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Gas Pricing and Regulation

China's Challenges and IEA Experience

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and IEA Experience

In line with its aim to meet growing energy demand while shifting away from coal, China has set an ambitious goal of doubling its use of natural gas from 2011 levels by 2015. Prospects are good for significant new supplies – both domestic and imported, conventional and unconventional – to come online in the medium term, but notable challenges remain, particularly concerning gas pricing and the institutional and regulatory landscape. While China's circumstances are, in many respects unique, some current issues are similar to those a number of IEA countries have faced. This report highlights some key challenges China faces in its transition to greater reliance on natural gas, then explores in detail relevant IEA experience, particularly in the United Kingdom, the Netherlands, the European Union, and the United States. Preliminary suggestions about how lessons learned in other countries could be applied to China's situation are offered as well. The aim is to provide stakeholders in China with a useful reference as they consider decisions about the evolution of the gas sector in their country.

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Anne-Sophie Corbeau, Dennis Volk,
Jonathan Sinton, Julie Jiang
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INTERNATIONAL ENERGY AGENCY

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International Energy Agency

International Energy Agency
9 rue de la Fédération
75739 Paris Cedex 15, France

www.iea.org

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Executive summary

In its current 12th Five-Year Plan (2011 to 2015), the Chinese government plans to double the share of natural gas in the primary energy consumption and reach consumption levels up to 260 billion cubic meters (bcm) by 2015, twice the level of gas consumed in 2011. Such a target is ambitious and implies that the country be able to attract sufficient supplies from all possible sources, not only from domestic gas production but also from imports of liquefied natural gas (LNG) and pipeline gas. This requires that all these supply sources deliver at the targeted level, whereby import levels depend crucially on the supply sources linked to long-term contracts to deliver supply in a timely manner at contracted levels.

Such targets of rapidly increasing gas consumption are not new, neither are the challenges associated with them. But these issues, mentioned above, have become more acute as Chinese gas consumption in 2011 has already increased fourfold from 2000 levels. While China's gas demand would double over 2011-15, the volumes implied are significant as China is already the fourth largest gas user in the world, consuming 130 bcm in 2011. China consumes more than any OECD country but the United States, and its gas consumption is foreseen to be one of the world's fastest growing. In 2002, China was already looking at doubling the share of gas in the primary energy mix within ten years. In 2011, it planned to do the same but within five years, potentially reaching an annual consumption level of 350 bcm by 2020, according to CNPC's forecasts. When the International Energy Agency (IEA) published a study with China in 2002, *Developing China's Natural Gas Market* (IEA, 2002), China was a self-sufficient country, and planning both long-distance pipelines to bring gas to coastal areas from far Western China (Tarim basin) and new terminals to import LNG (see maps 1 to 3). Since then, China has become a significant gas importer, with pipeline and LNG imports covering one quarter of its demand, and with increasing quantities of domestic gas production from areas far from demand centres. This trend is forecasted to accelerate, making China one of the world's largest gas importers.

A new development has recently emerged on the supply side that makes a rapid increase of gas demand potentially more achievable for China: the unprecedented availability of unconventional gas resources. Currently, resource assessments indicate that China has ample resources in conventional, and even more in unconventional gas. Technology, pricing and infrastructure to bring gas to market, not the resource availability, are the main issues. National plans call for these resources, notably shale gas, to be developed in a timely manner in order to feed Chinese gas needs.

Due to the size of its economy, the many different fuels within China's energy mix, and the growing interactions with international trade for oil, gas and coal, China's gas sector and the related challenges cannot be looked at in isolation from the global gas market. Domestically, the gas market cannot be viewed separately from markets for other energy sources, or indeed from policies and mechanisms to promote energy efficiency and to protect the environment. Cheaper alternative fuels are available, in particular coal, although the production of coal is no longer as inexpensive as in the past, and China has become a net importer of coal. Coal is still the main competitor to gas, in particular for the production of electricity, as well as in industry. The need to curb coal demand growth to reduce air pollution and improve air quality in big cities is as present and pressing as ever, and natural gas offers at least part of a solution here. Moreover, global energy markets have evolved, and rising import dependence means that China's gas market cannot develop in isolation.

The objectives of this study are two-fold: to develop an accurate picture of the current issues that China faces in planning to double its natural gas consumption by 2015, and to examine what challenges OECD countries have faced in the process of gas market liberalisation and how their experience may apply to China. The main purpose is to inform Chinese stakeholders, governmental agencies, local governments and gas companies, about what these relatively mature gas markets have learned in the hope that this information may provide useful insights for policy making and implementation in China. The purpose is not to give a detailed plan on when and how China should proceed to tackle specific issues – this could be undertaken in a following project, should Chinese stakeholders express interest in further analysis and recommendations.

A number of points arising from OECD experience stand out as potentially particularly relevant for China. These are summarised below.

OECD experience can be relevant for China

Despite the unique features of China's current situation, some experience in OECD countries with gas markets and regulations appears to be quite relevant to policy debates in China, while keeping in mind that regional adaptation will be necessary. The OECD countries profiled in this report share some common features with China: a regulated pricing system which proved to be not flexible enough to increase domestic supply (such as in the United States in the late 1970s); the need to increase specific parts of domestic supply as shown by the Small Fields Policy in the Netherlands; and the development of infrastructure not only to import but also to transmit, store and distribute natural gas to the final end user in many European countries. Most European countries had vertically-integrated gas companies present throughout the gas value chain, with monopoly or dominant positions in essential areas such as transmission, imports or domestic production. The liberalisation of gas markets was also conducted in parallel with the electricity markets liberalisation in Europe, unlike in the United States. Many OECD countries wished to progressively move towards a market price, although this process has been achieved only in the UK and US gas markets, while it is still under way in many OECD European countries.

Stage of market development and timing of reforms are crucial

In comparing China to other countries, it is essential to account for the timing and stage of development when these countries started to reform their gas industries. Of course, even among OECD countries, there is no uniform behaviour. Despite the significant growth of China's demand and growing interactions with global gas markets over the past decade, China's gas market is relatively young, established within the past decade. By comparison, many OECD countries reviewed in the study had well established gas industries for a few decades before they started to liberalise their gas markets. The United Kingdom and Spain are notable exceptions in terms of having relatively large markets[1], and are probably the closest to China when it comes to starting liberalisation at an early stage of market development. When the United Kingdom started liberalising its gas market in 1986 and pushed forward on the path towards liberalisation in the early 1990s, the UK gas market was only about 15 years old with a start in the early 1970s. Natural gas imports from Norway had only started to pick up in the late 1970s to early 1980s. The dash for gas in the power sector had not yet taken place, and actually occurred at the same time as market liberalisation (gas demand in the power sector increased from 1 bcm in 1990 to 30 bcm in 2000). Spain also saw the development of its gas-fired generation during the phase of liberalisation in the 2000s. These two countries also saw their gas demand double during the market liberalisation phase.

Many OECD countries had already built up significant gas transmission and distribution infrastructure, which had been largely or fully amortised, to supply gas to end users. At present, China's transmission/distribution network is more limited and still being expanded.

[1] Other smaller markets such as Greece and Portugal were also at relatively early stages of development when they started liberalisation, which was essentially driven by the European directives.

Governments are essential in giving direction and long-term objectives

Strong policy guidance is necessary. China still needs a clear vision about the future of its natural gas industry, and how this fits within the whole energy framework. Experience from OECD countries shows that many set up a natural gas law – or alternatively an energy law with a gas section. Much progress is contingent on issuance of laws to provide a basis for regulation. This is critical to provide certainty for upstream players, which in turn is necessary to ensure growth of supply. Gas needs a clear legal framework, notably regarding the infrastructure, to allow for and to encourage efficient and timely investments throughout the value chain.

Most OECD countries have put in place an independent regulator, in charge of energy matters. Where there is significant upstream production, one can make the distinction between upstream and downstream such as in the United Kingdom where the Department for Energy and Climate Change (DECC) has jurisdiction over the offshore oil and gas production while Ofgem has responsibilities of overseeing the downstream power and gas markets. As China has considerable production, a UK-style approach, with two separate regulatory authorities has merit.

China needs to clearly define the responsibilities between the different governmental entities, rather than just splitting the responsibility for the gas sector among different ministries and agencies.

Government should also work to limit the influence from the "Big Three" (CNPC, Sinopec and CNOOC) national oil companies (NOCs) in the setting of policy decisions. In particular, a national regulator or any other type of governmental entity in charge of upstream and/or downstream activities should not be subject to interference from the Big Three NOCs. This implies, for example, that the key people in charge should have no position/financial interest in Chinese companies. All interested players, and not only the Big Three, should be consulted in the process of developing new regulations.

China needs also to bring clarity to the distinction between the central and the local levels. Many conflicts exist, such as contradictory rights on CBM and coal production. This issue goes well beyond energy, and there is no particular relevant lesson to draw from any OECD country's experience. Nonetheless, this issue should be recognised and addressed for it has a significant impact on energy developments.

Liberalisation and hub development are lengthy processes

Even in the successful cases of the United States and United Kingdom, market liberalisation has taken one to two decades to fully mature. These two countries were indeed pioneers, and countries learning from them can be expected to accomplish market reforms more rapidly but this process will still require years to be completed. Even if European countries could benefit from the UK and US experience, liberalisation and hub development have yet to be achieved.

By contrast, liberalisation and hub development are still continuing in many OECD European countries. Some OECD countries, such as Japan, Korea or Turkey which have had established gas industries for decades, are still far from having liberalised gas markets. Besides this aspect of the development stage of the market, experience from OECD countries shows that liberalisation takes time, usually a decade (and often more), before reaching any quantifiable results.

Define what is desired regarding market prices for gas

Price has very often been described as the most important gas issue that China is facing. China has an overall regulated approach based on cost-plus for the production and pipeline tariffs – similar to what existed in the United States in the pre-liberalisation period. Many issues have therefore appeared as new (and potentially more expensive) unconventional gas resources need to be produced and more expensive imports enter the Chinese gas market. With growing LNG imports, China is increasingly exposed to global gas dynamics and the spread between cheaper domestic gas production and expensive spot LNG cargoes is growing wider.

The need to reform gas prices in such a way that they encourage end-use is as pressing as ever. However, it must be recognised that some Chinese customers are already paying relatively high gas prices (ranging between USD 12 and USD 25 per million British units, MBtu), notably compared to other non-OECD countries and the United States.

However, there is a clear issue of cross-subsidisation between different classes of customers. Indeed, in most OECD countries, residential gas prices are usually higher than other sectoral prices, due to the need to reflect distribution and storage costs on top of procurement and transmission costs, which is not the case in China where industrial prices or gas prices for public services are the highest. It is worth mentioning that a period of low inflation is actually the most opportune time to push forward reform of gas prices, especially when it can lead to price increases. The reform should also pay attention to the regional differences in terms of ability to accept higher prices.

China's government should have a view on whether it wishes to keep a market-approach based on indexation to alternative fuel prices, or move progressively to a hub pricing mechanism by continuing and developing the experience of the Shanghai hub. Indeed, the pricing issue is not only about the price level, but also about their structure, so that they properly incentivise production, imports, as well as utilisation of the different components of gas infrastructure. The regulated cost plus approach fails to send the appropriate market signals in terms of upstream development and demand response. Many stakeholders mentioned the move to a market oriented approach for gas pricing, but this needs to be further clarified. Pricing reform is already being piloted by the National Development and Reform Commission (NDRC) in Guangdong and Guangxi provinces and extending trials to other provinces has been proposed. This reform takes a netback approach based on oil price indexation, similar to the approach taken by many OECD European countries. This may be progress in methodology, but fails to account for the true competitor to gas in power generation – coal, not oil. The pilot reforms are in regions that are already paying high gas prices.

While this pilot reform puts China on a more market-oriented path, even if other types of indexation (reflecting both the fuels against which natural gas actually competes and regional differences) were used, it does not put China on a more-ambitious path toward establishing a spot market. There have already been preliminary attempts to create a hub in Shanghai based mostly on LNG imports. This nascent hub received coverage in summer 2012, as it was set to be used to cover additional demand by power generators, but the quantities traded have been negligible and the number of participants limited.

Establishing a spot market is also a lengthy process, wherein the Chinese government would need to take additional steps, including institutional changes such as wholesale price deregulation, separating transport and marketing activities and allowing at least large customers to choose their suppliers. Structural requirements for a spot market would include sufficient network capacity and transparent access, a number of participants large enough to enable competition, and the involvement of financial institutions.

Finally, opening the gas market for the largest gas users and making them eligible to choose their supplier and to negotiate their gas price directly has always been a key step towards market liberalisation. However, many OECD countries have not quite yet liberalised the residential sector.

Enabling third-party access to certain parts of the infrastructure

Third-party access to pipelines has often been an essential condition to effective wholesale pricing reform and to provide necessary incentives for domestic production and competition at the large-customer level. Experience in OECD countries shows that, without an effective third-party access to the pipelines, reforms usually fail to reach their targets. It also shows that effective separation of the management and accounting of natural monopolies (notably pipelines) on one hand and gas supply and trading on the other is crucial to ensuring non-discriminatory third-party access (TPA) and efficient regulation (IEA, 1998). Indeed, market dominance – and preventing competition using pipeline infrastructure in particular – remains a key barrier to development of more-efficient gas markets. In Europe, efficiency is not the only important policy goal; in some rare cases, pipeline infrastructure deemed essential for security of supply has been granted exemptions from third-party access (TPA) for 20 to 25 years.

By contrast, access to LNG terminals is not always regulated even if the European Directives require TPA to LNG regasification terminals. Indeed, many new terminals in Europe were granted partial or total TPA exemption. In the United States, all recent LNG terminals are not subject to TPA. China may wish to increase competition on the wholesale market and also potentially increase security of supply by giving limited TPA to some LNG terminals as has been done in some European countries (France, Italy).

Storage needs to be developed rapidly in China given the rising residential demand. Regulation is extremely varied among OECD countries, ranging from regulated to negotiated or hybrid access, with some supervision by the regulator. An important feature of storage regimes is which players get to use storage, and the types of storage products offered to them. Clearly, if China wishes to introduce TPA to LNG or storage facilities, TPA to pipelines is a pre-condition.

Liberalising the upstream sector

Given China's substantial resources in tight gas, CBM and shale gas, on top of conventional gas resources, the upstream sector is and will remain an essential component of gas supply. OECD experience in terms of upstream is quite diversified given that many have little to no production and a few such as the United States, Canada, Australia, Norway, have relatively large resources. They also have very diversified industry structures, which have also continued to evolve as liberalisation of the upstream sector was moved forward.

Based on OECD experience, liberalising the upstream sector is every bit as important as liberalising wholesale gas prices and introducing third-party access to pipelines. In the upstream sector, the move from a fully regulated system to a more market-based approach was a key driver for US gas production development. Another advantage of the US system, reflecting the large size of the country, is that different regional gas prices exist; they can indicate regional shortages or oversupply and be a driver for investments either in production, transmission pipelines or storage facilities.

Upstream regulation should prevent hoarding of licenses. In the United Kingdom and Norway, companies that are not respecting their work programme as agreed in the plans of development and operation (PDOs) lose their licenses, which can then be offered to the market again through tenders. This implies a careful monitoring of upstream activities by the authority in charge as well as the authority to be very well trained to understand PDOs, notably with such new types of resources such as shale gas. This incentivises companies to respect their work commitments to keep their licenses, rather than enabling them to avoid competition by buying and holding licenses indefinitely.

OECD experience shows that many countries have used specific policies to encourage the development of frontier areas, or more expensive resources as well as mature areas which lie fallow. In the United States, an R&D programme resulted in the development of technologies which later made the development of CBM and shale gas possible. The development of shale gas and other unconventional resources puts a spot light on safety and environmental issues. The technologies and know-how exist for unconventional gas to be produced in a way that satisfactorily addresses these issues, but a continuous drive from governments and industry to improve performance and to adhere to best practice is required if public confidence is to be maintained or earned.

Different competitive models for infrastructure investments

During the phase towards liberalisation in a deregulated/developing market environment, two market models serve as an alternative to the traditional monopoly (or oligopoly) market structure. The "pipeline-to-pipeline competition" model features two or more transport companies covering and competing within the same regional gas market. Competition may be limited, but the threat of new pipeline construction by a competitor may help to limit predatory behaviour in the setting of network prices, even when those are not directly regulated. An example is the US model of open seasons for interstate pipelines, whereby the Federal Energy Regulatory Commission (FERC) exerts ex-post control of the prices. The second approach, wholesale competition, is based on third-party access with proper regulation (see next point) and unbundling of transport and marketing functions, creating competition to supply large end users.

Setting appropriate tariffs for the use of infrastructure

China has done well over the past decade in building new import infrastructure, both pipelines and LNG terminals. There remains a pressing need to ensure that new projects will be supported by anchor customers, by supply sources, and, more importantly, that the costs of using and developing infrastructure are appropriately rolled into customers' bills.

Special attention should be given to the internal rates of return given to new infrastructure projects (notably long distance pipelines), as it appears that the current ones provide too high a return to pipeline activities, cross subsidise other activities and can represent an entry barrier for other market players. Cost regulation has to be fair and transparent, covering all costs. The individual rate of return can be pipeline specific but set by the regulator on a transparent basis.

Investments into pipeline infrastructure in particular remain natural monopolies and thus require regulatory cost approval. Ex-ante cost approval, a reasonable rate of return and properly defined depreciation periods for network investments have proven valuable tools to ensure cost stability, economic efficiency and long-term investment security in this part of the value chain. The framework for cost approval should be fully cost reflective, transparent and consultative to allow for full market insight and investment attractiveness.

It is worth mentioning that investments in domestic interstate pipelines in the United States are mostly done through open seasons, and driven by pricing differentials between regions. Such investments are usually performed by private companies, and made possible by the binding long-term capacity allocation required for securing the investments over the long life time. Regulation can take place ex-post, if required, to handle complaints

The regulated total costs should always be used to determine the charges for system use, which can vary by customer group and time of use to reflect specific cost-drivers. Cross-subsidisation between different parts of the value chain should be avoided, as this would have discriminatory effects on potential new market entrants and competition.

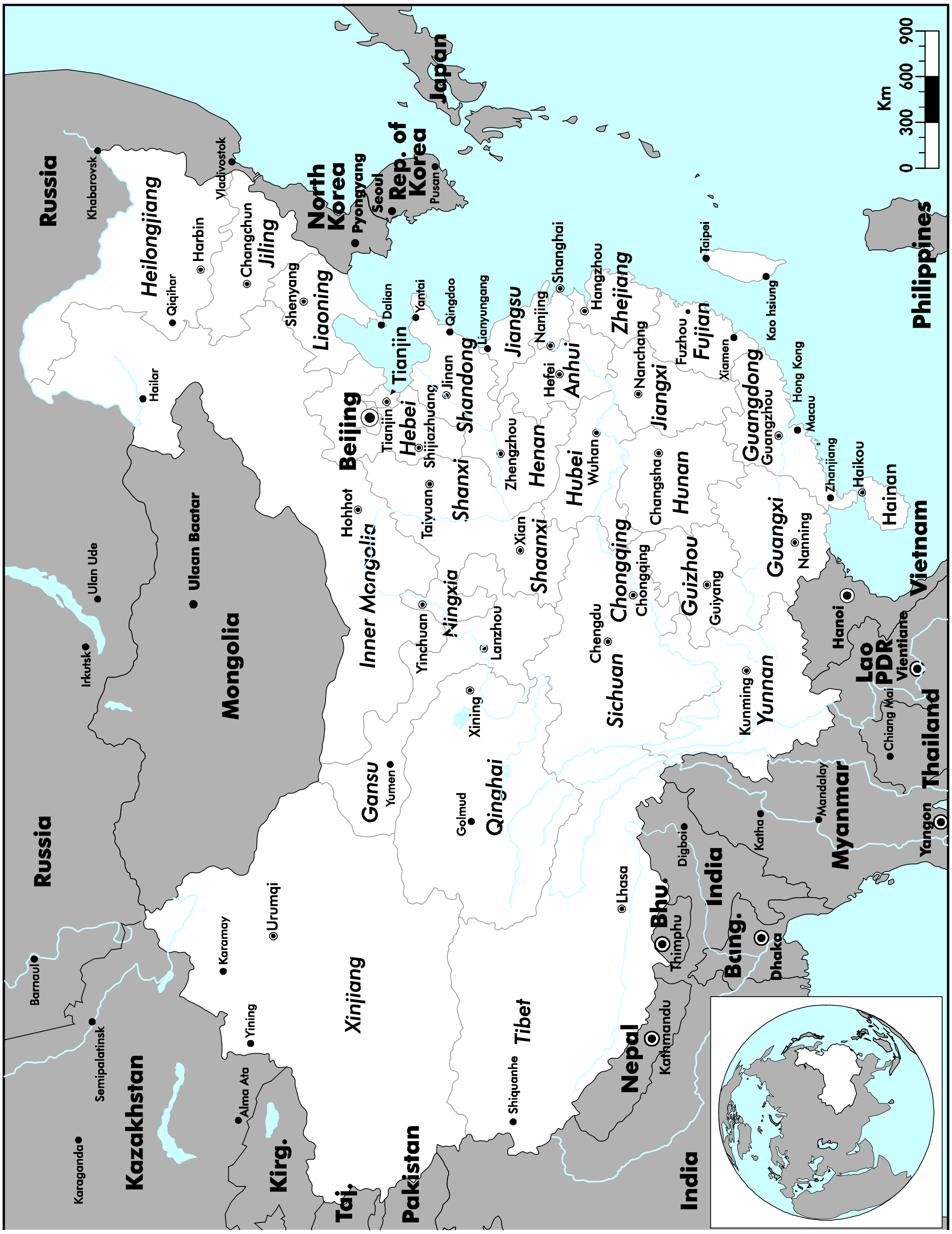
Investments in new LNG terminals in OECD countries follows two different approaches, either a *centralised approach* where the needs and regulation of the new capacities are planned in advance, or a *market-oriented approach*, where companies take FID based on their evaluation of market needs and regulation, are usually exempt of TPA but face higher risks in terms of utilisation of their LNG terminals. These two approaches have implications on the type of companies investing, the business model and the utilisation of the terminals.

Costs of developing underground storage facilities should be clearly borne by the end user, given the important needs for that sort of flexibility in China. OECD experience on developing storage shows a variety of approaches with negotiated or regulated access and even some TPA exemptions granted for a certain period of time. The specific conditions regarding who can have access to storage capacity and minimum storage requirements should be decided by the authority in charge. Each storage operator should give transparent information regarding the conditions of access to its storage facility.

Transparency is key

Transparency and availability of data are essential for building confidence among market players. This ranges from transparency regarding pricing when and if a spot market is developed, to the availability of the terms and conditions of access to the pipeline system, and potentially to LNG import terminals and storage facilities. This represents a critical factor in preventing discrimination among shippers, encouraging access and competition, and ensuring efficient operation of the industry.

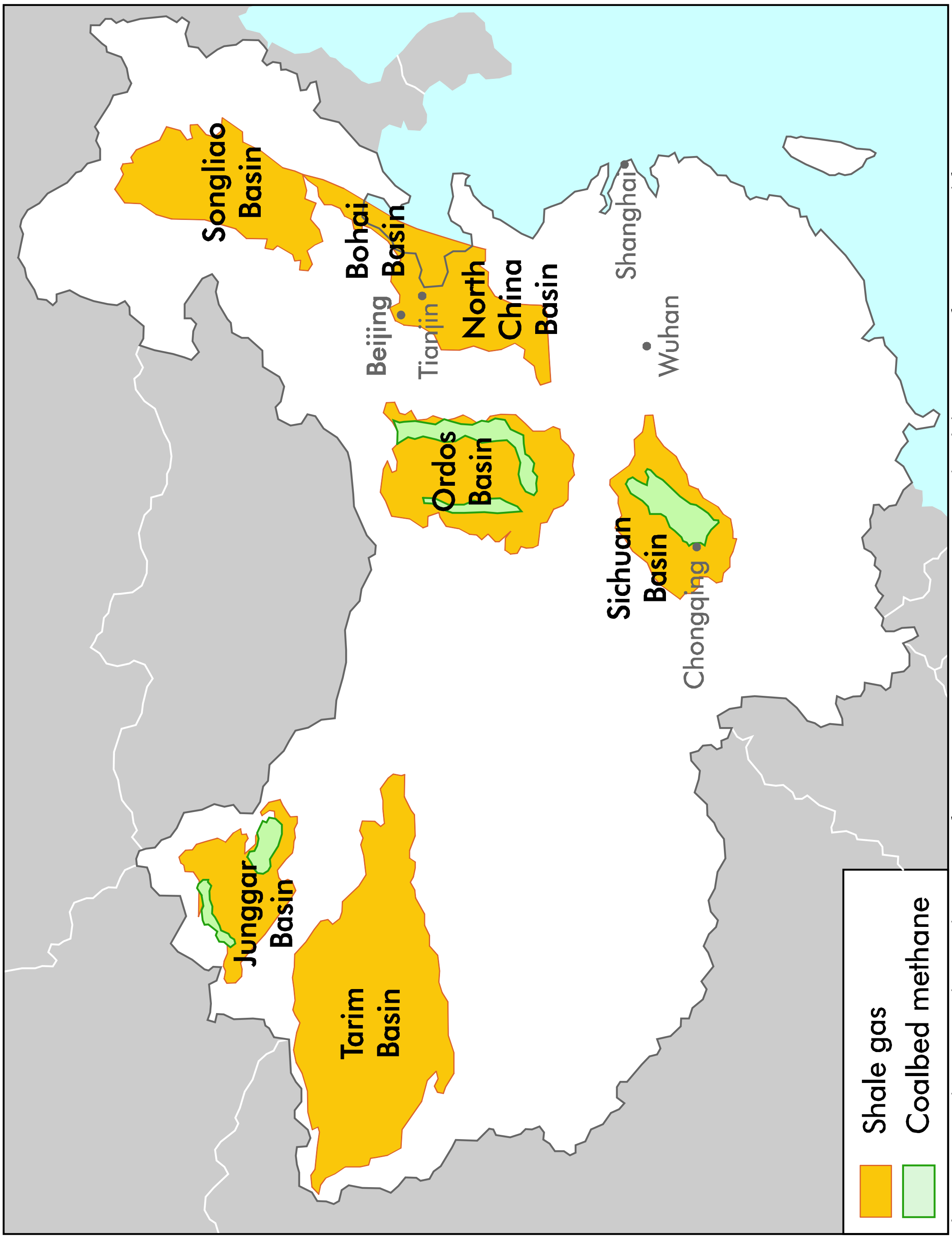
Map 1 • Regions of China



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: IEA, 2002.

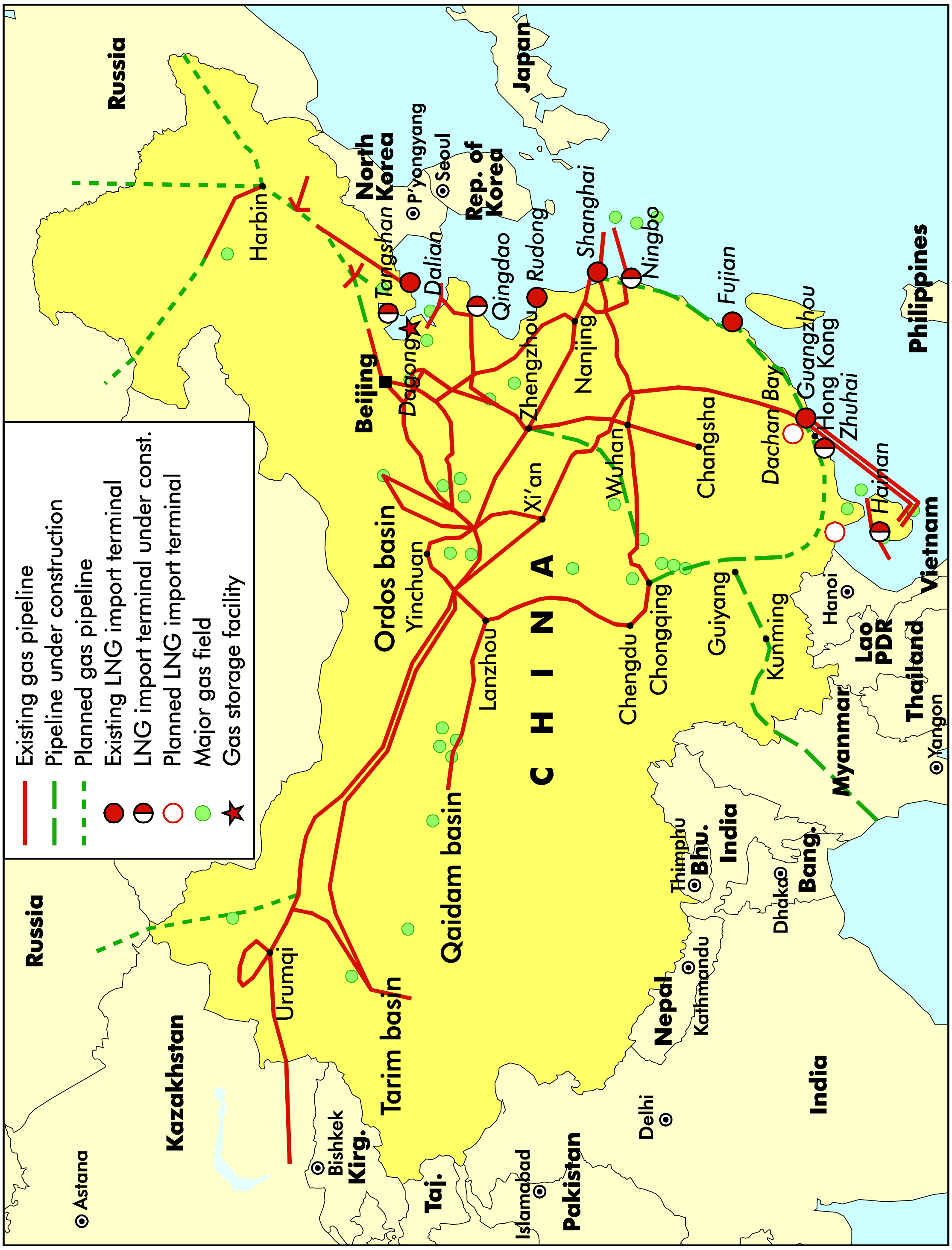
Map 2 • Major unconventional natural gas resources in China



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: IEA, 2012b.

Map 3 • Natural gas infrastructure in China



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1. Introduction

China faces many challenges in the coming years to achieve the 12th Five-Year Plan (FYP) target of significantly increasing domestic gas use by 2015. All sources of gas supply – domestic production, including unconventional sources, as well as imports of liquefied natural gas (LNG) and pipeline gas – will be necessary in order to satisfy a demand level by 2015 which could be up to twice that of 2011. Bringing sufficient gas supplies is only one part of the equation: gas needs to be transported to the final end-user, and to support regional developments while ensuring that security of gas supply is met. This requires therefore significant investments on the midstream and downstream sides as well.

There has been strong interest in the IEA carrying out a project on gas pricing and regulatory reform in co-ordination with a Chinese research organisation, China5e.

During the first part of this project, different Chinese and foreign stakeholders were interviewed in order to get an up-to-date and detailed overview of the current Chinese gas market and understand the obstacles to increasing gas supplies and expanding gas use in a least-cost manner. Additionally, the work and research done on these issues over the past decade was consulted extensively, identifying which issues had been solved or not and why.

In a second stage, the IEA investigated how comparable obstacles have been tackled in OECD countries, acknowledging the fact that no country is similar to China and that lessons from other countries have to be implemented with a regional adaptation. Additionally, most OECD countries already had relatively mature gas markets when they undertook liberalisation of their gas market. Priorities are also very different: China aims to diversify its energy mix away from coal even as it seeks secure supplies of a range of energy sources to power its growing economy, while OECD countries, where energy demand has plateaued, focus primarily on creating greater efficiencies and lower prices by liberalisation and fostering competition.

At the same time, a visit of five Chinese delegates from various agencies and companies to Europe was organised in order to give them the opportunity to get a better understanding of the regulatory and pricing environment in various European countries. Exchanges on issues such as pipeline and storage regulation and tariffs, state of competition and competition challenges, security of gas supply, infrastructure investment and planning are expected to lead to insights that can help to accelerate the growth of Chinese gas demand in the most affordable manner while ensuring security of supply.

Creating country-specific market frameworks is a sensitive topic, and an overly prescriptive approach will be ineffective. Instead, our goal is to place into the context of China's current debate up-to-date information on developments in gas markets elsewhere that will be most informative to stakeholders, and particularly to regulators.

Although an in-depth analysis of China's current gas market and regulatory landscape would be highly interesting to many readers, it would be very complex, and it is not within the scope and purpose of this report. In the next section, we simply highlight some of the features that aid in identifying what experience in OECD countries may be relevant to China at this time. In the concluding section of the paper, we provide some initial thoughts about how to apply those relevant lessons to China's situation, but this should be considered only a starting point.

2. Key challenges in pricing and regulatory reform in China's gas market

Key messages

- China is looking at doubling its natural gas consumption from 130 bcm in 2011 to 260 bcm in 2015. This step increase is challenging, not only in terms of attracting gas supplies and building the infrastructure, but also in terms of pricing.
- The pricing issue is by far the most important issue as it interacts with all the other aspects. This includes dealing with more expensive imports, incentivising future unconventional gas production, and avoiding cross-subsidies between large users and residential users. Also the pricing structure, whereby the upstream and pipeline tariffs are regulated based on a cost-plus approach and differ depending on the end user must be changed.
- Incentivising efficient investments along the gas value chain, from upstream, import infrastructure to midstream (pipelines and storage) is essential to ensure a timely and safe development.
- Chinese gas industry is characterised by an oligopolistic structure dominated by three companies. In most parts of the gas value chain, other players have limited roles.
- The gas industry needs a clear regulatory framework; this can be compromised by overlapping powers from different agencies and from the central and local governments.

Some of the issues faced by China regarding gas are not new, but as Chinese gas demand reached over 130 billion cubic meters (bcm) in 2011 (CNPC Research Institute, 2012), making it the fourth largest gas market in the world, they have become more acute and could represent obstacles to further demand growth. The 12th FYP aims at doubling the share of gas in the primary energy demand, which means almost doubling gas demand by 2015 from the 2011 consumption level. This requires sufficient import infrastructure to be built in an efficient manner in co-ordination with building new domestic transmission, distribution and storage infrastructure. This also implies the need to attract sufficient supply, potentially in a higher price environment. Stakeholders' opinions on the potential demand levels by 2015 differs widely depending on their views on how much could be imported and produced domestically, with an average consensus at around 230 bcm. Views also diverge on how such a demand level would be met, notably on the respective contribution of domestic production, including unconventional gas, pipeline imports from Central Asia and Myanmar and LNG imports.

Over the past decade, a reform had started to create a more market oriented oil and gas sector, including the state-owned companies. But this reform stopped at some crucial elements for the gas market, and is still characterised by a patchwork of targets and strategies, institutions and companies as well as regulations and practices. The gas market has a fragmented and monopolistic structure, regulation of prices at different stages based on a cost-plus approach, lack of access for small, medium-sized and foreign companies to existing infrastructure and thus markets, and a lack of a clear, efficient and transparent regulatory framework as well as diffuse and overlapping regulatory authorities.

Despite these issues, China has managed to build significant import infrastructure allowing for diversified supply from Central Asia, Myanmar (2013) and various LNG sources. This import infrastructure has a relatively diversified ownership structure, even if the Big Three NOCs dominate on the LNG side and CNPC on the pipeline import side. Infrastructure has been built at a relatively rapid pace, and the main challenge is to continue such growth and attract gas supplies to fill this infrastructure.

The challenges in terms of pricing and regulations can be grouped into four categories:

- pricing levels and pricing structure;
- incentivising efficient investments along the gas value chain, from production to import infrastructure and transportation/storage within China;
- oligopolistic structure of the gas industry dominated by three companies; and
- overlapping powers from different agencies and from the central and local governments.

While stakeholders wish to move towards a more market-based approach, according to the interview results, this can mean very different end results, depending notably on the government's vision on how it wants to proceed on issues such as pricing, network ownership and structure as well as on competition in domestic gas production. China has already moved away from the vertically-integrated approach that was the feature of pre-liberalisation Europe, and that, some may argue, could still enable it to reach higher penetration of gas (and consequently higher demand), albeit not always in the most cost effective manner. China though, is not yet at a liberalised stage, but rather in between: this carries the risk that the growth of some critical parts of the gas value chain will be insufficient.

Pricing

The current pricing system has been highlighted as the main issue to achieve China's gas goals by many domestic stakeholders interviewed, and as one of two main issues by foreign parties (with the second one being access to infrastructure). While price reform is widely recognised as necessary for China to reach its ambitious targets of increasing the gas role in the primary energy mix, the road to it seems paved with many obstacles. The pricing issue is not only a question of absolute level of gas prices (even if end-user prices are relatively high in comparison with many non-OECD countries), but also of pricing structure.

Pricing level

The issues regarding gas pricing levels are multiple, ranging from the rapid increase of procurement costs of imported gas to the resulting widening gap between domestic gas and imported gas prices and the difficulty to pass through the cost increase to the final end-user and make gas-fired plants competitive in the power sector. While some issues such as the lack of a market-based approach, the low level of regulated residential gas prices are not new, the divergence between prices for different gas supply sources really gained significance over the past two years. China is becoming increasingly import dependent (around 8 bcm imported in 2009 versus an estimated 31 bcm in 2011), while costs of imported LNG and pipeline gas have sharply increased. For example, the average price of LNG imports almost doubled between 2009 and 2011 to reach around USD 8.5/MBtu. This is still relatively cheap compared to Japan's import prices which reached USD 15/MBtu on average in 2011, but unlike Japan, importers cannot pass through all the additional costs to final end-users resulting in losses.

As China becomes increasingly import dependent, a widening gap has therefore appeared between city gate prices from different sources, in particular between that from cheaper domestically produced gas and more expensive imported pipeline gas from Turkmenistan and LNG (new contracts as well as spot LNG). For example, city gate prices at Shanghai are estimated to range between USD 8/MBtu (for gas from domestic sources transported through the first West-East pipeline) and USD 13/MBtu (for Turkmen gas imports) and even USD 17 to 18/MBtu for spot LNG imports as of end 2011.

This widening gap will become even worse in the next four years with increasing volumes of imported gas. Turkmen imports accounted for 4 bcm in 2010, and increased to 15.5 bcm (12% of total gas demand) in 2011 and are expected to further increase as the contract states 40 bcm. CNPC has been said to be losing money on Turkmen imports (CNY 1/m^3 according to press reports, which would equate to CNY 15.5 billion for the year 2011, but it is important to mention that CNPC produces its own gas in Turkmenistan) resulting in the central government granting tax rebates for import prices exceeding the wholesale gas prices for a period of ten years (2011 to 2020). Spot LNG has also become very expensive (USD 17/MBtu) due to a combination of increasing oil prices and LNG markets tightening after Fukushima. Meanwhile, new sources of LNG such as Australian LNG expected to start by 2014 to 2015 are unlikely to be cheap given the high capital costs of these projects (and possible delays would make them even more expensive). Keeping city-gate gas prices low will keep the distortion between the different sources of gas and could slow future increase in gas imports.

Chinese gas prices are not low. They are relatively high compared to most non-OECD countries; end users in the Middle East and Africa, for instance, usually pay prices ranging from USD 1 to USD 4/MBtu. There are also high compared to end-user prices in some OECD countries, notably the United States where industrial gas prices were at around USD 5/MBtu in 2011. A key issue is lower residential end-user gas prices, which are regulated, and often kept low to avoid triggering high inflation rates. As can be seen in Table 1, these prices are usually the lowest compared to industry, commercial, power and transport sectors. This reflects cross-subsidisation in order to protect residential consumers. Increases of residential gas prices are done through public hearings on a local basis, so that reforms decided by the Central Government could fail to be implemented locally. Some regional residential prices are also lower than the corresponding price of imports, creating losses along the gas value chain since the costs of transport, distribution and storage cannot be appropriately covered. This situation is the opposite of what can be observed in many OECD countries, where residential users usually pay higher prices than other users (excluding the specific social tariffs to protect the poorest). This cross-subsidisation among gas users can also distort the market's reaction to fuel prices and in the case of China could be counterproductive for gas use in the industry and commercial sectors.

