisms to a competitive market environment with short-term contracting and market-based pricing schemes does not happen overnight. Both in the United States and the United Kingdom, this contractual transition to nearly 100% market-based pricing schemes took around a decade and sometimes longer (Stern and Rogers, 2011).

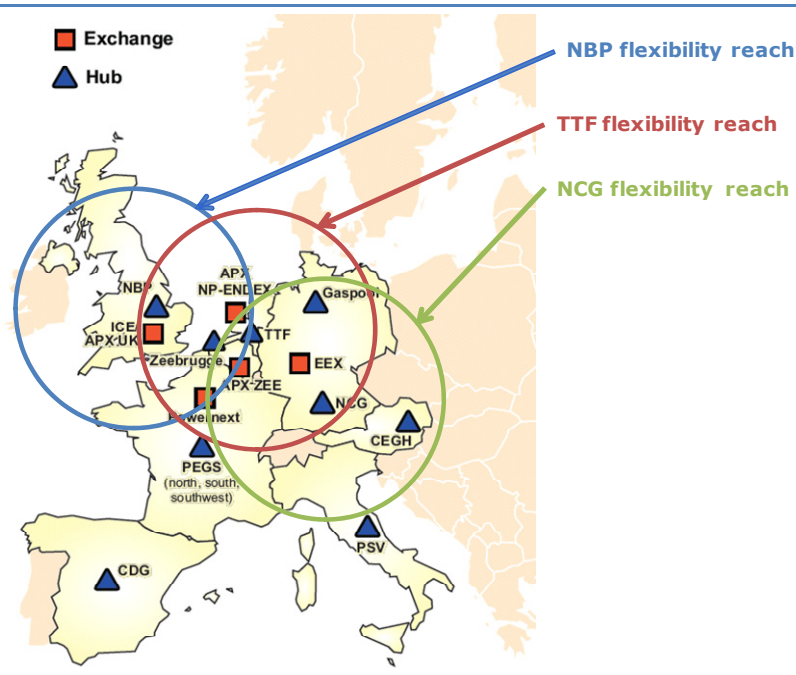
Hubs as a source of flexibility in natural gas markets

Despite the introduction of concepts such as virtual hubs, paper trades and forward curves, natural gas trading is fundamentally a physical process that needs a capital-intensive, physical

infrastructure. The number of physical connections between a national area serviced by a natural gas hub and other markets determines the supply and demand options on that hub. An increasing number of interconnections with other areas (both LNG and PNG) allows for increased competition in a market and subsequently supports the functioning of the natural gas market.

In a no-market gas supply environment, flexibility instruments are essentially used by the TSO/national gas company to adjust to changes in the demand and supply level in the network. The TSO has various tools at its disposal, such as swing in supply (domestic production, pipeline imports and LNG), underground storage (both short- and long-term), interruptible contracts and line-pack.²⁹ These are all used by the TSO/national gas company to keep the network in physical balance, frequently within safety margins set by the government (IEA, 2002).

Figure 25 • Sale of flexibility services through virtual hubs in Europe



Source: GasTerra B.V., 2010.

TPA is essential for the development of competition and introduces a separate valuation for transport capacity and commodity in the area serviced by the trading hub. Through TPA, trading hubs will provide additional instruments for network balancing, with the following consequences:

- As shippers can buy or sell their supply imbalances to other market participants, this will reduce the amount of flexibility instruments that a TSO needs to guarantee network integrity. The natural gas hub will provide balancing incentives through the gas price that stimulates market participants to adopt their supply/demand patterns accordingly.
- A well-functioning natural gas hub will provide an incentive to invest in flexibility instruments – considerable volatility in certain gas products might signal the opportunity for storage developers to build the required capacity, for example. Considerable spreads between summer and winter products on the futures markets would signal an expected shortage in seasonal swing in the market. This signal would provide the incentive to develop extra seasonal swing through UGS in depleted gas fields. Similarly, considerable volatility on the spot market should provide an incentive to develop more short-term UGS through aquifers and salt caverns.

²⁹ Line-pack: the ability of a gas network to absorb pressure differences as a result of shifting demand/supply patterns. The bigger the network the bigger line-pack that is available to absorb changes.

- A price signal that shows the expected flexibility requirements to market participants not only provides an incentive to develop additional UGS, but will also provide financing. A well-functioning natural gas exchange will provide a more solid business case for financial parties to support parties that develop UGS to sell capacity to market participants. However, overall confidence in the price signal will be crucial for financial parties to support investments in flexibility infrastructure in competitive markets. This makes the participation of financials in virtual trading on the spot and futures market an even more crucial issue to support trust and further financial participation in the physical market.
- Finally, through the interconnections with other markets and the availability of a price for transport capacity, parties find that the area serviced by the hub can increase significantly beyond the national boundary of a market. Through separating the price for commodity from flexibility, both become available for other parties in a connected market, and if they are priced advantageously, they will be introduced across the national border (or can be imported from beyond). In Europe, flexibility products offered from a virtual trading hub can expand into a geographic area of roughly 1 000 kilometres in diameter.

Price interaction with other gas markets

As a gas market moves from a non-competitive to a competitive situation, alternative sources of natural gas will be offered to wholesale consumers (in addition to long-term contracted gas). This offer can extend to customers in connected markets (unless explicitly forbidden through regulations, or made very costly through entry/exit requirements). The combination of TPA and physical connections with other market areas will thus spread competition across national borders.

Before 2009, there have been considerable price convergences across the Atlantic between Henry Hub and NBP. The United States and United Kingdom both have a clear price level and TPA to some regasification terminals, a situation that provided for considerable arbitrage opportunities (IEA, 2006). As a result, the respective natural gas prices remained within a margin of USD 2 to USD 3/MBtu for a long period. Natural gas prices started to decouple only after shale gas virtually eliminated demand for LNG in North America and a lack of LNG export capacity in the United States (with the exception of one single facility in Alaska) physically limited arbitrage with the rest of the world.

A pipeline connection between markets might be of even greater value than LNG, as it would generally be less costly to make use of arbitrage opportunities (provided capacity is available at a competitive price). In the United States, arbitrage in the natural gas market has shown to be so effective that differences between various physical hubs' prices have simply reflected transport costs.

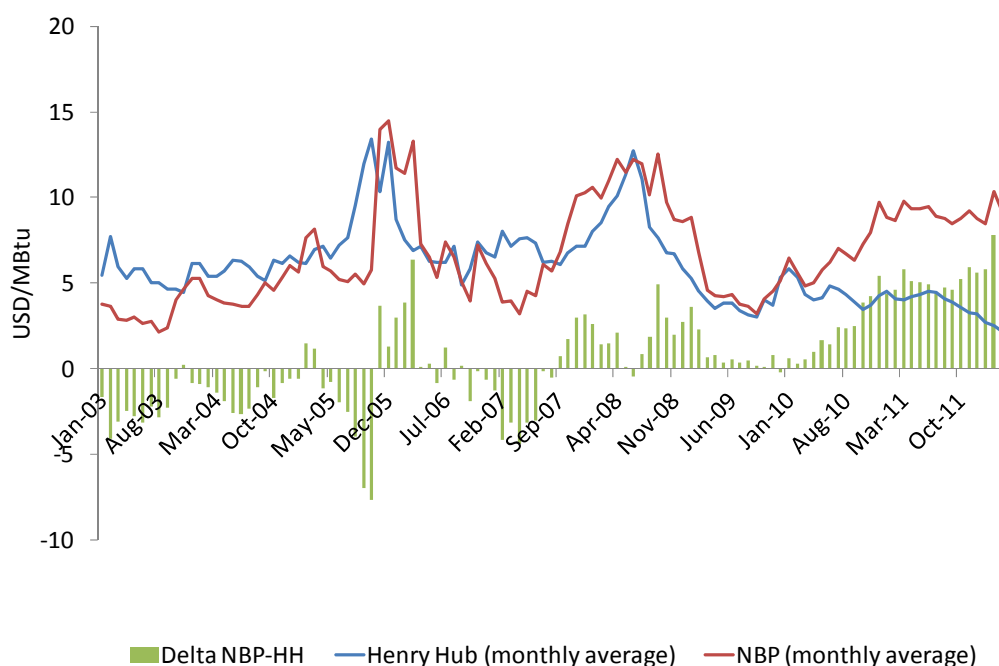
These examples show that the simple existence of an alternative hub increases the options for regional natural gas consumers, affecting the pricing environment beyond the borders of the competitive market.

It is generally expected that the various hubs developing in Europe today will converge to one price level, as regulatory regimes across Europe align in the future. In fact, despite the lack of a well-developed network code that describes capacity allocation between national gas markets, prices already converge considerably between various European natural gas markets (EER, 2010).

Analysis has shown that the relative law-of-one-price (LOP) holds in the Northwest European gas market: prices at various European gas hubs move in harmony. This is a consequence of the alternative supply option that will always "loom" over a gas market, even if it is not directly connected by pipeline (for example, NBP and NCG, which are connected via the TTF or the Norwegian supply system). Systematic price differentials will continue to exist as a result of difference in

transport costs and capacity availability, but a relative LOP analysis has shown that prices return to their relative level rather quickly between all Northwest European markets.³⁰

Figure 26 • Price development in the Atlantic Basin, 2003-12



Source: IEA database.

Several factors support price co-integration between natural gas markets in Europe. First, there is a continuous effort to increase the ease by which natural gas can be traded between markets (although it is still far from perfect) (IEA, 2012a). Then, there is the continued integration of various national balancing zones, which provides for increasing volumes traded on one single hub and better functionality. Finally, there is the existence of a flexible supply source in Norway that can arbitrage between all major European hubs directly, allowing prices to return relative quickly to their relative price levels on a day-ahead basis.³¹

Implications for Asia-Pacific

On the whole, the trans-Atlantic and European developments have shown that no perfect regulatory regime needs to be in place and not all markets have to be considered well-functioning to support a price effect beyond the national boundaries of the area serviced by a hub. In the case of Asia-Pacific, this would mean that if a functioning wholesale market were to be realised, the price effect would be felt in other markets, even if these other markets were in a different stage of development with regard to competition. Likewise, if LNG were to become a flexible source of supply with easy access to all of the various national markets in the Asia-Pacific region, this cross-border effect of competitive pricing would most likely be strengthened.

³⁰ The markets under review were NBP (United Kingdom), Zeebrugge (Belgium), TTF (Netherlands), PEG-Nord (France) and NCG and Gaspool (both in Germany).

³¹ The Norwegian pipeline supply system is directly connected to the following hubs: NBP, Zeebrugge, PEG-Nord and Gaspool.

Market maturity: when is a liquid gas market truly liquid?

As outlined above, increasing competition among natural gas suppliers and consumers in a market area is key to establishing a functioning wholesale market. The effective functioning of a competitive trading hub will result in the high confidence among market participants, indicated by increased usage of the market as the primary platform for natural gas exchange.

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After the outlined institutional and structural reforms begin to take place, will a functioning wholesale market emerge? Will the absence of a move towards a more functioning wholesale market confirm that the liberalisation process was flawed, or would other structural issues be to blame? In general, two factors need to be considered very carefully before judging gas market reform a success: confidence and timing.

Several factors could influence market parties' willingness to switch from the "old" natural gas market to the "new" competitive natural gas market. An example would be government pressure, whereby the government in essence mandates parties to start trading through a gas hub. Although this would be a fast way to force parties to use the natural gas hub, it would hardly create favourable conditions for sustainable market development. This would most likely incur considerable commercial litigation and eventual penalties for commercial parties involved that would interfere with their existing contractual obligations. It is unlikely that direct government pressure on market parties would lead to a sustainable competitive gas market.

A government would be more likely to inspire confidence if it met the institutional and structural requirements, and made a natural gas hub as attractive as possible by lowering barriers to entry (costs, infrastructure, bureaucracy) and increasing overall transparency (market data publicly available). The liquidity of a market is generally considered a fair indicator of market parties' confidence in the functioning of a hub and its ability to generate a representative price.

Generally, market liquidity is referring to the easiness to trade an asset. However, it is nearly impossible to express a level of liquidity in one all-encompassing indicator that accounts for market size, number of market participants, churn factor, number of products offered, and the bid-ask spread. In addition, all indicators represent the current state of affairs, and do not necessarily denote future development.

Different indicators are used to indicate a market's ability to function and set a reliable price. Each has its drawbacks.

- **Nominated volumes to a hub:** this indicator would compile all the nominated volumes on a hub as published by the TSO to show usage of the hub in the gas market. The value of this indicator would depend considerably on the practice and methodology of the TSO and thus would not provide an undisputed measure for hub attractiveness.
- **Volumes traded on exchange (supplemented with OTC):** this would give an indication of the usage of the hub in the future, as the exchange-traded volumes are also traded on the forward curve. However, as these volumes do not include OTC trades, which might be a far more successful method of trading on a hub (due to lower costs for market participants), this indicator would reflect the trading reality for both the spot and futures markets. A significant drawback, however, is that data on OTC trades is generally specialised data only available for market parties, which thus limits its general and widespread applicability.
- **Churn rate:** the most basic measurement of the liquidity in a spot market is measuring the churn rate, the traded volume of natural gas divided by the physical volume of gas delivered at the hub. The biggest uncertainty in using churn as a measure for liquidity is the subjectivity of the number, as there is considerable debate on the methodology and which churn rate actually represents a liquid market.