Table 1 • End-user gas prices in selected Chinese cities, 2011

USD/MBtu	Residential	Public services	Industry	Transport
Beijing	9.01	12.48	12.48	20.79
Tianjin	9.67	13.85	13.85	17.36
Shanghai	10.99	16.22	17.10	20.66
Nanning, Guangxi	19.21	25.19	25.19	21.76
Shenyang, Liaoning	13.80	16.31	16.31	16.31
Hefei, Anhui	8.78	14.97	10.37	14.97
Wuhan, Hubei	10.58	15.39	12.55	19.82
Chongqing	7.19	9.58	9.37	19.24

Note: prices have been converted from CNY/m^3 to USD/MBtu using an average annual conversion rate between currencies.
Source: CNPC Research Institute, 2012.

Affordability is very important, but while keeping residential gas prices at lower levels compared to other categories gives the opportunity to these customers to consume gas, it also encourages inefficient use of gas, forces the government or companies to bear the losses and can potentially result in industry or power generators lacking access to gas, as gas demand is still supply-driven in China (and expected to remain so in the next five years). Such a system can backfire by creating lower industrial output and lead to public dissatisfaction. There are actually many differences between sectors and regions. In the industry and residential sectors, the alternatives are expensive oil products, so that it should be possible to increase gas prices given current oil prices levels. While domestic consumers in general could afford an increase of their gas bills, an increase of gas prices to the industry and commercial sector would have an overall impact on all prices including essential products such as food.

Finally, the key sector is power generation, where gas competes against coal. Regulated and capped power prices make it difficult to pass through high gas prices unless there are regional shortages. This issue must be addressed for gas demand to increase in this sector and to play its role in meeting the flexible- and peak-times of electricity demand and to curb coal demand growth. This will require infrastructure and markets to be flexible to accommodate such demand fluctuations. The environmental benefits of gas as well as its flexibility should be recognised in the pricing system, which therefore imposes reforms in the electricity sector to be performed in parallel.

Pricing structure

Tariffs are currently based on a cost-plus approach. Except for the two pilot programmes in Guangdong and Guangxi regions, the whole pricing regime for domestic natural gas is based on three elements, *i.e.*:

- ex-plant (wellhead) price;
- pipeline transportation tariff; and
- end-user price, including fertiliser producer, industrial users (direct supply), city gas (industry or not industry).

The ex-plant (wellhead) price is proposed by the project developer and adjusted by the central government. It is based principally on the production cost of natural gas (wellhead cost plus purification fee, including financing cost and tax such as municipal construction fee and education cost fee) plus the appropriate margin for the producer. This price is a baseline, and producer and buyer can negotiate up to 10% above it. While this methodology allows for a common approach for domestic fields and for more expensive fields to be developed as long as the costs can be passed through, it also creates one price for each field: this complicates the regulatory handling of the pricing system when the number of producing fields increases.

The pipeline transportation price is also set by the central government. Before 1984, a flat pipeline tariff was applied. After 1984, new prices were adopted for new pipelines. All such prices differ, determined based on the pipeline cost (construction and operation) plus the appropriate margin (internal return rate [IRR] of 12%) with a variation by transport distance from each gas source to each city gate. Therefore, the transport tariff depends on the different consuming regions, and also the diameter and length of the pipelines. The IRR is standardised for all pipelines by the government at a current rate of 12%, which seems to be above OECD averages. The high IRR are accompanied by very short depreciation periods of ten years or so, while the technical lifetime would be more like 40 to 60 years. This has the potential to increase pipeline tariffs even more so or to lead to highly fluctuating transportation costs. According to interviewed market players, the high IRR is required to compensate for losses at the production, imports and sales side, where capped prices usually lie below the real production and sales costs. This pricing structure is very similar to that which prevailed in the United States between 1954 and the early 1980s, with capped well-head prices for gas and guaranteed IRRs (of around 12 %) for interstate pipelines (see Chapter 5). This level of cross-subsidisation hinders wholesale markets as it generally leads to a competitive advantage of the integrated companies in favour of non-integrated exploration and/or supply companies without own transportation capacities. In this case, such a system would require a continuous compensation by network charges, but this would either require building new infrastructure directly after its depreciation (which is 14 years) to continue to include the capital costs in the charges, or by continuing to charge for an existing infrastructure which has already been re-financed. Both cases are considered to be uneconomic, since the real life-time of the main components of the gas transportation network are closer to 40 to 60 years and charging for depreciated assets would mean massive overcompensation to network operators.

Additionally, city gate prices not only differ depending on the gas supply, but for each source there are different prices depending on the final gas use (*e.g.* residential, commercial, industry or fertiliser). Indeed, both the ex-plant and the transport tariffs are set depending on the use which introduces another layer of complexity. The reform currently being started in the Guangdong and Guangxi regions would result in one maximum single price at the city gate independent from the gas source, which would simplify the whole pricing system.

As transmission and storage activities are not split, storage costs are not yet properly identified and taken into account separately, which is likely to create issues as new storage facilities will be necessary to meet seasonal variations. Currently, gas storage facilities are examined, approved and constructed as auxiliary facilities of pipeline transport system, whose costs is covered by the budget of pipeline system. The current system would favour companies with existing transmission assets, which can cross-subsidise the development of future storage assets. Given the lack of storage capacity in China, proper incentives should be given for sufficient investments to be made.

The new pricing reform

The recent pilot pricing reform (Box 1) indicates a move towards a netback pricing and away from a cost plus regulated approach. Such an approach was already suggested in the IEA 2002 report (IEA, 2002). At the same time, Chinese companies and policy makers have shown growing interest in creating a hub in Shanghai that would be based on the Shanghai city gate price, when the NDRC reform is extended to Shanghai.

Box 1 • Towards pricing reform?

There have been many different proposals to tackle the pricing issue over the past few years; one of which was to increase the ex-plant price by CNY 1.5/m^3 (USD 6.3/MBtu) compared to the current average of CNY 1.15/m^3 (USD 4.8/MBtu), but this has not been pushed forward. End December 2011, the NDRC announced the start of a pricing reform in Guangdong and Guangxi, but this reform is actually different: the system is based on a netback approach rather than a cost-plus approach. The reform is so far limited to these two regions. Guangdong is a relatively large consuming area with over 10 bcm consumption, while Guangxi is a small market with a demand of less than 1 bcm. Guangdong sources its gas from offshore domestic production, LNG and started receiving Turkmen gas through the second West-East pipeline at the end of 2011 as well as LNG truck imports from neighbouring provinces.

Under the new system, city-gate prices would be linked 60% to fuel oil and 40% to liquefied petroleum gas (LPG). These linkages reflect the competitors of gas in the industry and household sector respectively, but fail to take into account the competition against coal. These prices are those of Shanghai (customs data), raising the question of when the reform would reach this specific market. The formula takes calorific differences into account, and includes a 10% discount to promote gas use. The system plans for an annual increase in a first stage before moving progressively to quarterly changes. Although this change is not expected to result in a price increase in the short term (prices in these two regions are already among the highest in China), it should ultimately result in price increases when the first change occurs. Monopoly activities should remain regulated.

Such a reform raised questions on how fast it will be expanded to other regions, how quickly there will be a move towards quarterly price changes and how high the regulated price will have to be to allow for a desired level supply-side delivery and competition. Some answers were already given by the announced plan in July 2012 to extend the reform to Shanghai as well as to Sichuan, which will start receiving Turkmen gas, in 2013.

The ultimate goal is to liberalise ex-plant prices and pave the way for the development of unconventional gas based on market prices, which in practice means that there will be many sellers and buyers trading in an open wholesale market. This implies to move the reform to those regions that depend more on domestic supply. Additionally, given that the netback approach covers the cost of producing and bringing gas to the market, defining a price for transportation for third parties will become imperative in order for them to get the appropriate revenues from their gas. Finally, the reform does not define the level of end-user prices, but encourages establishing upstream and downstream mechanism through hearing. Seasonality and the cost of storage are not included in the netback calculation. This is imperative to avoid seeing local distribution companies getting squeezed by having to purchase more expensive gas while being unable to pass through these cost increase. The Guangdong and Guangxi Price Bureaus supervise the local sales prices and should explore and establish a stepwise gas tariff.

The Shanghai Petroleum Exchange (SPEX) introduced LNG trading in December 2010. But until recently, volumes were relatively low (400 tons per day during winter and 200 tons per day during summer). Most of the LNG comes from CNOOC's Shanghai LNG terminal. In the summer of 2012, SPEX launched a natural gas peak-shaving spot trade, covering early July to mid-September. It aimed to ensure supply to gas-fired power plants during the summer period. It is also an opportunity for companies to get rid of expensive contracted LNG, which could not be sold otherwise. Companies such as PetroChina, CNOOC, Shenergy Group and Xinjiang Guanghui were to put 100 million cubic meters (Mcm) on the trading platform, again mainly from LNG. Such an experience is unlikely to affect significantly the Chinese gas market, which has annual volumes 1 000 times higher. Depending on the results of the summer trading, SPEX may decide to have a winter trading. Nevertheless, this experiment – instituted just a few months after the NDRC launched pilot price reforms – demonstrates a willingness to move to market prices and, at the least, promise to provide opportunities for participants to experiment with trading.

Investments along the gas value chain

Issues regarding investments are multiple, from making sure that enough supply (domestic production and imported gas) will be available to meet the demand level objectives to building the import infrastructure, transmission pipeline and distribution infrastructure to support this demand level and finally storage facilities indispensable to meet seasonal variations.

Based on views expressed as well as on other information received, it appears that China, while setting up an ambitious policy target for its gas use by 2015, does not have a defined plan or strategy with specific targets to reach it, at least nothing such was ever published or mentioned during interviews. Such a plan would include in-depth demand projections by sector (including specific targets such as number of households connected, or gas-fired capacity to be built), supply targets by source. Setting up sector specific policy plans can help to secure investors' appetite for continuous activity during a transition period towards fully marked based sector developments.

Upstream sector

The first and most important source of gas supply is domestic production. Although it is no longer expected to grow at the same pace as demand (domestic production reached 101.12 bcm in 2011, versus around 130 bcm for demand), it will continue to constitute the bulk of supply. Nevertheless, discussions reflected many uncertainties on future domestic production levels, even for 2015. Based on the current trend, it should reach around 135 bcm by 2015, but there could be different outcomes depending on prices and pricing reform, access to and development of the infrastructure and development of unconventional gas.

Since most licenses for gas exploration have been allocated to the three domestic companies CNPC, CNOOC and Sinopec, these three companies form an oligopoly in the upstream sector in terms of licenses and represent the bulk of domestic production. CNPC actually represents around three-quarters of total gas production as of 2011. There is little room for small and medium-sized companies as they own few licenses, often with less competitive economics. As the threshold for exploration to be performed in order to keep the license is low, these companies usually keep the licenses preventing new entry, and other companies have few chances to get these licenses through relinquishment. At present, to change this, one would require modifying the relevant laws. This is not expected to require complex law amendment procedures; the reform of upstream oil and gas mining rights could be achieved through public bidding of exploration rights for shale gas. It would also imply that the "mining right withdrawal system" needs to be enhanced so that compulsory withdrawal is required for enterprises which have the mining right, but fail to meet the requirement of investment, or fail to achieve the output within a prescribed time limit. The Ministry of Land and Resources (MLR) has also started to open up bidding in shale gas. Offshore, CNPC and Sinopec obtained four blocks via bidding in early 2012, thereby breaking CNOOC's monopoly on offshore resources, and potentially laying the foundation for further onshore bids from companies other than CNPC and Sinopec. The involvement of foreign or smaller Chinese gas companies is nevertheless so far limited and happens mostly through partnerships and joint-ventures with the Big Three NOCs. In that case, either international oil companies (IOCs) team up with small companies with which they have a voice (though these have small influence and the projects may not go forward), or they work with the Big Three, with which they have little influence but projects move ahead. Foreign participation is nevertheless welcome for fields requiring technological capabilities such as tight gas fields, or more recently, shale gas fields. CNOOC currently has exclusive rights to conclude production sharing contracts (PSCs) with foreign companies for offshore developments. Co-operation in the onshore area is mostly through CNPC and Sinopec.

Unconventional gas is so far unchartered territory for China, although significant volumes of tight gas (more than 20% of current gas production, but often considered as conventional gas) are already produced. There is still wide disagreement regarding coalbed methane (CBM) levels that could be reached by 2015, with opinions ranging from around 10 bcm to 30 bcm. Chinese laws do not differentiate CBM and coal mine methane (CMM). From a technical point of view, CBM is recovered from surface wells and CMM from underground capture. Previous CBM targets have been missed (around 2 bcm was produced in 2010[2] from surface wells and 7 bcm from underground mines, and only 3.6 bcm was utilised versus the 11th FYP target of 10 bcm) due to conflicts between coal producers and gas producing companies on overlapping rights, with on one side the local coal groups supported by local governments having the coal mining rights and on the other side, the central-owned NOCs holding the CBM mining rights for exactly the same resource regions. Each party looks at its own interests, which conflict with others'. Additionally, other factors include lack of access to pipelines (or absence of authorisation from the local government to transmit CBM), lack of experience, knowledge, and technology. CBM is currently essentially produced by coal producers, PetroChina and CUCBM. Although it is true that CBM is currently getting preferential treatment in terms of rebates, tax terms, and premium, and that companies have better knowledge on production, some issues remain: new pipeline infrastructure or access to pipelines for CBM producers will be necessary for large quantities of CBM to reach coastal markets (unless they build the pipelines themselves), to promote the use of gas in coal areas, and to improve the framework for CBM resource management including incentives to reduce GHG from mines and strongly enforce mine safety standards to get higher quality gas. Shale gas is not expected to reach any significant number by 2015 as the first tender was launched only in 2011,

[2] There is also an estimated 7 bcm whereby CBM is extracted from coal mines.

and it will face exactly the same issues in terms of pipeline access on top of finding the best shale gas producing spots and the technological challenges regarding producing this new resource. Since CBM development was well below targets, the same could happen with shale gas.

Box 2 • China's first shale gas bidding rounds

China is said to have large shale gas resources, estimated at 25 trillion cubic meters (tcm) by the MLR. This is attracting interest not only from the central government, eager to see natural gas demand targets in the FYP Plan being met, local governments interested in the development of local economy, and obviously Chinese and foreign oil and gas companies. In early 2010, the first hydraulic fracturing using US technology was performed in China, followed one year later by the first drilling of shale gas in Sichuan. Shale gas exploration activities have increased in recent years under a government-driven programme to evaluate the resource base. Results from several pilot projects, to be completed in 2012, are expected to inform the selection of high potential areas for further exploration. As of early 2012, an estimated 20 shale gas wells had been drilled by Chinese companies (IEA, 2012b). The FYP sets a target of 6.5 bcm of shale gas production by 2015, which is ambitious.

A first round of bidding for four blocks in Sichuan was launched by the MLR in June 2011. Six state-owned enterprises were allowed to take part in the round, but only Sinopec and Henan Provincial Coal Seam Gas Development and Utilisation Company obtained licences for one block each as only two offers were considered satisfactory. Foreign companies were excluded, despite the current lack of expertise of Chinese companies in this area, but they were allowed to form joint ventures and provide technology services to Chinese companies involved in the exploration and production of shale gas.

Companies are subject to conditions such as starting exploration work within six months, moving into production within three years, submitting their work plans. Shale gas blocks converted from existing oil and gas blocks will not apply to this system, but this may change in the future. Conditions for the second bidding round may also be stricter.

As of mid-2012, a second round is being prepared although it has already been postponed. Unlike the previous one, it has been opened to private companies and companies backed by local governments. Indeed, the MLR has to take into consideration the interests of local governments wishing to participate in the auction. Local governments hold land rights to the blocks and get revenues from land sales. Additionally, they may wish for some of the local shale gas production is consumed locally rather than exported to the coastal markets. Finally, how foreign companies may cooperate in the development of these shale gas licenses with the winners remains undecided.

Developing import infrastructure

Having enough import infrastructure is an essential condition to meet high demand levels given the constraints on domestic gas production. As of early 2012, China imports both LNG – from various sources – and pipeline gas from Turkmenistan. LNG import capacity amounts to 29 bcm as of early 2012, while another 23 bcm is under construction (Table 2). This means that China could import some 50 bcm of LNG maximum by 2015, unless additional LNG terminals which have been approved are built by then, which is possible as LNG terminals are usually built in three years.

According to a CNPC press release from August 2011, the capacity of the Central Asia Gas Pipeline from Turkmenistan will reach 30 bcm/yr by the end of 2012, and increase to 55 to 60 bcm/yr by 2015. To these volumes, one should add the 12 bcm Myanmar-China pipeline currently under construction and expected to be operational in 2013. The issue is not only the pipeline capacity being completed in time, but also suppliers' ability to deliver these volumes. While China and Turkmenistan have reportedly reached preliminary agreement on a deal that would supply 65 bcm/yr to China, no date has been officially mentioned for that deal and there are considerable technical and other challenges to quickly realising such volumes. 17 bcm/yr are expected to come from the Chinese-Turkmen production sharing agreement on Bagtyyarlyk, while Turkmenistan has to provide 13 bcm/yr from other fields. This leaves 25 to 30 bcm to be found to fill the Central Asia Gas Pipeline, possibly coming from other fields in Turkmenistan, or from Uzbekistan and Kazakhstan. Turkmenistan still exports to Russia and Iran, despite Russian exports being much lower since exports to China started. This would also require pipelines to link existing or new fields in Turkmenistan to the export pipeline, as well as new processing plants to be built. Additionally, there are doubts on whether or to what extent the pipeline from Myanmar would be filled due to the lack of finding sufficient identified supply in Myanmar. Most people interviewed had a conservative view on Myanmar supply (4 bcm by 2015).

Table 2 • LNG import terminals existing and under construction

	bcm/yr	Date	Companies
Dapeng	9.0	2006	CNOOC 33%, BP 30%, others
Fujian	7.0	2008	CNOOC 60%, Fujian Dvpt and Investment Corp 40%
Shanghai	4.1	2009	CNOOC 45%, Shanghai Shenergy Group 55%
Liaoning	4.1	2011	Kunlun 75%, Dalian Port 20%, Dalian Const. Inv. 5%
Jiangsu	4.8	2011	Kunlun 55%, Pacific Oil and Gas 35%, Jiangsu Guoxin Investment 10%
Zhejiang	4.1	2013	CNOOC 51%, Zhejiang Energy Company 29%, Ningbo Power 20%
Zhuhai	4.8	2013	CNOOC 25%, Guangdong Power 35%, & others
Yuedong	2.7	2013	CNOOC
Hebei	4.8	2014	PetroChina 51%, Beijing Inv. Holding Company 29%, Hebei Construction Inv. Company 20%
Shandong	4.1	2013	Sinopec, Huaneng Group
Yangpu	2.7	2015	CNOOC 65%, Hainan Development Holdings 35%

Source: IEA.

This means that, although China could theoretically import around 120 bcm of gas by 2015 based on infrastructure, imports are more likely to be around 90 bcm in IEA opinion with around 40 bcm of Central Asian gas, 5 bcm from Myanmar and around 45 bcm of LNG. Thus, domestic production would have to reach 170 bcm to meet the official demand target level of 260 bcm, or 140 bcm if demand is closer to the consensus given by most Chinese stakeholders (230 bcm). Official targets put CBM production at 20 bcm, synthetic natural gas (SNG) at 30 bcm, and shale gas at 6.5 bcm. Increasing domestic production by 70 bcm over four years still appear challenging, especially without a reform of ex-plant prices in place.

As mentioned earlier, a pricing reform started end 2011, even if it is extended nationwide by 2015, it is uncertain whether it would have an impact of production by then given the lead times to bring new green fields to production. With a domestic production of 140 bcm corresponding to current growth rates of 6 to 7%/yr, demand would be constrained to 230 bcm. Therefore, in order to meet the FYP target, more investments would be needed.

Big companies (CNPC) are the only ones investing in (underground) storage facilities. City gas companies have only tanks, LNG stations as storage as they do not have enough money to invest in storage. CNPC plans to invest CNY 70 to 80 billion in storage in the 12th FYP. However, the exposure draft of the *Control Regulation for Natural Gas Infrastructure Construction and Operation* stipulates that "the sellers of natural gas should construct storage facilities independently or entrust relevant enterprises to store gas, and possess natural gas reserves not less than 15% of the contracted annual sales volume to fulfil the requirements of seasonal peak shaving.

Finally, contracts for imported LNG or pipeline gas are subject to the NDRC's approval as new import infrastructure needs the Commission's approval and needs to have secured supply. This can potentially delay either contract negotiations or the construction of the infrastructure.

Developing midstream infrastructure

Pipeline network

Transport infrastructure is not developed enough to support a large demand increase and high demand levels. Indeed, China has over 50 000 km of long-distance gas transmission pipelines, including 36 116 km from CNPC as of end 2011 (CNPC, 2012). The gas transmission network is expanding fast: CNPC increased its network by over 3 280 km between 2010 and 2011, but the length of the network is still low compared to annual demand. By comparison, Germany had 117 000 km of high pressure gas transmission pipelines at the end of 2009, but its consumption was lower than China (97 bcm in 2010) and its geographical area represents only 4% that of China. The United States counts around 500 000 km of pipelines, 70% of which are interstate pipelines, which can be compared to China's long distance pipelines (China and the United States have roughly the same surface (including Alaska), while the United States consumes close to 700 bcm. By any account, China seems to have a long way to go before reaching the same developed network infrastructure as Germany or the United States. Even if CNPC meets its target of building another 40 000 km over the next five years, China would still have less pipeline than Germany with a demand level about 2.5 times higher.

Additionally, most of the pipeline network (80%) is owned by CNPC. In order to meet higher demand levels, the gas transmission network needs to be rapidly developed, not only between the import points and the consumption centres but also between the regions to enhance security of gas supplies and to foster intra-regional trade. The distribution networks need to further develop as well, if China wants to enhance the utilisation of gas at the residential and commercial level.

In particular, long distance CBM transport infrastructure needs to be developed, and the same requirement will apply to shale gas, for this supply to reach coastal areas. Additionally, new areas of gas production might emerge with a push towards more market-based approaches on exploration and production, and will have to be connected to the demand centres.

Storage

There is currently very little storage capacity in China (1.9 bcm of working capacity according to Cedigaz), while residential and commercial gas demand accounts for roughly one third of total gas demand (or an estimated 40 bcm for 2011). As a comparison, OECD European countries with a high import dependency and a similar high share of residential/commercial demand have a working capacity corresponding to around 20% of their annual gas demand. This would mean a total working capacity of 50 bcm for China. As China is expected to still get half of its supply from domestic production, storage needs would be less significant. However, China is a rather large country, and domestic production being far away from demand centres will not always be adequate to meet wide daily variations in coastal areas, so that China should look at underground gas storage, as well as LNG storage and linepack located closer to demand centres.

CNPC plans to invest CNY 70 to 80 billion in storage in the 12th FYP. Companies have now the obligation, according to the FYP, to have some days of storage. As this is not included in the costs, one can wonder how investments would be recovered for a small company unable to cross subsidise the investment through other parts of the gas value chain. Other, less rigid security of supply mechanisms with a more market oriented approach, do not seem to be trusted, since enforcement of regulations on a local level is challenging. The question of strategic storage has been also raised, in particular who should bear the costs should such a model be applied to the Chinese gas market.

Security of supplies is a political responsibility, as it is clearly impossible to let big cities be without gas, even if this implies buying very expensive gas (such as was the case with expensive LNG for Shanghai). Beijing residential users, for instance, must be supplied whatever the cost, even it implies cuts to factories.

Planning and co-ordination

Documents issued jointly by NDRC, the Ministry of Finance, the Ministry of Housing and Urban-Rural Development and NEA such as *Guidance on Developing Natural Gas Distributed Energy, The 12th Five-Year Plan for the Exploration and Utilisation of Coalbed Methane and the 12th Five-Year Plan for Natural Gas*, *Development Planning on Shale gas (2011 to 2015)* set the government's objectives for natural gas. Other documents such as *Regulations on Natural Gas Infrastructure Construction, Operation and Management* have not been issued yet. Although the general bases and objectives are set, a relative key issue would be the co-ordination between the State's agencies and the main companies. The Energy Department of the State Council is responsible for infrastructure, including interprovincial pipelines, pipelines with capacity higher than 2 bcm/yr, LNG import terminals, and storage. Plans for other gas infrastructure are prepared by each provincial government, autonomous region and municipality directly under the central government and sent to the State Council's National Energy Commission (which is different from the NEA) for information. The integrated companies may nevertheless invest depending on their commercial interest. Some objectives are set (such as 10 bcm CBM gas production in 2010), but as they are not binding (unless very essential), there is no fine if the targets are missed.

The new law issued in June 2010, *the Oil and Natural Gas Pipeline Protection Law of the People's Republic of China* could improve the consistency. It says that "The Energy Department of the State Council is responsible for organizing and preparing national development plan of pipeline according to demands of national economy and social development after consultation of the State Council and relevant provinces, autonomous regions and municipalities directly under the central government; The pipeline companies are responsible for preparing pipeline construction plan according to the national pipeline development plan and sending the pipeline construction plan prepared to competent planning departments of cities and towns of the People's Government higher than the level of county which have pipeline construction plan; and the competent planning departments of cities and towns of the People's Government are responsible for bringing the conforming pipeline construction plan into local plan of cities and towns."

The construction planning of natural gas infrastructure of each company is submitted to NDRC, which integrates and assesses the plans to issue national overall plans for the relevant units to implement. During construction of infrastructure of transport and distribution, the pipeline construction units should submit the materials to NDRC for approval.

Market structure

The Chinese gas market is characterised by oligopolies and monopolies in several parts of the gas value chain with three dominating companies.

The upstream gas market, including import rights and facilities, is dominated by the three major companies (CNOOC, CNPC and Sinopec) which are also dominant in the upstream oil market. Shaanxi Yanchang Petroleum (Group) Co., Ltd. is the only local oil gas enterprise which has the qualification for exploration and development apart from the Big Three. Since prices for domestically produced gas are low, there is less incentive to engage in significant exploration and production (E&P) activity, especially to produce non-associated gas or more technically challenging gas such as tight gas, and CBM (and shale gas in the future).

Competition from smaller players and new entrants is therefore relatively limited, despite some recent improvement. Many enterprises with no exploration and development qualification for gas and oil, such as Sinochem Group, CITIC Resource of CITIC Group and Zhenhua Oil, have no other option than either foreign tender offering from the Ministry of Land and Resources (MLR), block transfer by companies with qualification, co-operation with one of the four enterprises or acquisition of foreign assets. If existing exploration licenses cannot be transferred to these players, their only option is residual conventional gas plus some unconventional gas, which requires technological expertise. In the short term, until the end of 2015, unconventional gas would be CBM mostly, while the production has been until now marginal due to missing technology and access rights. Shale gas is not expected to significantly contribute to China's domestic gas exploration by 2015, since initial productivity and flow response to fracturing assessments have to be undertaken first. Recently, Xinjiang Guanghui and several other companies have emerged in the upstream sector. Henan CBM acquired a shale gas license, for instance, with the support of the local government. More joint-venture entities and local energy companies may emerge and move into upstream activities.

The midstream sector (pipeline transport and storage) can be seen as a by-product of the three big companies' exploration, import and sales activities: the pipelines are mostly built by and in accordance to the production and import plans and sales strategies of the three big players. The West-East pipelines or the Puguang-Shanghai pipelines are good examples. In this area, like for gas production, CNPC largely dominates, and even Sinopec struggles. Access to the grid or to LNG import facilities for other parties seems rare and, if any, is based upon bilateral negotiation and agreements.

Apart from the Big Three NOCs, there are few private companies that can import gas. However, in 2006, the monopoly of import and export of natural gas previously held by the Big Three was finally ended, when ENN Energy, a private company, became the fourth company with the right of import and export gas. Nevertheless, ENN Energy did not build any receiving infrastructure, so that in the absence of third-party access, import and export rights have not been implemented yet.

In the downstream sector, a variety of domestic suppliers exist with various ownership structures. Some are private companies such as ENN Energy Holdings, China Gas, while others belong to the local government. The standard market place for these distribution companies seems to be the city gate, while direct access to sources is limited. The big three NOCs are currently trying to take over some of the domestic markets, probably in expectation of future benefits since regulated retail gas prices are expected to be increased. They are consequently trying to enter the retail sector while the local distribution companies are already present, usually supported by the local governments. These distribution companies therefore face capped end-user prices on the retail market and new competition from the Big Three. By entering the retail market, the Big Three will complete their vertical integration throughout the whole gas value-chain in several regions, with all the associated possible impacts of market power, monopolistic pricing, slower rates of innovation, poorer service quality and a potentially sub-optimal level of security of supply.

Companies are vertically integrated and the pipeline, LNG and storage business units are not split from the marketing and production activities. There are worries that by unbundling these units, they would not be able to perform the same investments in infrastructure, a reaction similar to that of the incumbents in OECD countries before liberalisation took place.

Regulation

As regulation is one of the two key issues faced by the Chinese gas market, greater clarity is needed regarding agencies' responsibilities. For instance, regulation of the network infrastructure, the part of the gas value chain the most vulnerable to monopolistic behaviour, is a patchwork with many open spots.

A major issue is the lack of or limited access for smaller or foreign parties to gas infrastructure, be it transmission pipelines or LNG import facilities. Lack of access to the transmission infrastructure is probably the biggest hurdle, as it *de facto* prevents or limits any upstream competition as well as entry of new suppliers delivering LNG or pipeline gas to end-users or to gas distribution companies.

Regulatory entities

There is no independent regulator for natural gas; authority is split between different ministries and agencies, while both the central and the local governments also have distinct powers. One possible solution would be to pass a natural gas law that would *inter alia* define the powers of a regulator and a regulatory framework for access to infrastructure. Such a law could establish a gas market structure that would provide a reliable level playing field for all participants, and would thus ensure private investors' confidence. It could also help to avoid progressive structural consolidation throughout the gas value-chain, and thereby ensure highest cost-efficiency through market competition while strengthening security of supply. The sooner these structural changes were imposed, the lower the level of market monopolisation – and its associated welfare losses, created by monopolistic prices and sub-optimal system architecture – would be, and the easier it would be for the government to be successful with such a reform.

The above approach is not the only possibility, of course. Were policy makers to decide that supply development were the most urgent task, an alternative would be a step-wise approach that focuses first on upstream liberalisation (including pricing), to foster development of new supplies, and that takes up the issue of network access at a later stage, on the condition that producing companies can develop pipelines to transport the gas to demand centres. This alternative would, however, potentially conflict with other policy goals, such as encouragement of investment in the energy sector by a broader set of participants to develop as wide an array of sources as possible, and to encourage the competition necessary to drive efficiency and to bring down costs.

An independent regulator with strong powers would not only enable fair and cost-efficient access to pipelines, it would overcome the present variety of entrenched stakes held by government agencies and the NOCs. This does not automatically require that the regulator be responsible for both upstream and midstream regulation; there could be different entities responsible for upstream oil and gas activities and for power and gas markets.

Additionally, there are some cases of missing regulation, notably in the cases of granting authorisation to build new pipelines, and granting access to existing pipeline networks, LNG infrastructure and storage facilities. Many industry observers doubt that a powerful enough regulator could be formed, and that ministries will not give up key parts of their current powers. There is also the question of the hierarchy in the government; where, for instance, would such an entity fit? At what level would it have to be placed to exert the authority necessary to carry out its functions?

Regulating access to and planning of infrastructure

China currently has no regime for regulated access to pipeline networks. There is no regulated network tariff (despite negotiated tariffs for existing pipelines), nor are there any official conditions for access to pipelines, nor any established regulations regarding the access to transmission pipelines. This leaves companies without their own assets with only two options, *i.e.* either selling their gas to integrated companies that own pipelines on the incumbent's conditions, or trying to sell locally. Since there is not a single case where a foreign company or a Chinese company, other than one of the Big Three, has sold imported gas from outside China into the Chinese market, the option of selling locally seems to be blocked for foreign companies.

Given the monopoly nature of pipeline networks, the current sub-optimal level of co-ordination amongst market players, and the relatively high investment incentive due to favourable economics (high IRR and short depreciation period), central co-ordination and authorisation of major new pipeline projects could be beneficial. While boosting the pipeline network would help the development of new production, and potentially foster competition at the city gate, there is also risk in having multiple networks that have no links to each other, which would be detrimental to the security of gas supplies. A more co-ordinated approach to developing the network infrastructure would interlink networks, where possible and necessary, and could therefore lead to diversification of gas sources, thus bolstering security of supply. In addition, a strategically co-ordinated approach would favour development of an integrated – and thus least-cost – network infrastructure. With a central co-ordinator that has appropriate powers of approval, it could also be possible to minimise planning failures that lead to excess capacity and thus expensive stranded costs. The benefits of such an approach would have to be weighed against the potential to delay construction of needed infrastructure through lengthy procedures, or to impose other decisions that could have significant costs for market participants. This co-ordinator would also have to take responsibility for deciding how much capacity is sufficient and bear the potential financial consequences of being wrong.

For LNG, there have been some exceptions with cargoes from one company arriving to another if there is shortage, but the general rule is no access for third parties. Given that LNG can provide additional supply on a spot basis, some access to LNG terminals could provide additional supply. That said, a company having access to LNG terminals would also require access to pipelines, so that LNG considerations must not be dissociated from pipeline considerations and the competitiveness of the market in itself. In many European countries, there is limited access to LNG terminals, but players can have access to the network and in the United States, the Hackberry Decision allows LNG receiving terminals to remain private property, without TPA.

Regarding storage, there is currently no law to monitor storage use or access. The draft of the *Control Regulation for Natural Gas Infrastructure Construction and Operation* nevertheless stipulates that storage operators should give fair access, not deny serving the users conforming to access standards or raise any unreasonable requirements. The tariff is to be determined by the Pricing Department of the State Council and NDRC's Pricing Department to serve as a basis by storage operators while signing contracts for storage services.

3. Gas market liberalisation: objectives and key aspects

Key messages

- Liberalisation in OECD markets aims to let markets adequately determine the natural gas price while ensuring reliable gas supply. OECD countries are at different stages of liberalisation, the most advanced being the United States and the United Kingdom.
- The policy framework for natural gas needs to provide clear signals for both market investors and participants. This is usually achieved through gas-related laws giving the development objectives for the gas industry as part of the countries' energy sector. The laws often determine the parts of the infrastructure to be regarded as natural monopolies which will then subsequently become subject to regulatory oversight.
- North American and European countries have often a regulator in place to regulate access and tariffs of the natural monopoly parts of the gas market in order to prevent for the abuse of market power. These regulators often look after both electricity and natural gas markets. In case of substantial domestic production, a separate regulator dedicated to oil and gas upstream issues may exist.
- Setting an adequate network charge is crucial to promote both competition and network investments. OECD experience distinguishes two main methodologies: the cost-plus and the incentive-based regulation. Additionally, cost regulation enables to limit the allowed revenues to avoid cross-subsidisation and also to prevent abuse of market power.
- Enabling price discovery is an important aspect of market liberalisation. Eight different pricing mechanisms currently exist, with oil escalation and gas-to-gas competition (or spot pricing) dominating in OECD markets. It seems natural that China will evolve away from regulation towards one or both of these mechanisms, which both reflect market pricing.

Gas market liberalisation and why some items require regulation

The key aim of gas market liberalisation is to let markets adequately determine the price of gas delivered from suppliers to customers while ensuring reliable gas supply. Economic theory and experience from countries with liberalised markets suggest that liberalisation requires openness of the gas sector as a whole, from licensing and exploration in the upstream sector to trade and transportation to the final customer.

This openness ensures a reasonable level of competition between gas-supplying companies, lifting if necessary any pre-existing monopolistic supply structures. The European gas and power industry has indeed been built around monopolies and ministerial regulation of dominantly publicly or privately-owned companies controlling all parts of the gas value chain. Gas incumbents for example in France, Italy, as well as in many Central European countries were initially state-owned; meanwhile the German industry was largely privately built, and the Dutch was a 50:50 public-private partnership. These last two industries are central to the European industry. Amongst IEA member countries, the United States and Canada were the first to liberalise gas markets in the late 1970s, followed much later in the 1990s by some European IEA member states, notably those belonging to the European Union. By contrast, liberalisation is still at very early stages in Turkey, Japan and Korea. The European Union, as a region, has been the last IEA region so far to turn to market openness and competition.

Open markets can prevent monopolistic behaviour, which is typified by profit maximisation through producing fewer goods and selling them at higher prices than would be in the case under perfect competition. Open markets tend to reveal market-oriented prices, to maximise the use of existing capacity, and to facilitate efficient and timely scale-up of infrastructure. The existing inefficiencies of monopolistic markets are often referred to as "deadweight losses".

In closed markets with one or only a few dominant market players on the supply side (exploration & production as well as imports), the initial stage of market opening does not necessarily directly lead to a high level of competition, as new market entrants require confidence in the underlying market framework, time for building their business and also time to gain market shares over the already existing market players (incumbents). Market openness along the whole gas value chain is therefore necessary: having access to import capacity (LNG or pipelines) or having the right to produce gas through ownership of licenses is usually of little use if there is no regulated access to transmission pipelines as well. There might be special mechanisms, such as the Dutch Small Fields Policy discussed in Chapter 6, whereby the 50:50 public/private company Gasunie assured the purchasing of Small Fields by from smaller producers of Dutch gas.

Experience shows that open gas markets do not evolve automatically, but require policy action and the creation of a stable and transparent policy framework under which the market can then transform. Liberalisation of any gas market is largely driven by governments and then by the appointed regulatory authority. Meanwhile, all players involved in the gas market will be affected, including:

- the external suppliers of gas, such as International Oil Companies (Shell, ExxonMobil, Total, Statoil) and National Oil Companies (Gazprom, Qatar Petroleum);
- the upstream producers in the case they differ from the vertically-owned companies;
- the vertically integrated companies owning several parts of the gas value chain; and
- potentially the power sector as a key consumer of natural gas.

The question of the interdependence of liberalisation of power and gas markets is an important one, as the power sector has often proven to be one of the key drivers for gas demand, and the absence of power market liberalisation can affect the evolution of gas consumption. Experience differs widely; in the European Union, the liberalisation of power markets has usually been a step ahead of gas markets, while in the United States, liberalisation of the power sector is at different stages in different states.

Depending on the market situation, especially the countries' general experience with (private) companies' investments and engagement, but also on the dominance of the incumbents, the market growth, import dependency and market transformation can be a lengthy process and the outcomes are not always comparable.

Even though the fundamentals of each gas market differ, there are some features that are common to most of the open gas markets in IEA member states, *i.e.*:

- an overarching policy framework towards the gas market;
- establishment of an independent and credible market supervisory authority (or authorities);[3]
- acknowledgement that natural monopolies (in particular gas transmission or distribution pipelines) within the gas market value chain are fundamentally incontestable by competition; and
- the availability of transparent information, as well as its timely provision by the monopoly infrastructure operators, equally to all market participants.

[3] In many IEA countries, only one regulator exists for both downstream gas and electricity markets. Countries with a significant domestic production also have an upstream regulator in charge of overseeing oil and gas production.

The economic benefits of market liberalisation are hard to quantify since, as policy frameworks change, benchmarks disappear. However, some generalisations can be made about the opening of gas markets. In general, the costs for introducing market liberalisation and regulation[4] should be smaller than the benefits of mitigated deadweight losses. In small markets, this may lead to the conclusion that the introduction of liberalised markets is too expensive. But in a market of significant size and/or growth, liberalisation can be expected to achieve net economic benefits. However, no country is completely isolated from the external situation, notably global markets for fossil fuels, which have seen a rapid increase in prices since 2005. In that light, market prices can even rise after liberalisation, and it is essential to separate the benefits of liberalisation from the rise due to gas procurement costs. A liberalised market will always allow for commodity-induced cost increase and pass through to end-users, if these costs are competitive in the gas market. It will also provide incentives for upstream development.

The gas market value chain

The gas value chain starts with exploration and ends with delivery to final customers. Production, gathering, transportation, distribution and storage are the essential components of the gas value chain. The exploration and production stages are often common for oil and gas. Transporting gas to the final consumers is performed through three different types of pipelines: the gathering, transmission and distribution systems. The gathering system consists of small diameter pipelines transporting raw natural gas to processing plants. Indeed, before being sent to the market, natural gas needs to be processed, as it contains a variety of other compounds and gases such as ethane, propane, butane as well as oil, hydrogen sulphide, which must be removed (Natural Gas, 2011).

Storage facilities can have different forms, *e.g.* underground storage with capacity usually ranging between 100 Mcm and several bcm, and LNG peak-shaving facilities with a capacity of several Mcm. LNG storage located at LNG terminals can also provide storage services (in particular in the absence of the geological structures necessary to build underground storage); this is notably the case in Japan, Korea and Spain. Storage has also different usages. Not only can it help to meet seasonal and daily peak demand (in particular in case of a disruption), but can also support the transportation and production segments of the supply chain. Gas can be stored if too much is produced compared to demand, and storage can serve as a buffer between transportation and distribution.

Final users are broadly divided into two categories:

- those directly connected to the transmission network (large diameter pipeline with high pressure), typically power generators, as well as large industrial or commercial users; and
- those connected to the distribution network (smaller pipelines with pressure around 4 bars). While commercial and industrial users can vary in size and demand, residential gas users are supplied through smaller pipelines and local distribution companies.

Figure 1 illustrates the various players in the gas value chain, using the United States as an example.

The gas value chain can nevertheless differ widely from one market to another. Indeed, some countries do not have domestic gas production located in the country itself and must import gas, either by pipeline or by LNG import terminals. By contrast, some countries export natural gas, either by pipeline or by LNG. In the case of China, production covered only around 75% of total gas demand in 2011, the rest being imported by pipeline and by LNG. Over the past three years, the gap between demand and supply has been growing larger and larger.

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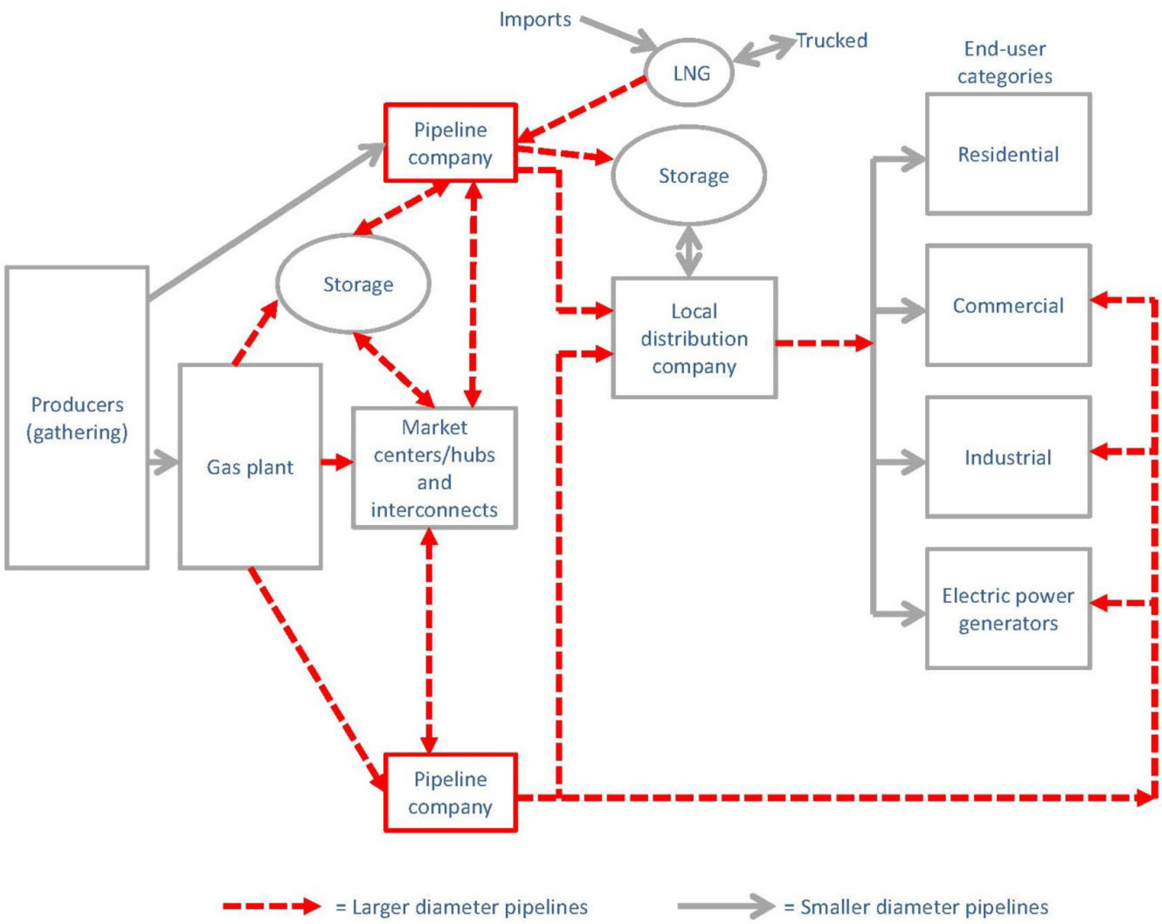
[4] Those costs are mostly associated to skilled staff – engineers, lawyers, accountants and economists – in the regulatory authority and the companies, but also for new market players such as traders and market facilitators.

Figure 1 • Gas value chain in the United States



Source: EIA, 2012a.

Gas market liberalisation also saw the emergence of new players, following the progressive disintegration of vertically-integrated players, among which are:

- wholesale suppliers, who buy gas from producers or from companies delivering gas at the border and sell it to retail suppliers;
- retail suppliers, who buy gas mainly from wholesale suppliers and then sell it to consumers;
- traders, who buy and sell natural gas in the wholesale market, and who do not necessarily deal directly with public gas transporters or customers;
- shippers, who have contracted capacity to transport gas to local distribution companies or through to the final consumers (many companies have both suppliers and shippers licenses);
- the transmission system operator (TSO), which operates the transmission pipeline;
- the LNG system operator, which operates the LNG import facility;
- the storage system operator (SSO), which operates storage facilities; and
- in fully unbundled systems, the distribution system operator (DSO), which operates the local distribution system, where separate companies compete as retail suppliers using the local pipeline grid.

Key principles of open and competitive gas markets

Independent of the country-specific gas market structures, several key items can be found in all open gas markets throughout the IEA member states. These items are the policy framework, the acknowledgement of natural monopolies and how they are embedded into the market, the regulatory authority and price discovery.

Policy framework

The policy framework for natural gas has to be the reliable fundament for both market investors and participants. In that regard, gas-related laws are present in most IEA member states and these laws often constitute the development objectives for the gas industry as part of the countries' energy sector. The laws often determine the parts of the infrastructure to be regarded as natural monopolies which will then subsequently become subject to regulatory oversight.

The law sets the tasks the regulator has to fulfil and also the enforcement powers at the disposal of the regulator. In some cases, the law also sets the level of unbundling for the vertically integrated market players and these levels can reach from unbundling of accounts to full (ownership) separation between networks and other parts of the company. The policy framework with regard to the unbundling regime will have repercussions on the regulatory competency and oversight in third-party access (TPA). While vertically-integrated companies will require a strong regulatory oversight in terms of TPA, fully unbundled network operators will have the intrinsic aim for maximising capacity use, independent of the network user: this can reduce the required regulatory oversight.

The rights and responsibilities of regulated companies, and also of other market participants such as gas traders and suppliers, are often covered by the gas laws. Security of supply requirements are also often determined. This clearly set out responsibilities of different entities for ensuring a continuous supply of gas to all customers, even in unusual cases, such as supply disruptions, high peak demand over long periods or bankruptcy of suppliers.

Natural monopoly

A natural monopoly may be best described as a market situation where a single firm can supply the market at a lower cost per unit than two or more firms can. Gas pipeline infrastructure in general is a classic example for such a natural monopoly where relatively high cost structures exist. Costs for the delivery of small amounts of gas are high due to the high capital intensity of the infrastructure, but with every additional cubic meter of gas delivered, the average utilisation cost of the infrastructure declines. Under such conditions real competition to build the infrastructure should not exist, as the existence of a large number of firms results in expensive duplication of capital equipment. With regard to the gas market, such natural monopolies can be seen on the transmission and distribution pipelines.

Whether storage or LNG import terminals enter in this category is more arguable. In principle, building excess LNG import capacity or storage should be avoided, in particular if the costs are regulated and passed through to the final gas user. However, a new market entrant with access to LNG supply may want to build its own LNG import terminal project in order to feed its own power plants projects and take market shares from the incumbent in other areas. It would therefore enhance competition through alternative supplies, and also develop gas demand in potentially less developed regions, while an infrastructure-only LNG terminal operator may not be interested to do so. A large part of the liberalisation in Spain was done on the back of LNG terminals developed by new entrants (power companies and IOCs), even though the TSO Enagas was fully unbundled. The same applies to storage projects, which additionally vary considerably according to their features and purpose, *i.e.* whether intended to cover seasonal or peak demand. As we will see later, how LNG import terminals and storage are regulated (or not) varies widely in both North American and European gas markets.

In most cases, natural monopolistic infrastructure constitutes just one branch within a company that also has ownership in the commodity itself, either through own production or imports, and sometimes also ownership in the distribution level reaching out to the final retail consumers. In the absence of regulation on access (tariffs and conditions) and transparency, those vertically-integrated companies have a position in the market where they can freely negotiate access rights to their infrastructure. This ensures them market power against other gas suppliers. Without adequate frameworks, such powerful vertically-integrated companies have incentives to abuse their market power to prevent competitive pressure from third parties.

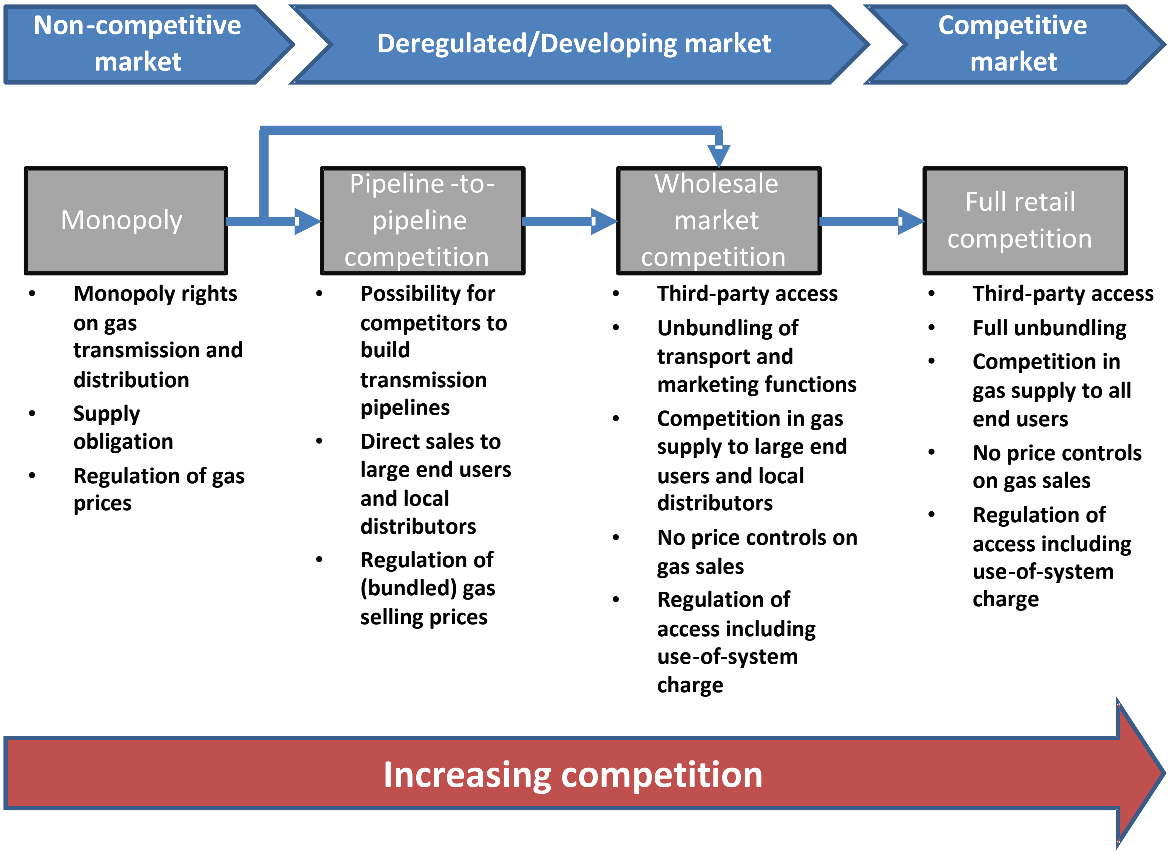
Figure 2 • Vertically integrated company in the gas market

While markets may develop where competition is suppressed, open markets can often provide with the economic benefits of reducing prices, or of at least mitigating price increases associated with external factors. There is no evidence that competitive markets cannot develop under competition or cannot maintain security of supply. The North American gas market, currently under "stress" with booming unconventional gas production, can be seen as a role model and shows how to develop these resources and to build up new infrastructure in order to bring gas to the final end user. This country is nevertheless not exempt from inefficient investment decisions from private investors, such as overbuilding of LNG import capacity, 5% of which is currently used, against a world average of 37.5% (IEA, 2012). But the important point in this case is that the money is lost by these investors, and the costs not spread to the gas users. The European gas market is currently transforming towards an open market comparable to the North American example, with the United Kingdom's market being the frontrunner in several ways. Both markets and how they treat certain parts of the gas value chain in particular will be further discussed in the following part on experience with market liberalisation.

Different competitive models

During the phase towards liberalisation via a deregulated/developing market environment, the IEA identified two market models that serve as an alternative to the monopoly market structure. These are the "pipeline-to-pipeline competition" model and the "mandatory third party access to the network" model (IEA, 1998). In the case of pipeline to pipeline competition; two ore more transport companies cover the same market and compete for the same end users. Competition may be limited, but the threat of new pipeline construction by a competitor may help to limit prices, when those are not directly regulated. An example was Wingas building its own network in Germany in the 1990s, benefiting from supplies from parent company Gazprom and sales to the other parent company, BASF. Pipeline to pipeline competition is also a common feature in the United States, where some interstate pipeline investments is performed based on open seasons (see the United States in the section on infrastructure investments and developments). The wholesale competition is based on TPA based on proper regulation (see below) and unbundling of transport and marketing functions, creating competition to large end users.

Figure 3 • Stages of development of gas-to-gas competition



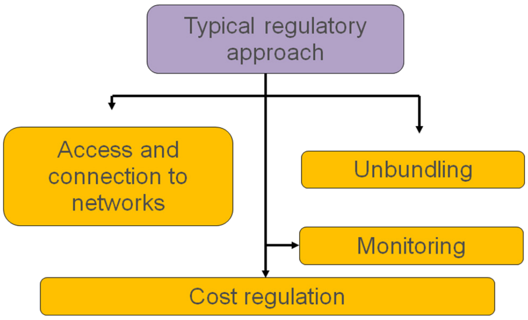
Regulatory authority and its tasks

A regulatory authority is the inevitable player for and in an open gas market to ensure adequate handling of the natural monopoly parts of the gas market to prevent for the abuse of market power. Regulation of gas infrastructure is required to ensure the best use of the infrastructure, which can be obtained by maximising the utilisation rates of the existing infrastructure and scaling it up efficiently and quickly while securing deliveries of gas to customers as inexpensively as possible. This implies equipping the regulator with a correct set of assessment, monitoring and enforcement rights, which can help alleviate the challenges.

IEA member states often equip their regulators with a high level of expertise and independence (most importantly from industry players, but also from other government agencies) and sufficient resources to allow adequate decision making, taking into account the complexities of the gas market and the features and usage of associated infrastructure. Independence from all stakeholders, including independence from political pressure, further strengthens regulators' decision making, ensures equal treatment of all market participants, and protects the needs of long-lasting infrastructure from short-term influences. To arrive at sound and acceptable decisions, the regulator typically decides in a consultative and transparent manner, involving all relevant market participants from the beginning, and publishing evidence and final decisions. Regulatory decisions normally are subject to appeal in independent courts.

Allowing all gas providers to get connection and access to gas supplies and infrastructure, as long as the delivered gas meets clearly defined quality criteria, is fundamental to competition. It is thus one main regulatory task. The concept of third-party access (TPA) allows independent gas producing-, importing- and selling-companies to become eligible to using gas infrastructure owned by incumbent market players. Capacity availability, capacity procurement and costs for capacity utilisation are the most critical items under TPA and the regulatory authority must be able to understand, to moderate, to facilitate and ultimately to enforce TPA between the different market participants. Facilitation of open access will require the regulator to set standards for the management of transmission network capacities in a transparent, reliable and fair manner, consulting all relevant parties while setting up these principles. As mentioned earlier, the level of regulation may depend on the type of unbundling.

Figure 4 • Typical tasks for regulating natural monopolies in competitive gas markets



In addition to the management of network capacities, the charges for capacity procurement and utilisation have to be determined. There are several methods of charging for network use and their arrangement can have impacts on the networks' technical structure. The choice of applicable method is often taken by national regulators, while there are also examples from IEA member states where the general policy framework sets the charging methodology by law.

The network charge often consists of a fixed and a variable charge. The fixed charge is often used to cover the long-term capital costs associated with the used pipeline(s) while the variable term often covers the operational costs of actual usage, in particular compressor costs. For gas pipelines, the total costs are largely dominated by the capital expenses (CAPEX), but the share of operational expenses (OPEX) is also not negligible and often reaches 10% of the total expenses (TOTEX). Independent of the charging methodology, the TOTEX has to be fully recoverable by the gas network owner. In practice, IEA member states usually give the regulator the authority to determine the TOTEX of regulated natural monopolistic gas infrastructure.

Two main methodologies for cost regulation are applied in IEA member states are:

- "cost-plus" regulation; and
- "incentive-based" regulation.

In cost-plus regulation, regulators calculate the total costs for the infrastructure assets, including capital and operational costs as well as a reasonable rate of return on invested capital. Once the TOTEX has been determined, the annual costs are calculated and represent the network operator's allowed annual revenues. These shall then be covered by the annual network charges for the network customers associated to the use and capacity procurement.

In "incentive-based" regulation, a more-recent form of cost calculation, the aim is to decouple the network operator's costs from the allowed revenues. Cost benchmarks, mostly between various networks, are therefore applied using statistical models. One of the main challenges is to obtain a statistical resilient set of comparable networks. In cases of missing benchmarks, analytical cost models are used, which form a virtual best-practice network structure to be compared with the real and existing network. Both benchmarks will then be used to determine the level of cost-efficiency of network operators' TOTEX. The difference between real cost-efficiency and the benchmark is the development target for the individual network operators' costs. In most cases, this target has to be reached within a pre-determined period of time, usually between four and ten years. Additional incentives vary and can comprise additional allowed revenues for reaching a desired quality of supply target, innovations and others. However, incentive-based regulation has often been seen as a methodology to be applied to an existing and almost stable network, to reduce cost-inefficiencies over time. Some IEA member states, applying incentive-based regulation, therefore often show additional regulatory vehicles, which treat the existing capital stock differently from investments into new capital assets.

Both methodologies require the initial determination of the asset value. Determining the asset value builds the fundament of the subsequent cost regulation, as this fundament will remain in place for the period of asset depreciation, which is often as long as 40 to 60 years in IEA member states.

On top of this asset value, the rate of return for invested capital is in most cases determined by the regulator. This often includes a risk factor representing the specific investment risks into gas network infrastructure. Some regulators determine the rate of return on investments on a general base, while others such as the US Federal Energy Regulatory Commission (FERC) apply a project-by-project rate. Determining the regulated rate of return is a significant driver for investments. If the allowed rate is set too low, the market will not be able to attract enough investors to facilitate market development. On the other hand, allowed rates also bear the risks of overcapitalisation when the regulated rate of return is higher than the regular return of expectations from investors. In that case, regulated entities will have the incentive to overinvest in capital intensive infrastructure in order to maximise returns (the Averch Johnson effect), which can minimise the benefits of market liberalisation.

Independent of the cost calculation methodology, there are two main requirements of cost regulation. One is to limit the allowed revenues to only represent the costs associated to the network and its use in order to avoid cross-subsidisation between different parts of the value chain (as this is currently the case in China for example between transmission and imports or production). Vertically-integrated companies can otherwise use cross-subsidisation to discriminate against competitors by shifting costs, *e.g.* from gas-production to network costs. Such behaviour would have the effect to increase the gas transportation costs for all participants but would enable the vertically integrated company to have a cost advantage regarding procurement. While the total costs for gas production and gas transportation remain unchanged for the vertically integrated company, the effects of increased transportation costs will increase the total costs for competitors. In that regard, cross-subsidisation can become a discrimination against third parties.

The second requirement of cost calculation is the general restriction of market power. Even a non-integrated network operator can use (or abuse) its market power as natural monopoly to impose excessive costs, which would translate into higher-than-required charges for network usage. While this allows for additional profit for the operator, customers will have to carry unjustified additional costs.

Price discovery

Market-based pricing is a fundamental part of the liberalisation. While the costs of using the network should be regulated, as seen above, in order to incentivise the construction of infrastructure and to ensure its safe operation, wholesale gas prices should result from competition between suppliers for consumers and not from regulation, whether cost-plus, social or even below-cost (subsidised).

In a first stage of liberalisation, it is crucial to define the term of "gas price". Indeed, gas price is a generic term which can hide many different components from the well-head price to the end user price paid by the customer. In this section, and unless mentioned otherwise, "gas price" refers to wholesale price, *i.e.* the price of natural gas at its point of delivery at a hub or border, *without* a transmission price component. It therefore differs from the "city-gate price", often referred to in China, which is the price at the inlet of the distribution system and usually includes a transmission component. End-user prices include not only transmission, distribution and storage charges as well as specific taxes, depending on the country and the region. End-user prices are usually quite dependent on wholesale prices.

Wholesale gas pricing varies widely throughout the world, depending notably on the development stage of the but also on regional or country conditions such as policy, regulation, the split between domestic production and imports when the country imports, whether the country exports gas, source of gas supplies, contracting practices, and existence of trading at hubs.

Different pricing mechanisms

The International Gas Union (IGU) has undertaken an ongoing study on wholesale gas pricing mechanisms since 2006, looking at global pricing developments since 2005. The last report, covering up to 2010, was released in June 2012 (IGU, 2012). IGU identified eight different mechanisms:

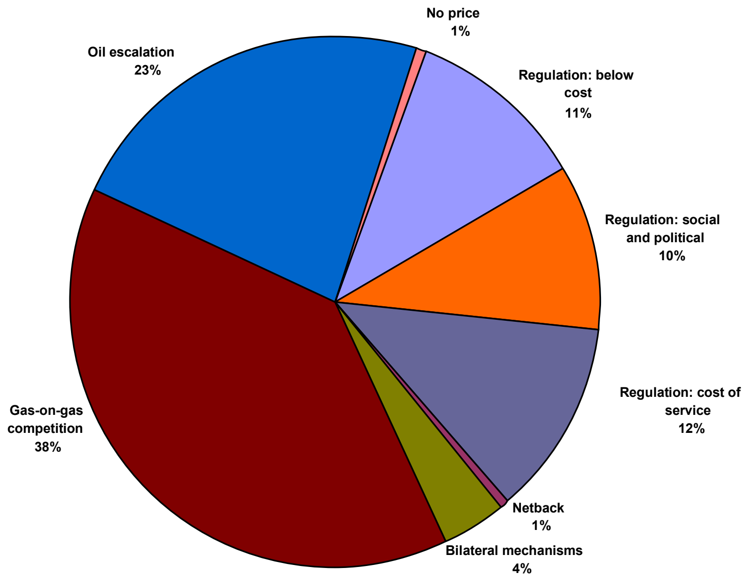
- gas-to-gas competition, which implies that gas prices are based on supply/demand balances, and which prevails in North America, the United Kingdom and some parts of Continental Europe, as well as a few other countries;
- oil escalation (also called oil indexation), used mostly in Europe and Japan, Korea, Chinese Taipei as well as a few other places, and which is usually a legacy of long-term import contracts with an oil linkage;
- bilateral mechanisms reflecting bilateral agreements between two countries (usually agreed directly between heads of states), mostly in the Former Soviet Union (FSU) (such contracts tend to disappear in favour of oil linked gas contracts);
- netback from final product (for example, gas price based on ammonia sale price);
- regulation – cost of service;
- regulation – social and political, whereby gas prices are decided on an ad-hoc basis;
- regulation – below cost (*i.e.* subsidised gas prices); and
- no price (*i.e.* where gas is given for free, as in Turkmenistan).

Wholesale price structure in 2010

Among the IGU's main findings, gas-to-gas competition (GGC) and oil escalation (OE) are the two pricing mechanisms most widely used, with a share of 39% and 23% of demand, respectively, in 2010, while the three types of regulated prices represent 33% together (Figure 5). The report shows a continuous increase in the share of GGC from 30% of demand in 2005 and 39% in 2010, while oil escalation has been varying between 22% and 24% between 2005 and 2010, but not increasing. GGC is the most widely used for domestic production (42%), where OE represents a mere 6%. OE has however the lion's share (59%) in total imports against 29% for GGC; bilateral agreements in FSU countries account for the rest. Finally, LNG imports tend to be more dominated by oil indexation (70%) than by GGC (30%).

According to the IGU report, China currently applies cost of service regulation to domestic production, having moved from social and political regulation after 2007. The recent NDRC reform started in December 2011 (Box 1) could establish an indirect link between oil prices (or oil products, *i.e.* fuel oil and LPG) and gas prices for domestic gas production. Most long-term LNG and pipeline contracts to supply China are estimated to be oil-linked (the first LNG imports based on the Australian LNG contract at USD 3/MBtu and the contract with Indonesia being the exceptions). Some relatively new contracts have a low slope (the slope being the ratio between oil prices and gas prices). However, it is also worth noting that Chinese NOCs have contracted significant quantities of Australian LNG, coming from LNG export plants expected to start over 2015 to 2018. These new supplies would be also based on oil indexation and are estimated to have a slope of 13% to 15%, translating into USD 13 to 15/MBtu for an oil price of USD 100/bbl, therefore on the high side of current import prices in China. Obviously how expensive future contracted LNG imports will be depends greatly of future oil prices. Oil indexation does not always mean expensive gas though as it depends very much on the slope in the contracts.

Figure 5 • Global wholesale gas price formation, 2010



Source: IGU, 2012.

The quasi absence of GGC in Asian markets (both Asia Pacific and Continental Asia) with only 5% of total demand in 2010, in the region, is mostly due to the absence of an Asian spot price, and largely reflects spot LNG trades. The reasons explaining this situation and potential remedies are investigated in Chapter 5.

Given the dominance of GGC and OE in today's markets, it seems natural that China will evolve away from regulation towards one or both of these mechanisms. This is also a view shared by market stakeholders during the interview process and following debates.

In the following section on price discovery and trading, the current situation in the two regions where the OE and GGC pricing mechanisms dominate (North America and Europe) is analysed in depth. As mentioned above, GCC dominates in North America while Europe has a hybrid system with both OE and GCC. Over the past years, OE's share in Europe has been declining in favour of GCC. The share of GCC indeed increased from 15% in 2005 to 37% in 2010, driven by the development of several spot markets in Continental Europe (IGU, 2012).

A last point is worth mentioning. In many people's minds, liberalisation should result in lower gas prices for the end user. This is not automatically true, as it depends on the evolution of the market price which can actually increase to signal either a shortage and need for more investments upstream or the fact that specific resources are more costly to develop. Actually, the objective of liberalisation is not to reduce prices per se, but to make them more cost-reflective and exert maximum downward competitive pressure. Indeed, the regulation of the transport components avoids that unjustified charges are imposed on the end-user. Finally, the government can decide to levy specific taxes on the use of natural gas, with variations from one sector to another depending on its policy objectives. Where carbon markets exist, this can also influence the price of gas.

4. The North American and European experience with gas market liberalisation

Key messages

- OECD markets had some similar features to China such as the presence of vertically-integrated incumbents in Europe, cost-plus regulation of pipeline and upstream in the United States, need to develop import infrastructure in Europe. Therefore, these countries can provide examples of useful experiences for the Chinese government.
- In both North America and Europe, the liberalisation process has taken a long time with laws, orders and directives being passed successively in order to improve and advance the liberalisation process.
- China's gas market is relatively young, established mostly within the past decade. By comparison, many OECD markets were already relatively mature markets since a few decades when they started liberalisation, and had already built and amortised infrastructure. By contrast, the United Kingdom and Spain were relatively recent markets when liberalisation was initiated.
- The role of the government to start and push forward the liberalisation process was crucial, even if it was often met by some resistance from the gas industry.
- Experience shows that third-party access to pipelines was an essential element to promote competition.

The North American and European gas markets have both successively experienced liberalisation processes. This took place quite early in the United States (late 1970s), followed by the United Kingdom in the late 1980s to the early 1990s. Liberalisation in other European countries started in the late 1990s and continued in the 2000s.

As explained in Chapter 3, liberalisation has had many consequences for gas market structure, gas pricing and market players (Box 3). In this chapter, we look in more details at the experience in the United States and United Kingdom.

Gas market liberalisation in the United States

In the United States, the fields of energy policy and conservation are primarily governed by federal statutes. They are supplemented by state law where federal law does not address the issue. Exploration of gas is subject to state policies, which gives a high variety of exploration and production handling. Each state has its own department/divisions/agencies with regard to activities relating to energy development.[5]

The handling of the E&P businesses is based upon open access and competition for reserves once land use planning has been determined. This enhances competition among existing gas producers and also creates room for new entrants.

[5] For example, in Oregon, the Oregon Department of Energy is responsible for energy development, research, and conservation activities. An overview over all of all state level authorities can be accessed under http://energylaw.uslegal.com/state-energy-regulations/.

Box 3 • Market participants in the US gas market

The US gas market is a mature market consisting of thousands of participants, most of which have evolved over time with market liberalisation. Due to the abundance of often relatively shallow gas reserves, there are around 6 300 natural gas producers in the US market producing from over 480 000 wells. Indicating the high variety of fields and the country-wide abundance, companies range from large IOCs with worldwide operations to small one or two person operations that may only have partial interest in a single well. The "majors" make up for 21 active companies.

Natural gas production reached an estimated 653 bcm in 2011. The gas is processed in over 530 plants. Once cleaned, it is then transported through pipelines of 160 different pipeline companies. The transportation system is of more than 300 000 miles length and continues to grow with the current integration of shale gas production. Of these 300 000 miles, 217 000 miles are interstate pipelines with a capacity of around 1900 bcm (183 billion cubic feet per day (bcf/d)) (EIA, 2009). There are also around 123 storage operators, controlling approximately 400 underground storage facilities. The working gas capacity for US underground working natural gas storage is estimated at 125 bcm (4 410 bcf) (EIA, 2011).

To make best use of the gas infrastructure, numerous marketers have entered the market and they aggregate suppliers' and customers' gas to achieve portfolio effects of gas marketing. The marketers supply about 1 200 natural gas distribution companies with gas, most of them still representing regional monopolies, delivering gas to the final consumer through more than 2.4 million miles of distribution and service pipelines (American Gas Association, 2012).

The pre-liberalisation phase

The US gas industry started at the beginning of the last century, but regulation of natural monopolies was exempt from regulation until 1935, when the Federal Trade Commission started a market investigation. This investigation acknowledged a high level of market concentration and abuse of market power by vertically integrated companies, on both the E&P and transportation segments of the gas value chain. The Natural Gas Act in 1938 introduced the Federal Power Commission (FPC) as the regulator for interstate gas pipelines, while the regulation of intrastate pipelines was left to state regulators (see the subsection on the evolution of the US pricing system in Chapter 5).

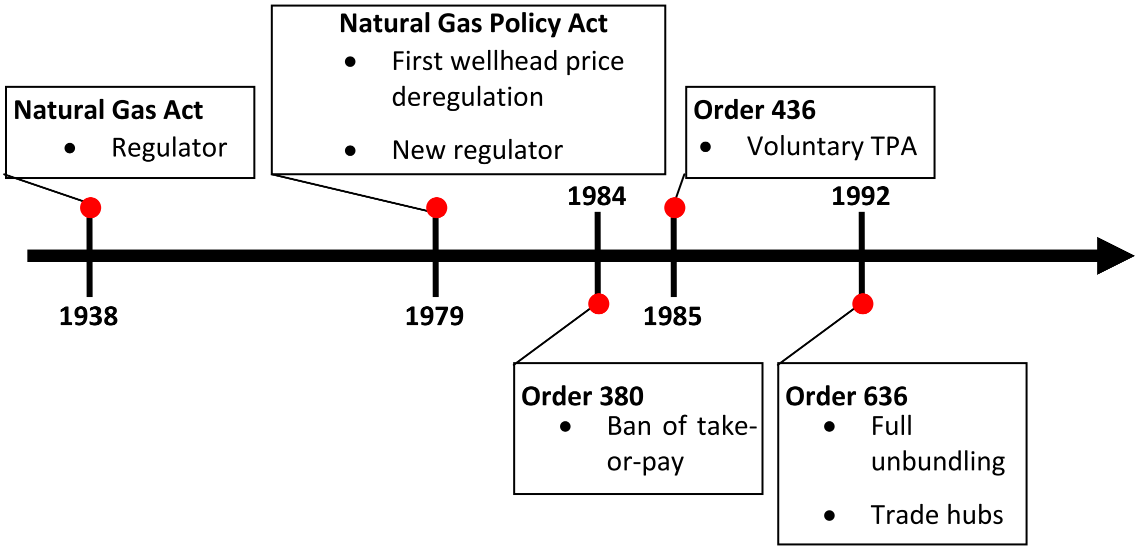
Price regulation increased over the following decades, but unfortunately led to gas shortages in the 1970s, as oil demand and associated prices rose but gas prices remained low, causing unprecedented gas demand increase. These shortages on the interstate level have been amplified by intrastate companies buying from the regulated market.

First stages of liberalisation

This situation became difficult to maintain for the FPC; in 1978, the Natural Gas Policy Act was issued. This Act removed the wellhead price controls for new contracted gas, while the existing gas contracts remained regulated (in 1993, "The Natural Gas Wellhead Decontrol Act of 1989" repealed the remaining price regulation). It also replaced the FPC with FERC but the commission's powers remained largely comparable.

In 1984, FERC Order 380 removed the minimum bill obligations from all long-term contracts. These minimum bill obligations represented take-or-pay contracts at fixed gas supply prices between producers and the vertically integrated gas supply companies. The ban of these obligations became necessary as gas market prices constantly remained below the long-term contracts prices while buyers could not make use of these lower prices since they had been locked into their existing contracts.

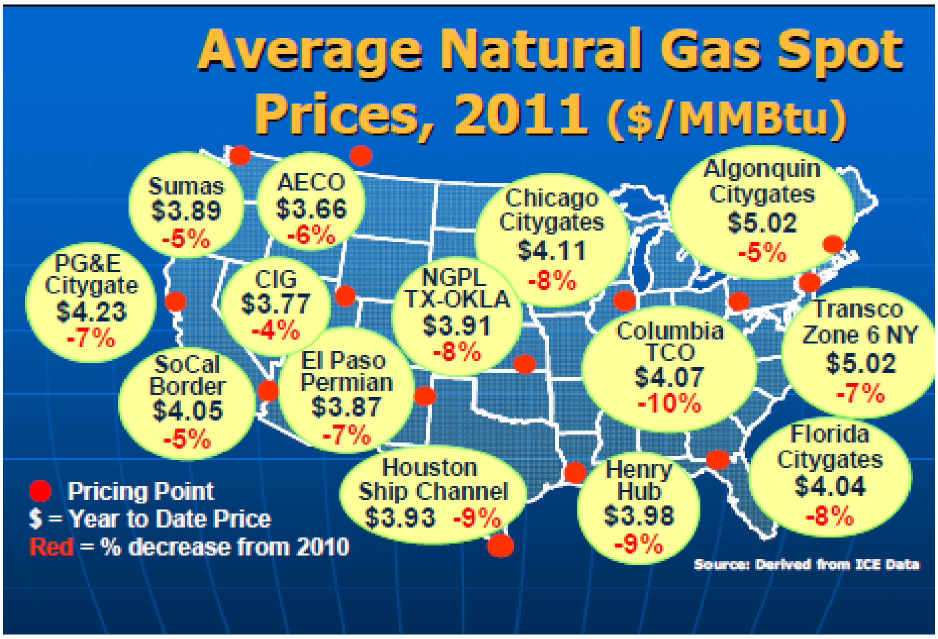
Figure 6 • Major developments towards gas market opening in the US gas market



This order was subsequently followed by FERC Order 436 issued in 1985, which introduced voluntary third-party access to the pipelines at a regulated bandwidth of transportation tariffs. Even though voluntary, most of the interstate pipeline operators participated in the new regulation, which lead to first services for transportation solely. This voluntary regulation became obligatory and standardised by FERC Order 636 (FERC, 1992), which required vertically-integrated companies to fully separate (divest) their transportation and storage services from their sales services and offer the pipeline and storage capacities on an open access base. The order states the unbundling and open access of upstream and downstream storages as well to prevent the sales services with unduly competitive advantages over their competitors. The "old system" provided integrated utilities with competitive advantages in terms of balancing seasonality and off-peak/on-peak buy and sell strategies (upstream storage), to maximise their supply flows even at times of fully utilised pipeline capacities and by balancing gas on a short-term basis to maintain a constant supply flow to customers (downstream storage). Under the new regime, all suppliers are able to contract storage capacities on a non-discriminatory basis and to store their own gas in these storages and thus are able to also make use of these advantages.

Order 636 also promoted the natural development of market centres and pooling areas to facilitate a "meeting ground" between suppliers and the demand side. These market centres were aimed at spots bringing different pipelines together and thus creating inter-pipeline market places, where different gas suppliers could compete. Additionally, pipelines operators were required to permit gas shippers to receive and sell gas anywhere in the gas system, unless deliveries were impossible due to system constraints. FERC also asked for the creation of pooling areas where different suppliers could meet to aggregate their gas deliveries and where balancing by pipeline operators could be done on such a pooled and aggregated base. In that regard, FERC acknowledged the utilisation of metering technologies so that pipeline operators could accurately monitor and measure injections into the system on a timely basis. By that time, New York Mercantile Exchange NYMEX (see the subsection on the evolution of the US pricing system in Chapter 5) started to build up a futures market on gas deliveries which especially gave stored gas a value over time. In parallel, induced by the customer aggregation, portfolio optimisation became possible and this led to the appearance of gas marketers which offered their services of bundled products to customers. These services included packages of gas procurement, pipeline management and storage capacities as well as the delivery of gas to the city gate. As of 2012, there are 29 different trading hubs in the United States and nine in Canada.

Figure 7 • North American trading hubs and associated spot prices for gas, 2011



Source: FERC, 2012.

Recent developments and current picture

The introduction of first voluntary and later mandatory separated pipeline and storage services created independent transportation service providers. However, due to their nature as natural monopoly, cost regulation had been implemented at the same time. The rules of cost calculation follow a transparent guideline developed by FERC. Pipeline owners are subject to these cost calculation rules and will be only allowed recovering the regulatory costs approved by FERC. FERC's latest manual for cost calculation has been issued in 1999 (FERC, 1999) and it applies the stipulated methodologies of cost-of-service regulation on a project-by-project base. The cost approval follows a transparent and consultative process where the pipeline company is required to justify its proposed rates by providing detailed information on its costs and proposed service levels (EIA, 1995). The ratemaking process can be separated into five distinct steps: the overall cost determination, cost separation between pipelines, storages and other, cost allocation and unit rate design. Cost allocation and rate design rules are designed to allow for higher charges for users with a large contribution to peak demand. Cost determination includes the determination of a reasonable rate of return on a project-specific base via the discounted cash flow model, the operation and maintenance costs, the depreciation costs and tax recovery mechanisms.