- **Trade horizon:** another indicator would be the time horizon on which products can be traded on the futures market. Increased trade in products later in the future should indicate that a market is moving away from the balancing function and has the ability to generate a price signal for delivery of gas in the future. However, a longer time horizon says little about the market depth and tradability of the products on the curve. By itself, it is generally considered a meaningless indicator.
- **Bid-ask spreads:** measuring the bid-offer spread for a product would indicate the tradability of individual products. The smaller the spread between the bid and ask prices, the better supply and demand are aligned. Measuring the bid-ask spread is frequently used to compile a tradability index that compares the number of products on the curve and their respective spread. Despite the insight this provides on product availability on the curve and the performance of one market versus another, it does not provide a clear definition of what level of spread is considered to mark a liquid product (except as small as possible).

Other quality indicators include: support of the incumbents, market makers, time-to-market, level of competition between OTC brokers, the number of registered members, quality of the market model, quality of services and overall system costs (Powernext, 2011). It is clear that none of the indicators on its own will express overall confidence for all market parties.

It will be the overall package that will persuade market parties (both physical and financial) to support the ongoing process of increasing competition. Confidence in the continuity of this process should be nourished and supported by increased transparency in the gas market. The timely publication of relevant and consistent data on the natural gas market by the exchange operator, TSO and regulator is essential for increasing transparency. The relevance of the data that is published should be secured through regular debate between market parties, TSO(s) and regulator(s) (Heather, 2012).

Setting the pace of change: the role of a regulator

One final important issue in a market that is developing into a competitive market is the changing role of the regulator, which is closely linked to the expected pace of reform. A government's role in a developing market will change from being a market participant (through its state-owned entities), to a market authority (monitoring market development and enforcing competitive behaviour) and will finally create a role for financial authorities, as well.

As this process frequently starts with a deliberate decision from the government to open up a market for competition, it is regularly expected that the result of this process will look a certain way (in the case of Europe, the United States is frequently taken as an example) (EER, 2012). These expectations are usually translated into expectations on how any of the indicators outlined above will develop. Answering the questions of when a trading hub is liquid and whether a hub is working well depends largely on these expected results. However, the ambition of regulators to deliver on expectations is also a considerable regulatory risk for market parties.

A regulator might be persuaded to "reregulate" when an outcome is not what was initially desired, increasing regulatory uncertainty for market participants. Therefore, the timeframe that a regulator sets itself to further market reform is critical for the overall process. Frequent changes in market rules to achieve a desired result more quickly might deter further participation from market parties, defeating the regulator's overall objective. Both the industry and the government need a realistic expectation on the timeframe in which results can be expected.

A clear pacesetter for gas market liberalisation is the scale of financial liabilities that will need to be unwound in the process. An efficient, economic path needs to be established because forced change to contractual structures carries significant financial risks for both companies and

economies. As shown in Chapter 2, adapting general contracts to new market circumstances took about a decade in the United States and the United Kingdom. For a regional system such as the European Union, which would involve even more governments, regulators, TSOs and commercial parties, it is likely to take longer (Stern and Rogers, 2012).

Future (regional) Asian trading hubs and their regulators will therefore have to take into account that increasing competitiveness in a natural gas market will take time, and will in all likelihood take more time when more governments are involved. A realistic timeframe in the government's and/or regulator's conveyed expectations to allow competition to develop will reduce regulatory uncertainty and benefit the transition process towards a more competitive natural gas market.

A transparent and competitive price for natural gas

The main requirement for a transparent natural gas price is the introduction of competition in the market, thereby moving from a non-competitive market to a competitive natural gas market at the wholesale level.³² An increase in competition among suppliers and consumers requires institutional changes initiated by government, and monitored and enforced by the government/regulator.

A competitive wholesale market requires a hub to facilitate ownership exchange of natural gas between market parties, both spot and future. The introduction of exchange-based trading will likely increase the financialisation of natural gas trade, making natural gas a financial derivative as well as a physical product. The resulting market price should reflect both the physical and financial market players' expectations of the price level a market is moving towards at a certain time in the future, thus reflecting current *and* future supply and demand in that market.

The impact of a natural gas trading hub is felt in the broader natural gas market, as it requires both consumers and suppliers to review, revalue, and ultimately rewrite business practices as has been (frequently) done since the invention of the industry. Generally, a shift from long-term to short(er)-term focus of the business will emerge, with adapting contractual and investment schemes likely to follow. This process may take at least a decade for national markets with a clear regulatory authority – and longer for more regional initiatives, due to the increased number of stakeholders involved.

When properly set up, gas-to-gas pricing in a market can deliver transparency on the state of the market and its investment requirements that is unsurpassed by oil-indexed alternatives for gas pricing. This confidence lies ultimately in the long-term resolve of governments to allow markets to determine a natural gas price without letting political considerations get in the way in the short term. Strengthening the role of a (preferably independent) regulator with a clearly defined anti-trust mandate in both the financial and physical area of the natural gas market will increase confidence of market parties and their willingness to play a full part in the market.

³² Introducing competition down to the retail level is not strictly necessary for a reliable price signal on natural gas trading hubs, but it will give residential consumers the benefit of choice.

4. Perspectives on Asian gas hub development

The ability of natural gas to effectively compete in an energy mix would be greatly enhanced if the price setting were competitive. However, because most Asian nations have, or will have, a considerable import dependency it frequently occurs that overall security of supply considerations take priority over price considerations in energy policy making.

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Overcoming the security of supply rationale that drives companies to pay oil-indexed prices for their long-term supplies will be a challenge. As global natural markets are forecast to tighten in the short term, governments will experience increased urgency to secure volumes of natural gas for their respective economies.³³ This zero-sum game reflex has so far limited a further drive to increase competition in these wholesale natural gas markets.

Future challenges to the energy sector as a whole might give an impetus to competition, as the main role of natural gas in the energy mix of several Asian nations might be flexibility. Several economies in the Asia-Pacific region will have to adjust to new realities in their energy mix in the near future. Although the challenges differ broadly among Asian-Pacific nations (*e.g.* reducing coal consumption, replacing nuclear power, or facilitating imports to prop up the supply/demand balance), all the ambitions critically hinge on the ability of natural gas to provide a flexible source of energy.

As the outlooks for various scenarios depend greatly on government decisions, energy markets are not likely to develop in a smooth fashion. On the contrary, it seems far more likely that energy mixes across the world will experience considerable shocks induced by shifting government priorities. Trading hubs for natural gas can be used as a source of flexibility in the Asian gas markets, allowing for cost-effective adaptation of companies' portfolios to mitigate the impact of external (government policy-induced or other) shocks to the energy mix.

As described in Chapter 3, creating a competitive natural gas market will involve a rigorous process that demands fundamental change from both industry and government actors in the natural gas sector, as well as attracting new participants. As there are no functioning wholesale natural gas markets in the net-importing nations of the Asia-Pacific region today, perspectives for such competitive markets to emerge will be assessed at the level of the institutional and structural requirements for a competitive natural gas market set out in Chapter 3.³⁴

Perspectives: consumers in Asia-Pacific

As Asia-Pacific is a region that encompasses various national gas markets in various stages of development (no market, developing and mature), this working paper presents analyses of four economies in the region that are broadly representative of the challenges that various economies face in creating a secure, affordable and environmentally friendly energy supply.

The Asian-Pacific market is a patchwork of diverse economies with similarly diverse natural gas markets and overall energy sectors. This analysis will limit itself to Korea, Japan, China and Singapore, but the range of issues explored below is representative to varying degrees of the other countries in the market.

³³ In IEA (2012a), the global gas market is tightening in the short term, while a wave of Australian supply is expected to loosen global markets beyond 2015.

³⁴ Six requirements: a hands-off government approach, separation of transport and commercial activities, price deregulation at the wholesale level, sufficient network capacity and non-discriminatory access to networks, a competitive number of market participants, and the involvement of financial institutions.

Japan

Japan was traditionally the largest natural gas-consuming market in Asia-Pacific, only recently overtaken by China. It will remain the largest LNG-importing economy for the foreseeable future, as it is an island economy with very limited domestic production and without pipeline connections to other markets. The March 2011 East Japan earthquake and subsequent Fukushima nuclear accident created considerable security of supply concerns about the Japanese nuclear-focused energy policy.³⁵

As a consequence of the Fukushima accident, the outlook for natural gas demand in Japan depends heavily on how much of the now idle nuclear capacity (if any) will be allowed to come back online in the future. With discussions on a new energy policy for Japan ongoing, overall energy policy development in Japan is most likely to be defined in terms of a pre-Fukushima and a post-Fukushima era.

Whatever the outcome of the current policy debate, it will have a significant impact on the natural gas sector, as carbon constraints will likely allow only low carbon energy sources to replace nuclear power generation. A recently published analysis of the effects of Fukushima on Japanese LNG demand beyond 2012 modelled a spread of around 10.6 million tonnes of LNG (14.4 bcm) between a re-nuclearisation and de-nuclearisation scenario. The effect of this single policy decision would (despite national energy conservation efforts) have an effect amounting to 15% of total LNG consumed in Japan in the pre-Fukushima era (*i.e.* 69.8 million tonnes or around 95 bcm of LNG in 2010) (Miyamoto, Ishiguro and Nakamura, 2012).

Before the Fukushima accident, Japan was considered a mature natural gas market, as Japanese LNG imports were expected to gradually decline towards the year 2030. Increasing competition would then most likely create considerable benefits, as infrastructure investments have been amortised. The Fukushima accident made it likely that natural gas demand will increase considerably in the medium term, which will require considerable investments in Japan's natural gas infrastructure.

Before Fukushima, the power sector represented 60% of total natural gas demand. This is estimated to have increased to around 65% in 2011. Given this important share of demand, changes on the gas market will be considerably hindered if competition is not introduced in the power sector. Experience with the opening of the European power and gas markets suggests that vertical integration of power generation is a very important new source of competition in gas markets. Likewise, well-functioning competitive wholesale electricity markets create pressure for the gas markets as well, through the need to reduce costs. Moreover, electricity or gas utilities with pre-existing retail portfolios are well positioned to bypass the entry barriers that exist at the retail level; consequently, a well-functioning competitive electricity market would greatly enhance the chances of establishing a liquid gas hub.

A hands-off government approach?

In parallel with the debate on the Japanese post-Fukushima energy policy, the role of the government in the Japanese energy sector will in all likelihood be reassessed. Additional impetus to this discussion is provided by the *de facto* nationalisation (for ten years initially) of the power company Tepco in the wake of the Fukushima accident; as well as the company running Fukushima, Tepco is a considerable LNG importer for its power plants. It is currently very unlikely that the Japanese government's involvement in the power sector will recede (Miyamoto, Ishiguro

³⁵ For a detailed account of Japan's natural gas market and policies before 2011, see: Miyamoto (2008).

and Nakamura, 2012). This increased involvement in downstream power markets will undoubtedly spill over into the gas market, as the power sector had been consuming about 60% of total gas consumption before the Fukushima accident (IEA, 2011b).

Similarly, the traditional focus of government policy on supply security in energy policy making has led to government involvement in accessing upstream development through the state-owned Japan Oil, Gas and Metals National Corporation (JOGMEC). JOGMEC is mainly a government vehicle for Japanese companies to reduce exposure to exploration risk: it seeks to create “a stable supply of natural resources for Japan” (JOGMEC, 2012).

The Japanese government actively encourages utilities to leverage buying power on the global LNG market through combined procurement of long-term LNG supplies; a partnership with Korea’s KOGAS is periodically considered (WGI, 2011a). Although this is frequently resisted by large LNG importers because it does not increase their domestic competitiveness (due to the end-user pricing scheme),³⁶ it does signify the government’s continued commitment to involvement in the supply of natural gas to Japan at every level of the value chain (WGI, 2011b). Despite past efforts to liberalise the gas sector domestically, the aftermath of the Fukushima accident will most likely deter any further efforts in the near future.

Separation of transport and commercial activities?

The Japanese natural gas transport and distribution infrastructure is owned and operated by vertically integrated private gas and power companies. Although a functional unbundling is required under Japan’s Gas Business Act of 2004, the regime has been lenient compared with European and United States regulations, as no legal unbundling is required. This has had limited effect on separating decision-making for transport and sales.

Moreover, there is no mandatory functional unbundling for LNG infrastructure. This further limits the separation of activities to the domestic trunk pipelines and distribution sectors in the value chain (Ming-Zhi Gao, 2010). Some LNG is redistributed to satellite terminals by domestic LNG vessels that improve regional distribution of LNG in Japan. However, this makes regional distribution companies considerably more dependent on supply from bigger utilities. This, in turn, makes overall distribution even more dependent on the commercial activities of a few LNG importers.

Price deregulation at the wholesale level?

Since 1955, the Japanese government has set its natural gas sector on a trajectory towards wholesale price deregulation. The government introduced legislation for both the power and gas industries to increase freedom of choice for consumers. This has resulted in the gradual introduction of freedom of choice for big consumers (>2 mcm/annum) in 1995, for consumers larger than 1 mcm per annum in 1999, larger than 0.5 mcm per annum in 2004 and larger than 0.1 mcm per annum in 2007. In effect, wholesale price deregulation has been established in Japan.

In November 2012, the Japanese government announced that it proposes to create an LNG futures market that sets a price based on supply/demand factors (Shimbun, 2012). The Japanese Ministry of Economy, Trade and Industry (METI) is to consult with 18 companies (power and gas utilities, trading companies and financials) to establish a futures market that allows companies to hedge against future price fluctuations. The consultation should be finished before March 2013, while listing on a commodity exchange should start as early as April 2014.

³⁶ For a retail pricing regime, a cost plus profit scheme sets procurement costs of natural gas at the average import costs for LNG for all Japanese utilities. This has generally provided an incentive not to engage in consortium buying with other companies, as this would reduce the ability to gain a competitive price advantage in relation to other gas companies.

Although the outcome and final structure are currently unclear, METI's decision is a very encouraging sign. A wholesale LNG price reflecting supply/demand in a market the size of Japan's would have considerable impact on natural gas pricing in the region. It would also constitute a break with the traditional Japanese focus on long-term supply contracts with oil indexation. However, the current focus on the price level of imported LNG (especially on lowering prices towards European and United States' price levels) could lead to disappointment with policy makers, as in a competitive market, lower prices are never guaranteed. The focus on price level seems to neglect the benefits of a price-setting mechanism that could create greater transparency and efficiency for the mature Japanese natural gas market.

In the power sector, despite the 1995 Electricity Business Act and the subsequent introduction of freedom of choice for nearly 60% of the market, the incumbent power companies have retained near-monopolies in their generation and retailing businesses. As highlighted in Japan's *Energy Policy Review* in 2008, Japan has undertaken a stepwise approach to market reform. But "competitive pricing is the cornerstone in an incentive-based market framework and it is the feature that allows market participants to communicate and interact in a way that delivers optimal outcomes – pricing is the glue of competitive markets" (IEA, 2008b).

Sufficient network capacity and non-discriminatory access to networks?

Currently Japan has an annual import capacity of around 250 bcm compared to natural gas demand of 123 bcm in 2011. Third party access to trunk pipelines and distribution networks was introduced in 2004 and is to be individually negotiated by parties proposing to supply customers. However, for LNG terminals, the requirement for TPA is deemed only desirable, limiting the obligation for companies to engage in negotiated TPA. Some companies have developed guidelines, but in general it has proven difficult to establish TPA at LNG import terminals, as these are developed to fit an importer's specific supply portfolio and subsequently the sales portfolio requirements in the hinterland. The lack of interconnections between regions then further limits the ability to increase competition through TPA.

Number of market participants?

The Japanese natural gas market has a considerable number of LNG importers (seven power companies, eight gas companies and several industrial importers). LNG imports are dominated by power companies that mainly use LNG to supply power stations (62% of total LNG imports in 2010). Gas companies imported 34% of total LNG supplies, while large industries imported around 4% of total deliveries. There are around 200 local gas utilities active in selling natural gas to end consumers in the Japanese city gas industry.

However, these companies purchase their gas from the larger gas and power companies that import LNG. As four major gas utilities (Tokyo Gas, Tepco, Osaka Gas and Chubu Electric) imported nearly 71% of total LNG deliveries in 2010, their price-setting ability is considerable. Despite the large volume of natural gas annually consumed in Japan and the considerable number of parties active in the sector, the lack of an interconnected pipeline infrastructure and limited, non-discriminatory TPA on LNG import terminals limit the market's competitiveness.

Involvement of financial institutions?

Japan has currently no trading hub on which natural gas companies can buy and sell natural gas; therefore, there are no natural gas derivatives that financial companies can trade on either a spot or futures market. Although the Japanese government has signalled the intent to create a futures market with the specific aim to provide tools to manage commodity volatility, it is currently unclear how this mechanism would function and whether financial institutions would participate.

This limits the role of the financial institutions (public and private) to providing capital for infrastructure investment (both upstream and downstream) in the natural gas sector.

The Republic of Korea

Natural gas consumption in Korea has grown rapidly over the past decades, primarily driven by continuous economic growth. Development of the Korean gas sector has been driven by the creation of the state-controlled Korean Gas Corporation (KOGAS) in 1982, which set out to diversify Korea's economy away from its dependence on coal and oil.

As a result, the first LNG cargoes arrived in 1986 and natural gas consumption grew at an impressive 14% annually, from 3.2 bcm in 1990 to nearly 45 bcm in 2010 (IEA, 2011b). The growth in natural gas consumption is projected to slow to around 1.8% per annum until 2024, reflecting the increasing maturity of the Korean natural gas sector (MKE, 2011). Natural gas consumption is dominated by the power sector, with 44% of consumption in 2010, while the residential sector consumed a substantial share of 28%.

This growth in demand has been met by LNG imports and a small volume of domestic production from the small offshore Dohngghae-1 gas field developed and operated by the Korean National Oil Corporation (KNOC). Currently under discussion is the usage of the Dohngghae gas field as an underground storage site from 2017 onwards. Korean natural gas imports are dominated by LNG imports by KOGAS (with one LNG terminal operated by another company, POSCO).

Korea has a natural gas infrastructure that is similar to the European market's, with an integrated high-pressure pipeline network and considerable seasonal flexibility requirements due to temperature-related changes in demand from the residential sector. Korea currently lacks underground storage and pipeline import alternatives to LNG and has to meet its seasonal requirements exclusively from the LNG supply chain.

KOGAS has several flexibility instruments at its disposal to make supply meet seasonal demand:

- high-cost, strategic onshore storage;
- spot purchases on the global LNG market. KOGAS is one of the most active buyers on the global LNG market during the winter (Stern, ed., 2008);
- LNG cargo swaps with other companies that have the opposite seasonal requirements, frequently Japanese power companies (Gas Matters, 2006a); and
- participation in upstream LNG developments, enabling it to match the required supply to the domestic market.

Although Korea currently lacks the underground storage facilities to accommodate swings in seasonal demand, it has successfully used its vertically integrated business model to provide security of supply. The establishment of the Korean gas market is the result of the government's strategic decision to develop a natural gas market in 1982. This has propelled the natural gas market beyond the intensive growth phase into what is now a mature natural gas market.

Hands-off government approach?

In 2001, the Korean government announced an initiative to split up state-controlled KOGAS (the government currently owns 26.86% of the shares) into three privately owned marketing companies and one publicly owned infrastructure company.³⁷ However, since 2002, liberalisation of the Korean gas sector has been progressing at a snail's pace.

³⁷ The Korean Electric Power Company (KEPCO) owns 24.46% of the shares, local governments own 9.59%, while the other 60% of the shares are publicly listed.

The Korean zeal for gas market liberalisation waned after shortages in the early 2000s that were blamed on KOGAS's inability to conclude long-term import contracts (Stern, ed., 2008). Korea's government continues to support direct LNG import ventures such as the 2005-opened Gwangyang terminal that delivers directly to industries and power companies.

However, security of supply policy remains a top priority for the government and KOGAS takes a pivotal role in this policy. The Korean government's most recent long-term natural gas supply and demand plan calls for more access to upstream natural gas production and KOGAS's leverage of its buying power on world LNG markets (Moonjong, 2011). It is therefore very unlikely that the plans to privatise KOGAS will be revived in the near future. This will mean that the government continues to exert a commanding influence in Korea's natural gas industry.

Separation of transport and commercial activities?

As the sole wholesaler in Korea, state-controlled KOGAS is in charge of natural gas imports, storage and transmission. Despite the existence of a fourth LNG import terminal independent from KOGAS, the subsequent transmission network is also owned by KOGAS, effectively leaving no room for separation of commercial activities from transport.

Price deregulation at the wholesale level?

KOGAS and the subsequent city gas companies that distribute the natural gas to customers and industries pass on price changes with a two-month time lag. Wholesale prices for power companies and city gas distributors have to be approved by the Ministry of Commerce, Industry and Energy (MOCIE), whereas local prices for end consumers must be approved by regional governments. This makes the Korean wholesale price scheme an effective Regulation Cost of Service (RCS) pricing scheme, with no price deregulation at the wholesale level.³⁸

Sufficient network capacity and non-discriminatory access to networks?

LNG is supplied by KOGAS, which operates the three main import terminals with a combined import capacity of around 100 bcm annually. KOGAS is required to reserve 22% of annual consumption by 2017 in its domestic regasification terminals (that level is currently 16%). This obligation gives KOGAS a dominant role in guaranteeing sufficient network capacity to accommodate overall demand and seasonal swing in the Korean gas market.

In 1999, the Korean government tried to introduce an open-access regime for the Korean natural gas network. At first, a regulated TPA regime was considered (under supervision of the Korean competition authority – not MOCIE), but this failed to materialise. Subsequently, a negotiated TPA regime was introduced for companies that wanted to directly import LNG (and had MOCIE's permission to do so) and needed to use KOGAS's facilities. The companies that want to import LNG directly can only do so for their own use (and are thus not allowed to resell), must have adequate storage capacity available and must have completed negotiations with KOGAS covering use of infrastructure (Ming-Zhi Gao, 2010).

The process of negotiated TPA has proven very cumbersome, as demonstrated by the steel company POSCO, which sought to import LNG for its own use. After obtaining permission from MOCIE, access negotiations to KOGAS's LNG terminals and pipelines failed and POSCO decided to build its own regasification terminal. In 2005, POSCO imported its first LNG cargo supplied from BP's Tangguh project through its Gwangyang terminal that represents 2% of total Korean import capacity and is dedicated to directly supply two industries and one power station (POSCO, K-power and GS Caltex).

³⁸ The major exception being the industries that purchase LNG on world markets through the Gwangyang terminal.

In April 2012, the Korean power company Korean Midland Power (Komipo, which is a KEPCO subsidiary) concluded a 0.4 mtpa ten-year supply contract with trading company Vitol to supply its power stations. It will import this volume through the POSCO terminal because a considerable obstacle to accessing capacity at KOGAS's terminals was that capacity has to be applied for five years in advance (WGI, 2012).

The inability of companies to resell their imported LNG in the Korean gas market and cumbersome access negotiations for KOGAS's LNG terminals are considerable barriers for natural gas suppliers.

Number of market participants?

KOGAS has a monopoly on natural gas sales through 98% of LNG import capacity, while the fourth Gwangyang terminal so far has only four customers (which are not allowed to resell their imported LNG). This currently creates a *de facto* monopoly for KOGAS as a supplier of natural gas for distribution companies. There are currently 30 city gas companies and 14 power companies that buy natural gas from KOGAS.

Involvement of financial institutions?

Korea has currently no trading hub on which companies can buy and sell wholesale natural gas; therefore, there are no natural gas derivatives that financial companies can trade on either a spot or futures market. This limits the role of the financial institutions to provider of finance for infrastructure investment (upstream and downstream) in the natural gas sector.

China

The story of the developing Chinese gas market has come under intense scrutiny as a Chinese gas market barely existed two decades ago (15 bcm in 1990). Driven by its well-documented economic expansion, natural gas consumption has increased more than fivefold since 2000, growing from around 26 bcm in 2000 to around 130 bcm in 2011. This makes China the fourth largest gas market in the world. Natural gas consumption is expected to grow about 13% annually for the next five years.

The 12th Chinese Five-Year Plan published in 2010 (covering the period 2011-15) outlined China's goal to significantly increase gas usage by 2015. The IEA analysis showed that the planned target might be somewhat overambitious, but estimated that this target (260 bcm, twice as much as China's gas consumption in 2011) could be met in 2017. This ambition is mainly an effort to wean the overall Chinese economy off its dependence on coal for environmental reasons. Gas-fired power generation currently comprises around 2% of total power production in China. However, Chinese natural gas demand will increase across all sectors (residential, industry, and power) with each sector consuming roughly one-third of natural gas demand in 2017.

In the next five years, natural gas in China will be supplied from three sources: domestic production, pipeline imports from Myanmar and Central Asia, and the global LNG market. Although natural gas production in China will continue to meet the bulk of demand, it is forecast that both PNG and LNG imports will increase as well, delivering slightly less than half of the total Chinese demand in 2017 (IEA, 2012a).

An extensive pipeline network connecting domestic and international production with centres of demand on China's east coast has already been developed, but is still fragmented. However, expanding this network to keep up with the projected growth in demand will be challenging. Both international pipelines connecting Myanmar and Central Asia are owned and operated by the China National Petroleum Company (CNPC), which also operates 90% of the domestic natural gas transmission pipelines. Import terminals for LNG have been rapidly developed as well and are

ideally suited to supply natural gas to the urban coastal regions. Chinese LNG import terminals currently have an import capacity of 29 bcm annually, which, together with terminals under construction will increase capacity to over 52 bcm per annum in 2015.

China will encounter considerable challenges for governments and companies to continue to meet the forecast growth and expand capacity at every level of the value chain.³⁹ As the demand level beyond 2030 is forecast to reach 450 bcm, China's demand will have considerable impact on the Asian-Pacific and world gas markets.

Hands-off government approach?

The Chinese government has a pivotal role in developing the Chinese natural gas market, both at national and local levels. Overall policy ambitions will be set by the National Development and Reform Commission (NDRC) and several other government stakeholders. In addition, the government has a direct stake in every level of the natural gas value chain through the state-owned oil companies (in addition to CNPC, the China National Offshore Oil Company (CNOOC) and Sinopec). Finally, local governments often own shares in the regional natural gas utility companies that are also directly connected with international markets through various LNG import terminals under development.