While storage and pipelines are always operated on a non-discriminatory, open access base, LNG plants, either import or export terminals, are treated individually by regulators. Applications for construction are submitted by project developers to FERC for approval, and FERC assesses the general need for the project as well as the economic and environmental impacts. This approval process is transparent, and all market participants have the right to comment, while FERC must take into account all objections in making its final rule. Several business models for import terminals exist, such as the full open access granted to Sabine Pass in 2011 (FERC, 2011), and the Elba Island import terminal (expansion) in 2003 (FERC, 2003), built with an underlying 30-year service contract with a gas supplying company.

Only one LNG export terminal exists so far, *i.e.* Kenai in Alaska. This was covered by long-term delivery contracts to Japan, initially for 15 years (FERC, 1967). Several LNG export plants are planned in the United States. They are subject to authorisations from both the US Department of Energy and FERC (IEA, 2012).

The US gas market is characterised by mature policy and regulatory frameworks, experienced market participants, strong and transparent economic signals indicating the state of the market, and is based upon the fundamentals of open access and competition. Long-term security of supply depends upon the collective foresight of market participants, and their expectations of future demand and supply and the associated infrastructure investments to deliver and balance gas supplies. However, short-term emergency situations are specifically addressed by law, including the existence of severe natural gas shortages, or imminent endangerment of the supply of natural gas to high-priority uses. Such situations make the handling by government authorities reasonably necessary, when other alternatives have been exhausted or employed to the maximum extent practicable. Such emergency situations are based upon a presidential declaration in the US Code (USC, 2012), which also names responsibilities and routes for supplying high-priority uses which are defined as residential customers, small commercial customers and other institutions where the curtailment of gas would endanger life, health or maintenance of physical property.[6]

However, in the United States, the eligibility of residential gas users depends on the State and not all of them have full unbundling. With complete unbundling, US residential users can choose their gas supplier, while the distribution company continues to provide distribution services. The various unbundling programs are often called "customer choice" programs in the United States. The last review performed by the EIA in 2009 showed that only very few States had this complete unbundling (DC, New York, New Jersey and Pennsylvania), while the majority (27 States) had no unbundling at all, and others some type of partial unbundling (EIA, 2009b). This is in sharp contrast with European countries, where in most countries there is a full opening of the market. Whether the residential users take advantage of it or not is another matter.

Gas market liberalisation in Europe

The First Directive

The European Union is based on the principles of the internal market, *i.e.* an area without internal frontiers in which the free movement of goods, persons, services and capital is ensured and competitive markets exist in all sectors. The European Commission (EC) started the process of market integration and liberalisation of its energy sector during the 1980s and issued in 1988 "The Internal Energy Market" as the fundament for further works (EC, 1988). Making the energy sector in Europe competitive and more efficient was viewed as part of the response to growing concerns on the competitiveness of European industries in globalising markets (IEA, 2008). European Community (now European Union) Directives have to be transposed into national laws, and the EC has proposed several Directives to facilitate gas market opening in its member states. EU law also includes Regulations, which are directly applicable to market participants. Building on Directive 94/22/EEC the European Commission has started to open the upstream sector (E&P) from 1994 onwards (EC, 1994). This Directive defines a set of common rules to ensure non-discriminatory access to the activities of prospection, exploration and production of gas and aimed at greater competition and enhanced security of supply.

The Directive limits the geographical areas covered by an authorisation and the duration of that authorisation to a justifiable proportion in terms of the best possible exercise of the activities

[6] US Code: 15 USC § 3363 - Emergency allocation authority.

from an economic and technical point of view. This aimed at preventing a single entity from having exclusive rights for an area whose prospection, exploration and production can be carried out more effectively by several entities. Authorisations are granted in a transparent manner and the selection of companies are based on criteria relating to their technical and financial capabilities, the way in which they propose to prospect, explore and/or bring into production the geographical area in question and, if the authorisation is put up for sale, the price which the entity is prepared to pay in order to obtain the authorisation.

The first push towards liberalisation in the midstream and downstream sectors happened in 1998 with the first Directive 98/30/EC (EC, 1998) which aimed to create a single internal market for gas within all member states. This Directive required owners of natural monopoly infrastructure, transmission networks, storage and LNG facilities, to provide access to parties other than their own customers. Member states were able to choose between negotiated and regulated access, while natural monopolistic infrastructure could remain within the vertically integrated companies with only separate accounts required.

Box 4 • Regulated versus negotiated access

Two types of access to infrastructure can be chosen: regulated or negotiated. In Europe, member states could in the early stages of liberalisation choose between both options, but over time the Directives have progressively moved towards regulated access.

Negotiated access refers to access on the basis of voluntary commercial agreements negotiated in good faith between network operators and users. The network operator is required to publish the main commercial conditions for the use of its network or facility on an ex-ante basis. The commercial conditions may include for example the contractual terms, the product offered, the rules and technical requirements as well as examples of prices.

By contrast, regulated access will have the terms and conditions of access determined by the regulator. The information published by the operator should be at least the same than in the negotiated access. With negotiated access, an ex-post control is required to make sure that users do not pay unjustified charges. This can be performed by the regulator or the competition authority, but, with increasing numbers of participants and contracts, market activity can easily grow beyond regulatory control.

The Directive also set a minimum threshold for the opening of the gas market by making all power generators and final end users consuming more than 25 Mcm per year eligible to choose their suppliers. The Directive also set objectives: the opening of the gas market should initially represent at least 20% of annual gas consumption of the market, then 28% and 33% respectively 5 and 20 years after the entry into force of the Directive (a very slow process). The Directive therefore gave suppliers access not only to the network, but also to consumers. As explained later, some countries, such as the United Kingdom, were already more advanced, having fully opened their gas markets.

The Second Directive

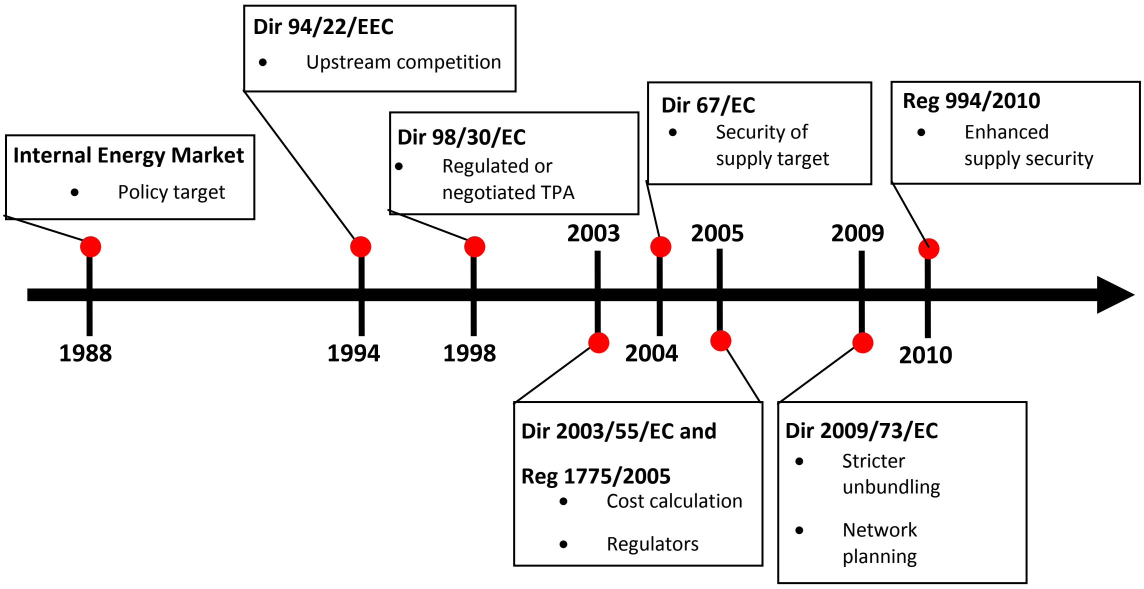
Even before the first Gas Directive was implemented in the national laws of member states, there was already a push to accelerate gas and electricity liberalisation (the first Electricity Directive was passed in 1996). To strengthen the process of market opening, a stakeholder forum, the "Madrid Forum", was formed shortly later in 1999, which reviewed implementation of the above Directive and started addressing the remaining impediments. Since then, the Madrid Forum[7] has

[7] The minutes and outcomes of the Madrid Forum Meetings can be found under http://ec.europa.eu/energy/gas_electricity/gas/forum_gas_madrid_en.htm.

met annually and to bring together all relevant stakeholders from the European gas markets. Meanwhile the European Council requested in March 2000 that the EC move faster towards completing the internal energy market. Market conditions were also changing, with nine out of 15 member states planning for full market opening by 2008.

The Madrid Forum's findings contributed to the adoption of the second Directive in 2003 (EC, 2003) and of Regulation 1775/2005 in 2005 (EC, 2005). These measures addressed the better co-ordination of congestion management, capacity allocation between member states, and balancing services. This time, gas and electricity were treated in parallel proposals. The Directive introduced legal unbundling, mandated the establishment of regulatory authorities in all member states. It also further improved third-party access requirements and prescribed the principles of network tariff calculation that had to be regulated, *i.e.* efficient costs based upon actual costs, appropriate rate on investments and incentives to construct new infrastructure. Meanwhile, the market was opened to all non residential users in 2004 and gas markets were fully opened in July 2007.

Figure 8 • Major developments towards opening in the European gas market



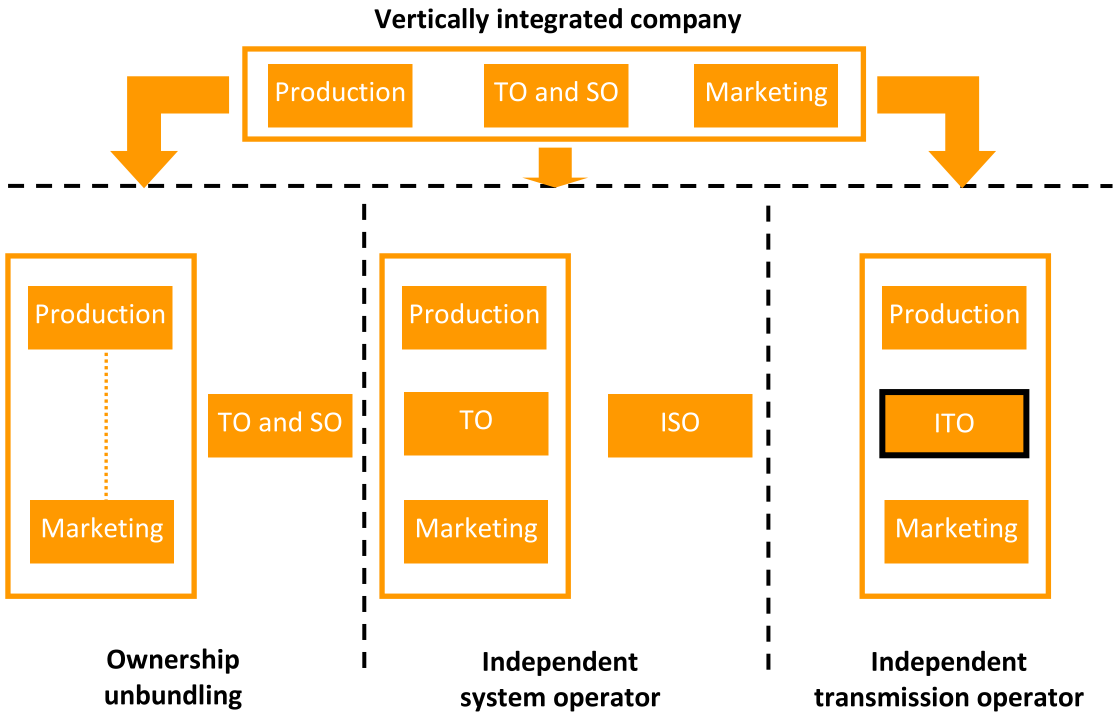
Article 22 of the Second Directive states that major new gas infrastructure (interconnectors, LNG and storage facilities) may be exempted from third-party access, cost regulation and others. It was considered as a key article for the facilitation of new infrastructure (or alternatively for significant increases in existing infrastructure enabling the development of new sources of gas supply). The rationale behind Article 22 is risk mitigation for infrastructure which will increase the level of competition between member states.[8] Regulators are required to decide on a case by case basis on the exemption. Since 2005, ten new pipeline projects and four new LNG terminals (all in the United Kingdom's market) have been granted exemption from regulation, while an additional exemption for one LNG plant in Italy is still pending (EC, 2012). There are also cases of partial exemptions; for example, only part of the capacity is exempted, TPA is required but an exemption on tariffs is granted with an ex-post regulation on the terms of the TPA, or there is a partial exemption from only parts of the tariff related rules (higher rate of return) (EC, 2009d).

8 Other criteria apply, including that the project must enhance competition and security of gas supply, that high risks would hinder the project's development, the owner is at least legally unbundled, costs are only allocated to users of that infrastructure and that the exemption is not detrimental to competition.

The Third Package

The latest Directive, the third legislative package on market opening ("the Third Package") was adopted on 2009 (EC, 2009a). All member states were required to transpose it into national law by March 2011. This Directive aimed at the further improvement of third-party access and equally effective regulatory oversight between member states. In that regard, it strengthened the independence of regulators from private or public interest and concluded that the lightest forms of unbundling, legal and functional unbundling, are ineffective in reaching the desired target of non-discrimination. It further stated "ownership unbundling as the most effective tool by which to promote investments in infrastructure in a non-discriminatory way, fair access to the network for new entrants and transparency in the market" (EC, 2009a). However, the Directive also allowed for two other forms of unbundling, the creation of an independent system operator (ISO) and the independent transmission operator (ITO), and left it to the member states to implement at least one of these unbundling models.

Figure 9 • Unbundling options under the "third package"



Article 36 of the Third Package replaced Article 22 with the European Commission still recognising that some new investments, "such as cross-border gas pipelines and LNG terminals…can be particularly risky. If, exceptionally, such projects cannot be realised if the rules on third-party access, tarification, congestion rents or (since 3 March 2011) ownership unbundling were applied, national regulators may "exempt" them entirely or partially from the respective rules of the EU energy *acquis* for a timely limited period" (EC, 2012b). The conditions are the same as in Article 22. Investment in new infrastructure, in particular networks became a major part of the Directive by imposing new requirements for long-term infrastructure planning in the ten-year network development plans. These plans are mandated to cover forecasted supply/demand developments over the next ten years to test the strength of gas infrastructure and to identify the weak spots of the gas infrastructure. Three levels of planning exist, based on TSO co-operation among Transmission system Operators (TSOs): EU-wide, non-binding, ten-year national development plans by a new European Network of TSOs in Gas ENTSOG, national (binding) investment plans and regional, ten-year national development plans. Investments for the coming three years can be enforced by the national regulators in the case of the independent transmission operator (ITO). Setting up the plan will require the network operator to publicly discuss and consult the underlying assumptions and results for required networks, LNG terminals and storages.

While storage and distribution systems remained largely unrecognised during the first years of market liberalisation, the third package demanded for an increased level of transparency regarding the access regime for storages.

Based upon concerns about security of supply, additional rules within this Directive required companies from countries outside the European Union to undergo the same level of unbundling as EU-based companies if they wish to invest in European transmission companies.

In parallel to the Third Package, the EC established an Agency for the Co-operation of Energy Regulators (ACER), acting as a supervisor and advisor in specific matters. ACER fosters co-operation among national regulators and harmonisation at the EU level. As an EU agency, it has no legislative powers, but takes independent decisions on exemption requests and in resolving disputes among national regulators. ACER prepares "Framework Guidelines" that form the basis for "Network Codes" to be subsequently elaborated by ENTSOG. Such Network Codes may then be adopted by the Commission, which may initiate a process involving member states in Council and the European Parliament, to render these legally binding (EC, 2009b).

Security of supply directive

In 2010, based upon experience with supply disruptions, the EU adopted a new Regulation 994/2010 (EC, 2010) to further strengthen supply security, which earlier had been established as a policy target by Directive 2004/67/EC (EC, 2004). The new Regulation, which replaced the previous directive, places security of supply within the market integration amongst EU member states to ensure trade and supply even under exceptional emergency conditions. It requires clear roles and responsibilities of all market players as well as stronger co-operation among member states (at regional level), regulators and market participants. It also provides for the introduction of supply obligations on companies, bilateral agreements between member states, minimum supply and infrastructure standards and greater reporting and information exchange on long-term contracts with gas importers and intergovernmental agreements.

Each member state is to carry out a sound risk assessment, on the basis of which measures are to be chosen for a national preventive action and emergency plan that could be taken in exceptional circumstances. The Regulation also emphasises infrastructure developments to facilitate additional imports into the EU, and also enhancement of bi-directional gas flows to diversify supply. For the latter case, the Regulation establishes an "infrastructure standard", *i.e.* the ability of the gas infrastructure to satisfy total gas demand in the event of disruption of the single largest gas infrastructure during a day of exceptionally high gas demand occurring with a statistical probability of once in 20 years (the "n-1 principle"). It further links the long-term network development plans to the n-1 principle, so that projects enhancing security of supply will be accounted for in the long-term network planning mentioned above. Additionally, the Regulation aims to protect customer groups from supply shortfalls during periods of high gas demand, also under contingency of the largest piece of infrastructure (the "supply standard").

The new supply standard requires EU member states to ensure gas supply to protected customers defined cases, *i.e.*: extreme temperatures during a seven-day peak period occurring with a statistical probability of once in 20 years; any period of at least 30 days of exceptionally high gas demand, occurring with a statistical probability of once in 20 years; and for a period of at least 30 days in the case of disruption of the single largest gas infrastructure under average winter conditions.

Gas market liberalisation in the United Kingdom

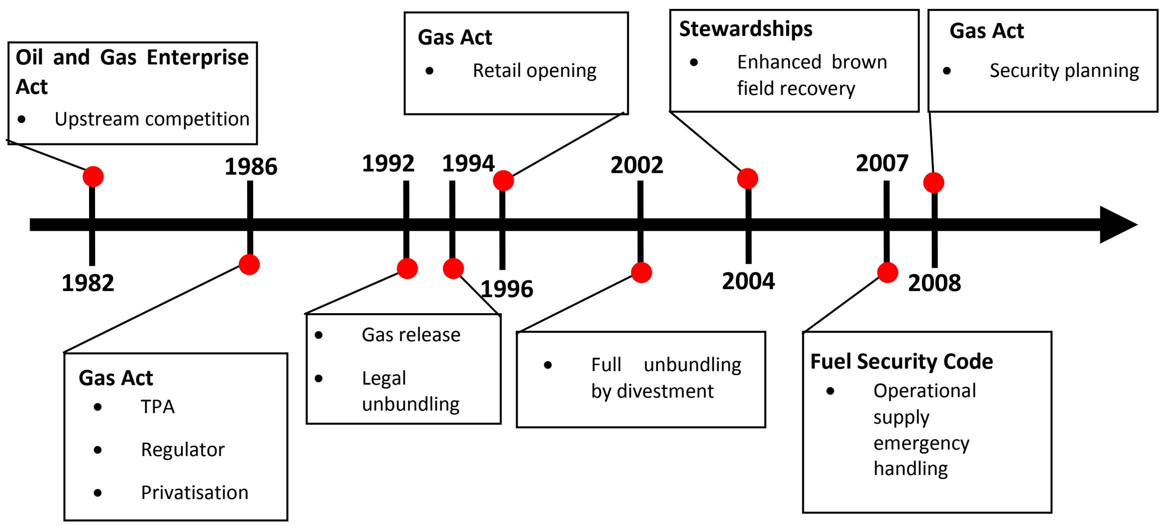
The United Kingdom started to liberalise its gas market well before the introduction of market opening on a European level. In many respects, the United Kingdom's experience served as a reference for other European markets. One can say that liberalisation started relatively early in UK gas market's history, as the market started to develop in 1970, so that when the first measures were taken, the UK gas market was not more than 15 years old.

First step towards liberalisation

In the upstream sector, the United Kingdom has implemented a transparent and open development regime for gas fields (see Chapter 6). In the midstream sector, the United Kingdom started market liberalisation driven by Prime Minister Thatcher's privatisation programme for nationalised industries in the late 1970s and the early 1980s. In that regard, liberalisation was less the aim than the desire for generating governmental income and requiring the newly-formed private companies to successfully fund new investments (Oxford Institute, 2010). The British Gas Corporation (BGC), the former public utility, initially had sole and full rights of buying all gas produced (monopsony) and also monopolistic right in supplying customers around Britain. In this position, BGC negotiated fields-specific prices while the downstream selling prices where regulated based on an average cost approach, plus costs for transportation and distribution.

The issued Oil & Gas Enterprise Act of 1982 was the first step towards liberalisation, as it opened up the upstream market for interested third-party buyers. Competition, however, remained low since the midstream sector remained subject to negotiated access for third parties. This changed in 1986 with the introduction of the Gas Act, which privatised BGC, leading to the formation of the vertically-integrated British Gas PLC (BG). It also introduced obligatory third-party access to the midstream sector and opened the market for large consumers (consuming over 25 000 therms [1 therm = 29.3 kWh]). At the same time, the Act created a regulator to supervise non-discriminatory access, the Office of Gas Supply (Ofgas).

Figure 10 • Major developments towards gas market opening in the United Kingdom's gas market



Enforcing competition

Competition was still developing rather slowly, as existing fields were committed to BG while new ones were more costly to develop (CRI, 2000). The Monopolies and Mergers Commission

(MMC) found that BG's practices were anti-competitive, notably regarding price discrimination (*i.e.* charging higher prices to the non-eligible users), and so proposed that BG's power to buy new gas should be limited to 90% and that supply tariffs had to be published (MMC, 1989). These recommendations were followed in 1992 by a further obligation on BG to reduce its market share (40% of the contracted market by 1995) and to release some gas from existing contracts to competitors. The gas market was also further opened by lowering the threshold for eligible customers to 2 500 therms. The MMC also recommended unbundling BG into separate subsidiaries (OFT, 1991). This took place in 1994, with the formation of Transco, which was given responsibility for transport pipelines and storages, and the creation of four other subsidiaries responsible for public gas supply, trading, service and retail businesses.

The opening of the market to retail customers by the Gas Act 1995 finalised the progressive market opening and brought competition and supplier choice to all end-customers. The Network Code further defined the rules and procedures for third-party access to the full pipeline network. In addition, the gas trading arrangements (GTA) were first introduced in 1996, simplifying procedures; until then, shippers had bought entry and exit capacity from Transco, which was responsible for balancing the whole system. The GTA were progressively reformed to include potential improvements gained through experience with the Network Code (notably on the costs of balancing the system). In October 1999, the first phase of the reform of gas trading arrangements (RGTA) introduced the on-the-day commodity market to help all market players to balance and incentives for Transco to minimise the overall balancing costs (CRI, 2000).

Transco was still part of BG Plc. After several changes, in 2000, BG Plc became two companies – BG Group Plc (international activities) and Lattice Group, which included Transco. Even if Transco was the national monopoly owner of the transmission and distribution systems, there was some competition in the transmission and distribution businesses in the area of system extensions and connections. In 2002, Transco merged with National Grid which since then, broadly speaking, forms the independent transmission network owner and operator of the United Kingdom's gas and electricity markets. It also has ownership and operational responsibilities over four of United Kingdom's distribution networks. The ownership and operation of storages and LNG facilities are independent from National Grid and usually held by several other private energy utilities, but National Grid is still the operator of one LNG import terminal in the United Kingdom (Grain LNG, which started in 2005) and one LNG storage facility (Avonmouth).

Improving security of gas supply

Gas supply security for gas is covered by several codes in the United Kingdom. In the downstream business, the Department of Energy and Climate Change (DECC) may instruct power stations to use alternative fuel sources to generate electricity based upon the "Fuel Security Code" (DECC, 2007). In more severe weather circumstances or in situations with damaged infrastructure, emergency situations may be declared. Triggers for the declaration of gas emergencies include *inter alia* gas supply deficits, gas storage safety breaches, transportation constraints, quality emergencies, supply losses of more than 50 000 customers, and the failure of one major gas market participant. In these circumstances, the National Emergency Plan for Gas and Electricity (DECC, 2010) will be used for responding[9], as the plan describes roles and responsibilities for all market participants.

In addition to improvements in downstream operational procedures, DECC also publicly debated and assessed the overall gas supply challenge (DTI, 2006 and DECC, 2007), leading to an amendment to the Energy Act that allowed private investments into offshore gas supply

[9] The defined elements of response include containment, management and recovery.

(UK Government, 2008). This set of laws complements the National Grid's long-term "Transmission Network Planning Code", which identifies weak spots in the gas transportation system based upon long-term demand and supply forecasts. The forecasts are based upon an open and transparent stakeholder consultation, intended to improve the accuracy of planning, and also cover investments outside the pipeline networks, such as storage and LNG terminals. The planning code requires both a security margin to cover uncertainties in forecasts, and design for maximum demand (defined as a once-in-20-years peak day), both of which affect the requirements for reliable network infrastructure (National Grid, 2010). This design margin is subject to approval by the regulator (Ofgem, 2010). Since 2005 National Grid has produced a winter outlook report, in which the TSO presents its analysis on gas and electricity supply and demand for the following winter and seeks opinion from market players (National Grid, 2012).

In accordance with EU Directive's "supply standard", DECC has determined that gas shippers are the gas market stakeholders responsible for supplying protected customers during the defined circumstances (OFGEM, 2012). These shippers will thus be held responsible if they do not supply sufficient gas to meet demand. In such cases, they will be subject to imbalance charges, to be paid to National Grid as the gas network operator (Gas Transporters, 2012). Protected customers have been defined by DECC as all households, plus category A customers under the Gas Priority Users arrangements (which would include hospitals and care homes).

5. Price discovery and trading in North American and European markets

Key messages

- Market pricing can be achieved through different paths as the North American and European experience shows. Although both oil escalation (which may include links to other fuels than oil) and gas-to-gas competition are market pricing methods by definition, even if they can result in relatively different outcomes in terms of pricing levels.
- The transition to market prices in North America from a regulated cost-plus approach has taken almost two decades. Most European countries still lack a truly liquid gas market, except the United Kingdom.
- China has already taken steps to move to market pricing with the NDRC reform and the still nascent Shanghai hub. The NDRC reform takes a netback approach based on oil price indexation, similar to the approach taken by many OECD European countries. This is progress in methodology, but fails to account for the true competitor to gas in power generation – coal, not oil. Further developments depend on what Chinese stakeholders aim at – a reference price largely determined by competitive fuels or the evolution towards a spot market.
- Different stages are required to move from a non-market situation to the development of a spot market. This includes in a first stage wholesale price deregulation, separating transport and marketing activities and less intervention from the government. Sufficient network capacity and transparent access, a number of participants large enough to enable competition, and the involvement of financial institutions are then required in a later stage to develop a spot market.
- In parallel to these developments, a functioning wholesale gas market requires governments to take a different role, from the regulator and ultimately the role of arbitrator via competition authorities.

As mentioned in Chapter 3, several pricing mechanisms exist. Two "market-based" pricing mechanisms prevail in North America and Europe (as well as in OECD Asia Oceania), in contrast to cost-plus approaches: gas-to-gas competition and oil escalation. Oil escalation is mostly seen in Europe, while gas-to-gas competition exists in both regions. In Europe, there has been since 2009 a move away from oil escalation towards gas-to-gas competition in response to increasing oil prices, and therefore gas prices levels. There is continuing debate on whether oil escalation is still pertinent as a pricing mechanism due to the different dynamics of oil and gas markets, waning competition on the end-user side, and higher gas prices as the result of high oil prices.

Relatively similar pricing mechanisms can result in widely differing price levels, as illustrated by the widening gap between prices based on gas-to-gas competition in Europe (United Kingdom) and in the United States. The United Kingdom's National Balancing Point (NBP) price averaged USD 9/MBtu in 2011, while the Henry Hub price averaged USD 4/MBtu. Although LNG trade increased significantly, it has not resulted in the emergence of a global price or increased trade between the three main regional markets – Asia, Europe and North America. North America is becoming self sufficient, so linkages with other regions are limited. Additionally, the pricing mechanisms in Asia are essentially oil indexation for the main LNG importers, and prices reflect stronger linkages to oil prices than in Europe where both OE and GGC coexist and interact.

Competitive trading in North America and in some EU member states (notably the United Kingdom) has taken years, if not decades, to mature. While liberalisation of the gas markets has tended to split transport activities from other activities in the gas supply chain, it was recognised at early stages in North America that managing transactions and balancing supply and demand would require a highly structured marketplace (IEA, 2008). These markets, creation of which was promoted by the regulator in the United States, would enable market participants to manage their portfolios of supply, transportation and storage. Market development was enabled by key pieces of regulation and by real-time availability of market information. Market liberalisation started in Europe in the late 1990s, and has resulted in the emergence of several hubs, the most liquid by far being the NBP in the United Kingdom.

Understanding gas trading

In order to develop trading, it is essential to understand a few principles which govern how gas trading has been developed and works. This encompasses the difference between physical and virtual hubs, the type of market participants, of products traded and the question of risk management.

Physical versus virtual hubs

Physical hubs and virtual hubs are the two different approaches used in North America and Europe. The **physical hub** is the approach used mostly in North America (Zeebrugge in Belgium being the European exception). This is a specific geographical point in the network where a price is set for gas delivered on that location. Henry Hub was chosen due to the different interstate pipelines arriving to that location providing gas from different sources. Prices in other North American hubs (such as Opal) are determined through transport differentials between gas producing and gas consuming hub regions. In the United States, Henry Hub was selected by NYMEX which was looking for a centrally located and sufficiently interconnected point for natural gas ownership exchange.

By contrast, the European approach is traditionally based on **virtual hubs**. Virtual trading points associated to determined market areas do not depend on any location – natural gas can enter any point in the area and exit through any other point, the duty of balancing (see Box 5) the area is borne by the market operator.[10] Since the trading hub has no physical location within the area tariffs for transmission use are independent on the distance and facilitated entry-exit system. Virtual hubs are used as a daily balancing tool for the corresponding area. The British virtual trading point, the NBP was the first to be established in Europe, in October 1994. The Intercontinental Exchange (ICE) then decided to use NBP as the pricing and delivery point for its natural gas future contracts.

In the late 1990s and early 2000s, other hubs started mostly in Continental Western Europe. A few hubs started but disappeared quickly afterwards. As of 2012, these hubs are not transnational; instead, they are either based on a part of the country's territory (France, Germany) or the whole country (the United Kingdom, the Netherlands, or Italy), taking advantage of a unique regulatory framework and existing regulation for the TSO's network operation. In most European countries, there is only one TSO, Germany and France being among the exceptions. The only European physical market, Zeebrugge, has seen its importance diminishing over the past few years, and both the Belgian regulator and the TSO have decided to move to virtual hubs. Virtual hubs are to become the norm in Europe, which is consistent with the Council of European Energy Regulators (CEER)'s decision to recommend virtual hubs as the basis of the European Gas Target Model.

[10] In most cases a TSO.

A key difference between the NBP and the other markets is that trades made at the NBP are not required to be balanced. At the end of the day, shippers out of balance are automatically balanced through the "cash-out" procedure, *i.e.* they have to buy or sell the difference, but at a price close to the spot price. The TSO, National Grid, is effectively in charge of putting the whole system in balance by buying or selling gas and transferring the costs to the shippers through the cash out system. While this provides with a market based approach, making use of holistic area wide balancing including all market participants, continental markets use penalties for shippers out of balance to encourage balancing.

In April 2011, the Netherlands started to use a new balancing system, whereby the TSO takes no balancing actions so long as the whole system remains within the available linepack. If the system is out of balance, the Dutch TSO will call on the Bid Price Ladder (BPL) to offset the short or long position of the system. The TSO will buy or sell from market participants that have offered gas beforehand on the BPL. The shippers that caused the imbalance will pay any costs that the Dutch TSO incurs when buying gas through the BPL, and also pay for assistance gas, while shippers that remain in balance and help to keep the system in balance are rewarded. The gas network is kept in balance with the least TSO interference possible, since market players have incentives to balance themselves.

The two different approaches of virtual and physical hubs reflect the different structures of the markets: transport activities are fully privatised in North America and regulated in Europe. Hubs are meant to facilitate trade in the United States, whereas they are used for balancing in Europe. With virtual hubs, pipeline congestion is avoided and traders perceive a greater liberty, but this requires markets to be large enough. Both approaches have, nevertheless, supported growth in trading and enabled creation of liquid futures markets, although room for growth remains in some European markets.

Bilateral trade and exchange-based trading

Trading brings together different types of market participants, from shippers to financial parties, and involves both physical and virtual gas supply. Generally speaking, gas can be traded either **bilaterally** ("over the counter" or OTC) or **based on an exchange** operated by a marketing organisation. In both cases, one makes the distinction between the spot market which refers to the period of close delivery (up to within the week) while future markets concentrate on periods which are beyond the week of physical delivery and can go to several years ahead: the difference is therefore the time of delivery in the future.

Exchange-based trading is based on standardised products (such as "day-ahead", "month ahead" to several years in the future depending on the liquidity of the market) delivered on the gas hub. Market organisations can be NYMEX, APX, ICE, which are independent from gas players or financial players. Market participants can therefore trade products, which are defined by their time of delivery in the future. Standardised products with a great number of market participants will increase liquidity of a market which in turn will strengthen confidence in the resulting price signal. The liquidity of the exchange will increase over time as the number of participants and number of products being traded increase. In its early stages, the traded products will focus on delivery in the next months and year. New products further ahead are progressively introduced over time, based on assessments from the marketing organisation regarding demand for these products.

Bilateral trade (or OTC) can be based on either the standard products mentioned above but also use customised products fitting the specific needs of some buyers. The trades will be delivered on the hub. They are frequently considered as less transparent by regulators than exchange-based trading as they are not taking place on a shared platform.

Market transparency is critical for participants to trust the exchange. It is therefore important that firms exist which can collect and disseminate information about trading, volumes and prices, usually through journals, websites and newsletters. Such companies include Platts, Argus, and ICIS Heren.

Box 5 • Balancing in a competitive market

A key feature of a responsive and flexible natural gas supply system is the ability of the network to maintain balance in response to constantly shifting supply and demand. This will not only require sufficient short- and long-term flexibility instruments (storages, LNG terminals, line-pack in the system), but also require a reliable flow of information on the status of the network.

In a non-liberalised market, this is fairly easy, as the balance in the network is maintained by one organisation that has access to all instruments and information necessary to deliver natural gas to consumers. However, in a deregulated natural gas market, the number of market parties that will use the natural gas network to service consumers will increase. In a deregulated system, a TSO (government owned or private) will be responsible to maintain the network's physical balance, while shippers are responsible for their "administrative balance" of the network. This "administrative balancing" by shippers will help the TSO to make optimal use of network flexibility guaranteeing consumers' supply security at the least possible cost for consumers.

Whether a shipper should be "in balance" on an hourly basis (as in the Netherlands) or on a daily basis (as in the United Kingdom) depends on the physical circumstances of the network. These circumstances include the amount of residential consumers connected to the network (with a considerable draw on within-day flexibility) and the line-pack available in a network that allows the system to absorb rapid changes in supply/demand more gradually. This physical reality is an important determinant of the time horizon when a shipper's input has to equal its withdrawal from the network (meaning hourly balancing or end-of-day balancing).

The obligation for shippers to remain "in balance" by specifying their gas flows in increasing detail requires the TSO to provide signals that allow them to adjust accordingly. The shared burden of balancing the network between shippers and a TSO raises the obligation on the TSO to develop IT systems that enable two-way communication on real-time network status, whilst guaranteeing commercial confidentiality. A reliable system of administrative balancing requires the following:

- A transparent network code to establish rules on how natural gas should be transported, defining an administrative flow of natural gas mimicking physical reality. A network code should also establish rules to ensure commercial confidentiality for shippers, and public service obligations for governments.
- A standardised IT protocol for information transfer that allows for two-way communication between shippers and TSOs.
- A certification of the system that ensures uninterrupted communication between relevant parties in the system, and increase confidence in the balancing system as a whole.

Different parties will therefore participate in trading, ranging from shippers using the spot market as a balancing tool and more interested in the spot market part as well as in physical deliveries to financial parties, which are traditionally more interested in the future market but much less involved in the physical spot market. The financial parties are critical to develop future pricing as they are willing to take risk exposure to capture a margin, while shippers are usually less active on the future market. The presence of financial parties also increase the number of market participants. However, financial parties depend on the physical spot market to unwind their positions. A strong relationship therefore exists between these market participants and spot and future markets – increased physical trading by shippers on the "spot market" is essential for financials to get out of their positions on the future market, while shippers depend on the financial derivatives that financial parties provide through the futures market to reduce risk associated with shipper activities. The more liquid a market is, the more easily a product in the future is traded. Finally, financial trade does not always result in natural gas exchanging hands.

Responsibility for supervision differs between physical and financial markets. Physical exchange through OTC trades on the spot market will fall under competency of the energy market regulator or the competition authority. Meanwhile, the Financial Market Authority will oversee financial trade. This means that a shift in regulatory competency can be expected when the merger of the physical and financial trade on an exchange hub takes place.

Quite often, the issue of **hub liquidity** is raised in order to gauge whether it can offer a reliable price signal. An indicator for liquidity is the "churn ratio" between traded volumes and physical volumes, but these do not always cover all the gas flowing or traded through the corresponding area. For example, OTC deals are not always reported by the TSO. Other indicators include the number of participants, the type of products traded and the spread between bid and ask price for a product. The further ahead in the curve the product are traded, with an ever smaller spread between bid and ask, the more liquid a future market is considered to be.

Another question regarding trading is the counterparty risk, a decisive point in the development of the NBP. In the case of OTC transactions, the risk rests mostly with the parties involved in the transaction. This usually involves lower transaction costs. Counterparty risk is usually reduced by companies' internal regulations managing commercial relations with counterparties. There is also the possibility to use a Clearing House (frequently part of the marketing organisation in charge of the exchange market), but this impacts the cost advantage of lower transaction costs through OTC trading transaction compared to an exchange based transaction. On exchange markets, clearing risk is always performed by a clearing house, which provides a protection against default risks and facilitates the transactions of the spot exchange products.

The above implies that market liberalisation entails significant changes to many aspects of market structures, from contracts to use and management of infrastructure. This is explained in the section below on possible ways forward to set up an Asian spot market.

The North American gas model

Current situation

The current North American model is based on supply/demand balance (or gas-to-gas competition). While it is usual to refer to "Henry Hub" as a proxy for the North American gas market, it is simply a physical trading point in Louisiana where different interstate pipelines converge and which has become the pricing reference in the United States. Moreover, there exist many other pricing points in North America that are defined by their pricing differentials against Henry Hub prices, *e.g.* Opal, New York city gate, and Alberta.

These regional gas prices tend to broadly follow the same trends, although regional supply/demand fundamentals may exacerbate some seasonal divergences notably in the regions which do not produce enough gas. The North American gas market shows how regional price disparities arise and how the arbitrage opportunities between the different regional hub prices can drive investment in pipeline capacity in order to resolve these price disparities. The investments are performed by private companies through open seasons (see subsection on pipelines in the United States in Chapter 7). Following the gas production increase of around 100 bcm in the United States between 2000 and early 2011, 14 600 miles of interstate pipeline grid have been added (INGAA, 2011).

The North American model is actually the result of gradual market evolution (as described above) which took decades to mature. For Chinese observers, an interesting aspect is that North America has always been a large gas producer, and only during brief periods was it considered that it might become a large net importer (of LNG). A major difference with China is the fact that thousands of producers co-exist in the United States, with the largest representing only 6% of total gas production, while in China, three companies dominate, and the largest accounts for three-quarters of domestic gas production.