Although the natural gas market in China has reached an intensive growth phase driven by government policies that support a diversification away from coal and oil, the government is already looking beyond a policy-driven natural gas sector, experimenting with less government involvement in price-setting and opening up technically challenging shale gas resources for international energy companies. However, despite these experiments with market mechanisms and market parties in the natural gas sector, the government's pivotal role in the natural gas sector remains firmly entrenched.

Separation of transport and commercial activities in the natural gas sector?

As the Chinese natural gas sector is in a phase of intensive growth, the overall focus of the industry is expanding its natural gas infrastructure at an extremely rapid pace to accommodate current and future demand. As a result, transport investment is intimately linked with upstream development and subsequent marketing activities from individual companies. There is currently no separation between transport and commercial activities, as these are linked through the activities of vertically integrated natural gas companies, primarily CNPC.

Price deregulation at the wholesale level?

Natural gas prices in China are regulated by central and local governments, which have generally favoured households over electricity producers and industrials. On the whole, the government sets prices for different stages along the value chain (wellhead, transport, ex-plant/city gate) on a cost-plus basis and differentiates between different end consumers (IEA, 2009). Effectively, this has led to an SPR pricing mechanism, which is far from deregulated prices at the wholesale level.

Natural gas has had difficulty penetrating the various regional markets in China (endangering government growth targets), as it was frequently considered too expensive compared to the alternatives of coal and liquefied petroleum gas (LPG) in consuming sectors. This pricing issue has triggered the government to develop regional market reforms in the Guangdong and Guangxi provinces. Under these new pricing mechanisms, city-gate prices are linked to a basket of fuel oil and LPG.

³⁹ A comprehensive report outlining these challenges was recently published: IEA (2012b).

This has effectively led to the introduction of a replacement value pricing scheme down to the end-consumer level. The scheme is expected to be expanded beyond the current areas to Sichuan and the Shanghai area, where exposure to oil-indexed natural gas imports is higher (WGI, 2012b). If this scheme were to be extended across China, it would effectively link wholesale natural gas prices in China to the oil products that they should replace (which would mirror European practices at a similar market development stage).

In December 2010, the Shanghai Petroleum Exchange (SPEX) launched the first LNG spot market in Asia. The spot market was intended to help relieve a tight supply situation, which had occurred in the Shanghai region in winter 2009. Since its introduction, trading has remained relatively low. More recently, SPEX has launched a natural gas “peak shaving” spot market to secure volumes of natural gas for gas-fired power plants during peak electricity demand in the summer. This simultaneously provides an outlet for companies that have contracted relatively expensive LNG. Although the initial volume traded during the summer (July/September) is limited to 100 mcm, it does show the willingness of the companies and the government to look into market-based mechanisms to address constraints in the natural gas (and power) sector.

Sufficient network capacity and non-discriminatory access to networks?

Due to the breakneck pace at which China’s natural gas demand is developing, infrastructure availability is a key concern for companies that aspire to enter the Chinese gas market. As there is no TPA regime and no regulator to monitor the overall Chinese natural gas transport network, individual companies have to negotiate for pipeline access and capacity. This severely limits their ability to supply or procure natural gas from sources other than the incumbent producers and importers.

Number of market participants?

Production of natural gas in China is the effective domain of the three big state-owned energy companies: CNPC, CNOOC and Sinopec. There are several smaller natural gas producers active in the regions, but they depend on transport facilities provided by the big three (especially, CNPC). In the area of transmission capacity, CNPC has a nearly complete monopoly, which limits the options for customers looking for competitive supplies.

There are already a considerable number of commercial parties connected to the grid (around 1 800 companies are members of China City Gas), and this number will continue to grow as the market expands.⁴⁰

However, as more regional utilities start to co-develop LNG regasification terminals, this could increase competition between imported LNG and city gate-delivered gas through CNPC’s pipelines. China is one of the very few economies in the Asia-Pacific region that has PNG and LNG directly competing for market share, which increases overall supply security, but also increases possible competition in the future.

Involvement of financial institutions?

China currently has two spot trading mechanisms, specifically developed to provide a (limited) option for companies to balance their portfolios in winter/summer. This has so far not triggered financial party activity to facilitate trade beyond the spot market. Therefore, there are no natural gas derivatives that financial companies can trade on either spot or futures markets, as market player activity is decidedly physical.

⁴⁰ At least 65% of all urbanised areas connected to the natural gas grid by 2050, according to the 11th Five-Year Plan.

In addition, China has currency and capital controls that limit international financial parties' ability to freely convert the Chinese Renminbi, to repatriate profits and to have financial instruments legally secured. This limits the role of the international financial institutions in commodity trading in China. Domestic financial institutions play a significant (but ultimately restricted) role in financing infrastructure projects (upstream and downstream) in the natural gas sector.

Singapore

As Singapore started to import natural gas in 1992 with the commissioning of the first pipeline connected to Malaysia, the city-state's natural gas story is one of growth rates similar to other developing Asian economies (albeit on a smaller scale). Natural gas consumption grew from 1.3 bcm in 2000 to 8.7 bcm in 2010. It is forecast by the IEA to continue to grow by around 5% per annum for the next five years.

Since Singapore has no domestic gas production, any increase in demand for natural gas simultaneously creates the necessity to increase import capacity. As of 2012, the Singapore import connections have a combined capacity 9.6 bcm per annum (see Chapter 2). The gas distribution network in Singapore consists of two separate gas pipeline networks: the town gas network and the natural gas network. Town gas, which is used for cooking and water heating by residential and commercial customers, is manufactured from natural gas. The town gas pipeline network serves about 50% of the households in Singapore.

In 2006, the Singaporean government decided to develop an LNG terminal to further diversify the state's natural gas supply. In 2008, BG Singapore Gas Marketing (BGSGM) was appointed aggregator to supply the initial 3 mtpa volumes of LNG for 20 years to the terminal. In June 2009, the government announced that it intended to take over the development and ownership of the LNG terminal through the Singapore LNG Corporation Pte. Ltd. (SLNG) to develop, build, own and operate the terminal. BG Group will source LNG supply for Singapore from its portfolio, but it is expected that the Queensland Curtis LNG project will serve as one of the main sources of supply.

In 2010, the Singaporean Energy Market Authority (EMA, 2011) announced the construction of a third storage tank at the SLNG terminal, as the initial 4.1 bcm of annual supply had been fully contracted by consumers. The capacity will then double to 8.2 bcm in 2014, increasing storage flexibility for LNG traders who want to take advantage of Singapore's geographically central location in the South-East Asian gas market. SLNG will be able to accommodate various sized LNG carriers, from large 265 000 cubic metre vessels to small regional carriers of around 10 000 cubic metres. Finally, the LNG terminal will have re-exporting capabilities and will be able to service the broader Asian market, if required.

With moderately growing demand, increasing infrastructure capacity and supply secured from various sources, Singapore's natural gas market can increasingly be considered a mature market located in the centre of a fast-growing demand region.

A hands-off government approach?

Despite being totally dependent on natural gas imports, the Singaporean government has chosen a free-market approach towards both the power and natural gas markets. Liberalisation of the electricity sector and natural gas sector are cornerstones of the current Singaporean energy policy. The Gas Act of 2001 set the Singapore gas sector on a firm course towards deregulation with the unbundling of transport and commercial activities, and oversight entrusted to the independent energy regulator EMA.

More recently the Singaporean Ministry of Trade and Industry (MTI) established its Pricing Energy Right as one of the five key strategies to meet its energy policy objectives. This acknowledged

that a competitive energy market will set the price level for energy in Singapore's economy and will provide a signal for investments in infrastructure and energy efficiency measures. The approach of Singapore towards the natural gas market can be considered as one of the most hands-off in the Asia-Pacific region.

Separation of transport and commercial activities in the natural gas sector?

The Singaporean Gas Act of 2001 separated commercial activities from transportation activities in the gas sector. As a consequence, PowerGas Ltd. divested its commercial activities in 2002. The commercial gas import activities were divested into Gas Supply Ltd. and natural gas retailing into City Gas Ltd. (both were transferred to the state-owned investment company Temasek). In 2008, the network assets of Sembcorp Gas were also transferred to PowerGas Ltd. (Sembcorp Gas retained its commercial import and sales activities). Subsequently, PowerGas Ltd. is the TSO that owns and operates the natural gas network (natural gas and town gas) in Singapore and is regulated by EMA. PowerGas Ltd is now a subsidiary of Singapore Power (SP).

Likewise, the LNG terminal currently under construction in Singapore is the first open-access terminal in Asia and deliberately separates ownership of the infrastructure from commercial activities. It is regulated by the independent regulator EMA. This has effectively separated commercial activities from any activity related to infrastructure in Singapore.

Price deregulation at the wholesale level?

Singapore has deregulated wholesale natural gas prices. However, wholesale prices do still reflect oil price movements, as long-term import contracts with Indonesia and Malaysia are linked to oil. This correlation with oil price movement may change beyond 2014, when the expansion of the SLNG terminal is completed and LNG priced at a different level enters the Singaporean market, further diluting the oil-indexed commodity price set by PNG imports.

Sufficient network capacity and non-discriminatory access to networks?

Third party access in Singapore is guaranteed in the Gas Network Code (GNC) that went into effect in 2008, setting set out the rules for the integrated Singaporean gas network. The GNC establishes a clear framework for network operation, capacity allocation and responsibilities for both the TSO and shippers on the network. It enables open and non-discriminatory access to the gas pipeline network.

The decision to develop an LNG terminal in Singapore will bring Singapore's import capacity far beyond its current domestic consumption requirements. The initial phase of the LNG terminal would require 4.1 bcm of contracted capacity through BG; as this capacity was rapidly taken up, the government decided to expand capacity. In an 8.7 bcm (2010) gas market, the eventual 8.2 bcm capacity of the new LNG terminal will provide a considerable supply capacity addition. In order to commercially operate the LNG terminal, the government needed a way to allow LNG to enter the market.

To achieve this goal, the Singapore government introduced import controls of PNG to allow the build-up of demand for LNG. Import control on natural gas has been in effect since 2006, and allows old PNG contracts to be honoured. New PNG supply contracts are subject to EMA approval and are only allowed for non-commercial and other usages. Other new PNG supplies are allowed to be concluded as a bridging option and will have to terminate before April 2013 (the SLNG terminal is to start commercial operations in May 2013) (EMA, 2011).

A considerable obstacle that remains is how the government will allow gas imports to evolve after the SLNG terminal has commenced operations. Initially, the limits on PNG imports would

not be revised after the LNG terminal started operating. The government has shown a willingness to support competition in the natural gas sector, but stated that it will limit direct competition between PNG and LNG as long as the first phase of SLNG was not fully contracted (EMA, 2011).

As the first phase was fully contracted and construction of the additional capacity of the second phase is fully underway, clarification on the future of the PNG import restrictions is essential for market parties to gain confidence in the competitiveness of the Singaporean gas market over time. In the Singaporean gas market beyond 2013, leaving TPA limitations for new PNG in place could potentially render the Singaporean gas market less competitive than it is otherwise expected to become. Timely disclosure by the government on the capacity allocation for both new PNG and the second phase of the SNLG terminal should greatly benefit confidence in, and competitiveness of, the market.

Number of market participants?

As the Singaporean natural gas market is rather small (around 10 bcm) compared to surrounding natural gas markets, it remains to be seen whether the sales would be able to generate enough liquidity to drive any future natural gas price (if a spot market were to be introduced). Currently nine shippers are active on the Singaporean natural gas market, of which six have booked a total of 2.7 bcm capacity on the SLNG terminal.⁴¹ The Singaporean gas market will be supplied by five gas importers when SLNG comes into operation.

BGSGM was appointed LNG aggregator through a competitive request-for-proposal to carry out the initial LNG procurement for the first phase of SLNG. EMA concluded an aggregator agreement with BG which sets out the pricing details and other terms and conditions for the supply of LNG to Singapore. BG's role as the LNG Aggregator is to aggregate demand for regasified LNG from all end-users of gas in Singapore and to procure LNG supply for these end-users from its own global portfolio. This has considerably increased the number of upstream sources providing natural gas to Singapore, and the subsequent expansion will allow more competitive sources of LNG to emerge.

As mentioned for China, Singapore has the capability to facilitate competition between PNG and LNG, increasing the number of possible upstream competitors (if current import restrictions are properly resolved). The SLNG terminal offers the possibility to service not only the Singaporean market, but through its re-exporting capability, the broader Asia-Pacific region (if economics allow). As LNG regasification infrastructure is slated to expand in the South-East Asian region, this will increase the relevant market area in which SLNG operates and thus the number of competitors for supply and demand.

Involvement of financial institutions?

Singapore is currently one of the biggest oil-trading hubs in the world, leveraging its central location in the growing Asian market. It has been the government's long-standing ambition to become Asia's dominant commodities hub, attracting commodity traders through a Global Traders Programme, which offers tax incentives for companies to set up trading desks in Singapore. This has led to a considerable inflow of energy trading companies.

Natural gas companies have also begun to set up trading desks in Singapore. The presence of various international oil companies secures the availability of financial services to cater to the natural gas trading industry. Financial LNG swaps were introduced by banks in Singapore in 2010. On the back of an already strong commodity trading infrastructure, Singapore is establishing itself as an LNG trading hub even before the physical infrastructure to import LNG is in place.