Evolution of the US pricing system

In the early stages of the US gas industry, prices were not regulated. This changed with the 1938 Natural Gas Act which started to introduce regulation, in particular on gas prices. The next four decades until 1978 saw a progressive growth of regulatory oversight of gas prices. The US Supreme Court's Phillips Decision in 1954 resulted in a wellhead price regulation that lasted until 1978. With thousands of wells to regulate, the initial burden became however too big for the regulator, so that it switched to an area approach. All producing wells in an area had the same tariff based on average cost of production, disregarding any specific differences between them. This resulted in some tariffs sometimes ending up being lower than production costs, creating regional shortages. This price regulation was a cost plus approach, therefore similar to what currently applies in China. The FPC was responsible for regulating the interstate transactions while the state agencies looked at intrastate transactions. The US system in the 1950s to 1970s appears, therefore, to have been quite similar to the current Chinese gas system, with regulatory agencies controlling most parts of the business in different parts of the gas value chain. One notable difference is that US pipeline companies were often separate from producers, and were buying directly from them.

This heavy-handed regulation resulted in gas shortages appearing in the regions which needed to import gas from producing areas, notably in the Northeast and Midwest. This was exacerbated by the fact that the regulation applied solely to gas traded across regions, but not to intrastate for their gas supply, so that interstate pipelines faced shortages. Therefore some producers preferred to sell gas in Texas rather than send it to the North. In the mid-1970s, a new regulatory system set a uniform national wellhead tariff based on an average of current and expected costs of gas production, but this applied only to contracts signed after 1975. Meanwhile, historical tariffs remained low. Despite the resulting sharp increase of wellhead prices, shortages were even worse, while gas demand was boosted.

The Natural Gas Policy Act of 1978 aimed at solving these shortages by deregulating partially wellhead gas prices while retaining most interstate gas pipeline under price control. This first deregulation of wellhead gas prices was based on competition between sellers and buyers. It also put intrastate gas under price regulation in order to eliminate the regional imbalances. Further deregulations (FERC Orders 380 and 436) followed up to 1985. They allowed utilities and then later other customers to contract directly with producers at market prices, and have the gas transported to their sites on pipelines subject to third-party access regulation. A key element is therefore that access to pipelines is necessary to liberalise the upstream market and that it led to the creation of a wholesale market and therefore a wholesale price.

While the combination of the deregulation of wellhead prices and the two oil price shocks resulted in a 15-fold increase of wellhead prices from 1970 to 1984, a slower economic growth combined with higher gas prices at a later stage led to a reduction in gas demand (demand dropped from 647 bcm to 557 bcm from 1979 to 1983), so that wellhead prices dropped back to levels close to USD 1.8/MBtu by 1985. A wide variety of natural gas purchasing and transportation patterns and practices therefore emerged due to the availability of choices to sell gas to the end user, as well as a new pricing pattern, the netback pricing. With the Natural Gas Wellhead Decontrol Act of 1989, all price ceilings of the Act of 1978 were removed by January 1993 (EIA, 2012b) rather than by 2000. In 1989, controls on over 60% of gas production were lifted, while another 33% had never been subject to the price controls of the 1978 Act. The new act aimed to mitigate market imbalances and led wellhead prices to better reflect supply/demand balances. It notably allowed some gas production, such as tight gas, to be freed from regulatory ceilings which were above market clearing prices.

Liberalisation changed the structure of the US gas industry. Before, strong regulation applied to the different stages, from production to transmission to distribution, and to long-term contracts between producers, interstate pipeline companies and distribution companies. Liberalisation and open access to pipelines starting in 1985 led to the creation of the competitive wholesale gas market and a new type of company appeared – gas marketers, which are the link between producers on one side, and distribution companies as well as large consumers on the other side. The liberalisation of gas marketing and wholesale gas prices attracted many new companies and created competition among marketing firms and gas producers, which increased the pressure on wholesale gas prices.

On the whole, gas prices decreased: wellhead prices (real) by 26% between 1988 and 1995, and city gate prices by 24%. The large consumers which now can buy their gas directly on the wholesale markets were the main beneficiaries with declines in gas prices by 26% to 31% from 1988 to 1995. Small consumers still are not able to get gas directly on the wholesale market and saw more limited benefits although real gas prices still dropped by 12% from 1988 to 1995.

It is worthwhile mentioning the interaction with Canada, the main source of US imports. In the early 1970s, Canadian gas prices were still unregulated while the United States experienced shortages. This led to an increase of imports from Canada, and therefore to an increase of Canadian gas prices to levels higher than in the United States. Canada therefore decided to regulate its domestic gas prices by linking them to oil prices and to set up one single export prices to the United States, which could be higher than domestic prices. In that case, the benefits would be redistributed to gas producers on a pro-rata basis. Following the US liberalisation, gas prices dropped and Canada also removed the regulation on gas prices in 1985.

In parallel, NYMEX launched the first gas futures contract with delivery at the Henry Hub in April 1990, even if work started in 1983 with the creation of a gas advisory committee, notably to discuss the location of the hub. Over the following years, several other contracts in other locations were created.

Over the past 20 years, there has been little change in the way US gas pricing works. Gas trading occurs a several physical hubs located on interstate pipelines. The trading activity related to financial gas markets has been increasing, enhanced by the development of internet and electronic trading systems over the past two decades. On the first day of trading on NYMEX, 918 contracts were traded compared to over 100 000 today (EIA, 2012c). The futures were progressively expanded to 36 months in 1997 and to 72 months in 2001. Today futures reach until 2022. At present, gas prices are set by supply/demand balances but also still depend on the development of oil markets. The surge in light tight oil means that gas is produced almost for free when associated with oil or natural gas liquids.

Pricing developments over the period 2000 to 2008 have been a key factor enabling the development of shale gas, along with improved knowledge of US geology and the availability of E&P techniques to produce shale gas. The rise of Henry Hub gas prices above USD 5/MBtu and increasing progressively to USD 13/MBtu mid-2008 incentivised small entrepreneurs to develop shale resources.

The European gas market: a hybrid of oil indexation and gas-to-gas competition

Two pricing mechanisms dominate in Europe – oil escalation and gas-to-gas competition. In 2005, GGC represented a volume of 88 bcm for wholesale gas price formation compared to a European consumption of 580 bcm (IGU, 2012). In 2010, it reached 217 bcm against a consumption of 594 bcm. At the same time, OE volumes dropped from 458 bcm to 349 bcm. GGC is not only present in the United Kingdom, but it has developed in Continental Europe as well through the establishment of different hubs.

The origins of oil indexation in Europe

The oil indexation finds its origins back in the 1960s when the Netherlands was looking at exporting part of its natural gas production from the Groningen field which was discovered in 1959 and started producing in 1964. At that time, European gas consumption was negligible (14 bcm), Dutch consumption lower than 1 bcm and European trade at the same level. Groningen gas had to be sold in a market which was still very much to be developed. Therefore, a price needed to be found. But the Dutch government did not want to give away this new resource at cheap prices, especially not using a cost plus approach since Groningen's production costs were low.

The idea came to base the gas price on the "market value principle", also sometimes referred as netback value principle: gas needs to be competitive against its best alternative in each consuming sector (residential, commercial, industrial and power). At that time, this alternative to gas was often fuel oil or gas oil. Additionally, some rebates were included in order to encourage switching from oil products to natural gas, as investments would be necessary for the user in order to be able to consume natural gas (boiler…).

Once the market value was calculated for each segment, this resulted into an average price to which the network costs (transmission, distribution, and storage) were subtracted to come up with the so-called "border price". Each of the parties bears certain risks: the seller must carry the price risk (some border prices went negative) and the buyer the volume risk (especially when the residential sector is the main component of the market). The long-term contracts also include revisions – typically every three years; such revisions could be outside of these dates if the market conditions had changed significantly. This type of indexation spread to other European and Asian markets, so that both regions remain today influenced by oil indexation through their imports of LNG and pipeline gas.

Typically, an oil-index pricing formula will look as follows (IFRI, 2011):

$$P_m = P_o + 0.60 \times 0.80 \times 0.0078 \times (LFO_m - LFO_o) + 0.40 \times 0.90 \times 0.0076 \times (HFO_m - HFO_o) + K$$

In this formula, P_m represents the gas price in month m. P_o is the reference gas price, while LFO_o and HFO_o are the reference prices of light fuel oil and heavy fuel oil, respectively. LFO_m and HFO_m represent the prices for the month m, but actually are usually the averages of the previous six to nine months with a time lag of one to six months. The coefficients 0.60 and 0.40 represent the shares of the market segments competing respectively with light fuel oil and heavy fuel oil. The coefficients 0.80 and 0.90 are pass-through factors, used to share risks and rewards between sellers and buyers when oil products prices change. K is a fixed factor.

Although oil indexation is the most commonly used, other indices such as coal, electricity prices or inflation as a proxy for electricity prices have been used in long-term contracts (IGU, 2011). Regarding the use of inflation as a proxy for electricity prices evolution, this is particularly the case in France due to the high share of electric heating in residential heating. More sophisticated approaches exist such as the S-curve, protecting both the buyer at very high oil prices and the seller at very low oil prices. There are also options in the formulas to move from one fuel to the other as an index, should the first one exceed a certain price; or options to turn to spot indexation if a certain index which is just being developed at the time the contract becomes significant in terms of volumes traded, churn ratio and types of forward prices traded.

Box 6 • Setting a gas price in Japan

When Japan started considering LNG imports, buyers put emphasis on the long-term security of gas supplies – which remains still a very important element today. Buyers need to meet supply obligations to end-users. However, given the investments costs for LNG projects, sellers required the corresponding security of demand, creating a common interest in long-term contracts. In the first years of LNG imports (1969), LNG was imported to Japan on a fixed price, which was not an issue until oil prices suddenly increased in 1973. The price of LNG was therefore at a discount to oil.

But the long-term contracts prices were progressively increased over time until they were codified with the creation of the Government Selling Price (GSP). However, some countries started to sell oil at market prices different from the GSP. After the 1986 oil price collapse, suppliers selling LNG at oil parity prices ran into difficulties securing the economics of their LNG projects. The LNG pricing formula was modified again. Today, most Japanese LNG contracts use the Japanese Crude Cocktail, JCC, which is the weighted average price of Japanese oil imports.

The United Kingdom's experience in pricing

The United Kingdom's gas market started to open in 1986, and consumers using more than 25 000 therms became eligible. The tariff market remained controlled by British Gas, with prices determined making the distinction between gas and non-gas (network charges) costs. Initially gas costs were based on the average gas costs of British Gas and could be passed through to the end user while non-gas costs were subject to the retail price index RPI-X price cap (CRI, 2000). But the methodology was modified over the years: the gas costs were replaced first by an index of gas costs minus an efficiency factor (1%). The X factor was changed from 2% to 5%. Further changes were introduced as the consumption threshold for eligibility was lowered, and following the recommendations of the MMC in 1993 regarding the unbundling of British Gas and the introduction of full market opening; these were done mostly in the form of adjustments factors. A final change was put into practice in 1997. It reintroduced the full pass through of supply costs, as future costs were deemed unpredictable and competition forced British Gas to keep costs down. There was a full pass through also for transportation, storage, meter provision and gas costs, while a price cap, based on RPI-X, was imposed for supply and meter reading costs. There were also individual caps for each of British Gas tariff formulas. These price controls were removed in 2002 after effective competition was deemed to have been achieved on the gas market.

The origins of gas trading in the United Kingdom

The origins of gas trading in the United Kingdom date back 1992 when the power company Powergen was forced to sell gas they had contracted from a producer. Before the introduction of a spot market in the United Kingdom, and even before liberalisation started in 1986, British Gas (BGC) had a monopoly and was effectively setting the purchase price from producers (there were no imports at that time) and the sale price to the end user (Oxford, 1999). Despite the privatisation of BGC in 1986 and introduction of TPA, BGC still held the majority of gas contracts with the upstream producers in which the gas price was very much field specific and linked to either fuel oil, inflation indices or even coal.

Until 1994, spot deals were very rare, and only started that year though some deals over the telephone, but at that time, all trades were still performed at the beach. A market requires transparency and Heren started publishing information about the bilateral trades in 1994, followed by Petroleum Intelligence and World Gas Intelligence in 1995. A key development was the creation of a trading company (Accord) between BG and the American Natural Gas Clearing House (NGC) in the summer of 1994, which enabled to move trades to the National Balancing Point. NBP had been created in 1994 as a virtual point following an agreement between Transco and shippers. The clearinghouse enabled to solve the question of liability after erroneous gas allocations at the beach took place, and most trades therefore moved to the NBP. The "network code" came into effect in March 1996 after two years of negotiation between Transco and the shippers, and, General Terms and Conditions were adopted by the industry under the name of Short-term Flat NBP Trading Terms and Conditions 1997, which defined items such as the trade price, billing, payment, nominations, and force majeure. Finally, the international petroleum exchange (IPE) introduced its first natural gas contracts in January 1997, creating the basis for the exchange-based trading. During the first years, IPE trades represented much lower volumes than OTC.

Among the key success factors were the single delivery point, without any transport cost, which also relied on the previous establishment of an entry-exit system by the transporter Transco. The availability of information on products traded first on the OTC and then on the IPE are also of importance as well as a clear set of guidelines and rules giving confidence to market players in trading at the NBP. The NBP price reflects the commodity price in the entire area without geographic differentials due to transport costs (transport cost are levied separately by the TSO that runs the British gas network and is regulated by the British energy regulator).

In the late 1990s and early 2000s, other attempts to create spot markets started. The first was with Zeebrugge in Belgium, which was since the construction and start of the Interconnector pipeline in October 1998 physically linked to the United Kingdom and therefore to the NBP. Unlike the NBP, Zeebrugge is a physical hub, where gas from the Interconnector enters the Belgian distribution system.

Some failures in developing gas hubs

Not all hubs have been successes. In the early 2000s, for instance, and experimental hub was established at the border between Germany and the Netherlands. It was the arrival point of pipelines coming from Norway and supplying northwestern Europe. At that time, only Zeebrugge had some significance in Continental Europe, and it was mostly a twin brother of NBP, therefore the development of another hub made sense. Two companies, HubCo and EuroHub, were trying to develop each their own hub place. HubCo was owned by Ruhrgas, Statoil and BEB, another German company. Eurohub was supported by Dutch Gasunie. In 2004, given the lack of development and liquidity of the hub, both companies decided to merge operations. Besides the competition between the two companies, issues which prevented the take-off of the hub included cross-border issues and the lack of available capacity, different methodologies – Eurohub had an entry-exit system, and HubCo a point-to-point system – reflecting the different transport system in the two countries, deals were also limited to physical trades as opposed to virtual trading. Finally, the birth of the Title Transfer Facility (TTF) in the Netherlands created a new competitor, and only this last hub survived. TTF was introduced as a virtual hub, and its development was supported by the Dutch TSO Gasunie (fully unbundled), which constantly improved the services offered, including quality conversion and cross-border services, and also by the gas exchanges APX and Endex, even if OTC trades were still the majority.

Recent changes

Over the past three years, a major issue in Europe has been the persistent differential between oil-indexed prices and spot gas prices (usually represented by the NBP). In 2009, the economic crisis and the drop in gas demand that coincided with availability of new LNG on the markets (in particular due to lack of demand from the United States) resulted in a wide gap between oil-linked contracts prices and spot prices. This resulted in re-negotiation of some long-term contracts, with the introduction of spot indexation and more flexibility on the take-or-pay quantities from 2010 onwards, resulting in an increasing differential between the Brent oil price and the German Border Price (GBP) since 2009.

At the same time, gas markets tightened in 2010. These two factors helped to reduce the gap between the NBP and the GBP, but this differential increased once again at the end of 2011 due to the strong oil price increase and very weak European gas demand stemming from mild weather. The average price premium of the GBP on NBP prices was USD 1.6/MBtu in 2011, slightly above the USD 1.5/MBtu premium in 2010.

There are, however, more voices being raised against oil indexation for reasons including: the diminishing direct competition between the two fuels "at the burner tip"; the lower correlation (notably in the United States) between their prices; the fact that coal is a more important alternative in the power sector; the increased use of shorter-term contracts, which are more based on spot pricing; and improving interconnections between and within markets. Additionally, the European Commission itself seeks to pave the way for gas-to-gas competition as an alternative to oil indexation (IGU, 2011).

By contrast, there is more trust in markets for crude oil and refined products, where commodities are fungible and globally traded. Apart from the Henry Hub in the United States and NBP in Europe, other Continental European hubs remain small and thinly traded. Illiquidity spells unpredictability, and entails a risk of market manipulation. Finally, there is still a lack of trust in using spot pricing as a reliable indexation method.

Box 7 • Long-term gas contracts

Long-term contracts are not *per se* incompatible with liberalised markets and wholesale prices. They offer advantages on the investment side in order to support expensive investments, but have in different cases resulted in difficulties in liberalising gas markets and subsequent stages of market development. Some long-term contracts are already completely or partially based on spot prices. For example, the most recent imports contracts from the Netherlands or Norway to the United Kingdom are based on NBP spot prices.

Long-term contracts can be seen as a measure of risk mitigation for market players. They often ensure a defined amount of gas to be traded between producer/seller and buyer during a time span which can reach up to 20 or 25 years. These contracts often include buyers' obligations to receive a specific amount of gas over a specific period (months, quarters, years) and these take-or-pay contracts ensure a steady production stream for the producer/seller, while demand fluctuations are to be balanced by the buyer. As shown above, the price is often linked to oil, but other types of indexation including gas, coal, and inflation can exist.

Long-term import contracts are often a good measure of risk mitigation for producers, as the contracts guarantee a steady income stream. This steady stream allows for long-term and significant capital investments to be taken into exploration, production (including upstream pipelines) and also conditioning of the gas. On the midstream level, vertically-integrated companies prefer such contracts between them and their customers (distribution companies and large single users) in order to secure their supply revenues and also minimising the risk associated with their long-term import contracts with their own suppliers and their investments into pipelines. Guaranteed demand with downstream gas customers often favours contracts with suppliers. It is important to keep in mind that in an early stage of development, no gas market has started out with anything other than long-term contracts.

While there are obvious benefits from long-term contracts throughout the whole gas value chain, these contracts can also be seen as an obstacle to reaching a fully liberalised and competitive market and efficient investments in production and network infrastructure.

Bilateral long-term contracts lock-in customers with buying obligations. This forecloses a large quantity of gas demand from supply-side competition over a long period, excluding these customers from potentially cheaper gas sources. The issue was particularly apparent in Europe in 2009 after the economic crisis where not only gas demand was very low but also long-term contracts much more expensive than cheap LNG prices. As a result, European buyers had difficulties to respect their minimum take-or-pay commitments as their contracts were largely covering their import needs. They managed to renegotiate their contracts by adding not only a spot price component but also more flexibility on the annual contract quantity.

The foreclosure by long-term contracts on the import side may result in low liquidity on the spot markets and therefore lead to high price uncertainty. This uncertainty will often be reflected in frequent and high price variations since small changes in the demand or the supply side can create situations with relatively large over- or undersupply. Such inflexible price mechanisms can create situations of overly expensive gas deliveries as it was the case in several gas markets such as the US, the United Kingdom (both with long-term contracts with producers, see following section) and the German gas markets.

In these markets, a ban of long-term contracts on the downstream side lead to a situation of some suppliers facing severe economic losses as they were left with too highly priced gas from the upstream or import side.

Long-term contracts can make producers inflexible to variations on the demand side and thus can create oversupply. In addition, long-term contracts in fully liberalised gas markets, such as the US gas market, can hinder efficient investments into network infrastructure due to the non-transparent price determination procedures of these long-term contracts.

Managing the transition from contracts to spot markets

Experience from several IEA member states show that the transition from contract based gas sales towards spot market based gas sales can imply significant economic distortions for market players. The quantity and quality of long-term contracts in gas markets requires significant consideration during gas market opening and can impose significant opening barriers. In that light, avoiding excessive use of long-term contracts from the very beginning can be a key cornerstone of a least-cost market opening process.

The United Kingdom

The transition from a monopolistic market dominated by long-term contracts to a more market-based approach has consequences on the incumbents, which see their role evolving and can find themselves in difficult financial positions. This was particularly the case in the United Kingdom, where the historical long-term bilateral contracts between the incumbent BGC became a burden after the opening of gas markets, in particular due to the long-term contracts and the price differential emerging between the pricing of the old contracts and the new market price that was emerging.

Not only were the gas prices agreed between BG and the upstream producers linked to competing fuel prices and inflation, there were also no price revision clauses in the long-term contracts, so that there was no means to stop divergence from market prices. However, in the early 1990s, several factors contributed to an oversupply situation, *e.g.* excessive market entry, satellite field development and BG's own production increases. The liberalisation and market opening meant that upstream producers were developing new gas fields in the hope to get a piece in a growing market by selling their gas either to the new gas-fired plants or to the new marketers. In 1992 and 1993, the prices agreed in these long-term contracts related to these fields were in line with BG's purchase costs. Given the large share of associated gas fields, an estimated 90% of the fields would produce up to 6 p/th, there was little incentive to shut down production when prices started to collapse.

A combination of mild weather in 1995, combined with delays of power plants and excess purchases by BG from the Morecambe field (one of the largest gas fields in the United Kingdom, also used as virtual storage in the past due to its high production flexibility) exacerbated the company's imbalance. BG had take-or-pay obligations to purchase 47.6 bcm (4.6 bcf/d) versus an estimated demand of 45.0 bcm (4.35 bcf/d), leaving it with 2.6 bcm (0.25 bcf/d) having a value of GBP 528 million. As BG's weighted average cost of gas (WACOG) was much higher than the spot price, this left the company with two options: selling gas at a loss (either on the spot market or to its own customers, and since the volume represented around 30% of the spot market at that time, there was a risk to make prices drop even further) or restricting supply and maintaining high gas prices. This led to the renegotiation of gas contracts and the de-merger of British Gas.

The company decided to split first into two parts in 1996; Centrica became responsible for gas sales, services and retail business as well as the North and South Morecambe fields, and BG PLc, was allocated exploration, production, transport and storage. The deal was finalised in early 1997. This de-merger, seen as a correction of the government's failure to restructure the industry in times of liberalisation, had a cost – the combined market value of the assets fell by half from GBP 15.5 billion to GBP 7.7 billion (World Bank, 1998). During the split, all the contracts went to Centrica, which had to renegotiate them, which was done by the end of 1997. For example, in December 1997, Centrica announced that it had renegotiated the contracts with Conoco, Elf and Total. But in return, it had agreed to pay a compensation of GBP 365 million (before tax) and further provisions were made for further potential volumes to Conoco. Then, agreements followed with Philips, Agip and Fina for GBP 43 million, contracts with Chevron were terminated. At the same time, due to the opening of gas market for residential users as well, Centrica lost many household gas customers, while it gained new electricity customers, so that the number of energy customers as a whole was increasing.

The United States

The liberalisation of wellhead gas prices and increase in competition had consequences on some parts of the gas value chain, in particular the interstate pipeline companies. Before third-party access to the pipelines, interstate pipelines had concluded long-term contracts with the gas producers and were selling to the distribution companies.

The US gas market went from a period of shortage during the 1970s to one of oversupply from 1980 to 1985. The new wellhead prices established after 1978 often exceeded the costs of the various gas producers, so that exploration activity and production levels jumped. Despite the rising wellhead gas prices mentioned the subsection on the evolution of the US pricing system in Chapter 5, the companies still accepted these contracts. The high cost of these supplies were simply transferred from the pipeline companies to the next stage of the gas value chain – the distribution companies and then to the final consumers. High gas prices drove demand steeply downward, leaving the vertically integrated midstream suppliers with long-term buying obligations but no market.

Additionally, with FERC Order 436, pipelines were open to third-party access and distribution companies, which could bypass the midstream companies and source gas more cheaply. They were given the opportunity to exit their contracts with pipeline companies, but pipeline companies could not exit their contracts with producers. They negotiated new and cheaper supply contracts, further undermining sales of the pipeline companies, which had to charge more for their gas to a shrinking customer base. The transition costs related to FERC Order 436 were estimated at USD 11.7 billion (World Bank, 1998), which represented half of the total book value of interstate pipelines (USD 23.4 billion in 1984).

This forced most such companies into litigation with producers and therefore required FERC to set up a mechanism to distribute the costs among all industry participants. FERC issued Order 500 in 1987 allowing the pipeline companies to pass on up to 75% of the transition costs to producers, distribution companies, and large consumers. Only then did the interstate pipeline companies begin to implement the open access regime on a large scale.

Creating a trading hub in Asia

While trading hubs exist in North America and Europe, they are still missing in Asia, despite the presence of mature gas markets, such as in Japan and Korea, currently the world's largest LNG importers. Several countries will start or increase imports over the medium term – China, but also India, Thailand, Malaysia, Indonesia, Vietnam and Singapore. The last three still have their LNG terminals under construction, the first four are already LNG importers. Although Indonesia and Malaysia will remain net exporters in the medium term, they will become importers at the same time. Regional trade as well as international trade is deemed to increase, mostly through LNG.

However, these markets are far from being liberalised, characterised by a lack of competition both upstream (when relevant) and downstream. The Chinese situation has been explained in some detail earlier in this report. Japanese and Korean companies purchase their LNG under long-term contracts, mostly oil-indexed, with limited flexibility for consumers and with high certainty regarding demand for suppliers. These contracts also require limited competition in the downstream sector, since LNG buyers need a guaranteed market for distribution to end-consumers (IEA, 2012).

Establishing a wholesale market for natural gas in Asia with a spot and futures market will take a long time. The European and North American experiences demonstrate that several years are necessary to complete this process. For most countries, liberalisation means considerable changes to their gas industry, and also different pathways that consider their often quite different starting points. Experience also shows that interventions by governments are necessary to introduce well-functioning gas markets. Fundamentally there are two major requirements, *i.e.*:

- institutional changes, including wholesale price deregulation, the separation of transport and marketing activities and making at least large customers eligible to choose their supplier; and
- structural conditions, including the existence of sufficient network capacity, transparent access to it, a number of participants sufficient to engender competition, and the involvement of financial institutions.

Achieving this would require radical changes of the natural gas sector in China. In a first phase, third-party access is a prerequisite, as the US and European examples show, as are increased competition and wholesale price deregulation (Figure 11). The gas industry would have to move from a vertically-integrated structure to smaller, less vertically integrated energy companies. In principle, this also requires less government interference in the operations of the natural gas market, in particular when it comes to setting wholesale gas prices ("hands off attitude"). Independent regulator in charge of setting the network charges is also a prerequisite.

Then in a second stage, OECD experience shows that accessibility, via non-discriminatory access to pipelines and availability of capacity on these networks are essential to a well functioning natural gas markets. This implies that the TSO is investing in a clear and unbiased manner, which implies a good regulatory framework incentivising these investments. Increasing competition also brings along a higher number of market participants. Apart from their role in investments, financial parties willing to cover financial/operational risks for parties involved in the natural gas trade, are also needed. As explained in Chapter 4, a link between natural markets and financial institutions is needed to reduce counterparty risk and to provide a clear long-term price signal.

European and US experience also demonstrate that investors' confidence is boosted by increased transparency, in particular concerning the conditions of access to gas networks. Such transparency means increasing OTC and exchange-based transactions, the involvement of non-traditional (financial) parties willing to take on the price risk of gas volumes for future delivery, and trading of an increasing number of products with delivery in the future.

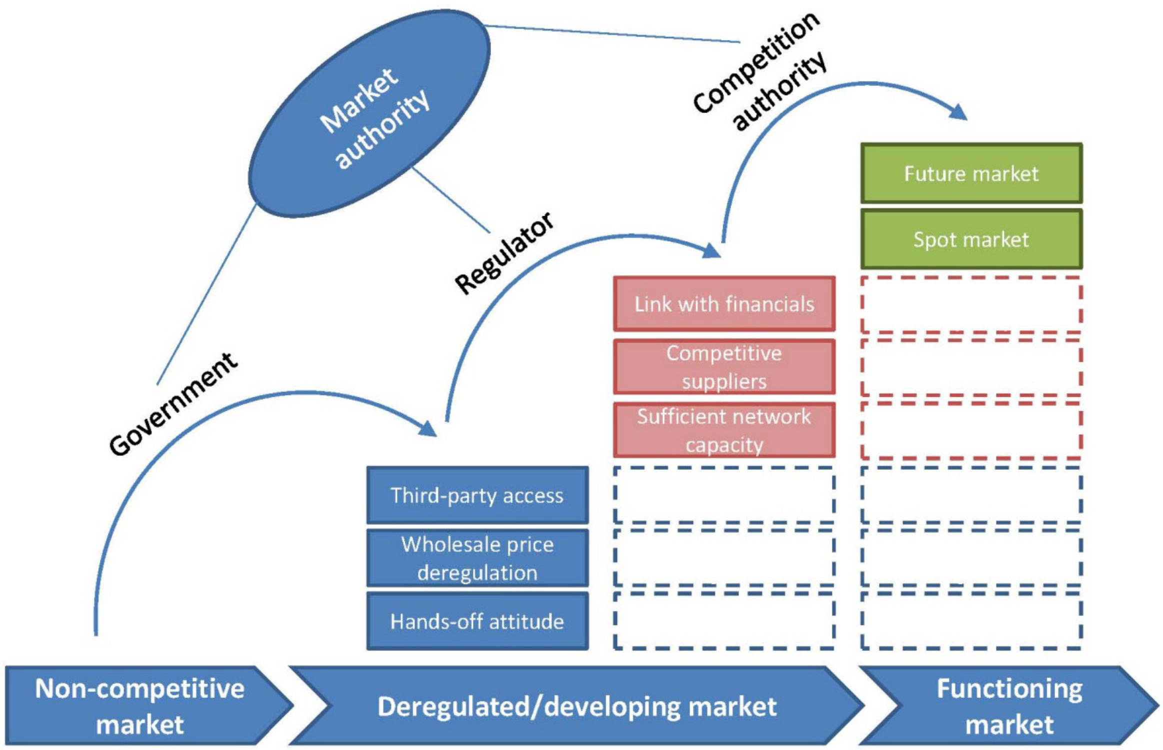
As a result, prices on the spot and future markets that would represent the final stage of evolution would increasingly reflect the supply-demand balance for the covered geographical area in the near future.

In parallel, a functioning wholesale market for natural gas will require the government to take a different role than it is used to. In a liberalised system, the government must adapt to the role of the regulator and will ultimately move into the role of arbitrator via competition authorities. This will require a consistent mindset towards liberalisation and handing over of control of a part of the economy, frequently perceived as crucial, something that governments are likely to find very difficult to do.

According to current estimates by Chinese experts, China's gas market should be around 350 bcm by 2020. This seems large enough to create a gas price driven by domestic supply/demand dynamics, supported by the growing number of sources ranging from domestic gas and imports from Central Asia, Myanmar, LNG and maybe Russia.

This also depends on what the Chinese stakeholders really mean by creating a hub. Will it be the standard definition based on the US or European experience or their own Chinese reference price based on a netback from competing fuels, which increasingly will include competing gas supplies? The question then will be what would happen to the current long-term contracts, not only targeting China but also for LNG sold in the Asia Pacific region.

Figure 11 • Creating a wholesale natural gas market



6. Production and trade of gas

Key messages

- Upstream regulation generally focuses on three aspects to successfully develop a natural gas resource: licensing and ownership, safety and environmental, and access to infrastructure.
- Companies generally prefer to roll these regulatory requirements into one transparent, consistent and overarching set of procedures that will ensure the long-term stability needed to develop natural gas resources and their capital intensive infrastructure.
- However globally a model for such an integrated structure does not exist due to local conditions and the number of national agencies involved. This frequently results in parallel procedures that can span numerous agencies on various levels of government.
- OECD experience shows that many countries have used specific policies to encourage the development of frontier areas, or more expensive resources as well as mature areas which lie fallow. In the United States, an R&D programme resulted in the development of technologies which later made the development of CBM and shale gas possible.
- The development of shale gas and other unconventional resources puts a spot light on safety and environmental issues. The technologies and know-how exist for unconventional gas to be produced in a way that satisfactorily addresses these issues, but a continuous drive from governments and industry to improve performance and adherence to best practice is required if public confidence is to be maintained or earned.

Production in IEA member states is mostly handled on a competitive basis, albeit with notable variations between countries. Usually the upstream sector is regulated by a specific regulator which is quite often different from the one in charge of downstream markets. Additionally, differences in regulation can exist between offshore and onshore resources, regarding the government level involved (federal, national, regional, or local), the various government agencies involved with their respective mandate (*e.g.* environmental protection, competition, labour relations, tax revenues etc.) and the specific resource (conventional gas, associated gas from oil and non-conventional gas). The following parts explain the regulation of exploration and production in several IEA countries and focus in particular on the Dutch and Norwegian upstream policies.

Regulation of exploration and production

The regulation of exploration and production of petroleum resources, and natural gas in particular, generally focuses on ensuring collective benefits from the development of these resources. Governments develop a regulatory regime clarifying the roles and responsibilities of governmental and private entities to reduce the risk of accidents, to secure revenues from natural gas development and in the case of liberalised gas markets, to ensure equal access to networks.

There are three main areas of regulation in the upstream sector:

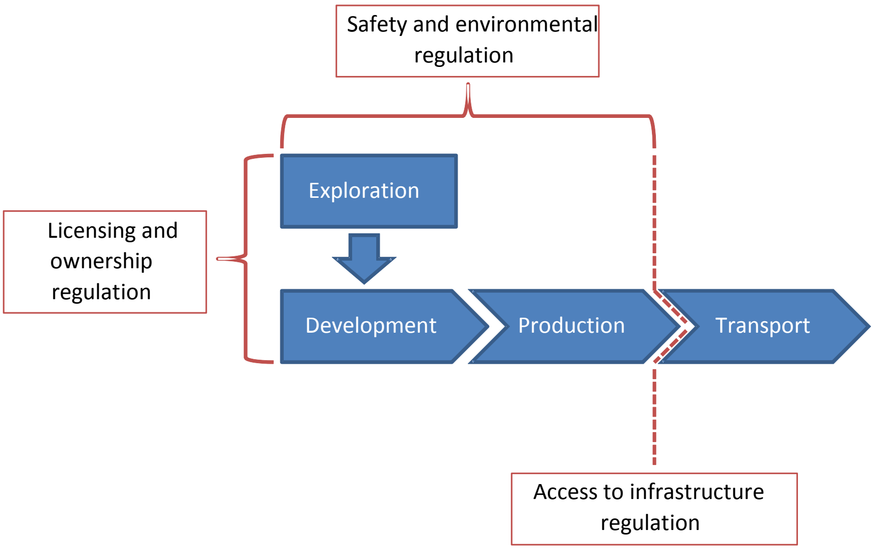
- licensing and ownership regulation during the exploration development and production phases of a natural gas project, effectively establishing who owns what and who gets what;
- safety and environmental regulation that ensures the public interest of safe and environmentally responsible development of natural gas resources; and
- regulation of access to infrastructure for producers creating the security that natural gas can competitively sold in the downstream market.

Market parties usually prefer to roll regulatory requirements into one transparent, consistent and overarching set of procedures that will ensure the long-term stability needed to develop natural gas resources and their capital intensive infrastructure. However, achieving a stable long-term regulatory regime is difficult as the authority to regulate, and number of regulatory bodies involved may shift with the location of the resource.

Below a general outline is given on regulatory regimes in the United States, United Kingdom and the Netherlands in upstream natural gas development. It is important to stress that no standard model exists globally, since the question of ownership of the resource and responsibility for developing the resource is treated quite differently across the globe.

A considerable difference between resource ownership in Europe and the United States exists. In the United States, the owner of the land also owns the resources located beneath surface, while European societies and government have a more communal perspective on resource ownership, with resources beneath the surface generally owned by the government. This difference in ownership considerably alters the role and responsibilities of governments and private industries in the United States and Europe.

Figure 12 • Three areas of government regulation in exploration and production



Upstream regulation in the United States

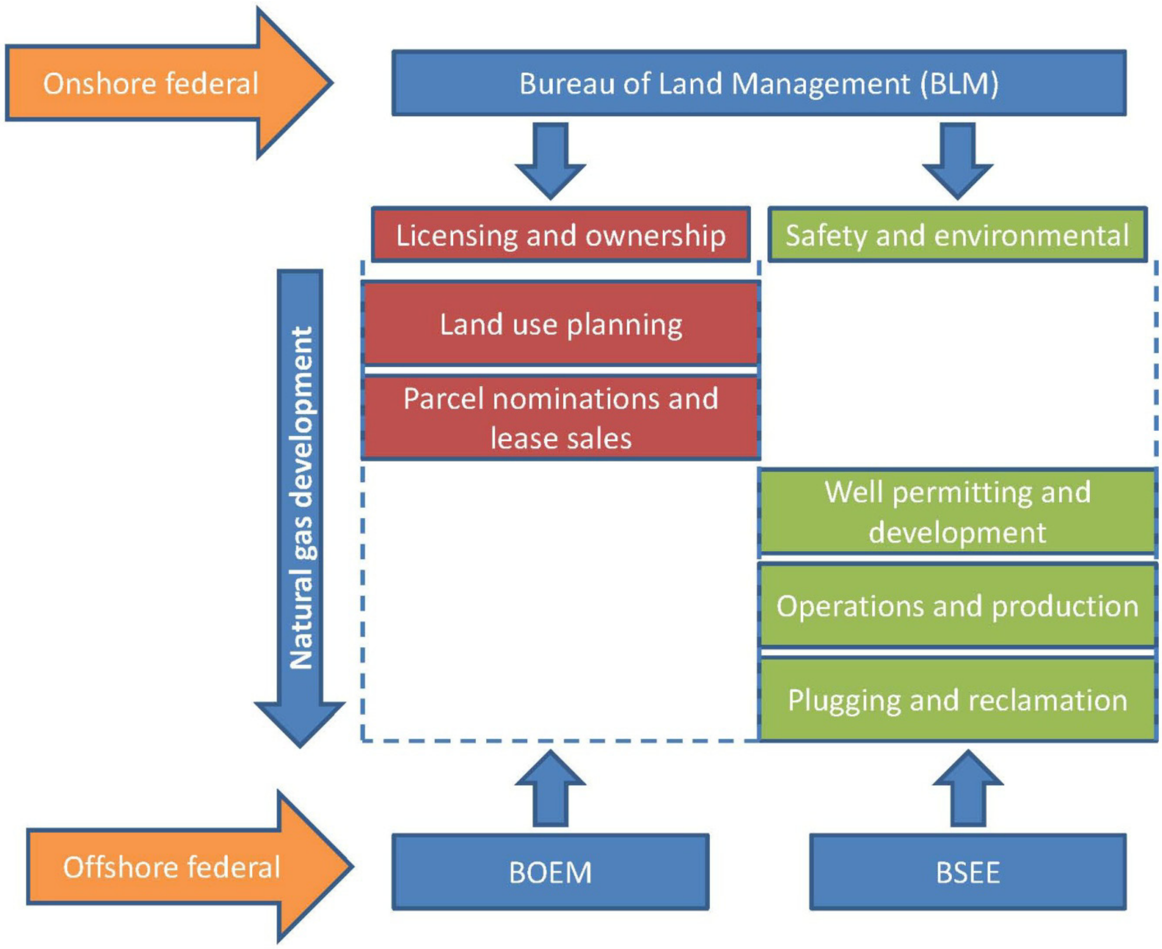
As resource ownership in the United States will reside with the one owning the land, the role of the federal government in managing natural gas resources is restricted to federal lands and offshore oil and gas developments on the outer continental shelves. When licensing and ownership lie with the federal government, development of natural gas projects will still have to comply with the respective state environmental, safety and access to infrastructure regulations. The role of the federal government in developing onshore oil and gas resources is therefore that of a mediator ensuring that development on federal land complies with both federal and state regulations.

Development of both onshore (on federal lands) and offshore natural gas reserves is managed by the US Department of the Interior (DOI). In addition, the US Environmental Protection Agency (EPA) has a considerable role in developing minimum environmental requirements for resource development. FERC is an independent body regulating interstate gas industry, with an important role on ensuring third-party access to inter-state transport pipelines.

The 50 US states, the District of Columbia and United States Territories have a large role in regulating natural gas development within their borders. These states generally have regulatory commissions that are appointed or elected and deal with all aspects of energy development within a state throughout the value chain. Federal lands are leased to individuals and companies for natural resources development. Lease holders competitively bid, initially pay a bonus, and subsequently rent, for the right to develop the resources on these onshore and offshore lands. The successful bidder obtains the right to explore and drill for, extract, remove, and dispose of deposits of oil and gas found on the lease. Leases are valid for ten years or as long as there is at least one producing well.

Within the DOI, the Bureau of Ocean Energy Management (BOEM) is responsible for offshore federal leasing, the Bureau of Land Management (BLM) is responsible for federal onshore leasing, while the Bureau of Indian Affairs co-ordinates leasing on Indian lands. Both the BLM and BOEM agencies work closely together in establishing a fair return policy for energy development in the US. The Office of Natural Resources Revenue (ONRR) is responsible for the management of revenues associated with federal offshore and onshore mineral leases. The Bureau of Land Management is the designated government agency that administers the leasing of lands for resource development. The BLM considers the process to consist of the following stages: land use planning, parcel nominations and lease sales, well permitting and development, operations and production, plugging and reclamation. To ensure safe environmental operations, the BLM established Best Management Practices (BMPs) to reduce the environmental footprint on federal lands.

Figure 13 • Bureau of Land Management regulation of natural gas development on federal lands



Following the 2010 Macondo disaster, federal oversight of offshore oil and gas development was tightened and reorganised. This resulted in a split of the DOI's Mineral Management Service

(MMS) in the Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE). Activities related to licensing and ownership were given to BOEM, while environmental and safety oversight and enforcement was transferred to BSEE. On a federal level, FERC is responsible for providing third-party access regime by interstate pipeline operators. In addition, FERC enforces a regime for third-party access for offshore oil and gas developments. At the state level, Public Utility Commissions ensure access to transport infrastructure.

Development of unconventional gas in the United States

Until now, most unconventional gas developments have been concentrated in North America. In 2011, an estimated 550 bcm of unconventional gas was produced worldwide, with around 280 bcm coming from this region (IEA, 2012). Shale gas production (around 200 bcm) is entirely a North American phenomenon. Unconventional gas is not new. Tight gas has been produced for over 40 years in the United States, US CBM production started in the 1990s although CBM has been known for as long as coal has been exploited and was often considered as a risk. Shale gas, due to its very low permeability, was the last one to be developed and its growth since 2005 has been exponential (from 20 bcm then to almost 200 bcm in 2011). Several factors made shale gas development possible, including:

- better knowledge of best resource potential, acquired with over a century of E&P, but also improved by R&D performed since the 1970s;
- entrepreneurs willing to start drilling shale gas while the big IOCs stayed away;
- improved drilling and completing (fracking) technologies, which were also partly the result of government's driven research; and
- a rise in wholesale prices to USD 6 to 8/MBtu over 2005-08.

A lot of research directed and funded by the Department of Energy started in 1976 and was terminated in 1992. This research would considerably improve knowledge about unconventional gas, even though this resource was not attracting so much interest at that time. Research concentrated on three major resource areas: Eastern gas shales, Western gas sands, and coal seams. There was also research on other resources such as hydrates. Research items include the use of nitrogen foam to effectively stimulate shale gas production, a better understanding of CBM resources in place and technology for dewatering coal seam, the improvement of measures implementation of directional drilling in shale reservoirs to improve productivity by intersecting fractures, and the early development of micro-seismic monitoring techniques for mapping hydraulically-created fractures. This later translated in the availability of technologies, improved and complemented thereafter by the companies' own R&D. This means that when the economics became interesting mid-2000s, the technology was ready (NETL, 2007).

Additionally, the government put in place tax credits for unconventional gas (CBM, tight gas and Devonian shale) as early as 1980, on the back of gas shortages. Section 29 tax credits provided a USD 1/Mcf incentive for gas shale. During the early 1990s, wellhead gas prices were around USD 2/Mcf. These measures worked as unconventional gas production was multiplied by 2.5 from 1990 to 1999. CBM production grew considerably to around 30 bcm. By 2001, unconventional gas production represented 30% of the lower 48 gas production, compared to 8% in 1982. The measures were also criticised due to the ratio of the tax credit compared to the wellhead price, which may have incentivised companies to drill only for the tax credits.

The legislation in the United States applies to oil and gas generally, and was in place before unconventional gas took on such importance in US gas production. It is a mixture of laws, statutes and regulations at the federal, state, regional and local levels. The legislation covers virtually all phases of an unconventional resource development, from exploration through to site restoration, and include provisions for environmental protection and management of air, land, waste and water. As mentioned previously, the states play an important role in the regulation and enforcement on lands outside federal ownership. This can consequently results in some differences among the states.

Given the now prominent role of shale gas, it has attracted a lot of attention, notably in terms of consequences on water and air. Hence, the focus of regulation has shifted from promoting shale gas development to making sure that unconventional gas development is performed in a safe and environmental friendly way. Some federal laws are directly relevant for unconventional gas and relate mostly to environmental protection, *i.e.* the Clean Air Act, the Clean Water Act and the Safe Drinking Water Act. These rules can be complemented at the state level by additional regulations addressing growing public concerns, notably about the risk of pollution of water resources. Additional regulation con include enhanced disclosure of information on fracturing fluids, additional measures to ensure adequate integrity in well casing and cementing, and rules on the treatment and disposal of waste water. Additionally, some states have decided to put in place temporary bans on hydraulic fracturing pending further review of its environmental impacts and the need for changes to regulations.

As an illustration of the focus on environmental and safety aspects, the EPA has been working on a report investigating the impact of shale gas, due to be released in 2014. In May 2011, US Energy Secretary Chu charged the Secretary of the Energy Advisory Board natural gas subcommittee to make recommendations to improve hydraulic fracturing of shale gas. The subcommittee issued a set of 20 recommendations in November 2011. These recommendations to reduce the environmental impact and improve the safety of shale gas production were either to be done on a short-term basis by federal agencies (such as increasing public information, improving communication between state and federal regulators or disclose fracturing fluids information), by states (such as adopting requirements for background water quality measurements) or would require a longer-term approach through new partnerships. In April 2012, the EPA issued new regulations under the Clean Air Act to reduce harmful air pollution from the oil and natural gas industry. These rules include the first federal air quality standards for natural gas wells that are hydraulically fractured, along with requirements for other parts of the gas value chain, such as gas processing plants.

Upstream regulation in the United Kingdom

The United Kingdom has implemented a transparent and open development regime for gas fields. Initially based upon the Petroleum and Submarine Pipelines Act 1975 and later on the Petroleum Act 1998, the Secretary of State is responsible for granting single-field licenses. This follows a pre-determined process which allows for every interested party to put an application forward.

Within the United Kingdom, a single regulatory body is regulating natural gas development. The Department for Energy and Climate Change (DECC) has jurisdiction over the offshore industry, which includes hydrocarbon production by the oil and gas industry (natural gas production in the United Kingdom is 99.9% offshore). DECC holds licensing rounds, awards licences for development and production, and access to upstream pipelines. DECC awards three main types of offshore production licenses that can cover three successive terms. In a traditional production license, the first term (exploration) is four years, second term (development) also four, and the third term (production) is eighteen years.

According to the *"Guidance notes on procedures for regulating oil and gas developments"* (DECC, 2012), applicants have to put forward a Field Development Plan (FDP) which will be tested on policy objectives and results in mutually satisfactory conclusions between the applicant and DECC. Policy objectives in that regard, amongst other aspects, ensure environmental compatibility, the full recovery of all economic reserves, the adequate and competitive provision of pipelines and facilities via anticipated development and negotiated third-party access to upstream pipelines.

The resulting FDP provides a summary description of the actual development and the principles and objectives that will govern its management. One key regulatory aspect following the development authorisation is the focus of DECC on the actual development compared to the FDP. This will enable DECC to identify quickly deviations from initial the FDP and take remedial actions. Due to a significant amount of acreage left untouched, so-called "Stewardships" have been introduced in 2004 to enhance economical brown field recovery by detailed negotiations, third-party investments or divestment (DECC, 2012 and Pilot, 2005).

Certain drill-or-drop clauses may apply in the license, stimulating the licensed party to keep up with the agreed upon work programme. DECC can also revoke a licence if the operator is deemed to be a "poor-steward", *e.g.* does not meet the required safety, operational, and environmental standards. Recently, DECC has introduced new offshore licenses with lengthened terms, to account for the increasingly difficult terrain offshore operators need to work in on the United Kingdom Continental Shelf.

Upstream development in the Netherlands

The Ministry of Economic Affairs, Agriculture and Education (MinEL&I) is responsible for the regulation of exploration and production in the Netherlands. The regulatory process is divided in two parallel processes co-ordinated by MinEL&I. The exploration and production licensing procedure is divided in two parts.

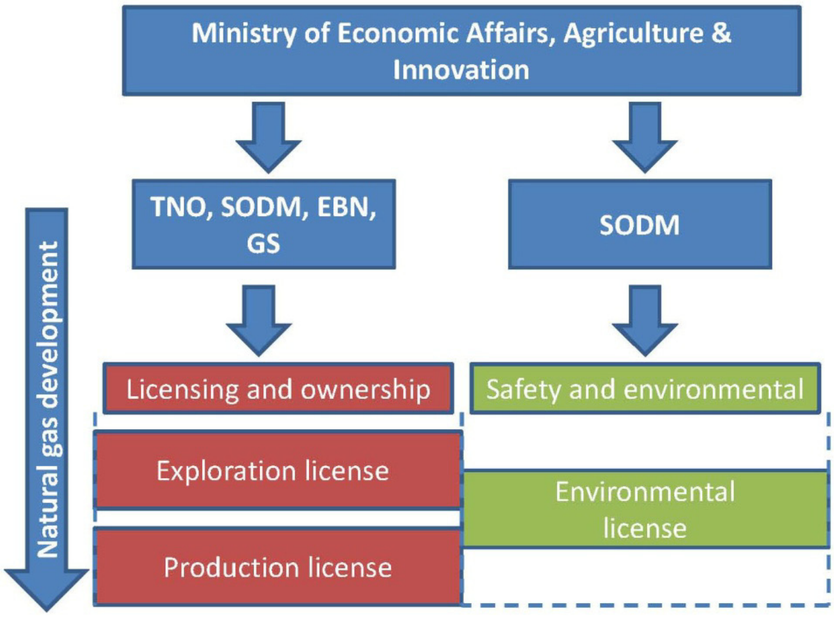
Firstly, the company needs to obtain an exploration licence, requiring the company to disclose a programme of activities, the geological area for exploration, the financial capabilities of the organisation, the technical capability of the organisation and specific information related to the area (if onshore). The ministry will gather advice on the licence request from four governmental agencies (if onshore, otherwise three) that vet the procedure for the geological, financial, technical, and spatial aspects.[11] If a licence is given the whole procedure will take about eight ton nine months. Secondly, if exploration is a success, a production licence can be obtained that will examine the economic viability of the resource development plan, and seek advice from the same agencies. This process can take up to eight months to complete.

Parallel to the exploration and production licensing process, an environmental licence needs to be obtained if permanent production activities are developed (a separate regime exists for exploration and seismic activities of temporary nature). This "Environmental" licence regulates the environmental impact on the area of operations on the Dutch onshore and within the nautical twelve mile zone. The licensing procedure integrates the environmental and operational requirements of several governmental bodies (National, Provincial, and Municipal) into one procedure supervised by the government body "State Supervision of the Mines" (SODM). Once an environmental licence (omgevingsvergunning) is obtained, production can start.

Under the Gas Act of 2000 there is regulated third-party access (TPA) for all customers on distribution gas networks and transportation pipelines, but not production pipelines.

[11] The government will seek the advice of : TNO, Energie Beheer Nederland (EBN), Staatstoezicht op de Mijnen (SODM), and Gedeputeerde Staten (GS).

Figure 14 • Exploration and production regulation in the Netherlands



Upstream access regulation

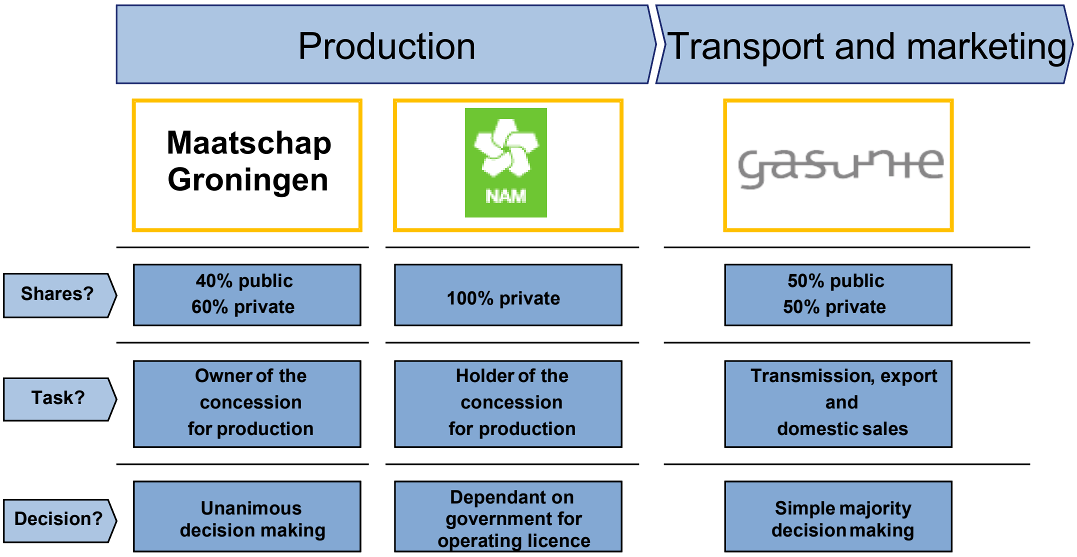
The Dutch upstream policy

When the super-giant gas field Groningen was discovered in the Netherlands in 1959, it posed the Dutch government with a particular problem on how to monetise this resource and to maximise benefits for the society through tax revenues and subsequent government expenditure. A gas market needed to be developed, which required a stable governmental vision, trust of market participants and a division of labour through clearly defined roles and responsibilities between the government and the private industries (Smit, 2006). In 1963, arrangements were subsequently shaped into the "Gasgebouw", a public-private partnership (PPP) between the state and a private joint-venture called NAM (Shell and ExxonMobil). State and private companies shared the responsibility for the investments necessary to develop the Groningen field and a natural gas market along the whole value chain.

This PPP succeeded to rapidly develop natural gas consumption and exports aided by two important features. Firstly the *netback value principle* that linked the gas price to that of its most likely competitors (see part on pricing and trading), and guaranteed that gas would always be competitive. Secondly, a monopoly on natural gas marketing was established for a specific region through destination clauses (prohibiting reselling of the gas). This allowed the natural gas market to grow at the expense of alternative energy sources (oil and coal) as opposed to alternative natural gas suppliers (Correljé, 2000).

Within the PPP, Gasunie (50/50 public/private owned) was responsible for transporting and marketing natural gas. In the 1960s, natural gas was generally expected to have a limited role in the Dutch energy mix, as nuclear power was expected to eventually replace all existing demand for fossil fuels. Gasunie was therefore instructed to develop additional sources of demand, since the Dutch economy could not physically absorb all Groningen gas in the required timeframe (roughly a decade). This led to the signature of many long-term export contracts usually with a national gas utility that had regional monopoly to market gas in another country. As gas was usually priced at 65 to 85% of the oil product equivalent, there was in considerable demand in neighbouring countries, providing the PPP with its desired additional outlet for Groningen gas (Correljé, 2003).

Figure 15 • Public-private partnership governing development of Groningen field until 2005



Shocks to the system: Oil crisis

The oil crisis of 1973 provided public pressure in the Dutch parliament to decrease oil and fossil fuels imports. As a result, the government needed policies that focussed on securing long-term gas supply. Although long-term gas supply contracts dedicated large shares of the Groningen field gas to exports, a breach of contract was not an option. A revision of exports would have caused significant stranded investments in the already developed export pipeline infrastructure. As a consequence, increasing gas supply security was required to come from additional gas or changes on the demand side.

One effect of the oil shock was through increased commodity prices investments were recouped much faster than initially anticipated. This allowed for room between buyers and sellers to renegotiate natural gas prices upwards, even if export volumes dropped from 50 bcm in 1975 to 30 bcm in 1985 contributing to the original goal of preserving natural gas volumes for the Dutch market. In 1974, a major change in resource policy was introduced when the government decided to extend the operating life of the Groningen field by stimulating the exploration and production from smaller natural gas fields both on- and offshore. This henceforth came to be known as the "Small Field Policy" (SFP).

Small Field Policy

The establishment of the Dutch SFP aimed to stimulate the development of other fields than the Groningen field. The policy had to tackle the "problem" of cheap gas supplies from the onshore Groningen field which effectively blocked incentives to develop more expensive production in the Netherlands. The public policy target was to develop the entire resource base of the Netherlands (both onshore and offshore) to enhance long-term supply security, while private partners aimed at developing low-cost reserves, maximising their profits from oil-indexed natural gas sales.

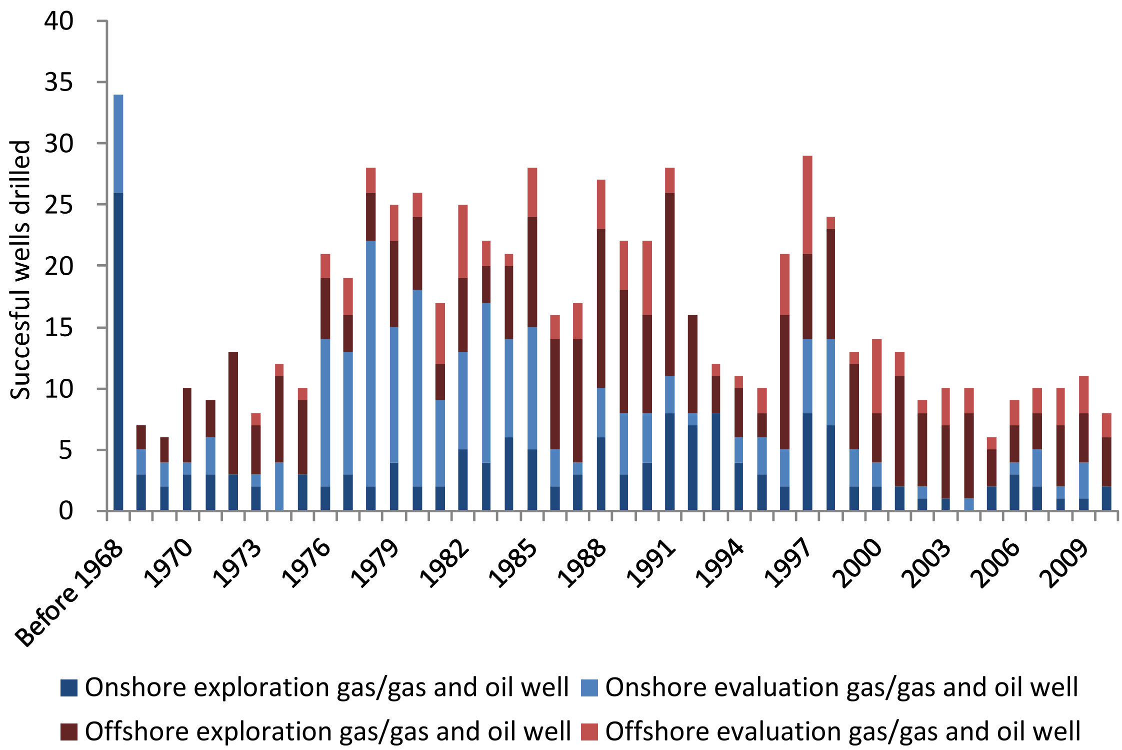
The SFP created the obligation for Gasunie to contract gas other than Groningen gas if it was offered at a reasonable price. This meant that gas from "smaller" fields would be baseload contracted in the Dutch transport system, while the Groningen field would balance the total flow with overall natural gas demand (including exports and minus imports). The Groningen field became supplier of last resort, balancing the Dutch and Northwest European gas networks. The price was the average of the sales price of oil-indexed gas in the markets supplied by Dutch gas.

This allowed the small field producers to benefit from rising oil prices as well. Overall, the change in government attitude towards the development of the Groningen field significantly expanded the resource base that could economically be developed.

For new upstream developers (but also NAM) the obligation for Gasunie to buy and take in the gas guaranteed created demand for gas from fields that would otherwise be too risky to develop. Secondly, as the Groningen field continued to deliver seasonal swing, the small field production was contracted at a continuous flow by Gasunie. This meant that small fields could be developed at the lowest cost possible (Mulder). In addition, this arrangement would immediately provide developers with a revenue stream, since parties would not have to wait until more cost effective natural gas fields were depleted.

For the shareholders of the "Groningen Maatschap" (40% state, 60% Shell/ExxonMobil) who were the owners of the concession and therefore were the primary beneficiaries of the revenue stream generated from Groningen gas sales, this policy had quite substantial consequences. The aim to preserve the Groningen field meant production had to be capped, thus reducing overall shareholder revenues and profits. Immediately after 1974, this cap can be regarded an informal cap since at the behest of the government Gasunie was instructed not to expand the volume sold through export contracts and to start importing natural gas from Norway (in 1977) (Correljé, 2003).

Figure 16 • Successful exploration and evaluation wells drilled in the Netherlands until 2010



Source: Dutch oil and gas Portal: www.nlog.nl.

In 1995, the Dutch government made the decision to cap total Dutch production (including production not marketed through Gasunie) at 80 bcm annually, this production cap became law in 2000 (Dutch Ministry). Revenues from Groningen gas sales were determined as a residual sum of total Gasunie revenues minus small field purchases and operating cost. The rise in oil prices (and thus oil linked natural gas prices) meant that on average the price received for "Groningen" gas per cubic metre was also higher than originally anticipated. This helped smooth over private companies' objections to a limit to Groningen sales.

The SFP can be considered a success measured by the exploration activities that were unleashed (Figure 16), as various producers increase their efforts to find natural gas. These companies were other parties than NAM. The continued involvement of the "Gasgebouw" maintained the monopoly on gas sales by Gasunie, ensuring the survival of the "netback value principle" and ensured continued involvement of the PPP.

The subsequent volumes of natural gas produced from small fields, both onshore and offshore, increased rapidly growing from less than 1% in 1973 to around 57% of total Dutch production in 1988. In 2010 production from small fields still amounted to about 36% of total Dutch production of 86 bcm. Although there has been considerable critique aimed at the economic efficiency of making the Groningen field the "producer of last resort", the overall social aim of preserving the Groningen field was achieved.

The main factors contributing to the success of the "Small Field Policy" and subsequent continued support from both the natural gas industries and the government in the "Gasgebouw" were as follows:

- the immediate consequences of the SFP (through lower Groningen gas sales) to the revenue streams of private parties in the "Gasgebouw" were offset by the increase in global oil prices, and thus a higher price per cubic metre than anticipated;
- the government saw its policy aim of security of supply in the long-term effectively addressed; and
- the dominant role of the "Gasgebouw" in marketing the gas from small fields provided for a stable and long-term business environment that increased trust amongst partners and willingness to compromise on Groningen field development.

Small Field Policy in the age of liberalisation

The SFP and the supporting "Gasgebouw" structure remained broadly intact during the 1980s and 1990s. However, with the liberalisation of European gas markets, the Gasgebouw had to be adapted. This primarily involved separating the marketing and transport activities of Gasunie. The transport activities were sold to the state creating the TSO Gasunie and establishing the separate commercial entity GasTerra that had the original shareholder structure Gasunie used to have.

The liberalisation process swept away the netback value principle and destination clauses in long-term contracts. However, long-term contracts and the demand security attached to it were deemed indispensable by small field producers and the Dutch government for the future of small field gas development.[12]

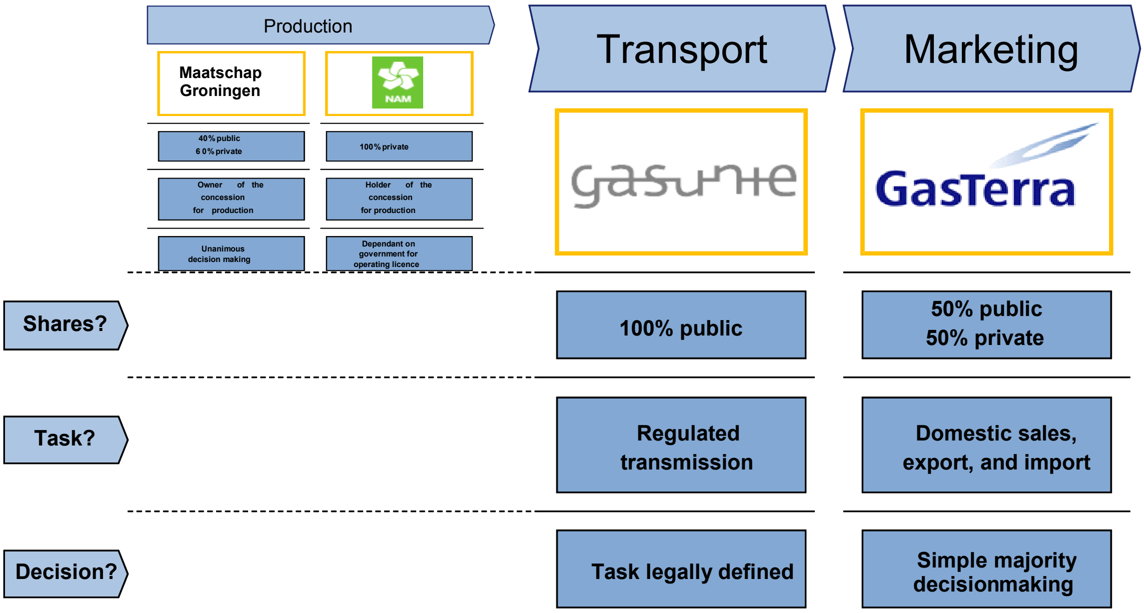
Since the old "Gasgebouw" structure safeguarded public interest in the SFP, the new structure needed to safeguard these interests as well. This required splitting public SFP obligations between the two newly formed companies (Figure 17). Gasunie had to "take in" and to transport the gas produced from small fields. GasTerra was given the public obligation to contract the natural gas at a reasonable price when offered to her (in the liberalised market producers can also sell the natural gas at the trading hub TTF or directly to customers).

These public obligations in the updated PPP create the security of demand for small field producers to continue to explore and develop small natural gas fields, thus reducing overall demand for Groningen gas. Simultaneously, the cap on overall Dutch production of 80 bcm was formally replaced by law in a production cap on the Groningen field of 425 bcm from 2006 to

[12] Although some of the larger small field producers with an end consumer portfolio could now directly deliver to their customers.

2015.[13] This multi-year cap structure provides commercial production flexibility between years, but serves public interest by securing supply in the long-term.

Figure 17 • The "new" public-private partnership since 2005



The Norwegian upstream policy

Norway has seen a rapid growth of its gas production over the past decade, from 25 bcm in 1995 to 50 bcm in 2000 and over 100 bcm in 2011. The acceleration of gas fields' development since 2005 has been quite striking compared to the slow development until 1995. The first step increase was due to the start of the Troll field, Norway's largest field with still more than 1000 bcm of proven gas reserves. The stagnation of oil/condensate compared to the brightest prospects of gas is one reason.

The Norwegian government has always played a very active role in E&P activities. Petroleum resources are considered the property of Norwegian society; therefore, their development has always been carefully monitored. This came from early decisions in 1971, also known as the "10 oil commandments" (NPD, 2010). This led to the creation in 1972 of the Norwegian Petroleum Directorate and of Statoil to look after the State's interest, and the Ministry of Petroleum and Energy in 1978. The Norwegian government has always been reluctant to develop its petroleum resources too fast. There is first a desire to sustain the level of petroleum revenues for the next generations, as well as to avoid having high levels of petroleum revenues resulting in an over-valuation of the currency and damaging other parts of the economy.

The evolution of the relationship between Statoil and the government

In the early stages of Norway's E&P industry, foreign companies dominated the first petroleum activities. There was nevertheless a preference for Norwegian companies in Norway's upstream, with companies such as Norsk Hydro appearing very soon. Foreign participation was still welcome as a way for Norwegian companies to learn from large IOCs and improve their competencies. Following the creation of Statoil, it was decided that the state would have a mandatory 50% participation in each production licence. Statoil was responsible for the state's

[13] Similar targets are in place beyond 2015.

ownership holdings in production licenses. In 1993, this principle was changed to have an assessment in each individual case regarding what would be the state's participation and ownership interest (NPD, 2012).

The role and relationships with Statoil evolved over time. In 1985, the State's Direct financial interests (SDFI) was created. Through the SDFI, the state owns directly interests in some oil and gas fields, pipelines and onshore facilities in order to take the risk and costs, as well as all the economic rent. The state pays its share of investments and costs, and receives a corresponding share of income from the production. Before then, the state had ownership in production licenses through Statoil. In 2001, Statoil was partially privatised, and a new state-owned company, Petoro, was created to take care of SDFI. As of 1 January 2012, the State had direct financial interests in 146 production licenses, as well as interests in 14 joint ventures in pipelines and land facilities (NPD, 2012).

Originally, gas sales were organised centrally, notably through the gas negotiations committee (GFU). The GFU organised the joint marketing of gas production to foreign countries. The GFU was comprised of two permanent members, Statoil and Norsk Hydro and occasionally other Norwegian gas producers. It was in direct relationship with the ministry regarding the negotiation of export contracts. Due to the liberalisation in the European Union, Norway had to dismantle the GFU in 2002, so that each producer became responsible of the sale of its own gas. This also led to the creation of two new players in 2002, the independent network operator of Norwegian pipelines Gassco and the owner of this pipeline system, Gassled. With Gassco, access to the pipelines became regulated, enabling later small and foreign players to have access to the pipeline system to export their gas. Gassled owns the pipeline network on behalf of oil and gas producers.

The Petroleum Fund

The government created in 1990 the Petroleum Fund to manage the revenues from petroleum activities. The fund is managed by the Central Bank on behalf of the government and receives petroleum taxes, the income from the SDFI, and dividends from Statoil. One of the Fund's main purposes is to ensure that future generations will benefit from the revenues raised from petroleum activities, which again does not incentivise to develop petroleum resources too rapidly. Part of the money raised by the Fund is invested in foreign financial assets, in order to help managing the NOK exchange rate. The government can also transfer 4% of the Fund to the state budget according to the fiscal regulations, but in practice they have already exceeded this number.

Enhancing petroleum activity

In order to maintain a high level of exploration, the government has worked on increasing the attractiveness of the Norwegian Continental Shelf (NCS). This has been performed through a two-tier approach: opening access to new producing areas and encouraging exploration in mature areas. Both included opening the NCS to new players, including foreign players. There are two types of licensing rounds: the numbered licensing rounds which comprise less mature parts of the shelf. In recent years, they have been held every second year. The award of production licences in predefined areas (APA) program offers annual awards in mature areas that lie fallow: if the companies do not prepare a PDO, the entire area must be relinquished. So far, nine annual rounds have been carried out over 2003 to 2011. In 2012, 55 companies have either operatorship or are licensee in a field or a production license. Although Statoil has 182 operatorship and 247 production licenses over 495 operatorships and production licenses, there are many IOCs, European gas companies as well as smaller companies active in the NCS. These strategies have therefore been successful in attracting new and smaller companies while keeping the Norwegian and the big international players.

7. Frameworks for infrastructure development and investment

Key messages

- Investment in infrastructure requires a clear and reliable national gas policy with a set of clear, transparent and predictable rules that provide long-term visibility to investors.
- Approaches regarding infrastructure investments tend to differ in OECD markets, so does the attitude towards pipeline, LNG import terminals and storage facilities. Third-party access to pipelines seems a relatively common feature across markets, but this tends to be less the case for LNG terminals. Specific projects can also be given total or partial TPA exemptions for durations of 20 years if such an exemption is necessary for the project to move forward and the project brings benefits in terms of competition and diversification.
- Investments in domestic interstate pipelines in the United States are mostly done through open seasons, whereby the investment is driven by pricing differentials between regions, performed by private companies, proceeds based on market interest and is made possible by the binding long-term capacity allocation required for securing the investments over the long life time. Regulation by FERC can take place ex-post, if required, to handle complaints.
- Europe presents a different investment framework for transmission pipelines and cross-border pipelines, due to the large number and smaller size of the countries. In the absence of regional transparent pricing signals similar to those in the United States, the national and European approaches lies more upon network planning at the national and European level, notably through the pan-European ten-year network planning system. This is based on anticipated changes in demand, import flows and domestic production and involves essential the respective TSOs of each country. Most European countries have one TSO (Germany being a notable exception), which can be either private or state-owned companies.
- Investments in new LNG terminals in OECD countries follows two different approaches, either a centralised approach with a planification of the needs and regulation of the new capacities, or a market-oriented approach, where companies take FID based on their evaluation of market needs and regulation, are usually exempt of TPA but face higher risks in terms of utilisation of their LNG terminals. These two approaches have implications on the type of companies investing, the business model and the utilisation of the terminals.
- Costs of developing underground storage facilities should be clearly transferred to the end user, especially the residential end user, given their needs for that sort of flexibility. Whether access is negotiated or regulated, or whether TPA exemption is granted for a certain period of time should be decided by the government, as well as the specific conditions regarding who can have access to storage capacity and minimum storage requirements. Each storage operator should give transparent information regarding the conditions of access to its storage facility.
- For any investment in midstream infrastructure, special attention should be given to the economic conditions for new infrastructure projects to avoid cross subsidies, which can represent an entry barrier for other market players.

Competition in gas markets is generally able to facilitate timely investments in all types of infrastructure, from import facilities (pipeline and LNG import terminals) to transmission pipelines and storage facilities. The regulatory framework in which companies operate is key in order to trigger timely and sufficient investments that will ensure an adequate delivery of natural gas supplies to the end user in a cost effective and secure manner. After its Energy Sector Inquiry performed in 2006, the European Commission concluded that "only a strengthened regulatory framework can provide the transparent, stable and non-discriminatory framework that the sector needs for competition to develop and for future investments to be made" (EC, 2007b). This requires enhanced power for energy regulators, co-ordination between them, and reinforced co-operation between TSOs as well as enhanced consistency regarding cross-border issues.

Before liberalisation takes place, and in particular, before unbundling and third-party access are imposed on transport, LNG import as well as storage facilities, there is always a certain apprehension that investments will not be made in time or in a sufficient manner, or at least this is one of the main arguments advanced by companies reluctant to go through that phase. Liberalisation in the United States and Europe has shown that investments have continued since liberalisation and responded to new market needs, but that in some cases, exemptions were necessary.

As explained in Chapter 4, third-party access to pipelines and storage has been in place in the United States for 30 years. In the European Union, the Third Package requires non-discriminatory regulated third-party access for all transmission and distribution infrastructure and for LNG import terminals. But as explained in the part on liberalisation, the EC also recognises that some new infrastructure require exemption for third-party access and regulated tariffs. The Commission gave its first exemptions in 2005 and has given on average four by year since then (EC, 2012b), although it is not certain that exemptions will continue at such a pace.

Transport pipelines

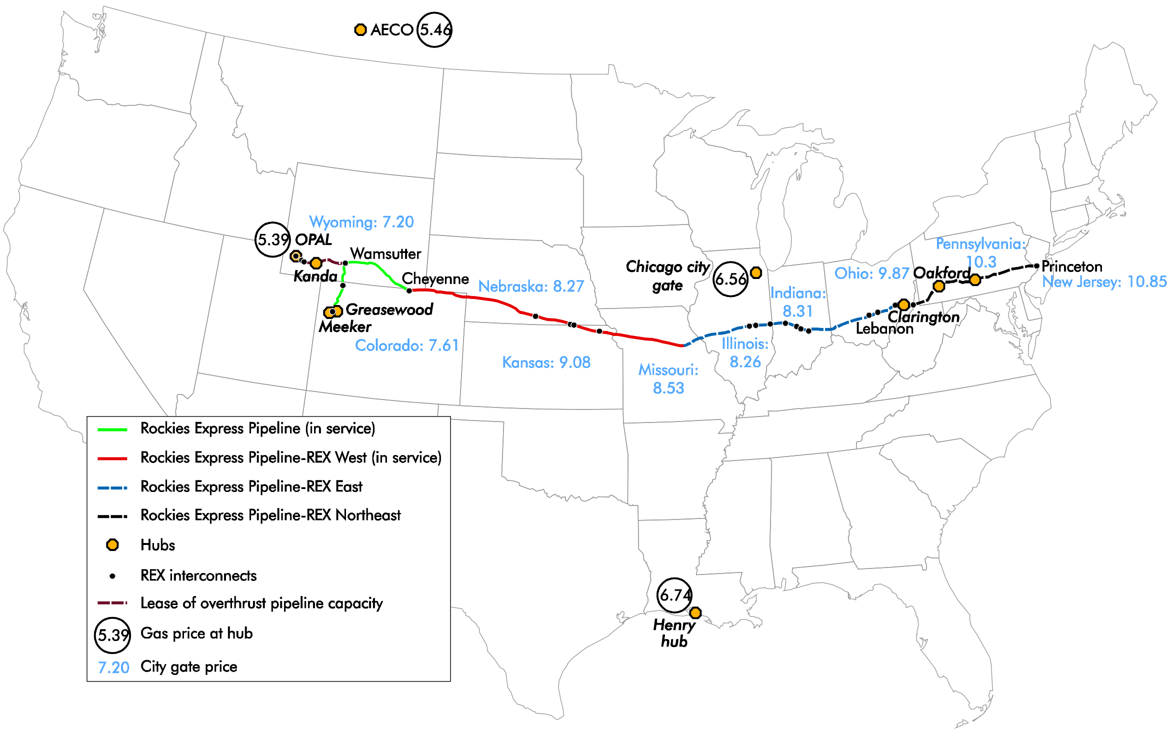
Capital-intensive investments into network transport pipelines need reliable anchor points for promoting a business case for the new to be built infrastructure. Since pipelines are naturally monopolies, there remains demand for regulatory cost control even in liberalised markets. Business cases and the regulatory cost control are two aspects which can facilitate timely and efficient investments, if business cases are transparent and reliable and regulatory frameworks correctly adjusted. Depending on the development methodology for the business case and the cost regulation, both aspects have the potential to also create an investment barrier or a driver for investment overshooting (see Averch Johnson effect discussed in Chapter 3).

Pipelines in the United States

Business cases for new transport pipeline investments in the US gas market are fully market based and driven by price differentials between hubs. The case of the Rockies Express Pipeline Project ("REX project", Figure 18) shows the drivers, process and regulatory framework from designing a project to its final commissioning. During the late 1990s, the Rocky Mountains gas area saw production increase by 4% per year, and it was expected to continue to grow quickly until 2010. Overproduction in that area meant depressed prices at the Rocky Mountains gas trading hub and a drive for other markets, but physical exports were limited by bottlenecks in transport capacity.

Pipeline companies continuously look at the price differentials between North American trading hubs, which is facilitated by transparent and reliable price information. Over the course of early 2000, such price differentials existed continuously at a level of USD 2 to 3/MBtu between the start and the end point of the subsequently developed western part of REX. Kinder Morgan Energy Partners, a US energy infrastructure operator started to evaluate the market interest in such a pipeline, supposedly crossing eight states over a length of 2 700 km at a total expected cost of USD 4.4 billion. This made REX the largest pipeline project over the last 20 years in the US gas market. To evaluate the market interest, Kinder Morgan performed an open season procedure on the proposed project and the market responded even more than initially planned for, leading to a planned extension of REX towards the northeast to New Jersey.

Figure 18 • The Rockies Express pipeline project



Source: IEA, 2008.

The open season procedure also made possible the binding long-term capacity allocation required for securing the investments over the long life time. Using the open season process, the pipeline capacity was sold and allocated over the course of ten years before the pipeline itself was built. Total upfront commitments from all shippers to the project amounted to over USD 4 billion – enough for the pipeline to be constructed from the investor's perspective. Being an interstate pipeline, FERC had jurisdiction over the proposed REX pipeline. In order to secure the project's regulatory approval, a dialogue was initiated with FERC during the project development phase. Since the project was done in three phases, FERC approved three different projects over several years, with the final decision being taken in 2008 (FERC, 2008b). All approvals were subject to the evaluation of potential benefit-consequence balance of the new projects.