⁴¹ These are: City Gas Pte Ltd, Gas Supply Pte Ltd., Keppel Gas Pte Ltd., YTL PowerSeraya Pte Ltd., Senoko Gas Supply Pte Ltd., SembCorp Gas Pte Ltd., GMR Energy (Singapore) Pte Ltd., Tuas Power Generation Pte Ltd. and Tuaspring Pte Ltd.

Creating competition in Asia-Pacific natural gas markets

That the Asian-Pacific natural gas market operates within a patchwork of developing and developed economies presents specific conditions for increasing competition in the natural gas sector. Two important issues stand out with regard to governmental attitudes towards national involvement in the natural gas sector.

First, in most natural gas markets, the government considers that its most important role is to guarantee security of supply of natural gas for the economy. While a valid policy choice, this can be detrimental to increasing competition in a natural gas market, as seen in Korea and Japan.

Second, the role of the government in the natural gas market as a market participant through vertically integrated energy companies does limit competition and the economic efficiency in which markets can develop. This can be seen in Korea, China and also Japan, since the nationalisation of Tepco. Government ownership in mature energy markets such as Korea creates considerable barriers to entry and puts a brake on any move toward a competitive market. Similar barriers are observed in China, although at this phase of market development, it is certainly encouraging to see the government initiating (limited) market-based measures to increase flexibility in the gas market.

Even if most natural gas markets discussed above comply to some extent with some of the requirements to increase competition in a market, the current outlook for the emergence of a competitive market remains bleak. The most likely candidate to have reformed its natural gas sector in such a way that a competitive market will evolve is currently Singapore, which complies with nearly all the institutional and structural requirements set out in Chapter 3.

Table 4 • Competitive market requirements in selected countries

Institutional/structural requirement	Japan	Korea	China	Singapore
Hands-off government approach	-	-	-	+
Separation of transport and commercial activities	-	-	-	+
Wholesale price deregulation	+	-	+/-	+
Sufficient network capacity and non-discriminatory access	-	-	-	+
Competitive number of market participants	+	-	+	+/-
Involvement of financial institutions	+/-	-	-	+

Note: "+" = currently contributing towards a competitive natural gas market; "-" = currently not contributing towards a competitive natural gas market; "+/-" = currently unclear.

A concerted effort from the government is pushing for increased competition both from the consumer and supplier side. The Singaporean government has considerable experience in regulating the energy commodity trade because it is already one of the major oil-trading hubs in Asia. The most important factor is that Singapore has a supporting system to facilitate a trading hub with spot and futures markets.

However, so far, no indication has been given by the TSO or regulator that developing a hub that provides balancing services on the spot market (and possibly a futures market) is being considered. The Singaporean government conducted a consultation round to assess different market models in early 2012; a second consultation round has been delayed, and the outcome is thus currently unclear. To develop a Singaporean natural gas trading hub and increase confidence among market parties will likely require the regulator to revise current import limitations on PNG. It is crucial that these issues be resolved in a timely manner in order to allow for a reliable pricing signal to develop in this market.

Although it is questionable whether the volume of the market is sufficient to support liquidity on a spot market, it has been observed in European markets that even a limited price signal in an

insufficiently interconnected market will provide an alternative that has implications beyond the geographical limit of a market. Singapore has certainly positioned itself (both through geography and infrastructure) to expand the effect of a Singaporean natural gas price beyond its borders.

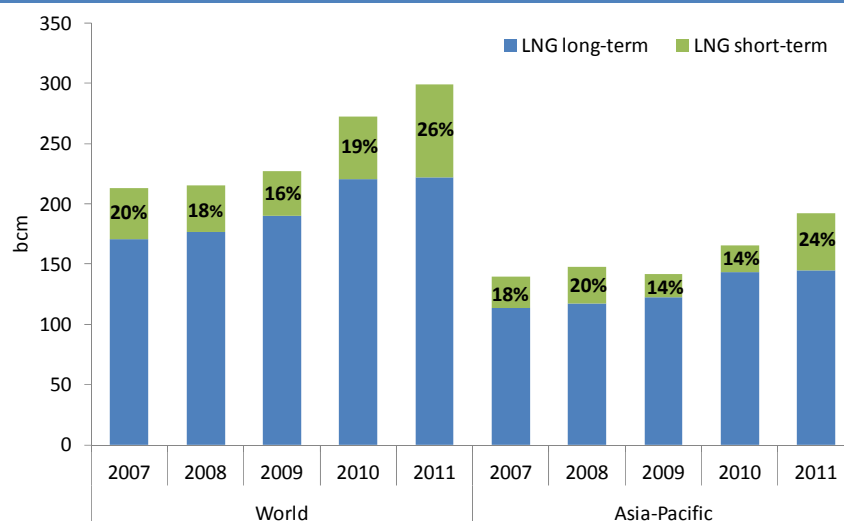
However, the institutional and structural requirements to increase competition are not solely defined by a government of an importing economy. The ability of a competitive natural gas market in the Asia-Pacific region will crucially depend on the ability of the global LNG market to provide flexible and competitive supplies. These will reflect both the changing nature of a competitive spot market with less demand for long-term contractual arrangements and more demand for a short-term oriented, diversified supplier base. However, these are circumstances generally beyond governments' control if they are not willing to engage directly in the global market.

Obstacles in upstream LNG supply flexibility?

In principle, there should be no difference between increasing competition in a natural gas market primarily supplied by LNG and doing so one primarily supplied by pipelines. In the downstream market, this would require the steps set out in Chapter 3. Increasing competition among LNG suppliers, however, would require a change in the global LNG market, which is far more difficult to influence by any one government.

Despite a growing number of regionally dispersed LNG suppliers and the technical ability to send LNG anywhere in the world (provided there is a regasification terminal), the LNG supply chain itself has considerable rigidities that currently limit the free flow of LNG on world markets (Zhuravleva, 2009). The availability of short-term contracted volumes has increased considerably over the last decade, from 5% in 2000 to about 26% in 2011 (Figure 27).

Figure 27 • Long- and short-term contracted LNG in the world and Asia-Pacific, 2007-11

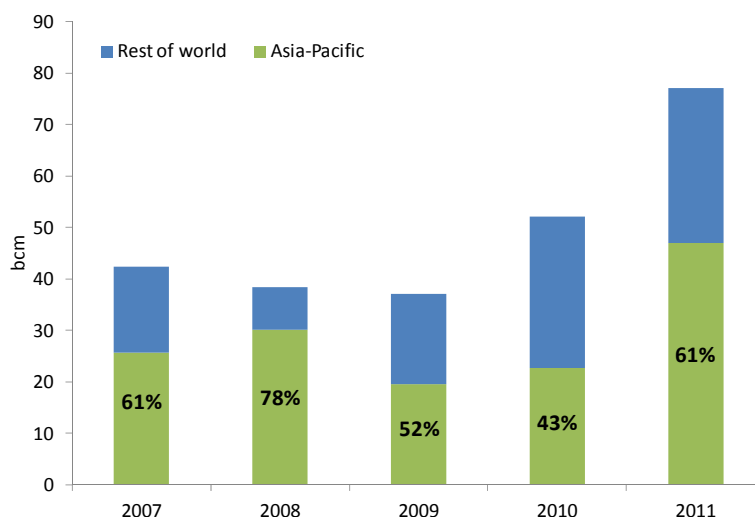


Sources: GIIGNL, 2008; GIIGNL, 2009; GIIGNL, 2010; GIIGNL, 2011; GIIGNL, 2012.

The share of spot volume consumed in the Asian-Pacific market (24% in 2011) lags slightly compared to global spot consumption worldwide (26% of total consumption). The Asia-Pacific region has generally received the largest share of the short-term contracted volumes in the LNG market. In 2011, 61% of the short-term contracted cargoes were delivered in the Asia-Pacific region, a 43% increase compared to 2010. Asian-Pacific short-term imports increased by 52% compared to 2010, which reflected greater Japanese LNG demand after the Fukushima accident and increased Korean and Chinese imports (Figure 28).

This overall increase in short-term supplies in world markets reflects a substantial increase in short-term trading in the Atlantic Basin, as the North American natural gas market is much more competitive. LNG contracting in the North American natural gas market is far more short-term oriented, with 44% of total LNG supply imported under short-term commitments in 2011.

Figure 28 • Short-term contracted LNG in the world and Asia-Pacific, 2007-11



Sources: GIIGNL, 2008; GIIGNL, 2009; GIIGNL, 2010; GIIGNL, 2011; GIIGNL, 2012.

Short-term traded LNG volumes are predicted to increase by 11% annually for the next three years (Poten, 2012). However, a distinction needs to be made between short-term and spot purchases. The term short-term purchases signify volumes contracted for delivery within one to four years into the future.⁴² Spot purchases usually indicate cargoes that are purchased and delivered within one year. Generally it is believed that roughly one-third of short-term contracts can be considered spot; in 2011, this was around 8% to 10% of total imported LNG, or about 1% of global natural gas production.

The increase of available short-term LNG supplies is driven by four factors:

- The unexpected drop in the LNG import requirement of the United States as a consequence of the shale gas revolution provided both the liquefaction capacity and transport capacity in the LNG supply chain to significantly increase short-term available LNG. This also resulted in increasing LNG re-exports from the United States;
- The emergence of self-contracting portfolio players who sign long-term commitments, but retain destination flexibility, allows for the best netback on their portfolio. Frequently these marketing organisations have a global portfolio that enables them to optimise transaction costs through swapping arrangements;
- The emergence of large price differentials that make it attractive for both the buyer and the seller of LNG to divert cargoes to other markets (mostly Asia), as consent of both parties is frequently required to engage in arbitrage activities; and
- The number of LNG suppliers has increased and is likely to expand into new frontier areas (e.g. East Africa, the Russian arctic and North America). This will provide more supply security for consumers, but also increase opportunities to swap cargoes. It limits the overall distance that LNG has to be transported to reach consumers, increasing efficiency of the global supply chain.

⁴² This follows the definition from the International Group of Liquefied Natural Gas Importers.

In the near future, an even more short-term oriented LNG supply system will be difficult, as LNG is a capital-intensive industry which makes volume risk for producers an even bigger issue, just as with PNG, since the customer has (potentially) a large number of alternative sources available. The investment requirements for LNG supply are heavily tilted towards upstream development and transport, as a regasification terminal will generally require no more than 10% of total expenditures on the LNG supply chain (depending on upstream development cost).

To overcome the inherent demand insecurity, LNG supply is generally conducted through long-term, oil-indexed contracts that have even more stringent take-or-pay conditions than PNG contracts. In addition to all the technical and economic restrictions on LNG supply flexibility, the current contractual structure of the LNG business stands out as a considerable barrier to increased short-term trading of LNG.⁴³

LNG contract structure

Increasing flexibility in the LNG supply system would ideally result in a freely floating supply source for markets that would immediately respond to price differentials via swap and spot transactions among market parties (suppliers, traders and consumers), allowing the most efficient supply routes to service demand. To enable the current pipeline structure in LNG contracts, better support for competitive natural gas markets in Asia would require the reduction of transaction costs in short-term contracts and adaptation of current contractual arrangements in long-term supply contracts to allow for more flexibility.

Short-term supply contracts

If a competitive natural gas market in Asia were to succeed, a more responsive LNG supply system would be crucial to attract supplies to the market, thus increasing overall liquidity. As outlined in Chapter 3, this would also reduce the consumers' need for long-term contracts due to the supply security provided through the spot market and lower transaction costs.

Currently, short-term transactions in the global LNG market are individually negotiated contracts that do not give parties the benefit of lower transaction costs, because products are difficult to separate from flexibility requirements, as shipping availability is an indispensable requirement. In essence, the lack of a regional/global regulatory regime (as LNG is still a bulk cargo business) to coordinate transport capacity and the sheer size of LNG cargoes makes it very difficult to create a standard product in which a considerable number of companies can easily trade. This is even more complicated by technical requirements (the quality of LNG, the sort of tanker, etc.) that further impede the development of standardised products for short-term transactions.

As outlined above, short-term transactions in an LNG market are quite different from short-term transactions in an interconnected pipeline system such as in the United States. Currently, short-term contracting consists of roughly four types of transactions:

- **Short-term supply contracts:** one- to four-year supply bilateral contracts which do not differ markedly from long-term supply deals, but have no option for price renegotiation (see long-term contracts below);
- **Portfolio optimisation:** a company makes long-term commitments for supply, but retains destination flexibility, allowing for the best netback on its portfolio. This would frequently still involve short-term transactions, breaking up (several) long-term contract(s) into shorter-term contracts to optimise transport costs in face of supply obligations;

⁴³ The Oxford Institute for Energy Studies has distinguished 12 barriers to arbitrage: lack of a price differential, lack of LNG supply, lack of information on markets, lack of price transparency, lack of specialist traders, contractual limitations, technical restrictions, regulatory and market restrictions, lack of shipping capacity, lack of regasification capacity, and inefficient hedging instruments.

- **LNG spot deals:** the sale of cargoes that are not dedicated to any specific market is frequently made through competitive tenders, brokered trades, cargoes sold in longer trading chains, and speculative trading positions taken up by non-traditional participants (*e.g.* banks); and
- **LNG arbitration:** where a (long-term or short-term) transaction already in place is modified to create value for both the original seller and buyer and a cargo is subsequently delivered to a third party.