This regulatory check included checking for the need of the project, the full cost coverage by its customers (pipeline users) and side effects on other existing pipelines and customers. It received final approval by FERC since the benefits exceeded the consequences in the economic test. This final approval also prescribed the financial conditions of the project, including the cost base (roughly USD 2 billion), the allowed rate of return at 10.19% (13% on equity, 6.75% on debt with a 55/45 equity/debt structure) and the depreciation period of 35 years using straight-line depreciation.

In 2011 alone, FERC jurisdictional natural gas pipeline companies added roughly 2 100 miles of new pipelines or about 96 bcm (9.3 bcf/d) of transportation capacity, while major intra-state pipelines added another 400 miles of new pipe and 49 bcm (4.7 bcf/d) of transportation capacity. Due to the ongoing shale gas development in 2011, pipeline developments shifted to projects focused on relieving local bottlenecks in new producing basins rather than long-haul pipelines. Most are located in the Northeast and Southeast and include the Tennessee Gas Pipeline Line 300 Expansion, the Texas Eastern TEMAX/TIME III project and the Acadian Haynesville Extension, an intrastate pipeline which feeds into the Henry Hub.

Box 8 • Open season procedures in the United States

In the US gas market, gas pipelines are developed by independent developers that aim to provide sufficient new capacity for gas transportation from one point to another. Long-distance interstate projects are subject to regulation by FERC. FERC has not issued one specific order on the exact process for an open season, but business cases exist to show the general application of the open season in the context of project economics. One of these cases is when FERC determined open season procedure as part of the development of the Alaska Natural Gas Transportation Projects (FERC, 2005).

Once a project developer has assessed the current gas market and its price differentials, his conclusions can be the requirement of additional pipeline infrastructure. Since the pipeline developer is not able to ship his own gas, he is bound to the interest of other market participants. The open season procedure will help the network developer to identify the interested parties for shipping gas between the markets through this planned pipeline. The open season represents a process following a fixed timeline for market participants to signal their interest in (shares of) the pipeline capacity over various stages. This process fosters accuracy in terms of developing the efficient pipeline capacity and allows all interested parties for gas deliveries. For the Alaska projects, this timeline was an open season notification with FERC at day 0, the notice to market participants on the open season at day 60, the opening of the process at day 90 and the ending of the open season at day 180. Before notification with FERC, anchor shippers have already committed to a certain amount of capacity (pre-subscription).

Throughout this process, the capacity bids and associated tariffs were determined and fixed. In cases where the capacity is oversubscribed and the network developer does not redesign the project to accommodate all capacity requests, capacity bids after pre-subscription phase were subject to allocation on a pro-rata basis. Tariffs can vary depending on the commitment period for the subscription of capacity rights, but there is usually a minimum subscription period of ten years firm capacity rights.

However, the changing supply patterns also show the investment risk under which pipeline operators are willing to work and invest. Gas flows in REX declined by more than 40% between November 2010 and the end of 2011; the decline was so severe that REX's credit rating was reduced. The downgrade was the result of a persistent low profitability in shipping Rockies natural gas eastward. This occurred because Rockies natural gas was displaced in the Northeast by increased flows from the less expensive Marcellus Shale gas from Pennsylvania. Also, a new pipeline competed with REX, providing Rockies producers access to a more profitable market in Northern California (FERC, 2012).

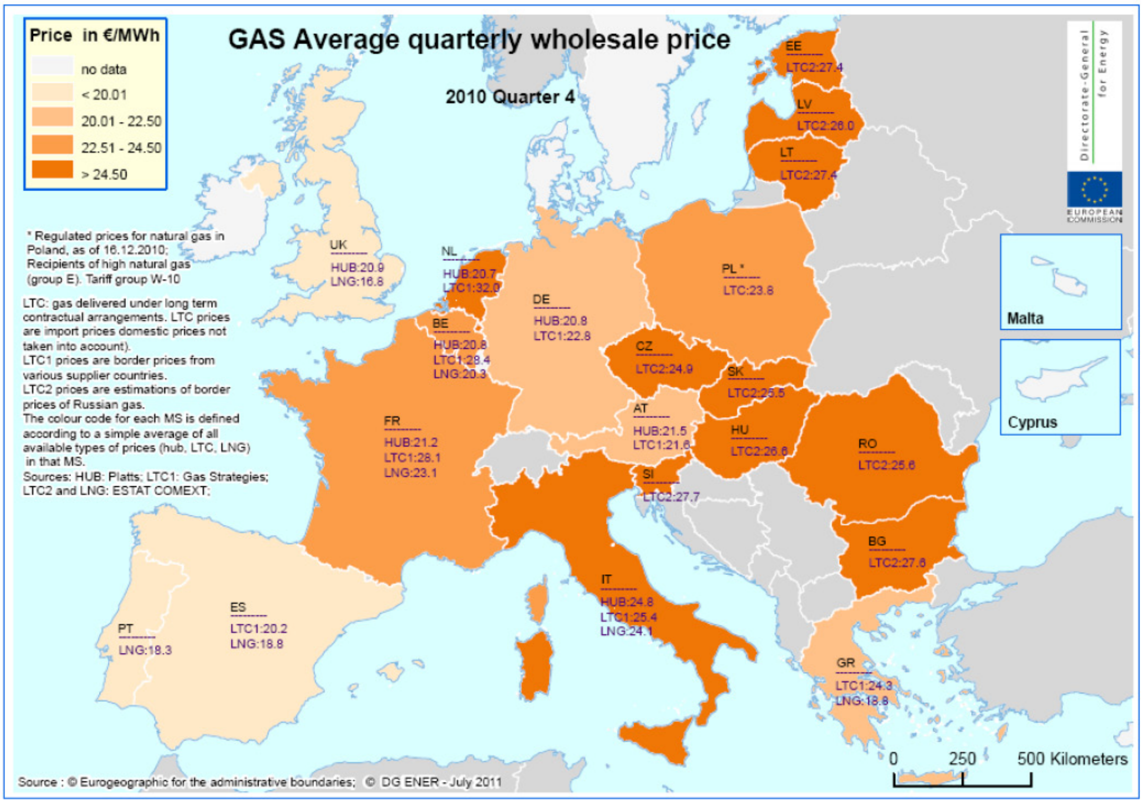
Pipelines in Europe

The European gas market consists of national gas markets managed by one to several transmission network owners. The structure of the network companies varies from vertically integrated companies to fully unbundled network owners; their ownership varies between state-owned and private entities. Each EU member state has its own regulatory authority setting the regulatory framework on cost determination and allocation. Each national framework determines the operational procedures for network operators, such as balancing and capacity allocation.

The European gas market remains fragmented in price discovery for gas and trade between EU member states. Some member states have achieved to develop market areas (virtual trading points) where gas can be purchased and sold, while others rely on gas delivered through long-term contracts, usually with an oil price linkage. Figure 19 shows prices for various countries, differentiating spot prices at hubs[14], long-term contract and LNG import prices. Spot prices show only few price differences, which are based upon transportation costs. Where hubs and associated prices are missing, assessments of prices from long-term contracts can be regarded as indicator.

[14] These include the United Kingdom, France, Belgium, the Netherlands, Italy, Austria and Germany.

Figure 19 • Snapshot of European average gas prices on hubs and through long term contracts



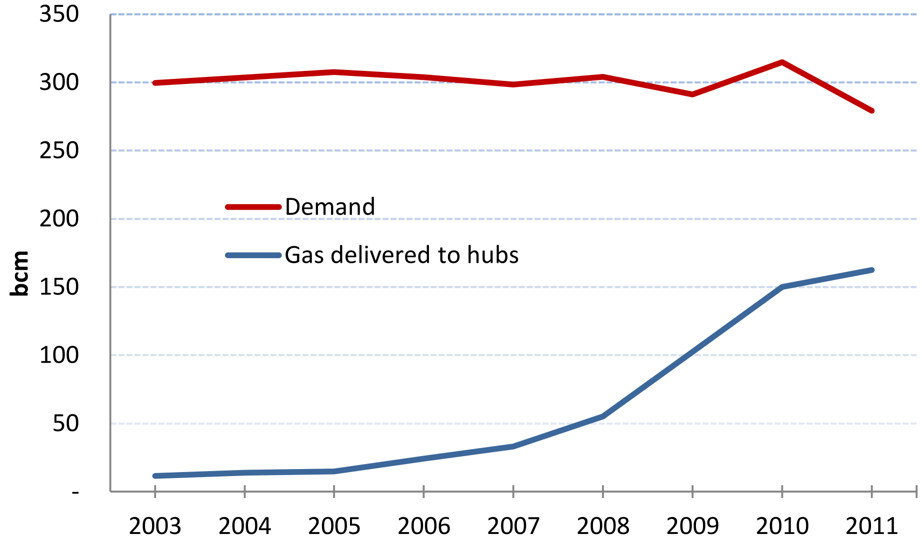
Source: EC, 2011a.

However, European transmission investments are commonly not built by pipeline companies trying to make profit from market price differences as it is often the case in the US gas market. A variety of possible reasons can influence the decision to invest into new pipelines. There is still missing confidence in the market over the reliability of spot prices due to low liquidity levels on several the trading hubs and/or by prices derived outside the market (IEA, 2012). Bringing more gas to the trading hubs is therefore one key target member states aim for. An increasing availability of gas at trading hubs will therefore help to aggregate customer portfolios and only balance their aggregated deviations. Such services are provided by marketers in the US gas market and it will depend on the continuous development in the separation of network owners from certain amounts of gas in the market, whether such aggregation and balancing services can become available on European trading hubs in a non-discriminatory manner. The "type of gas" delivered to the trading hub will be essential for the contribution of balancing services but also for the gas market price. Figure 20 shows the increase in gas physically delivered to hubs in key European members states over the past seven years compared to the markets' overall gas demand. However, the convergence does not necessarily mean additionally traded gas at the hubs at market prices (and potentially with effects to the market price), since gas under long-term contracts can also be delivered to these hubs.

Market price uncertainty is further magnified by short-term futures trading at most European hubs, limiting the ability of market participants to assess the market's value for gas deliveries between regions in the future.[15] This short-term valuation leaves potential pipeline developers with uncertainty over their cash flows for a considerable time of the project.

[15] While the US and UK markets trade gas until 2020 and 2019, continental European markets such as Germany and France trade gas for the following three to four years.

Figure 20 • Evolution of physical gas demand and gas delivered to hubs in some European countries[16]



Source: IEA, 2012.

Long-term valuations of infrastructure projects on the basis of natural gas purchased under long-term contracts without access to upstream parties is very uncertain as well. The price level *vis à vis* other markets, that should incentivise investment in transport capacity, is difficult to assess. In cases where markets are fully or partially supplied under long-term contracts, the gas price formulae in unknown and not accessible for external market participants. Depending on the contracts' share on overall trade, this makes the valuation of gas in this market even more challenging for European market investors as reduced transparency and unforeseeable price-negotiations (due to commercial confidentiality) as well as commodity developments outside the gas market can influence gas market prices. In that light, several European member states struggle to deal with the legacy of existing long-term supply contracts between suppliers and downstream customers. The 2006 decision of the German Federal Cartel Authority (Bundeskartellamt, or BKartA) against one of the biggest German gas importing and retail and distribution company supplying enterprises can be exemplary for the juridical force required to deal with such long term legacies[17] (BKartA, 2006).

As Figure 18 above indicates, there are still a remarkable number of EU member states left without a gas trading hub. Next to the foreclosure by long-term contracts making trading hubs largely unnecessary, the methodology for pipeline capacity allocation can also be a barrier to the development of trading hubs. A trading hub has to be understood as a virtual marketplace covering a wide physical area of demand and supply sources, including pipeline infrastructure and storages. Such market places will allow to trade gas between one supplier and one customer without physically delivering it between these two, but maybe from other sources closer located. So called Entry-/Exit systems for capacity allocation facilitate these trades since these systems do not require available capacities on a specific route but only for the entry into and the exit from the physical trading hub area. To overcome this barrier, the European Commission has implemented changes to the capacity allocation procedures, requiring all EU member states to implement

[16] These include the United Kingdom, France, Belgium, the Netherlands, Italy, Austria and Germany.

[17] In the case BKartA against E.ON Ruhrgas AG the existing long-term supply contracts between the wholesale and the retail level had to be replaced immediately and this decision has changed the long term contracts for all other retail customers subsequently. New contracts have to remain below four years if 50% to 80% of the customers' demand were covered, and below two years in case of above 80% coverage.

these Entry-/Exit systems on a national level (EC, 2007) and good implementation practice can be seen amongst several states such as the United Kingdom, the Netherlands and Germany.

In the absence of long-term reliable price levels between markets, a frequently used business model for trans-European network investments is the regulatory exemptions which have already been discussed above. These exemptions usually bring the long-term legacy of uncompetitive pipelines into the market where over the course of often more than two decades, the network owners, often with specific interest in associated gas, decide freely and potentially in a discriminatory manner upon the capacity allocation.

To tackle the missing long-term signals and associated investment barriers, the European Commission has introduced a pan-European network planning system (EU, 2009c), under which demand for transmission pipeline capacities between different EU member state markets (interconnectors) will be determined on an administered European base. In parallel, the Third Package has also brought the level of network operators' independence from gas marketing activities further ahead, potentially reducing the market power of vertically integrated companies. The newly formed group of European Transmission System Network Operators for Gas (ENTSO-G) is obliged by these regulations to produce an EU-wide Ten-Year Network Development Plan (TYNDP). This plan has to be refreshed every two years under extensive consultation involving all relevant stakeholders and the plan is accompanied by Winter- and Summer Supply Outlooks on annual basis. Already published twice, the plan shows relevant transmission pipeline corridors to be developed over time to facilitate market integration. Aspects of security of supply planning will also be included in the plan to enhance long term security by assessing infrastructure needs for a high demand case of 1 out of 20 peak demand situations. In 2010, ENTSO-G published its second edition of the TYNDP indicating the need new pipeline capacity to be developed from 2011 to 2020 (GIE, 2011). On the European level the European Commission has identified a need for investments of roughly EUR 70 billion for gas pipelines, storages and LNG terminals, requiring a 30% rise of expenditures by the transmission network owners (EC, 2011b).

It is up to regional groups within the EU member states and also to all single EU member states to set up regional and national TYNDP's. These plans will have to be in line with each other and will help to bring the pan-European top-down and the local bottom-up approaches together. The national and regional plans will be more precise and binding in terms of timely development. Their development will be transparent and involve from the very beginning all market players while the national regulators will facilitate the discussion and ask for amendments throughout the whole process. In that regard, the EC also hopes to further harmonise cost regulations between EU member states. Harmonisation of cost regulation can be expected to drive infrastructure investment, as investors all want one EU regulatory system and not 27 ones. Harmonisation is progressively achieved with the network codes and framework guidelines under the third package.

One good example in terms of structuring the development of national plans can be found in Germany, where the 14 different transmission network owners have recently published their co-ordinated draft plan for to be developed infrastructure between 2012 and 2022 (NEP, 2012). This plan identifies an investment need of EUR 4.8 billion associated to 1 840 km of new pipelines and an additional compressor capacity of 740 MW to be developed from 2012 to 2022 (Figure 19).

ENTSO-G also fulfils the task to monitor the development of these national and regional projects and thus acts as an information portal to interested market participants on specific projects (ENTSO-G, 2012b). The subsequent step to bring a planned project forward is the determination of pipeline capacity commitments by gas suppliers and this is done via open season procedures comparable to the US.

Box 9 • Network planning in Germany

Based upon the 2009 European Directive on further gas market opening (EC, 2009a) national and international network planning became obligatory for each member state and their market participants. Network planning became the measure of choice in Europe as purely market-driven investment decisions were seen as insufficient to help establish a strong infrastructure for facilitating trade while meeting Europe's security of supply obligations.

In that light Germany translated the European obligations of long-term transmission network planning into national law and amended the existing Energy Act (EnWG, 2012). This co-ordinates network planning among the 14 existing transmission network owners and operators in the German gas market since these 14 companies will have to set up one national plan. The national plan allows for a holistic approach towards meeting the expected transport challenges and thus identifies secure and least cost transportation solutions which are often crossing the boarders of several network owners. In that regard the results of the network plan will also help determine the responsible stakeholders for bringing cross-company projects forward in a co-ordinated manner.

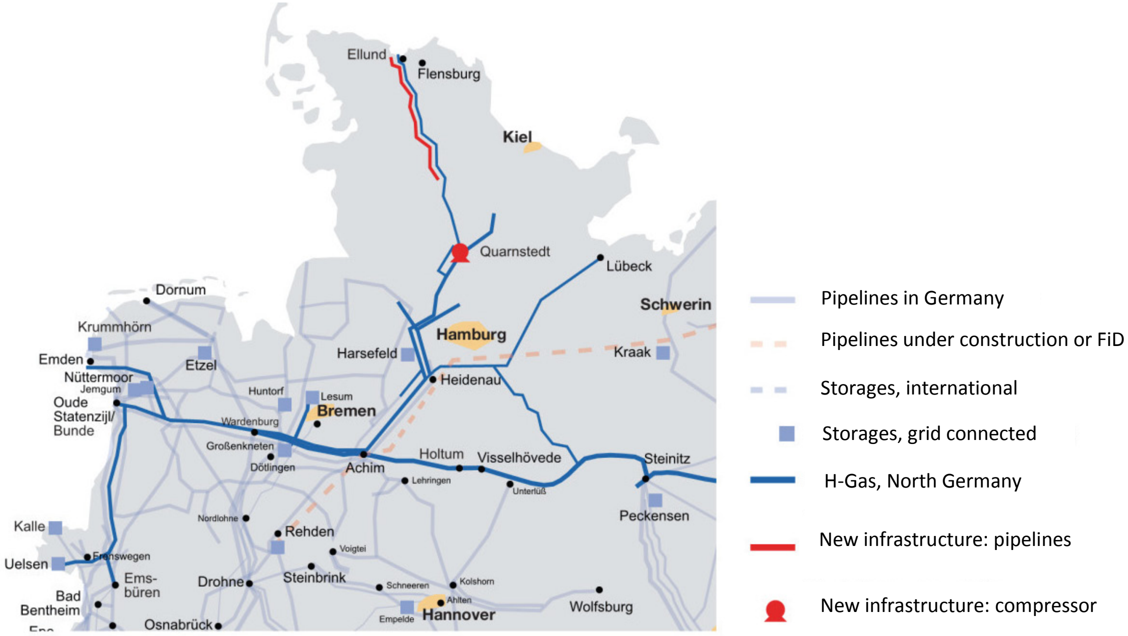
The planning process is described in steps, responsibilities and open stakeholder (gas suppliers, transporters, marketers, distributors) consultation to ensure highest accuracy of assumptions and non-discrimination of market participants. The involvement of the regulator (Bundesnetzagentur – BNetzA) ensures the timely and open discussion and planning process and can act as mediator and decision maker in required cases.

The initial step of network planning is the determination of relevant parameters influencing the gas flows and the associated pipeline, storage and import infrastructure. These parameters, largely local demand and supply forecasts and known infrastructure developments, are varied within three different scenarios over ten years. International developments will be taken into account to achieve congruency with the European network plans. The process of scenario determination is done by the network operators in a co-ordinated manner and ends in an open consultation of the scenario results, facilitated by the BNetzA. Amendments can be made during the consultation phase, representing the market players' expectation, which helps to foster long term accuracy.

The final scenarios will become binding for the network operators to perform the second step where the network operators determine the investment needs for new infrastructure to allow for the expected developments. Economic tests throughout this step allow for the determination of least-cost infrastructure development by choosing the right set of infrastructure out of the existing alternatives. In cases of missing economics leading to infrastructure shortage evaluations of security of supply issues can foster even smaller projects. The results of the network modelling will again be openly consulted and further amendments to the solutions are possible if the BNetzA demands for. In parallel to the determination of the new infrastructure projects the timeline for implementation and responsibilities between network developers will be fixed. The binding projects will be monitored in reference to their development, which allows for further action by the regulator if projects face delays. In that light the regulator has the right to tender projects if the responsible network developer does not proceed in the envisaged time frame.

Based upon the results of the network planning, network operators will also be able to proceed with the regulatory cost approval. Once the general need of the projects is determined in the plan, regulatory cost approval can build on that. It is up to the network operator to bring the application process forward and the regulator will then decide on a project-specific base upon the allowed network costs. In general there is no project-specific risk for pipeline development projects, so that a general rate on return is applied. This rate is determined over the course of every five years by using the Capital Asset Pricing Model (CAPM) for investment risk evaluation by the regulator. The current allowed rate on return (pre-tax equity) is at 9.05% with an allowed maximum equity rate of 40% for all assets (BNetzA, 2011).

Figure 21 • Gas infrastructure demand in North Germany, national development plan



Source: NEP, 2012.

LNG terminals

There is currently 2.3 times more LNG import capacity in the world than liquefaction capacity (870 bcm versus 373 bcm as of the end of 2011), resulting in an average utilisation of LNG terminals of 37.5% (IEA, 2012). There are different reasons explaining this imbalance: some terminals are used only for seasonal peak demand (Kuwait, Dubai), or for arbitrage purposes, they can also be needed to complement or replace underground storage (Spain, Japan, Korea). This unbalance can also be due to a country's geographical structure resulting in lack of network interconnections (Chile) or finally, due to an overestimation of market needs (United States).

Over the past decade, at the same time that liberalisation took place in Europe (it had already occurred in North America), substantial changes took place in the LNG world and these have an important impact on investments' strategies of some players. Until 2000, LNG importers were concentrated regionally: from 1980 to 2005, Japan, Korea and Taiwan represented around two-thirds of global LNG imports (from around 50% over the mid 1970s), their share has been dropping since then, but still represented 53% in 2011. Diversification started around 2005 with the United Kingdom, China and India stepping in. Since 2008, new regions – Latin America and the Middle East – became LNG importers. Gas markets are globalising, with the notable exception of the United States, and there are more exchanges between regions and basins. As mentioned earlier in the report, some markets (in Europe and North America, much less in other regions) transformed from highly regulated to open markets with multiple players and sellers in the same country.

Additionally, practices within the LNG industry changed. Long-term contracts with destination clauses and diversion restrictions gave room to more short and medium-term contracts, and increased flexibility and diversion. According to GIIGNL, short-term and sport trading represented one quarter of the LNG trade in 2011 (GIIGNL, 2012). Spot and short-term trading is also facilitated by companies present all along the LNG value chain (including shipping) and with regasification capacity in different markets, allowing them to re-direct cargoes. Before 2000, no company except GDF (now GDF Suez) had capacity in different countries. Upstream players were also rarely owners of regasification terminals or had capacity booked at regasification terminals. This began to change as well: the three trains in Trinidad and Tobago (Atlantic LNG Trains 2, 3 and 4) were built in the early 2000s as fully integrated projects for the BG Group from the production to the regasification in US LNG terminals. The same strategy applies to Train 2 of Egyptian LNG, sold by BG to BGGM which can send it to its US terminal at Lake Charles or divert to other markets. Finally, more parties are involved in the LNG business than just the producer and the buyer; aggregators, sellers, traders are also active players.

LNG terminals are key interface between the production in LNG exporting countries on one side and the downstream market on the other side. From the investor's point of view, several approaches exist when looking at building an LNG terminal. They may have an integrated LNG approach, securing the LNG through direct participation in LNG projects or long-term contracts with producers, own ships, have regasification capacity and market shares downstream, or be in only parts of the LNG value chain. The picture is far from being uniform though and one can distinguish three different cases for investors in LNG import terminals, *i.e.*:

- LNG terminals built by companies with gas marketing activities, intending to sell it to the downstream market and usually importing gas through long-term contracts;
- LNG terminals built by transmission companies, totally unbundled from any marketing activities (they will usually sell the capacity on a long-term basis to other companies with marketing activities); and
- LNG terminals built by "aggregators", *i.e.* companies with an LNG supply portfolio and LNG capacity available in different regions (they will use the LNG terminal for arbitrage purposes).

From the country's perspective, liberalisation had consequences on how LNG terminals are built and operated. Two main approaches can be distinguished:

- A centralised approach with a planification of the needs and regulation of the new capacities. This approach requires nevertheless a long-term visibility on tariffs, a fair treatment by the TSO regarding the connection to the transmission network, and sufficient information available on the different infrastructure to enable the investor to take its FID.
- A market-oriented approach, where companies take FID based on their evaluation of market needs and regulation but face higher risks in terms of utilisation of their LNG terminals.

The examples of the countries below (Spain, the United Kingdom, France and the United States illustrate the different approaches regarding regulation and fostering investments.

LNG terminals in Europe

While European LNG terminals used to be built by vertically-integrated companies, this has changed over the past decade due to the unbundling between marketing and transmission, LNG operatorship and storage activities. One must distinguish between the pre-liberalisation time – roughly before the Second Directive in 2003 and when the implementation of the Directives in national laws started to have a real impact on LNG companies.

Historically, companies were pursuing the investment in LNG terminals supported by an existing (and presumably growing) set of customers, which gave them legitimacy *vis-à-vis* the supplier to negotiate the long-term LNG supply contract. In Europe, historical incumbents used to have long-term contracts corresponding roughly to the capacity of their LNG terminals. Although yearly changes of the utilisation rates of the terminals were observed throughout the years following the evolution of demand, they were not dramatic changes. Before 2003, LNG terminals capacity amounted to 77 bcm, in France (17 bcm), Italy (3.5 bcm), Spain (29 bcm), Greece (1.4 bcm), Belgium (4.5 bcm) and Turkey (6.5 bcm). In all cases but one, the LNG terminals had been built by the incumbent. The only exception was the Bilbao terminal in Spain built by new entrants including Repsol and Iberdrola.

An additional 115 bcm of LNG capacity was built in Europe over 2004-12; 58 bcm was supported by new entrants (half of the capacity was in the United Kingdom) and 36 bcm by TSOs independent from marketing activities. It has to be noted among those supported by new entrants, one terminal (Teesside) in the United Kingdom has been barely used, while the Turkish terminal struggled to get connected to the grid. Five LNG terminals were granted total or partial TPA exemptions by the EC (three in the United Kingdom, one in Italy and one in the Netherlands), representing 67 bcm, therefore half of the capacity added. This shows the importance of TPA exemptions for future investments. So far, 12 LNG terminals have been granted TPA exemptions, with another two are under construction in Italy and France and five still planned (EC, 2012c). Among the other LNG terminals which have started operating since 2003, one in France is 90% booked by the investors, which are also incumbents (see below).

In some cases, LNG terminals were built by transmission companies not involved in marketing: this is the case in the Netherlands (GATE) and in the United Kingdom (Isle of Grain) where all the capacity is bought by other companies (involved in the marketing of gas) for a certain period of time (usually 20 years). Although built by independent TSOs, both LNG terminals got TPA exemption under Article 22. The investor therefore gets his investment back through the capacity leases paid by these companies, so that the risk falls on the side of the marketing companies in terms of finding the supply and selling gas to customers. In both cases, the terminal's capacity is divided in shares allowing companies to buy a smaller capacity than that of the average terminal (6 bcm to 8 bcm).

LNG terminals in Spain

The Spanish gas market was one of the fastest growing gas markets from 2000 to 2008, until gas demand was hurt by a combination of economic crisis and strong growth of renewable energies. Incremental demand had been driven mostly by the power sector. While the Spanish gas market is relatively isolated from the wider European market, Spain depends entirely on imported gas – both pipeline gas from Algeria and LNG – and has become the second largest LNG importer in Europe behind the United Kingdom. Spain has six operating LNG terminals and three main import pipelines (two from Algeria and one from France).

Among the six LNG terminals, three are operated by the TSO, Enagas, which is now independent from marketing companies (whose share is limited to 5%). The three other terminals were built by new entrants (consortiums of several companies). Since 2008, the Spanish gas market is entirely open, although liberalisation started in 1998. Historically, Gas Natural was the dominant company, of which Enagas was part, but its share has been dropping with new companies increasing their market shares (Spanish companies such as Iberdrola, Unión Fenosa, Endesa and foreign companies such as BP, Shell, and GDF Suez). Crucially, these companies entered the market through the construction of their own LNG terminals. Some are also power generators and took advantage of the fact that they were building their own power plants as a consumption centres for the LNG terminal.

The Spanish market is under the supervision of the Ministry of Industry and the regulator CNE (National Energy Commission). A ten year gas and electricity infrastructure plan is prepared by TSOs and submitted to the ministry with input from the regions, CNE and market players. This includes the development of sufficient LNG infrastructure based on demand forecasts. The final planning proposal is approved by the council of ministers and ratified by the parliament. Among the LNG planning criteria are the n-1 criteria in case of failure if one entry, 10% overcapacity to guarantee that higher demand levels will be met. Additionally, LNG storage should enable the country to face six to eight days of hard weather conditions (closed ports) (CNE, 2010).

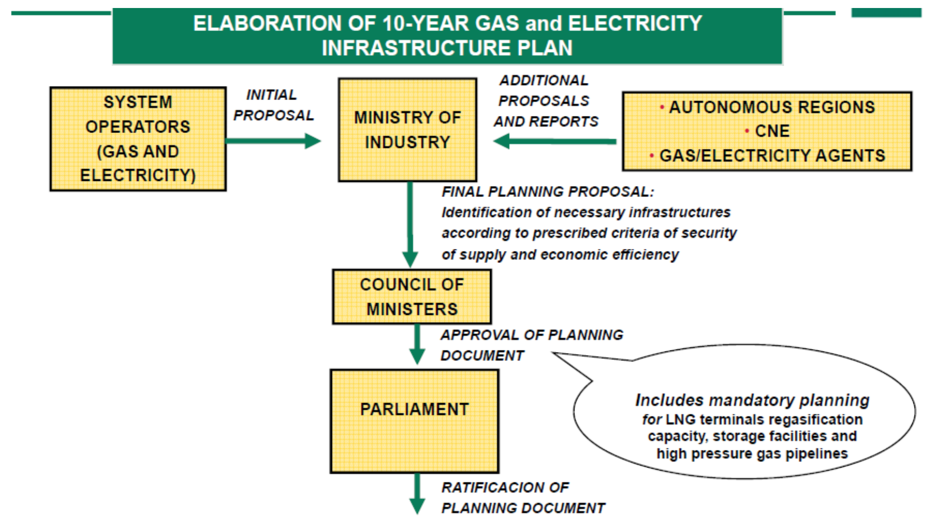
CNE has also developed standard forms to apply for TPA and for TPA contracts. Infrastructure owners must also publish every three months contracted and available capacity in their assets.

The regasification tariff is regulated and is the same for all Spanish terminals. Regulation is based on the Royal Decree 949/2001 and on the ministerial orders that the Ministry of Industry approves on a yearly basis which provide the values of the tolls and fees associated with third-party access to natural gas facilities. All the services involved in making the gas available at the entry of the transmission system once regasified (at the connection joint between the LNG plant and the transmission system) are jointly included in the regasification tariff: slots assignment, unloading operations, vaporisation, loading of trucks transporting the LNG storage capacity; ships cooling; loading of ships with LNG and transferring of LNG between ships.

The article 15 of Royal Decree 929/2001 sets up the criteria for remuneration of LNG payments. The remuneration includes a fixed component and it could include a variable charge set according to the utilisation rate of the facility. Remuneration for new investments in regasification is set in Article 5 of Ministerial Order ECO 31/2004, as the sum of the accredited fixed and variable cost estimated per Article 5 of Ministerial Order ECO 31/2001.

While the capacity is allocated on a "first come, first served" basis, at least 25% of the total entry capacity is allocated to short-term contracts (less than two years), and no party can have more than these 25%. Capacity can also be lost in case of under-utilisation.

Figure 22 • Infrastructure planning process in Spain



Source: CNE.

LNG terminals in France

Three LNG terminals exist in France, while a fourth (EDF's Dunkerque) is under construction. The first two LNG terminals at Montoir and Fos were built in 1972 and 1980 and are now operated by Elengy, the LNG branch of GDF Suez. Historically, these LNG terminals were developed by GDF; the different directives resulted in the creation of Elengy, which is the LNG unbundled arm of GDF Suez (based on ITO system, see Figure 9). Fos-Cavaou is owned by the STMFC (Société du Terminal Méthanier de Fos-Cavaou, owned 71.21% by GDF Suez and 28.79 % by Total).

Tariffs were first introduced for TPA in 2006 (CRE, 2012a). New tariffs were proposed due to the planned start of Fos Cavaou (Arrêté, 2009). Unlike Spain, each terminal has its own tariff. Tariffs are calculated based on the Arrêté of October 2009, which takes into account the regulated assets base's (RAB) rate of return and depreciation in addition to the rate of return on current assets. The rate of return is 7.25% real before taxes, plus a premium of 200 points.

The terminal operator proposes different options depending on the use of the LNG terminal (either at least ten cargoes, maximum one per month, or spot). The tariff is based on the following terms:

- a fixed term per cargo unloaded (TND);
- a term proportional to the quantity unloaded (TQD);
- a term reflecting the spread between quantities delivered during winter and summer; and
- a term for the use of regasification capacity applied between the arrival of two cargoes.

In order to trigger new investments in LNG terminals, the tariff methodology is fixed for 20 years and another premium of 200 points may be added for ten years. Additionally, the Commission de Régulation de l'Energie (CRE) can give TPA exemption.

Regarding the third terminal, the regulator decided to favour the utilisation of the terminal by the investors provided that no party had more than two thirds of the capacity and at least 10% is open to other parties. In the first years of operation of the terminal, GDF Suez had 62.7% of the capacity, Total 27.3% and EDF 10%. The tariff methodology is set on a long-term basis, with tariff revisions every four or five years to adjust the tariff. Additionally, capacity is mostly booked on long-term basis (20 years) but some capacity is reserved for short-term contracts.

Finally, the terminal under construction at Dunkirk will have a capacity of 13 bcm and start by 2015. EDF has a long-term share of maximum 8 bcm and is not allowed to buy gas from other shippers holding long-term capacity. The competitive requirement led to the development of an LNG terminal larger than what the main investor needed. From EDF's point of view, the exemption was necessary to design a service adapted to its needs as a new entrant on gas market. 2 bcm have been booked by Total and the remaining 3 bcm are available (Dunkerque LNG, 2012). Also GDF Suez, the incumbent, is not allowed to have more than 1 bcm. The TPA exemption was associated with a market test (approved by the CRE) to test interest from other players. Finally, information available on available capacity, slots should be comparable to that of other regulated terminals (CRE, 2012b).

LNG terminals in the United Kingdom

The United Kingdom has attracted four different LNG terminals representing over 50 bcm of import capacity. All terminals were built between 2005 and 2010 as the United Kingdom was becoming a net importer of natural gas. Apart from Teesside, all LNG terminals got TPA exemptions for 20 to 25 years. One was built by the TSO, National Grid, and the others by new entrants – one being Qatar Petroleum in association with ExxonMobil.

Grain LNG terminal, owned and operated by National Grid, is underpinned by 20 year long-term contracts with GDF Suez, Sonatrach, E.ON, Centrica, BP and Iberdrola (the terminal has three trains, in which the companies had different shares of the capacity). For each train, the capacity has been auctioned through open-season processes. The regulation requires the primary capacity holders to offer to sell spare importation capacity to secondary users. If the primary and secondary capacity is not sold, capacity has to be offered due to use-it-or-loose-it conditions.

South Hook was granted a 25 year exemption from TPA. Nevertheless, third parties can apply for spare capacity. In 2011, three companies signed agreements to get access to spare capacity (ConocoPhillips, EGL and Trafigura). The same conditions as for Isle of Grain regarding primary capacity apply.

Dragon LNG was granted TPA exemption, on the condition that Dragon would be "providing facilities for secondary trading and anti-hoarding mechanisms". BG and Petronas are the primary shippers and can sell capacity to third parties through secondary trading.

LNG terminals in the United States

The first LNG terminals were developed in the United States in the late 1970s. However, liberalisation at that time resulted in oversupply and lower gas prices while LNG prices were increasing (due to the oil price increase). Therefore, LNG import terminals were barely used and some even mothballed.

The oldest terminal, Everett, was built by Suez for New England market. It has been the only continuously operating LNG terminal since 1971. Lake Charles, built by Southern Union, received authorisation in 1977 and started in 1981. Cove point was built by the Consolidated Natural Gas Company (parent of what is now Dominion Transmission) and the Columbia Gas System to import LNG from Algeria, after authorisation from the FERC. It stopped importing in 1980 and was used as storage. Elba Island was built by Southern Energy Company (after authorisation from the FERC in 1972). The gas would then be sold to Southern Energy's parent, Southern Natural Gas Company, and transmitted by pipeline to Southern Natural's interstate transmission line. LNG deliveries started in March 1978 and stopped in March 1980.

Box 10 • The consequences of an unused LNG terminal

The investors in the US LNG terminal of Elba Island initially asked that the pipeline purchaser to pay the full cost of service, including a return on the company's capital investments, regardless whether LNG would be delivered or not. This was rejected by the FERC, which, in order to help the investment to proceed, decided to include in the tariff a "minimum bill" provision, allowing the company to recover certain fixed costs in the event of non-delivery of the LNG. It prevented Southern from receiving any revenue on equity during that time. These "tariff provisions are required by the public convenience and necessity as an equitable apportionment of the risk between customers and stockholders and in order to assure the financing of the project on reasonable terms to the consumer". In April 1980, LNG deliveries from Algeria stopped and the deliveries from Southern Energy to the grid declined progressively to minimum levels (1% to 2% of normal levels). The FERC initiated an investigation on the rates charged by the company. Meanwhile, Southern Energy and Southern Natural came to an agreement early 1981, whereby the first could continue to bill the full cost of service as long as minimum deliveries occurred. Some customers did not consent to this agreement. Once they drop below these levels, Southern Energy could invoke the "minimum bill", which it eventually did in April 1982, two years after the LNG supplies stopped. This implies that, during two years, the company had collected a greater amount of money than its tariff authorised.

The administrative law judge and the FERC afterwards, first decided that, since the company delivered even small quantities of gas, it was sufficient to prevent the implementation of the "minimum bill". The FERC also decided that pipeline companies had acted imprudently and ordered them to refund their customers the difference between what would have been paid under the minimum bill tariff and what was actually paid under the full cost of service tariff. Later, the FERC nevertheless started to look at the issue from a broader perspective, on the assumption that the minimum bill was not referring to the capacity to deliver any gas at all (which Southern Energy did), but rather quantities close to the daily deliveries on which the project was designed. The FERC therefore concluded that the minimum bill should have been called immediately after the disruption of LNG supplies started: mid-June 1980. Despite Southern asking courts to review this decision, the court agreed with the FERC (US Court of Appeals, 1987).

Interest in LNG import terminals surged again in 2000 with the start of liquefaction plants in Trinidad and Tobago. Mothballed terminals were reopened. The first LNG terminals are regulated and the tariffs regulated by the FERC (CRE, 2008). The tariffs are different for each LNG terminal.

In 2002, the FERC decided to encourage new LNG terminals by removing regulation as forecasts indicated that LNG import requirements would increase rapidly (Hackberry decision). This eliminated third-party access requirements, so that the FERC could not deny an application to a company wanting to use the facility to import its own gas or condition its approval to the investor giving access to any third party.

The FERC nevertheless still reviews applications, notably regarding environment protection. Indeed, the Energy Policy Act of 2005 (EPACT, 2005) amended the Natural Gas Act to grant the FERC express exclusive authority to approve or deny the siting, construction, expansion or operation of an LNG import terminal located onshore or in State waters (Sutherland, 2005). The FERC may approve an application "with such modifications and upon such terms and conditions as the Commission finds necessary or appropriate."

It appears that private merchants have a leading role in new LNG investments (von Hirchhausen, 2008). Their terminals are developed as a service provided to industry, without any link to other activities of the investor, which offers LNG capacity to the market ("tolling"). Cheniere and Excelerate are examples of such companies.

Gas storage

Gas storage facilities serve several purposes: meeting seasonality of gas demand, helping meet a sudden and rapid increase in gas demand due to extreme conditions (cold weather, disruption), and, more recently, backing up trading activities or the rapid variations in gas demand from the power generation sector.

Meeting seasonality relates mostly to the difference between winter demand and summer demand, the latter being traditionally higher in countries with gas use for heating. Due to the recent needs for air conditioning, summer demand can also be high, which is typically the case in countries such as the United States or Japan. Storage facilities are also used by transport operators to smooth the demand differences between the upstream and downstream markets. Storage can also help to prevent gas price volatility (FERC, 2004).

There are three different types of underground gas storage: depleted fields, aquifers and salt caverns. Depleted fields and aquifers are usually better suited for seasonal variations while salt caverns are better suited for meeting important intra-daily demand variations. Investments costs differ widely depending on the type of gas storage. There are also peak shaving LNG facilities which are used to meet peak demand variations. They are not considered in this report.

Common features in the development of underground gas storage are the long lead times needed to make such investments. It can take up to eight years for design, permitting, construction and build up (IGU, 2012b) and this can actually be longer in case of local opposition as has been observed in various European countries (IEA, 2009). Lead times vary depending on the country's regulation and permitting process and the properties of the storage facility. Among the current concerns for the storage operators are whether sufficient incentives for new facilities exist and whether the operation of existing storage facilities can be carried out economically in the future. In Europe, while the operation of UGS has moved from being national to being more regional through the development of interconnections, storage facilities are still subject to widely different regulatory frameworks.

Storage costs should be rolled in the final end-user price, similarly to pipeline and distribution costs. This requires in particular residential end-user prices to be increase, as this type of user is usually the one with the most variable spread of demand between summer and winter. In the case where end-user prices remain regulated by governmental or regional agencies, the final tariff should take into account not only the wholesale price – based on the NDRC reform, this should be at the city gate, as well as the remaining network costs not covered in the wholesale price. Regarding the largest users, assuming that these users pay a market price freely negotiated between themselves and their supplier, the price of flexibility that the supply has to bear should be included in the final price.

Storage investment is strongly linked to the regulatory and tariffs framework in the country. For example, there are many planned storage projects in the United Kingdom, but a few are moving forward due to the decreasing spread between winter and summer prices which represents the basis of the revenues of the United Kingdom's SSO. There are also depending on the country some specific rules regarding the companies which have access to storage services in priority, third-party access, tariffs or strategic stocks.

The economic attractiveness of a storage facility depends upon the physical characteristics and capabilities of each project, the services to be provided and to a lesser extent, regulatory regimes. According to an analysis by the FERC, "independent, unregulated storage projects will generally be expected to have returns on equity exceeding 20% while jurisdictional storage projects will typically have equity returns between 12% and 15%. The higher return for unregulated projects, often salt-cavern based, is due to the perceived market, geologic and development risks" (FERC, 2004). Besides, storage costs depend a lot on the type of facility: salt caverns will usually be more expensive on a volume basis, but less on a deliverability basis. There can also be significant variations depending on the amount of cushion gas necessary and how it is provided.

In both North America and Europe, the liberalisation of the gas industry has driven demand for storage flexibility. As some countries gave TPA to storage facilities, this gave access to different market players with different needs in terms of flexibility, pushing storage operators to improve the storage products offered. Additionally, due to the increasing role of gas-fired plants as a back-up to renewables, there is more need for flexible gas infrastructure, and in particular for storage facilities with high withdrawal rates – salt caverns, and in some cases, the other storage types.

Whatever the region, storage investors usually use four valuation options in order to decide on new storage investments (FERC, 2004), including the following:

- cost of service valuation, based on the valuation of storage according to regulated tariffs;
- least-cost planning, which is typically performed by local distribution companies and other large-volume gas customers, and in which one considers the savings resulting from not having to use a more expensive option, which depends upon a gas consumers' load profile;
- seasonal valuation (intrinsic), which looks at the price spread between the injection period (summer) and the withdrawal period (winter), and in which seasonal storage is often valued based on the intrinsic value, *i.e.* by looking at the spread between future winter and summer prices, with the risk that the coming online of new storage facilities reduces this spread; and
- option-based valuation (extrinsic), which takes the opportunity of price differentials that can be captured through fast-cycling storage.

Investing in gas storage has become a very important issue in China, in particular to meet seasonal and peak winter demand. According to IGU estimates (IGU, 2012b), there is only 3.97 bcm of working capacity in China representing 3% of total demand as of 2011. This is very low for a country where city gas consumption represents more than 40% of total gas demand in

2010 (Chinagas, 2011). By comparison, countries with a high share of city gas use such as Germany, France or Italy have a ratio between working storage capacity and demand of 20% to 25%. Investment in storage is therefore not only necessary; it has to be performed rapidly. Fortunately, China has many depleted oil and gas fields which can be used as seasonal storages and also has potential to build salt caverns which can meet daily variations. Finally, LNG can be used as storage for customers located in coastal areas, but we will not look at this sort of storage in this part.

What predetermines the development of storage is first the geological potential, on which we assume that Chinese companies and authorities have good knowledge. Building new facilities face then the following issues: uncertainties on demand, costs, and regulatory framework. There are already important seasonal needs; the need for short-range storage (salt caverns) will depend on peak demand during very cold days and increasing flexible demand from gas-fired plants. There are not yet trading opportunities, but this could arise in a later stage.

The cost uncertainties surround cushion gas and cost recovery. The different types of storage (depleted field, aquifer or salt caverns) would need different quantities of cushion gas for the same working capacity. It is usually the highest with aquifers and the lowest with salt caverns. This cost depends highly on gas prices. Cushion gas can vary between 50% and 85% of total initial investments cost according to the gas price promoters pay (Glachant, 2008). There is a higher risk for depleted fields or aquifers due to very long lead times (over three years) and uncertainties on future prices at which the gas will be bought.

Regarding the cost recovery, this will depend on how storage is used and the regulatory framework. Since the liberalisation, and in particular with the development of trading and gas-fired plants requiring more flexibility, a large share of storage investments have been done in salt caverns rather than large seasonal storage, which is due to uncertainties on future demand and on the regulatory framework. The FERC also recognises that dangers of under-investments tend to lie more with seasonal storage than with small and high deliverability storage facilities (FERC, 2004). In a study dedicated to the issue to the lack of investment in seasonal storage in the United Kingdom, Glachant and Codognet (Glachant, 2008) looked at possible regulatory incentives for seasonal storages. Among the solutions, they examined:

- promoting open-season and long-term contracts, whereby the investor assesses interest from market players and ask them to sign long-term contracts with future users, diminishing the investments risks;
- securing storage demand through storage obligations, so that each supplier would be required to have a certain percentage of their supply already storage at the end of the injection season, and enabling a minimum filling of the facility while leaving sufficient capacity for parties to use; and
- securing operators' income by setting a regulated minimum revenue in order to avoid loss and increase investors' incentives (this may create a distortion between storage operators, but options exist to provide investment incentives that would be in the public interest.

Another key aspect for security of supply is transparency, not only on the offers but also on stock levels. The issue of confidentiality is very important for storage operators. In Europe, Gas Storage Europe (GSE) gives data on an aggregated basis on stocks levels in different regions. This could be a possibility for China to investigate if they are sufficient storage operators.

Finally, experience from OECD countries also shows various authorisation processes in order to build storage. In some cases, only the approval of the competent national authority is needed, but sometimes different authorities or local councils have a say (in particular if the facility is onshore). Having to deals with several stakeholders who have different perceptions on the need to have storage often lead to increasing lead times and costs for the investor, resulting in some projects being cancelled. The authorisation process should therefore be as streamlined as possible. But the key concern from the investor's point of view is the regulation and uncertainties linked to that.

Who can use storage?

Owners or operators of underground storage facilities are not always the owners of the gas held in storage. This was the case before liberalisation, as the storage was usually owned by vertically-integrated companies, but more widespread third-party access means that all sorts have users can store gas. In some countries, however, there are some rules regarding companies which can or must have gas stored. It seems to be particularly the case when storage access is regulated but it can also happen with negotiated access. It has to be noted that the regulation on who can get access to storage capacities has been evolving over time.

In Belgium, the SSO Fluxys used to allocate storage capacity in priority to the distribution companies based on the capacity reserved on the transmission network up to the delivery points to the distribution companies. If some capacities were still available, the allocation was then based on "first arrived, first served" basis. In July 2011, the regulator CREG changed some rules due to the third Directive (CREG, 2011). In particular, the priority allocation of storage capacity to distribution companies no longer exists (CREG, 2011). But the CREG can still require distribution companies supplying "protected" customers to have sufficient storage capacity.

In Spain, there are some obligations put on companies to hold stocks (Criteria set out in paragraphs 1, 2, 3 and 4 of Article ITC/3862/2007 of 28 December) (Spanish Ministry of Industry, Tourism and Energy, 2012). Strategic stocks correspond to 20 days of firm gas sales of the previous year, operational stocks correspond to ten days of total sales of the previous year, 30 days of sales to consumers entitled to benefit from the tariff of last resort. The remaining capacity is available through auctions. Any company selling gas can participate.

In France, storage capacity is allocated depending on the customer portfolio of the gas company. In conformity with law 2003-8 of 3 January 2003 (modified by the law 2004-803 of 9 August 2004), the decree 2006-1034 of 21 August 2006 organises access to gas storage sites (Storengy, 2012). Article 3 provides for the allocation of storage capacity to suppliers with an existing portfolio of end customers, on the basis of the provisions in the ministerial order of 7 January 2009 on profiles and unit rights to storage (French Ministry, 2011). If there is any storage capacity still available (article 14) (or not taken by the companies which have the right to take storage capacity but not the obligation), it can be auctioned.

In Italy, suppliers can make two different (separated) requests:

- The first concerns the "averagely rigid seasonal peak demand". In this case, the maximum storage rights (Maximum Admissible Request, MRAmedio) are 33.4% of the consumption of the end user served by the supplier during the previous year (See Chapter 5, Attachment 4, Section 1.2.1.1. page 81 of the storage code (Stogit, 2010)). If there is still capacity available, it is attributed on a prorate basis based on demands.
- The second concerns a severe peak of demand. Maximum rights are calculated as follows: $MRA_{rigido} = 0{,}25 * MRA_{medio}$.

In many other countries, storage capacity can be contracted by any company which simply chooses among the storage products available.

Storage products

An important way for SSOs to recover their investment is to offer storage products which are as close to market demand as possible and enable different types of users – distribution companies, industrials, power generators, major suppliers, to find the flexibility their need for their operations.

Storage products are very different not only in terms of tariffs, but also in terms of what is actually offered to customers. Usually there is a basic package often called "bundle storage capacity" including storage capacity, withdrawal and injection capacity. The ratios between these three quantities vary a lot depending on the storage properties: the more a storage is used for seasonality, the lower the withdrawal rate would be in comparison to storage capacity or said otherwise, the higher the ratio capacity (million m^3)/ withdrawal rate (million m^3/hours) would be high. By contrast, salt caverns will have a low ratio – usually below 1 000 hours.

Additionally, the products offered can vary in many ways, including:

- duration of the contract, usually one year but sometimes for shorter (days, months) or longer periods (several years) enabling users to have more visibility or more flexibility;
- possibility to book separately additional storage capacity, injection or withdrawal (sometimes with restrictions), often requiring to have already booked a bundled product;
- possibility to book interruptible capacity (bundled or unbundled);
- possibility to be on reverse flow;
- possibility to renominate flows a few hours before;
- balancing services;
- cession of rights or capacity to third parties;
- trade of rights/capacity on the secondary market;
- penalties in case or underuse or overuse of capacity; and
- obligation on minimum or maximum stocks.

Storage in Europe

European storage facilities were built by the then vertically integrated gas companies. As of today, despite legal unbundling, incumbents tend to dominate in terms of storage ownership. Storage development often depends on the historical evolution of gas demand, the share of residential customers, the presence of domestic production (the UK and Dutch domestic production provides a lot of flexibility, although this is now less the case for the United Kingdom), the availability of other sources of flexibility (long-term contracts, demand side measures such as interruptible users).

The United Kingdom and Germany are the European countries with the highest diversity of ownership; for the United Kingdom, this is a result of the liberalisation. In Germany, this tends to reflect a multi-tier market structure and the presence of distribution companies on that segment. There are also a few non-European gas companies entering the market such as Taqa energy (owned by the Abu Dhabi government), or suppliers such as Gazprom or Exxon.

Gas storage was largely left out of the First Directive (EC, 1998), but the Second Directive required "account unbundling while the access to storage could be either regulated (based on published tariffs) or negotiated (based on publication of at least the main commercial conditions applicable)". The decision regarding storage regulation was therefore left to the individual member states or their regulators. Regulated access means that tariffs, or at least the methodologies underlying their calculation, are to be subject to ex-ante approval by the regulator. Some countries with negotiated access could also have involvement of the regulatory authorities, for example an ex-post action in case of anti-competitive behaviour or disproportionate tariffs. Both systems have their advantages and disadvantages.

The Third Directive passed in July 2009 went further to ensure the independence of storage system operators and improve third-party access to storage facilities (Article 15 of the Directive). Storage system operators, part of vertically integrated undertakings, shall be independent at least in terms of their legal form, organisation and decision making. There should be no conflict of interest for persons responsible for the management of storage system operator. The parent company could nevertheless approve the annual financial plan, or any equivalent instrument, of the storage system operator and to set global limits on the levels of indebtedness of its subsidiary, but it cannot give instructions regarding day-to-day operations, nor with respect to individual decisions concerning the construction or upgrading of storage facilities, that do not exceed the terms of the approved financial plan.

Storage in the United States

Prior to 1994, interstate pipeline companies owned all of the gas flowing through their pipelines, including gas held in storage facilities, and had exclusive control over their storage facilities. They were subject to the jurisdiction of the FERC. With the implementation of FERC Order 636, pipeline companies were required to give third-party access, apart from a portion that may be reserved by the pipeline operator to maintain their system's integrity and for load balancing. Today, many storage facilities are also owned/operated by large LDCs, intrastate pipelines, and independent operators (merchant companies) also operate on an open-access basis, especially those sites affiliated with natural gas market centres (EIA, 2012b).

The type of use of the facility therefore depends quite a lot on the owner. Interstate pipeline companies use underground storage for the balancing and supply management of their long haul transmission lines. Intrastate pipeline companies use it for that purpose as well, but most of the gas stored is actually used for the end users. Distribution companies use their storage facilities primarily for the end-users; however, since the liberalisation, they also lease part of the capacity to third parties.

The FERC is responsible for regulating storage facilities serving interstate commerce, state agencies the others. Open access has increased the use of storage in response to price variations (arbitrage opportunities) as well as the use in conjunction with various financial instruments in order to take advantage from market conditions. The deregulation of underground storage, combined with other factors such as the growth in the number of gas-fired plants, drove the interest in facilities with high withdrawal rates. Many salt caverns as well as a few fields with high deliverability have been initiated by independent storage service providers (merchant companies, similar to the ones developing LNG terminals). Facilities are therefore mostly dedicated to third-party users interested in such facilities characteristics.

FERC's position on storage has evolved due to increasing gas prices after 2004, more focus on security of supply issues. In particular, FERC's interpretation of market power prevented storage operators from applying market-based rates (Von Hirchhausen, 2008). The EPAct 2005 allowed companies to set their own rates based on open season and market characteristics – similar to negotiated access in Europe. FERC can still modify these.

The Gas Storage Pricing Order 678 (of June 19, 2006) (i) expands the definition of the relevant product market to include close substitutes for gas storage services for the authorization of market-based rates; and (ii) implements the new Natural Gas Act Section 4(f), which permits FERC to authorise market-based rates even where an applicant has market power. Current rate policies thus provide more flexibility when designing cost-based rates, negotiated rates, and market-based rates.

Strategic storage

The issue of strategic gas storage is often brought up but in fact only a few countries have strategic storage. Strategic gas storage is more expensive than for oil, and there are technical constraints for some certain types of storage such as aquifers (the facility must be filled and emptied regularly). In the EU, there is no obligation on stockpiling of gas or specific use of gas storage for security of supply, and the EU Gas security of supply regulation does not foresee such strategic storage. The IEA considers that strategic storage could be part of the answer to a better supply security but this is up to the country to decide, provided that they have a good geological potential.

Some European countries have strategic storage: Italy, Poland and Hungary. In Italy, Strategic Storage Service is imposed by a decree and the ministry determines the quantity of strategic storage. The strategic gas reserve shall correspond to the possibility of withdrawing gas during a 60-day period in winter conditions at a delivery rate of 50% of the import capacity from non-EU countries. Shippers have to maintain strategic stocks corresponding to 10% of their annual non-EU imports. It will be made available by the operator STOGIT to these shippers that import gas from non-EU countries (Italy imports from the Netherlands, but also Norway, Algeria and LNG exporting countries). Similarly in Poland, companies importing gas from abroad have the obligation of maintaining stocks of gas in storages located within the territory. Currently the quantity amounts to 15 days of daily imports, but will be increased to 30 days by 2012. Hungary decided in 2006 to build strategic storage facility due to its high dependence on one supplier – Russia. The Act 26 of 2006 on the security of gas storage prescribes a capacity of 1.2 bcm, and the construction of such a facility with a daily withdrawal capacity of 20 Mcm/d for at least 45 days. It would serve to supply gas to household and communal customers, as well as to those consumers who cannot replace their gas consumption with other energy sources.

In other countries, despite the absence of "strategic storage" per say, there are sometimes obligations for market players as part of Public Service Obligations (PSO). Shippers to hold a certain number of days of consumption in storage (like Spain). In other countries, companies are allocated storage capacity depending on their customer portfolio (France) so that those serving residential customers have enough storage. Stockpiling is imposed indirectly through imposed PSO on the TSO (Denmark, Belgium, and the Czech Republic). SSO are indeed obligated to make storage capacity available for TSO to fulfil their balancing role. For example, in Denmark, in case of a total supply disruption, the TSO has to be able to deliver gas to all consumers for 60 consecutive days during normal weather conditions and for three consecutive days with temperatures of -14 °C (1 in 20 winters). Corresponding gas volumes are stored in underground gas storage in Denmark, referred to as "Storage for Emergency Supply". There is a similar regulation in Belgium in case of severe winter conditions in order to have all uninterruptible customers supplied. Concerns about security of gas supply have led in the case of the United Kingdom to look closely at stock levels through the national transmission system operator. They ensure that stocks do not fall below specific levels.

8. Customers in liberalised gas markets

In many European countries, customers have become eligible, which means that any of them can choose their supplier (see section on market liberalisation in Europe in Chapter 4). In the United States, the eligibility depends on the state and not all of them allow full unbundling.

There is still regulation on the end-user side

Many European countries still regulate tariffs for the supply of gas to the end user according to the ERGEG Status Review of End-User Price Regulation as of 1 January 2010 (CRE, 2011). While in 2010, the majority of EU countries (15) still had some regulation of the residential end user price, only six regulated energy-intensive consumers (France, Portugal, Bulgaria, Poland, Lithuania, and Romania). Among the countries with no regulated end-user prices are Austria, Belgium, Czech Republic, Estonia, Germany, Luxembourg, Slovenia, Sweden, and the United Kingdom. This does not mean that prices are automatically regulated, but that the end-user has the choice between a regulated and a market price. In most cases, the regulator sets the end-user price, but in France and Spain, they are set by the government sometimes with political motivations while the regulator only gives its opinion. It appears that in most countries, in 2010, over 95% of the residential users had kept regulated prices and not opted for market prices. However, 11% had opted for market prices in France and 51% in Spain.

Regulated tariffs need to cover the procurement costs as well as various network charges. As seen in the previous parts, the network charges are usually regulated, the issue therefore lies with the right assessment of procurement costs. This is even trickier in Europe since companies source their gas from a mix of oil indexed contracts with more or less spot indexation and at the spot market.

Usually, the procurement costs are split between a fixed component and a variable component, the latter reflecting the price of gas supplied. In Spain, the variable component is based on an average of NBP and HH and on an average of Brent prices over the last six months (CNE, 2010b). The ratio between market prices and Brent prices can vary depending on the time of the year. In Ireland, procurement costs are based on NBP and use monthly forward prices for later delivery illustrating a gradual purchase of supplies for a later month (CER, 2007). In Italy, it is based on a basket of oil prices, and can be modified by the regulator whenever necessary. The regulator changed the coefficients in 2010 and in 2011 to reflect the benefits from sourcing gas on spot markets. In France, by contrast, only GDF Suez long-term contracts are taken into account for the period 2010 to 2013 while the company sources significant volumes on the spot markets or through short-term contracts. Since the end of 2010, the CRE has used a partial indexation on spot prices (9.5%, which reflects the partial indexation to spot prices in GDF Suez's long-term contracts. The current formula does not enable the small end-user to benefit from arbitrages that GDF Suez could make between short- and long-term contracts.

How customers in liberalised markets buy their gas

Customers in liberalised markets can choose their supplier, or possibly between different offers from the same supplier (residential users). The larger the gas user, the earlier it has been granted eligibility (the possibility to choose its supplier) and the more negotiating power it has with its potential supplier. As mentioned earlier, there is still the possibility in many countries to opt for either a market price (not regulated) or the regulated price defined by the competent authority. In some cases, moving back and forth between the two options is restricted.

It is imperative that the switching procedure should be very transparent, not only in terms of steps to follow to switch supplier, but also in terms of conditions of gas supply from the new supplier – pricing, places of delivery.

For both small and large customers, switching suppliers requires the following steps (CRE, 2012c):

- Step 1: The customer chooses a supplier. This consists first in signing a new contract with the new supplier. The starting date of the new contract must be compatible with the time necessary for the distribution/transmission network operator to note the change and the right of the client to modify their decision (In Europe, it happens frequently that people change suppliers following phone calls). The new supplier also defines how the basis on which consumption will be set in the first stage – historical consumption for residential users, or use of monthly or daily metering for large users. Once this step is performed, there is little more to do from the customer's point of view.
- Step 2: The new supplier informs the network operator about the switching.
- Step 3: The network operator controls the change of supplier.
- Step 4: The network operator registers the change.
- Step 5: The network operator informs the former supplier.
- Step 6: The network operator organises and implements the switch, which includes all the technical details of measuring consumption until the day of switching and implementing how consumption will be measured afterwards.

Retail gas consumer

Retail consumers can choose not only between different providers, but also sometimes between different offers from each of these providers. These offers can be for natural gas only, but also since many companies are gas and power companies, dual offers of gas and power. They will depend on the level of annual consumption, but also on where the customer lives (for companies offering a nationwide offer). Rebates can be granted for users opting for dual offers, or depending on the payment method (direct debit customers, customers registering through internet can get a discount).

Among the offers that one can find in different countries,[18] there are:

- offers at variable terms usually including a fixed annual subscription term (can also be monthly, sometimes daily) and a variable term per kWh, in which the supplier can change the terms at any time (with appropriate warning in advance);
- offers at fixed prices for one, two or three years, usually including a fixed annual subscription term (sometimes daily) and a variable term per kWh, in which, usually, early terminations fees apply;
- offers including a carbon term, which they are similar to the previous ones, with a variable carbon price per kWh;
- offers at a fixed discount to what the utility offers (Energyshop, 2012);
- fixed-bill contracts, where the supplier guarantees that the customer will not pay more than a fixed amount for their annual energy consumption, based on the customer's historical usage and adjustments for weather (this contract type transfers the risk of a long, cold winter to the energy marketer); and

[18] Based on offers seen in France, the United Kingdom, Germany, the Netherlands, and Belgium.

- offers based on natural gas including some biogas, following the same principle as offers with variable or fixed prices, but usually more expensive.

There is in some countries, such as the Netherlands or the United Kingdom, close monitoring from competition authorities or the regulator. In the case of the Netherlands, all suppliers must submit their offers to the regulator to check whether these are reasonable. This can be seen as a safety system that ensures retail customers pay reasonable prices (the system does not cover wholesale customers).

Large gas users

Larger gas users are very different from residential gas users, not only by the size of their demand, but also from their specific requests in terms of flexibility, place of delivery and pricing indexation. Unlike residential users, a large gas user can also buy gas on the spot market, provided that it has a team of employees to do so.

Similar to the residential users, these gas users need to compare all their contracts' conditions. This is notably the price of gas and the conditions relative to their evolution, the duration of the contract and conditions of cancellation of the contract, the price for access to customers' services, payment methods. Among the offers available on the websites of suppliers, some are relatively similar to the ones for residential users – fixed price, discount compared to the regulated tariff, but there are also offers taking into account the seasonality of gas prices (lower during the summer).

The most complicated gas customer is probably the power plant, which is the most sensitive to rapid power market changes (electricity market prices, gas, coal, and CO_2 prices, as well as general electricity supply/demand and dispatch conditions). These customers tend to have important flexibility requirements (but do not want to pay for them), which stem in part from the need to provide back-up for growing reliance on renewable energy sources. The first difficulty arises with the amount of gas they need to contract every year, as from this they need also to negotiate the flexibility around that amount. They need also to take into account the part of their gas supplies that they would contract on the spot market. Additionally, some power generators contract gas for their different power plants located in various parts of the country. Obviously, this is easier to serve with a virtual hub.

Industrial users can offer more certainty in terms of their gas use, which would be beneficial to their ability to negotiate better tariffs with their supplier. This is obviously more complicated for small users with consumption in the order of a million of cubic meters per year. The strategy for them could consist in regrouping themselves to gain a critical mass and be able to negotiate better tariffs and conditions with suppliers. They can also buy their gas directly on the spot market, if they have sufficient visibility on their monthly gas demand.

9. What US and European experience with gas markets is applicable to China?

As highlighted in Chapter 2 of this report, the Chinese gas market currently faces many issues regarding regulation and pricing. Over the report, we have looked at how liberalisation developed in European and North American countries, and in particular, how this has affected the upstream, midstream and downstream issues.

China is unlike any OECD market; therefore no lessons can be directly applicable without regional adaptation, but Chinese stakeholders can still draw lessons from experience gained in the various OECD markets.

One essential factor must be taken into account in the comparison: the stage of development of the OECD markets when they started liberalisation compared to that at which China now stands. Despite the size of its domestic market (larger than any OECD country but the United States) and its growing interactions with global gas markets through imports, China's gas market is still at a relatively early stage. Most aspects such as imports, the development of domestic production in the West, the construction of long-distance pipelines across the country, only took place within the past decade. China's long-distance and high pressure transmission network is therefore relatively limited and still being expanded to bring gas from the producing regions in the West. The number of gas users has been and is still growing very fast, while gas demand in the power generation sector is negligible compared to coal.

By contrast, many OECD countries reviewed in the study had already relatively established gas industries for several decades before they started considering market liberalisation. This is certainly true for the United States if one considers 1978 as the key date for liberalisation there. Most European countries started liberalising their gas markets in the late 1990s and consequently, they had already built significant gas transmission, storage and distribution infrastructure, which has been largely or fully amortised. They also had large residential customer bases, which had been growing at a more modest pace over the previous decade.

The United Kingdom, a precursor in liberalisation, was probably the closest to where China stands now. When it started liberalising its gas market in 1986 and continued with measures in the early 1990s, its gas market was only about 15 years old, and imports had only started to pick up in the late 1970s to early 1980s. The dash for gas in the power sector had not yet taken place, and actually occurred at the same time as the market was liberalised. Spain also saw the development of its gas-fired generation during the phase of liberalisation over the 2000s. In some OECD markets still under development, such as Turkey or Korea, market liberalisation has stalled or is progressing only at a slow pace.

It is almost worth mentioning that most European countries have seen a more modest growth of their gas consumption since liberalisation started – gas consumption in OECD Europe only increased by 20% over the 2000-10 period, mostly in countries such as Spain and Turkey. However, UK gas consumption increased by 80% over 1986-2000, while its market was liberalised. China expects to see its demand almost tripling according to CNPC's forecasts of Chinese gas consumption reaching 350 bcm by 2020.

From the upstream point of view, China has some common points with the United States, such as the size of the country, the diversity and wealth of gas resources, but political and industrial organisation is quite different. At the same time, China faces issues comparable to Europe as it needs to attract new imports and to develop the corresponding infrastructure. So far, China has been relatively successful in developing import infrastructure – both LNG and pipelines. China's gas consumption has been and will continue to be supply-driven over the next few years, but as the price of gas increases, the affordability of gas in key sectors becomes a key issue, notably in the power generation sector.

1. In OECD countries, the government or the European Commission have played an essential role in driving liberalisation, notably through the establishment of independent regulators. In China as well, the government should be the driving force behind market changes, even if one should also recognise that the authority on energy markets in China is currently divided among different ministries and agencies and that there are different views between the central government and provinces. The setting-up of a national entity responsible for energy would clarify the government's communication regarding energy issues. Some specific tasks in upstream and downstream can be left to regional governments (as happens in the United States between FERC and state regulators, or in Germany with the federal and state level regulators), as long as the division of roles and duties is clear.

2. OECD markets are usually guided by white papers and gas-related laws, which constitute a clear policy framework giving the government's policy objectives regarding natural gas development and providing the basis for investors and market participants. They set the development objectives for the gas industry and the rules regarding infrastructure regulation, and/or domestic gas production and the entities (ministries, regulators) in charge of overseeing different parts of the gas value chain. Such policy documents should be consistent, and in China not limited to the government's Five Year Plans.

3. One of the key lessons is that liberalisation takes time, usually a decade, before reaching any quantifiable results. Given China's objective of rapidly increasing gas demand, the accent should be put on liberalising the upstream sector, introducing wholesale prices, which also implies introducing third-party access to transmission pipelines, and developing infrastructure.

4. Direct involvement of Chinese companies in policy-making and energy regulation should be avoided, and replaced by open consultation processes. In particular, if China were to set up a national regulator or any other type of governmental entity in charge of upstream and/or downstream activities, there should be no interference, notably from the Big Three NOCs. This implies for example that the key people in charge should have no position/financial interest in Chinese companies. Chinese companies can however be consulted in the framework of developing new regulations, but this should involve all interested players.

5. The pricing challenge is the most important to be addressed as pricing issues have knock-on effects in the whole gas value chain. Additionally, the gap between domestic gas prices and import prices requires this issue be tackled rapidly as China is set to become increasingly import dependent over the coming decades. Measures based on subsidies (such as the VAT rebate put in place one year ago) should be avoided, not only due to their costs (China already imports over 30 bcm of natural gas, and this number is likely to reach 100bcm in three to four years), but also because the value of natural gas is not properly reflected either on the demand side and on the supply side.

6. Many OECD countries, notably those with significant domestic gas production, such as the United States and the United Kingdom moved to a market-based system combined with third-party access to pipelines. The NDRC has already engaged a pricing reform in two provinces taking a netback approach based on oil products priced indexation. China needs to think carefully about the indexation it wants to put in place, notably whether oil is appropriate as being the only linkage to be used in the formula. Oil products are pertinent when it comes to residential/commercial use and also for some industry, but coal is also an important competitor to natural gas, notably in the power generation sector. This implies a careful choice of the coal index to be potentially used in the formula (import cost or another

index should be transparent, reliable and not based on governmental prices) as well as of the weighting given to coal in the formula. China could implement the NDRC reform progressively, province after province, to test such indexation in provinces where the share of coal generation is particularly high.

7. Regional differences are crucial, not only because some provinces are wealthier than others, but also due to their differing structure in terms of domestic gas supply, LNG and pipeline gas as well as the costs of each of these supply sources will be different. Provinces which are closer to the supply sources or poorer than others should not be disadvantaged by inadequate pricing structures.

8. China's government should have a view on whether it wishes to keep a market-approach based on indexation to alternative fuel prices, or move progressively to a hub pricing mechanism by continuing and developing the experience gained in the Shanghai hub. This should also include a discussion of whether this mechanism should be based on a virtual or a physical hub. Creating a hub should include both institutional and structural changes. The first include wholesale price deregulation, the separation of transport and marketing activities – or at least allowing transparent third-party access, and making at least large customers eligible to choose their supplier. Structural requirements include the existence of sufficient network capacity, a competitive number of participants and the involvement of financial institutions.

9. Finally, regarding end-user prices, opening the gas market for the largest gas user has always been a key step towards market liberalisation. OECD experience shows however that many countries have not quite yet liberalised the residential sector. However, OECD residential gas prices are usually higher than other sectoral prices, due to the need to reflect distribution and storage costs on top of procurement and transmission costs. This is not the case in China, but the government could take the opportunity during a period of low inflation to gradually increase these prices. Such a measure can be complemented by targeted social measures to help the poorest.

10. The next challenge is therefore to identify the most cost-effective supply strategy based on domestic conventional and unconventional gas resources and import availability – taking into account domestic demand and affordability. The upstream sector is key for China, as it represents and will continue to represent the bulk of China's gas supplies. China has substantial resources in tight gas, CBM and shale gas, on top of conventional gas resources. There are also foreign gas sources which can be imported (and developed or not by Chinese companies). Investors in upstream need the proper incentives to develop these resources, which can be divided into three parts: price; access to markets, which are developed in points 7 and 9; and long-term regulatory clarity. Foreign investors show interest in investing in China, but such companies need long-term regulatory stability and transparency, no political interference, and freedom in commercial decision-making.

11. Liberalising the upstream sector and introducing third-party access to pipelines in order to increase domestic gas supply including unconventional gas resources should be accelerated. Upstream regulation should also prevent hoarding of licenses. In many upstream systems (United Kingdom, Norway) whether companies are respecting their work programme agreed in the plans of development and operation (PDOs) determines whether they keep the licenses or not. This requires the authority in charge of upstream activities to be very well trained to understand PDOs, notably with new types of resources such as shale gas. Otherwise, they risk losing the license which is then offered to other players. This drives efforts from all parties involved in E&P development, rather than allowing them to stave off competition by holding the licenses for an indefinite period of time.

12. In the upstream sector, the move from a fully regulated system to a more market-based approach was a key driver for US gas production growth, in particular shale gas development over the past decade. It enabled the rationalization of a fully regulated system which had resulted in either shortages or oversupply; in that respect, the main danger for China is that upstream investments do not proceed at a pace quick enough to meet rapidly growing gas needs. Another advantage of the US system, reflecting the large size of the country, is that different regional gas prices exist; they can indicate regional shortages or oversupply and be a driver for investments in production, transmission pipelines or storage facilities.

13. The recent development of LNG infrastructure in the United States and Europe shows that TPA on LNG terminals is not always the optimal choice: the United States decided to remove TPA while many new LNG import terminals in Europe have been built with TPA exemption for 20 years. Additionally, it appears that development of LNG import terminals can be either driven by a national infrastructure development plan, including open and regulated access (like in Spain), or be left to the market with some national regulatory oversight and restrictions on TPA access for new entrants. LNG terminals with long-term contracts do not represent an issue, as long as they do not cause any economic harm to the existing market. Plants with open access and no long-term contracts attached should be allowed as well, as they can provide relief in case of higher local demand, as well as enable new entrants to enter the market and provide competition at the wholesale level. In both cases, regulatory cost control is not required but LNG regasification costs must be reflected in the price of delivered gas. In case the government wants to pursue the path of TPA for LNG import terminals, this should be clearly indicated to investors beforehand and specified whether this applies to existing or new LNG terminals. Many options can be envisaged which maximise the investment security for the project sponsor, such as partial TPA where only part of the capacity is reserved for third parties. In case there is no TPA, the regulator can set up a "Use-It-Or-Lose-It" requirement to make capacity available on short notice to third parties.

14. A key step in achieving competition in the upstream market as well as the development of wholesale markets was obtained by giving access to third parties to transmission pipelines. Several unbundling options can be chosen, with the regulators usually preferring maximising flexibility for marketing activities in order to ensure maximum capacity utilisation and efficient capacity development.

15. Fostering investment in pipelines is also key, gas supplies reaching the final end-user will increasingly come from long distances, even if domestically produced. Pipeline business should be open to every interested party, as long as unbundled, but regulators should make sure that pipeline companies do not create different independent networks, but rather their pipelines are connected like they are in the United States. Transmission pipelines can be built based on larger shares of long-term capacity contracts (but without fixed price and gas take-or-pay obligations), as long as open seasons determine incremental need. Costs need to be regulated and rolled into the delivered gas prices. These pipelines can also be built under regulation as long as planned by the market participants and approved by the regulator. TPA is a prerequisite. Costs can be allocated to all gas transported in this pipeline.

16. Special attention should be given to the internal rates of return given to new infrastructure projects (notably long distance pipelines), as it appears that the current ones provide too high a return to pipeline activities, cross subsidise other activities and can represent an entry barrier for other market players. Cost regulation has to be fair and transparent, covering all costs. The individual rate of return can be pipeline specific but set by the regulator on a transparent basis.

17. Costs of developing underground storage facilities should be clearly transferred to the end user, given the important needs for that sort of flexibility. Whether access is negotiated or regulated, or whether TPA exemption is granted for a certain period of time should be decided by the government, as well as the specific conditions governing access to storage capacity and minimum storage requirements. Each storage operator should provide transparent information regarding the conditions of access to its storage facility.

18. Experience from OECD countries shows that market openness was a critical element to start liberalisation. This usually begins with the largest gas users, which became eligible to choose their supplier. This was facilitated by TPA to pipelines. While opening markets to large users is essential to competition, many OECD markets took a longer time to introduce this for residential users. Even many countries with fully open markets still limit switching and show a strong preference for regulated gas prices. Opening markets to small gas users may therefore not be regarded as a priority by China.

19. Availability of information is critical at all stages. This applies to basic information regarding the market (supply, demand, and imports), access to the infrastructure (access and tariffs, capacity available), as well as wholesale prices.

Acronyms, abbreviations and units of measure

Acronyms and abbreviations

ACER	Agency for the Co-operation of Energy Regulators
AGA	American Gas Association
APA	Award of production licences in predefined areas
BG	British Gas PLC
BGC	British Gas Corporation
BKartA	Bundeskartellamt
BLM	Bureau of Land Management
BMP	Best management practices
BNetzA	Bundesnetzagentur
BOEM	Bureau of Ocean Energy Management
BPL	Bid Price Ladder
BSEE	Bureau of Safety and Environmental Enforcement
CAPEX	Capital expenses
CAPM	Capital asset pricing model
CBM	Coalbed methane
CRE	Commission de Régulation de l'Energie
DECC	Department of Energy and Climate Change
DOI	Department of the Interior
DSO	Distribution system operator
EC	European Commission
EIA	Energy Information Administration
ENTSO-G	European Transmission System Network Operators for Gas
EnWG	Energiewirtschaftsgesetz (Energy Act)
EPA	Environmental Protection Agency
E&P	Exploration and production
EU	European Union
FERC	Federal Energy Regulatory Commission
FDP	Field development plan
FPC	Federal Power Commission
GGC	Gas to gas competition
GFU	Gas negotiation committee
GIE	Gas Infrastructure Europe
GSP	Government selling price
HH	Henry Hub
ICE	Intercontinental Exchange
IEA	International Energy Agency
IGU	International Gas Union
IRR	Internal return rate
IPE	International petroleum exchange
LDC	Local distribution companies
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
MinEL&I	Ministry of Economic Affairs, Agriculture and Education
MLR	Ministry of Land and Resources
MMC	Monopolies and Mergers Commission

MMS	Mineral Management Service
NBP	National Balancing Point
NCS	Norwegian Continental Shelf
NDRC	National Development and Reform Commission
NEA	National Energy Administration
NEP	Netzentwicklungsplan (Network Development Plan)
NYMEX	New York Mercantile Exchange
OE	Oil escalation
OFGAS	Office of Gas Supply
OFGEM	Office of Gas and Electricity Markets
OFT	Office of Fair Trading
ONRR	Office of Natural Resources Revenue
OPEX	Operational expenses
OTC	Over the counter
PDO	Plan for development and operation
PPP	Public-private partnership
PSC	Production sharing contract
PSO	Public service obligation
REX	Rockies Express Pipeline
ROI	Return on investment
RPI	Retail price index
SDFI	State-directed financial interests
SFP	Small Fields Policy
SNG	Synthetic natural gas
SODM	State Supervision of the Mines
SSO	Storage system operator
TOTEX	Total expenses
TPA	Third-party access
TPES	Total primary energy supply
TSO	Transmission system operator
TTF	Title transfer facility
TYNDP	Ten-Year Network Development Plan

Units of measure

bcf	Billion cubic feet
bcm	Billion cubic metres
CNY	Chinese Yuan
GBP	British Pound
MBtu	Million British thermal unit
Mcm	Million cubic metres
Tcf	Trillion cubic feet
USD	United States Dollar

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