Box 2 • The Japan/Korea Marker

The Japan/Korea Marker is a spot assessment price published daily by the energy consultant Platts. It provides a spot price for traded LNG in the Asia-Pacific market and facilitates swap and spot deal making. It has a limited trade horizon into the future, as the prices assessed are reported for the third, fourth, fifth and sixth half-month in the future (maximum delivery horizon of three months).

Launched in February 2009, the JKM is used as a reference price for swap and spot deals by large producers and consumers who thus engage in what might equate to pipeline-to-pipeline competition on the high seas. In January 2010, the JKM started to be published as a single value assessment instead of a tradable range.

The assessment price is a result of editorial engagement with market participants (producers, consumers, traders, brokers, shippers and other) by Platts. Prices of trades included in the assessment are delivered (*ex-ship*) in a region spanning several ports in Japan and Korea. Cargoes delivered in Chinese Taipei and China are included in a normalised way, corrected for assessed deviation costs (Platts, 2012). Standard cargoes of 135 000 to 175 000m³ size are considered in the assessment.

The JKM has become the main alternative Asian pricing indicator for parties engaged in global LNG trade. In June 2012, Platts launched a JKM-swap assessment derived from JKM, which is assessed (using the same methodology as JKM) for three months into the future. The JKM-swap is effectively the first LNG derivative with sizes that are set at a standard of 10 000 MBtu. In September 2012, the first 200 000 MBtu JKM-swap was cleared by ICE Europe, signalling the emerging interest of financial service providers in the LNG trade, although overall activity from financial parties has been limited.

Two major points of concern stand out when regarding JKM as a transparent and representative price signal for the Asian natural gas market.

- **Liquidity:** considering the size of a 140 000 m³ LNG carrier, this would roughly translate into a USD 45 000 000 transaction (at USD 14/MBtu). To participate in LNG spot trade would thus require access to considerable financial reserves and risk-mitigating instruments. This financial threshold limits the number of market participants and the liquidity that underpin the JKM assessment. The minimum size of a product on spot markets in the United States and Europe would be considerably smaller (even compared to the JKM-swap size of 10 000 MBtu).
- **Transparency:** despite the liquidity issues described above, the establishment of JKM as the international benchmark does signal the continued need for such an Asian marker in global LNG trade. However, the method used to assess the JKM price cannot be considered transparent when compared to a possible functioning wholesale market, as JKM price discovery does not evolve through direct competition for supply/demand on a spot market or exchange.

JKM is most certainly an important addition to the available international price indices (with considerable price development in the last three years) and as such, supports the emergence of an efficient global LNG market. However, it remains the best alternative available only as long as there is no Asian natural gas price derived from transparent and competitive price discovery.

The LNG spot and arbitration deals can require considerable time-consuming negotiations between seller and buyer (in case of arbitration between seller, buyer and third parties involved). To facilitate trade and increase legal security (for both seller and buyer), master sale and purchase agreements (MPSA) have been developed.

The European Federation of Energy Traders (EFET) LNG Master Agreement launched in 2010 is increasingly used in Europe and has been used in some deals in Asia-Pacific.⁴⁴ The EFET LNG contract is generally simpler, shorter and easier to use for all parties than the traditional LNG MPSA. Similarly, the International Group of Liquefied Natural Gas Importers (GIIGNL) has updated their standard MPSAs to reflect changes in the global market in 2011.⁴⁵ In a response to an increase in short-term supplies, the Association of International Petroleum Negotiators (AIPN) has also recently (2012) updated its standard MPSA. These changes in MPSAs further facilitate trade, simplify increasingly complicated transactions and potentially reduce transaction costs and increase liquidity on the international LNG market.

In addition to contractual details, the main negotiation issue for any MPSA would be the price for which the LNG is to be sold. For suppliers and sellers to the Asia-Pacific region, this price would currently reflect the buyer's and seller's urgency to conclude negotiations and an expert's estimate of the value of a cargo in the Asian-Pacific market. No transparent reference pricing point currently exists (although JKM is an alternative increasingly used for this purpose); the introduction of one would considerably speed up this negotiation process, further increasing liquidity in the global LNG market.

Long-term contracts: destination clauses in LNG

In essence, a long-term LNG supply contract is still a shipping contract with features similar to that for other bulk commodities traded on international maritime trade routes. However, LNG trade requires a very capital-intensive and specialised supply infrastructure that is quite different from other globally traded energy commodities (*e.g.* coal and oil). This has led parties (both buyer and seller) to organise the LNG supply chain in such a way that it could be regarded as a pipeline connecting supply and demand centres.

In a traditional long-term MPSA, a buyer commits to off-take a predetermined volume of LNG (or number of cargoes) over a set timeframe, with agreed limits on short-term fluctuations and only a small downward tolerance before risking a volume take-or-pay penalty. Thus the LNG producer shoulders the price risk, while the LNG buyer is committed to strict take-or-pay obligations and shoulders the volume risk (Zhuravleva, 2009).

Long-term supplies are generally still delivered free-on-board (FOB) or delivered ex-ship (DES). This reflects standard international commercial practices and derives from the fact that LNG trade is in essence international bulk commodity trade, which requires insurance and shipping.⁴⁶

- **Free-on-Board (FOB):** the transfer of risk occurs when LNG passes the ship's rail at the port of shipment, after which all cost and liability of transporting the LNG to the port of destination will transfer to the buyer. FOB means that a buyer has higher flexibility with regard to destination. However, this increases procurement cost for the buyer as it has to provide for shipping, insurance, regasification capacity and other costs. Buyers will most likely choose FOB delivery if it has options available that reduce insurance and transport costs compared with ex-ship delivery in the port of destination.
- **Delivered Ex-Ship (DES):** the transfer of risk does not occur until the ship has arrived at the named port of destination and the LNG is made available for unloading to the buyer. The seller has agreed to bear not only freight and insurance costs, but also risk and title up to the

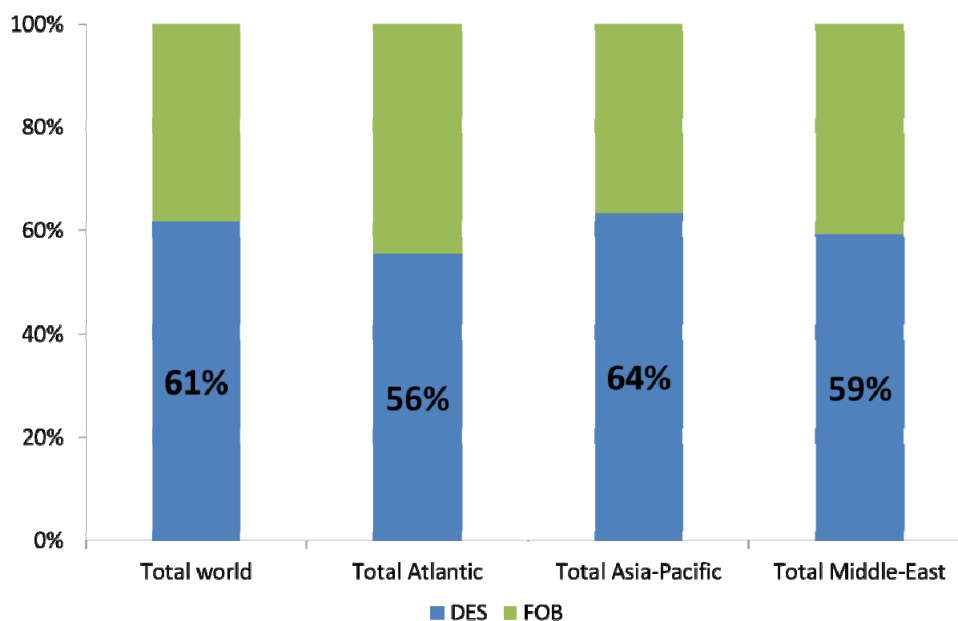
⁴⁴ The EFET LNG MPSA can be accessed at: www.efet.org.

⁴⁵ The GIIGNL MPSA is available at: www.giignl.org.

⁴⁶ Market parties are increasingly considering alternative delivery arrangements such as CIF or regional delivery points (sometimes on the high seas) such as the JKM delivery point.

arrival of the vessel at the named port. Costs for unloading the goods, additional duties, and taxes are for the buyer.⁴⁷

Figure 29 • Long-term contracted LNG delivered FOB or DES in 2011



Source: GIIGNL, 2012.

In 2011, a considerable share of global LNG deliveries was DES (61%), with the Asia-Pacific region taking the biggest share of long-term contracted supplies as DES (64%). Delivery ex-ship usually provides less room for reselling, as the cargo is delivered at port. To redirect a cargo would thus either involve LNG arbitration with the seller or incur reloading and shipping cost at the port of delivery. Both options would require a price spread between markets to make either practice profitable. Usually LNG buyers in the Asia-Pacific region are utilities with a supply obligation to customers (a fixed sales portfolio) and therefore generally limited need to divert cargoes.

Historically, long-term LNG contract prices were negotiated at a level that would reflect the value of natural gas in the (electricity) market where it would be delivered. A long-term contract was thus also a considerable tool for arbitrage if natural gas was valued at a different level in a connected (or geographically close) market. In a way similar to the European long-term supply contracts, a contractual restriction was needed to limit abuse through arbitrage by either party in the contract. Subsequently, destination clauses were added to long-term LNG contracts stipulating to which market a contracted LNG needed to be delivered (which take-or-pay clauses could not provide as LNG can be shipped around the globe).

Destination clauses in long-term LNG supply contracts forbid buyers to resell a cargo outside the country where they are established, which thereby guarantees the seller a form of protection of competition in other markets. The destination clauses have helped to maintain price differentials across different regional markets and are mainly used by large Middle Eastern producers, as they are geographically conveniently located to arbitrage between the markets in the Atlantic and Pacific basins.

Destination clauses have since then served as a tool of security of supply *and* demand on which supply chains and distribution systems in target markets were developed and amortised. Destination

⁴⁷ In Incoterms 2010 (published 1 January 2011) DES was replaced by Delivered at Terminal (DAT).

clauses can take various legal shapes and forms and the restrictions need not be as explicit as an outright ban on reselling, but can raise the arbitrage threshold to a *de facto* prohibitive level.

In the Atlantic Basin, destination clauses have come under considerable pressure. In the 2003 second European gas Directive, the European Commission forbade destination clauses (for both PNG and LNG), as they are considered to be market-partitioning devices for exporters. Although the United States' government has taken a more lenient approach, new contracts have been drafted that increase contractual flexibility in the Atlantic Basin.

Overall, the reduction of destination clauses in the Atlantic Basin has led to increased destination flexibility from producers in this area, mainly Nigeria, Equatorial Guinea, and Egypt, since the first quarter of 2012. Subsequently, a number of sellers have started to self-contract cargoes, selling directly in the downstream market, thus reducing off-take risk. Currently this has increased destination flexibility and led to an increasing amount of LNG that is exported towards the higher priced Asia-Pacific basin (see Chapter 2).

However, this development has lagged for producers in the Asia-Pacific basin, where destination clauses are still regarded as a way to provide supply/demand guarantees for buyers/sellers (it is also not likely that under current contractual obligations, LNG supplies for Asia-Pacific markets can easily be diverted towards for the Atlantic Basin even if prices did allow). However, the increased availability of flexible LNG from the Atlantic Basin is putting pressure on flexibility provided by long-term LNG contracts. This in turn will put considerable pressure on producers and consumers in the Asia-Pacific basin to new find ways to divide risks in LNG supply contracts.

Price review in long-term LNG contracts

As long-term PNG and LNG contracts span more than a decade, they need to include regular contract reviews to recalibrate the contract to overall market conditions. Buyers and sellers will look to reduce the costs that either party can incur from the price disparities between the long-term contract price and the price of the most likely alternative (in a non-competitive market) or an alternative source of natural gas (in a more competitive market). Any price review in long-term LNG contracts will have to be conducted through commercial negotiations.

The approach to price renegotiation clauses in long-term LNG supply contracts is generally one of four different types:

- no clause on renegotiation is included;
- prices shall be reviewed every three to five years;
- prices may be reviewed every three to five years if buyer(s) or seller(s) wish to do so; and
- a specific interval is not included in the contract, but a price may be reviewed if buyer(s) or seller(s) wish to do so.

Long-term contracts without a renegotiation clause are rare, as this would represent considerable risk to the buyer and/or seller. Generally, the latter three contracts represent roughly the same renegotiation on price with a different trigger to start renegotiations.

The scope of the contract review is generally limited to the issue of price. In the oil-indexed dominated supply contracts of the Asian-Pacific region, this would entail a discussion on the slope of the price relationship between oil and LNG, but a complete review of the price structure is not explicitly denied in most renegotiation clauses. This means that a significant price review beyond the change of the slope of the S-curve is usually an option. This would provide the opportunity for LNG suppliers/consumers to adapt the pricing system to include an alternative regional pricing signal in the future.

As opposed to long-term PNG contracts in Europe, renegotiations for LNG supply do not discuss contract conditions such as indexation, destination flexibility and take-or-pay level. Long-term contracts

were structured to provide maximum supply/demand security and therefore are very strict in their take-or-pay obligations compared to long-term PNG contracts.⁴⁸ Thus the ability to significantly change the volume obligations or flexibility clauses in long-term LNG contracts is very limited.

Changes in volume and/or flexibility (if not caused by a *force majeure*) are generally possible only when contracts come up for renewal. By 2017, nearly 50% of the volume currently supplied under contract will have been terminated.⁴⁹ This will mean that a considerable amount of LNG supply will be replaced (this is already happening). There has been a recent trend of long-term LNG buyers looking for shorter-term contracts and considering increased supply flexibility a special point of interest (Argus Global LNG, 2012).

Perspectives for change in contracts

Despite contractual, technical and transport rigidities, the physical flow of natural gas remains crucial for any spot market development. The existence of a spot market will not necessarily undermine the rationale for long-term supply contracts, as sellers are likely to still value the ability to conclude a long-term agreement.

A flexible LNG supply chain would both benefit from and support spot market development. The establishment of a reliable trading hub in Asia-Pacific would induce a change in price setting for long-term contracts and the sort of contracts that are offered to buyers. The question would then be: what developments on the global LNG market could impede or support a more flexible system of LNG supply?

Change in shipping availability

Current expansion in the number of market parties without upstream access (nearly 50% of ships on order are not dedicated to any upstream project) will increase the number of non-contracted LNG carriers to nearly 10% of total ships in operation. A reinforcement of this trend will not only show increased confidence from market parties in their ability to make money in LNG shipping, but will also support increasing flexibility of the LNG supply chain.

Change in regasification capacity availability

Third-party access to LNG regasification terminals in the Asia-Pacific region is extremely limited, due to regulatory hurdles and the fact that terminals are generally purpose built. With only one open-access terminal currently under development in Singapore, the immediate prospect of more TPA regasification capacity coming available in the region, without government action, remains rather bleak. Expanding TPA in the Asia-Pacific region will require substantial changes of policy among governments, either to create a favourable investment climate in additional TPA regasification capacity, or to require incumbent companies to reduce barriers to entry.

Market parties involved

The number of companies that use their portfolio to supply customers with short(er)-term LNG volumes has been increasing. This is a considerable game changer, as these companies use their global upstream portfolio to arbitrage between markets and optimise shipping routes within the portfolio. These companies are frequently international oil and gas companies (IOGC) that not only have upstream access, but also regasification capacity available in different regions, which always provides them with an outlet for their natural gas.

⁴⁸ Long-term PNG contracts frequently have a predetermined bandwidth that provides considerable flexibility with regard to the ACQ, with the possibility to use carry-forward and make-up volume.

⁴⁹ From IEA databases.

A relatively new phenomenon in the Asia-Pacific LNG market will be developing import requirements from LNG exporting giants such as state natural gas company Petronas in Malaysia and Pertamina in Indonesia. As pricing in the domestic market is frequently below cost, this has driven domestic consumption to levels that domestic production cannot sustain without compromising export commitments. Consequently, both companies will become considerable portfolio players with long-term, oil-indexed export commitments and an increasing volume of oil-indexed/spot import commitments.

In Malaysia, a target date has been announced by which domestic gas prices should reach market parity. Although this should have an encouraging effect on energy efficiency, it is not likely to solve Malaysia's long-term challenge of increasing imports. This could provide an incentive for Petronas to start looking at alternative short-term supply sources from the spot market and ways to accurately price natural gas in the region, as this would reduce price risk for the company. A functioning trading hub in the region improves the number of tools available to manage portfolio risks for companies that focus on creating a margin.

In addition, financial players such as banks have made inroads in LNG trading by focusing on hedging opportunities for market parties and trading physical cargoes themselves. However, physical trade remains limited, as the value of a cargo bought in the Atlantic Basin and destined for Asia would be valued around USD 45 million.⁵⁰ Effectively, without regasification capacity contracted, or a sizeable end-consumer portfolio to supply, or a competitive wholesale market available that can absorb such a volume, such a cargo would be a considerable un-hedged position, a risk not all financial players are comfortable with. So far, the specialist nature of the LNG trade and the limited availability of financial hedging facilities have restricted financial parties' participation in the global LNG market (WGI, 2012d).

New flexible supplies: North America and East Africa

There has recently been considerable speculation about the potential of new LNG producers to deliver volumes to market beyond 2017. In the medium term, Australian production is expected to deliver sizeable volumes, but this will not increase market flexibility, as 91% of it is long-term contracted, thus leaving about 9 bcm not contracted.

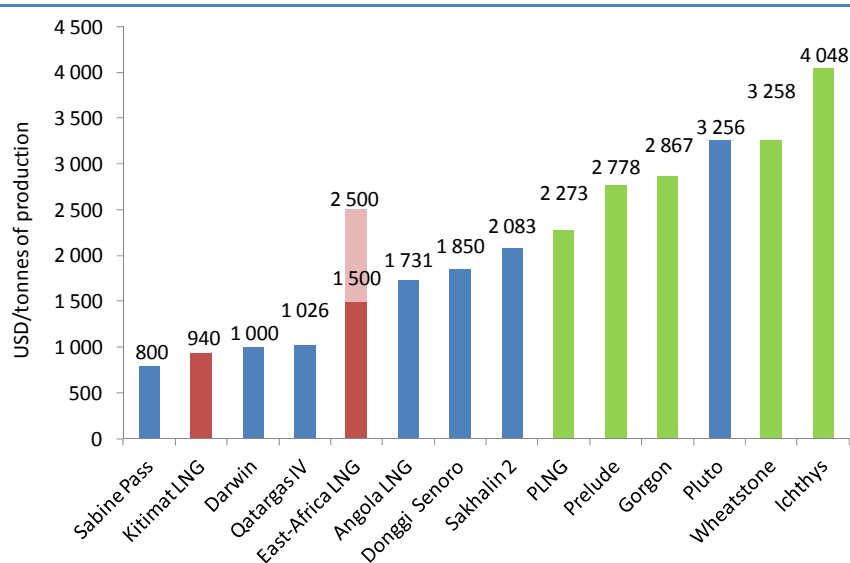
This second wave of LNG is expected to originate from liquefaction terminals built in the United States and Canada, and from recently discovered natural gas deposits in East Africa. Cheniere's Sabine Pass terminal phase I (in the United States) was the first terminal to receive a Final Investment Decision (FID) and will be built on a new business model that indexed LNG to spot market prices (in this case, 115% Henry Hub, which covers energy usage during liquefaction and trading overhead to offload the volumes in case they are not lifted) and levies a separate use-it-or-lose-it charge of between USD 2.25 and USD 3.00/MBtu (depending on contract) for liquefaction. The 21.9 bcm of LNG supply is long-term contracted but (unlike the Australian example above) sold with complete destination flexibility. Initial contracting parties are BG, Gas Natural, Gail and KOGAS.

Although the pricing on Henry Hub is currently competitive with Asian oil-indexed volumes, this might significantly change in the future. It is therefore currently unlikely that HH-indexation will make a significant impact on oil-indexed pricing, as the volume sold from Sabine Pass alone is not enough. Moreover, these volumes from North America will also not contribute to a transparent pricing signal representing supply/demand in the Asia-Pacific region, as HH-indexation responds to supply/demand in North America. However, considerable impact might be felt through the more flexible contract arrangements, as lower development costs allow for less stringent volume requirements (such as a use-it-or-lose-it fee).

⁵⁰ Cargo of 140 000 m³ at USD 14/MBtu.

In the United States, a total of 302 bcm of LNG export capacity is currently proposed (as of end-December 2012), part of which could come on stream beyond 2017. In addition, Canada could add another 42 bcm by 2017.⁵¹ The proposed Kitimat 13.6 bcm LNG liquefaction project (developed by Encana and EOG resources) is estimated to be very competitive, especially considering that its western location is close to Asian-Pacific markets. However, it is questionable whether freely available LNG will be available from Canada, as the main partners in developing other terminals (PetroChina, KOGAS and Mitsubishi) have dedicated markets for sales in Asia. Meanwhile, several issues, such as domestic transport capacity, need to be ironed out before LNG could leave the western Canadian shores (WGI, 2012c).

Figure 30 • Construction costs for various LNG projects



Notes: green under construction, blue is producing, red is proposed. Sabine Pass is FID phase one. PLNG is Papua New Guinea LNG. East Africa Project costs are estimated.

Sources: IEA database; various companies' websites.

In East Africa, Mozambique LNG is the most recently proposed development, after considerable finds were announced by Anadarko and ENI. Both companies are moving towards developing LNG export capacity and negotiating terms and conditions with the government. Several significant discoveries have also been made in Tanzania. As exploration is currently underway in the region, with several IOGCs vying for acreage and takeover opportunities, the full scale of East-African reserves will become apparent over the next few years. A current estimate is that at expected production costs of between USD 1 500/tonne and USD 2 500/tonne, East-African LNG fits well within the global LNG portfolio.

Several of the companies involved are major portfolio LNG marketers (such as ENI and BG), which increases the likelihood that the development of these reserves will increase the available LNG flows without a specific commitment to a market. In addition, the LNG facility that would be built on either Mozambique's or Tanzania's coast would be ideally located to arbitrage between the Atlantic and Pacific basins, increasing the scope of competition for LNG powerhouse Qatar.

It seems likely that natural gas developments in North America and East Africa will increase overall flexibility to the LNG supply chain. This might have an impact on overall LNG contracting, making destination flexibility a key issue for LNG procurement, as LNG producers will have to provide more flexible terms if they want to sell volume to customers.

⁵¹ Derived from IEA databases.

LNG as a link between markets?

The LNG supply chain can generally provide flexibility in both the long and short term. Long-term flexibility is derived through investments in the overall supply chain. Short-term contracting and portfolio management will reduce travel distance, increase flexibility and optimise revenues for the parties involved. There are several encouraging signs that the LNG supply chain is becoming more responsive to shifts in global demand through increasing destination flexibility.

However, even in the theoretical and highly unlikely situation with universal third-party access for suppliers to LNG import terminals and no flexibility restrictions in supply contracts, the ability of an LNG carrier will most likely never be as responsive as a direct upstream connection via a pipeline. Short-term fluctuations in demand will always have to be met by the regasification terminal, flexibility from pipeline imports, additional storage withdrawals and line-pack in the distribution system.

Theoretically, in an Asia-Pacific natural gas market with several transparent pricing hubs, LNG could reduce pricing signals between markets in a similar way to that observed in Europe. With a flexible source of supply, it is possible to send natural gas to where it is most advantageously priced in a region that would have several pricing points. Although this has resulted in considerable convergence of prices on the spot market in Europe, it is unlikely that (without a more interconnected pipeline network) this will be the case in Asia. However, LNG trade is able to create a price convergence between futures markets (month-ahead and beyond) if these develop, which would limit price differentials in the Asia-Pacific region.

A shock to the system?

Despite the growing demand for natural gas in Asia-Pacific energy markets, perspectives for a functioning wholesale gas market remain currently limited. This is a result of governmental policies that value security of supply over economic objectives in the more mature Asian markets; and the different stages of development of the natural gas markets.

Security of supply considerations have resulted in considerable government interference along the natural gas value chain in mature Asian economies. Government interference in developing economies might be a reflection of the overall developmental stage of the market, something that can change but will require time.

On the supply side, contractual limitations restrict LNG's flexibility to serve as a market arbitrator and supply the market with an effective price incentive. This is hampering LNG's ability to provide the flexibility needed to support a competitive natural gas market which inspires confidence in spot/future prices. While the global LNG market has become decidedly more short term over the past decade, the Asian market has benefited less from this development.

Long-term supply contracts generally have price renegotiation clauses that allow for price adaptations to changes in the market. However, volume or destination clauses are generally not part of renegotiations. Increasing volume and destination flexibility in LNG supply contracts will therefore require a change in the overall market that will increase these features in new contracts. Currently, changes in the market look promising on several aspects, namely the increasing role of portfolio players and the expected destination-free volumes from North America and East Africa that will arrive after 2017.

As LNG is increasingly allowed to be shipped destination free, it is likely that its arbitrage role between competitive markets will increase and price movements will likely co-integrate (if a competitive market is available). But it is liable to perform this role on the futures market and not necessarily on the spot market, as the physical responsiveness of LNG supply is likely to always lag behind pipeline supplies.

Conclusion: chicken or egg?

Among the major gas-consuming regions, the fully functioning North American and quickly improving European wholesale natural gas markets both reflect prices that closely correspond to regional supply and demand. A third price benchmark in the developing Asian natural gas market would make sense for long-term Asian economic competitiveness and the future of gas in the region.

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The Asian natural gas market is the fastest-growing market and is expected to become the second-largest gas market by 2015, with 790 bcm of natural gas demand. However, the entire Asian-Pacific region lacks a trading platform to facilitate the exchange of natural gas and consequently a price signal that is able to steer investments in natural gas infrastructures.

As governments look to an increased share of natural gas in power generation (for security and environmental considerations), gas will frequently need to compete with domestically produced coal. To compete efficiently in the electricity mix, natural gas will need to be priced not against the oil market (as oil has a very limited role in power generation), but on demand and supply for the gas itself.

This issue has come to the forefront in the aftermath of the Fukushima accident. Asian LNG import prices were pushed to record highs as a result of oil price developments rather than demand/supply of gas. Indeed, the flexible gas supplies drawn in from the Atlantic Basin to meet the extra Japanese demand were notably cheaper. In a competitive natural gas market, otherwise competitive LNG would not be rendered dear thanks to pricing trends of an altogether separate commodity in a different market.

Creating a competitive gas market

Getting to that market model starts by increasing competition between suppliers (and consumers) at the wholesale level. The final objective in natural gas market liberalisation would be the establishment of a trading hub with a natural gas exchange providing a reliable price for future delivery.

Governments will need to take a different role than is now common among developing Asian-Pacific markets, adapting to the role of regulator and ultimately that of arbitrator via competition authorities. This will require a consistent mindset toward increasing competition and surrendering control of what is often considered a strategic sector of the economy. That is something many governments will find difficult to do. And yet it will be necessary to instil the necessary confidence to draw in new participants (especially financial parties), and for market players to start using the hub to balance their portfolios.

Institutionally, that means a hands-off government approach, separation of transport and commercial activities, and price deregulation at the wholesale level. Subsequently, three structural requirements have been identified: sufficient network capacity and non-discriminatory access, a competitive number of market participants, and the long-term involvement of financial institutions.

The creation of a natural gas market will influence the way natural gas changes hands, as physical and financial trading worlds will meet on the gas hub. First, OTC trading will be supplemented with exchange-based trading, which requires much more risk mitigation through financial institutions. This financialisation will attract an increasing number of players other than traditional physical portfolio players. The resulting price for natural gas should reflect expectations of all market players, including current *and* future supply/demand in a market.

The impact of a natural gas trading hub is typically felt in the broader natural gas market, as it requires both consumers and suppliers to review, revalue and ultimately rewrite business practices. Most likely, a shift in focus from long term to short(er) term will emerge, and different or modified contractual and investment schemes will follow. This process will probably take at least a decade for national markets with a clear regulatory authority – and longer for more regional initiatives, due to the increased number of stakeholders involved.

The institutional and structural requirements for a competitive gas market (set out in Chapter 3) should enable a transparent and level playing field for market players. A competitive natural gas market can provide better information on the status of the market, something that oil indexation cannot. Necessary investments in the natural gas industry rely on confidence in competitive gas prices. This confidence can be derived from market arrangements, but will ultimately come from governments' demonstrable intent to let market forces determine an outcome. Confidence also requires a strong and preferably independent regulator with a clearly defined anti-trust mandate in both the financial and physical areas of the natural gas market.

The introduction of competition aims to make the procurement of natural gas by gas companies more efficient, and investment needs more transparent. This will not mean, however, that natural gas is automatically priced lower than oil-indexed equivalent volumes. It will mean that, when properly set up, the market will price natural gas at its relative value in a specific energy mix.

Prospects for a competitive gas market in Asia-Pacific

Currently, prospects for a functioning wholesale natural gas market remain limited. Even in the more mature Asian-Pacific markets, the basic requirements for a wholesale market are not currently in place, since governments continue to put an emphasis on security objectives over economic ones. In addition, several governments have developed and keep in place preferential price-setting regimes that limit competition in the natural gas market.

Security of supply considerations have resulted in considerable government interference along the natural gas value chain in mature Asian markets such as Korea and Japan. Although the policy emphasis on security of supply is an entirely legitimate one, the result is ongoing government interference and resistance to more downstream competition.

In China, the market is developing fast, with intense demand growth. Such enormous investment requirements reduce the scope for competition. Consequently, the Chinese government has looked at ways to introduce more flexible pricing schemes in some developed gas market areas on the east coast.

Currently, Singapore seems the best-suited candidate for a regional natural gas trading hub, as its government has a distinctly hands-off approach to markets. The government has also introduced wholesale pricing for natural gas and effectively unbundled both the power and natural gas infrastructure. An open-access regime will be established for the future SLNG terminal, and financial parties serving global commodity markets are already in place and well-positioned to serve emerging natural gas trade. Singapore itself is a relatively small market, which could limit the number of players in the wholesale market, but a well-connected hub could serve the region well beyond the city-state.

Obstacles to a competitive gas market in Asia-Pacific

A unique characteristic of natural gas trade in Asia-Pacific is the limited amount of gas that is traded via international pipelines – only about 10% of traded volume in the region.

An increasingly flexible supply chain will require a continued increase of LNG shipping availability and third-party access on Asian regasification terminals. Usually such terminals are built with capacity dedicated to LNG-importing companies (frequently dominant national or regional organisations), leaving little (if any) spare capacity for competitors. Increasing competition between LNG suppliers for market share in several Asian markets (beyond Singapore) will therefore be a very difficult process from a regulatory, technical and commercial perspective.

In addition, destination clauses which were introduced to reinforce investment security have the unfortunate knock-on effect of creating market segmentation and stiffening the overall supply chain.

Chicken or egg?

It is clear that the possible development of a competitive natural gas market that ultimately generates a reliable price signal in any Asian market will not happen overnight, and will not necessarily lead to lower prices in most markets (as some protagonists frequently assume). It does however give the Asian-Pacific economies an opportunity to increase supply flexibility and overall economic efficiency to meet their growing demand for energy.

The move towards a competitive natural gas trading hub cannot depend solely on external shocks in the global market. Governments will need to signal whether they would accept such a change to happen.

In the very long term, as markets in the Asia-Pacific region mature and infrastructures are in place and amortised, a likely outcome might be that multiple pricing areas will develop. Japan/Korea, China, and especially Singapore stand out for this on the basis of their current and future market structure demand.

In the medium term, this is truly a “chicken or egg” discussion. A more destination-flexible LNG supply is needed to drive the momentum towards a gas trading hub in Asia, but without initial steps towards such a hub, flexible LNG would not have a haven in Asia at which to arrive. A Singaporean move toward a competitive natural gas market might not immediately lead to a competitive Asian-Pacific pricing signal, but it is a very important and remarkable first step.

Acronyms, abbreviations and units of measure

Acronyms and abbreviations

ACQ	annual contract quantity
AIPN	Association of International Petroleum Negotiators
ASEAN	Association of South-East Asian Nations
BGSGM	BG Singapore Gas Marketing
BM	bilateral monopoly
BOW	balance of week
CEER	Council of European Energy Regulators
CH	clearing house
CM	clearing member
CNOOC	China National Offshore Oil Company
CNPC	China National Petroleum Company
CO ₂	carbon dioxide
DA	day ahead
DAT	delivered at terminal
DES	delivered ex-ship
EMA	(Singapore) Energy Market Authority
EU	European Union
FERC	Federal Energy Regulatory Commission
FID	final investment decision
FMA	financial market authority
FOB	free-on-board
FSU	Former Soviet Union
GECF	Gas Exporting Countries Forum
GIIGNL	International Group of Liquefied Natural Gas Importers
GNC	gas network code
GSP	government selling price
HH	Henry Hub
HHI	Herfindahl-Hirschman Index
ICE	Intercontinental Exchange
IGU	International Gas Union
IOGC	International Oil and Gas Company
JCC	Japan Customs Cleared (oil price) or Japan Crude Cocktail
JKM	Japan/Korea Marker
JOGMEC	Japan Oil, Gas and Metals National Corporation
KNOC	Korean National Oil Corporation
KOGAS	Korean Gas Corporation
LNG	liquefied natural gas
LOP	law-of-one-price
LPG	liquefied petroleum gas
METI	(Japanese) Ministry of Economy, Trade and Industry
MOCIE	(Korean) Ministry of Commerce, Energy and Industry
MPSA	master sale and purchase agreement
MTI	(Singaporean) Ministry of Trade and Industry
NBP	national balancing point
NCM	non-clearing member
NDRC	(Chinese) National Development and Reform Commission

NP	no price
NYMEX	New York Mercantile Exchange
OECD	Organisation for Economic Co-operation and Development
OPEC	Organisation of Petroleum Exporting Countries
OTC	over-the-counter
PNG	pipeline natural gas
RBC	regulation below cost
RCS	regulation cost of service
SLNG	Singapore Liquefied Natural Gas
SP	Singapore Power
SPA	sales and purchase agreement
SPEX	Shanghai Petroleum Exchange
SPR	social and political regulation
TAGP	Trans-ASEAN Gas Pipeline system
TPA	third-party access
TSO	transmission system operator
TTF	Title Transfer Facility
UGS	underground gas storage
WA	weekend ahead
WD	within day
YA	year ahead

Units of measure

Bcm	billion cubic metres (40 MJ/m ³)
Gtoe	gigatonnes of oil equivalent
GW	gigawatt
MBtu	million British thermal units
Mcm	million cubic metres (40 MJ/m ³)
MJ	megajoule
MT	megatonne
Mtpa	million tonnes per annum
MWh	megawatt hour
TWh	terawatt hour
USD	United States dollar

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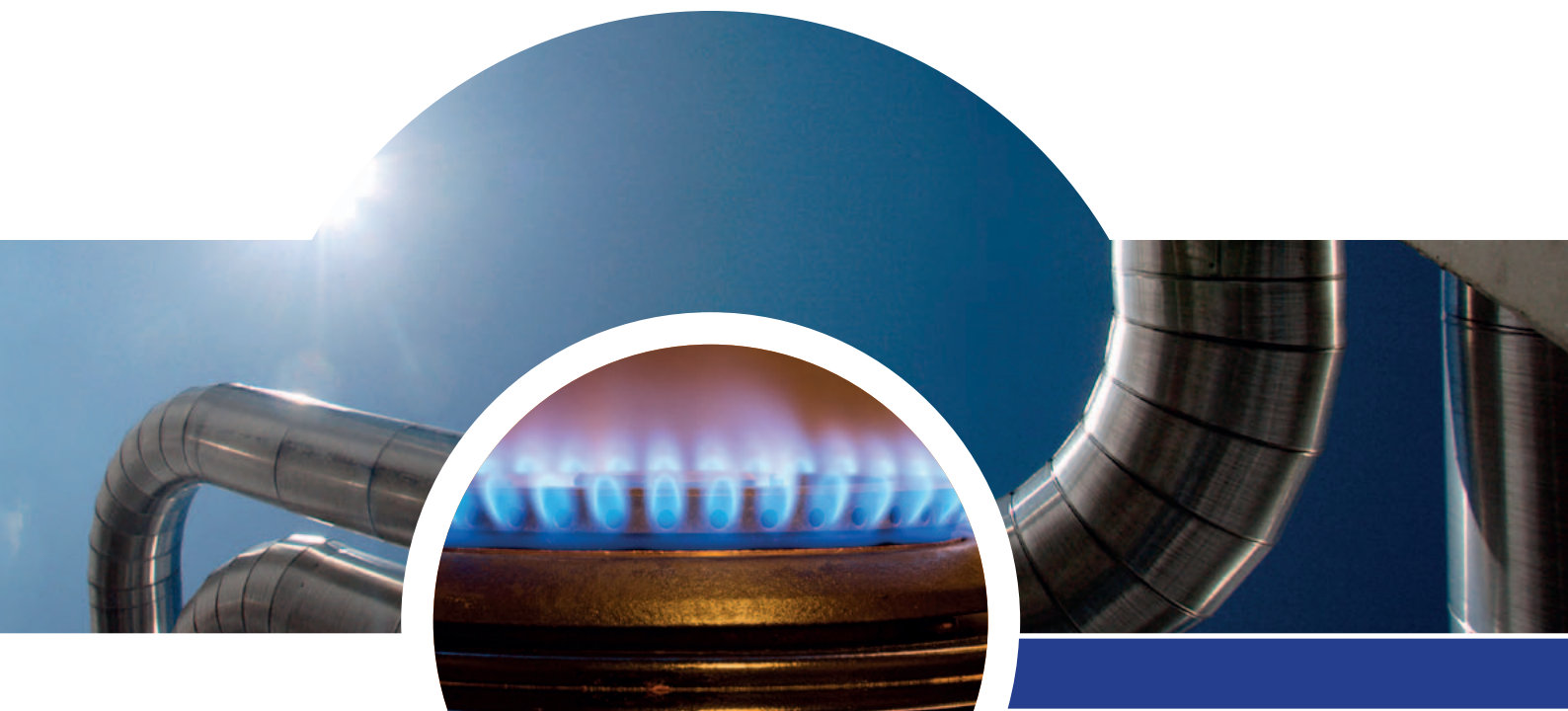
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Developing a Natural Gas Trading Hub in Asia

Obstacles and
Opportunities



The market for natural gas in Asia is dominated by long-term contracts in which the price of gas is linked, or indexed, to that of oil. In recent years, this has helped keep Asian gas prices much higher than those in other parts of the world, leading to serious questions about whether such a system is sustainable. In this report, the IEA shows what it would take to create a regional natural gas trading hub in which prices aren't indexed to those of oil but rather reflect local supply and demand fundamentals.

Long-term contracts can play a beneficial role in providing investment security, but their current pricing does not take into account fundamentals and the competitiveness of gas within the energy mix of the mature economies where the gas is consumed. Moreover, without a competitive spot market for natural gas – one that supports and encourages price discovery – there is little incentive and little scope to change current commercial practices. This leaves both consumers and producers with insufficient room to explore different options, which limits the degree to which natural gas can serve as a flexible source of energy for both growing and mature economies.

Developing a natural gas trading hub in Asia aims to provide stakeholders with insights on the changes that are required in the Asia-Pacific natural gas sector – both downstream and upstream – to allow a competitive natural gas price to emerge. Building on OECD Europe and OECD America experiences, this report sets out to assess perspectives for these changes in the Asia-Pacific natural gas markets. It identifies obstacles and opportunities for a competitive natural gas price in the Asian economies to emerge.