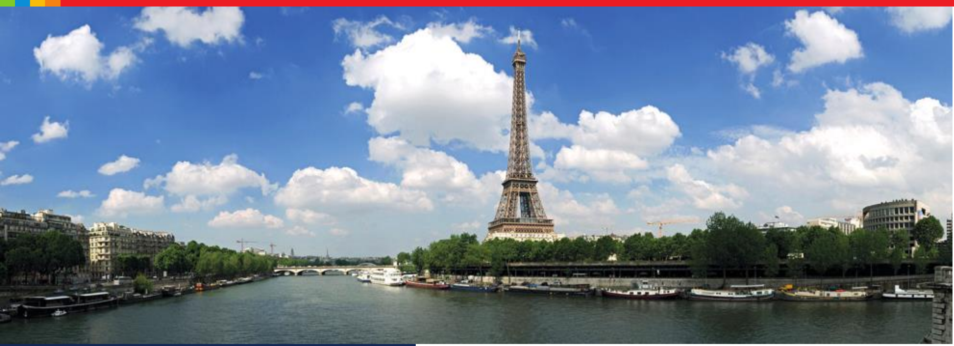
2012-2015 Triennium Work Reports



Wholesale gas price formation

International Gas Union

Programme Committee B Study Group 2

June 2015

WGC PARIS 2015 WORLD GAS CONFERENCE

IGU INTERNATIONAL GAS UNION UNION INTERNATIONALE DU GAZ

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Preface

This report was prepared by Study Group 2 of PGCB under the chairmanship of Mike Fulwood, Nexant Limited. I am grateful for the significant contributions from Mike who needless to say gave everything and more for the success of this task, he showed strength and devotion to his work and lead the Group with a high level of professionalism. Also I would like to thank all the participants of Study Group 2 but especially sections of the report prepared by Floris Merison (Gasterra), Ahmed Mazighi El Hachemi (Sonatrach), Jean-Noel Ntsama (SNH Cameroon) and Carlos Mata (EDP). Throughout the triennium the Group enjoyed a number of presentations on gas pricing issues, which helped shape the report and its conclusions, from Gazprom, Sonatrach, EDP, BP, DEPA and Gasunie.

We would also like to thank all members of the Group, too numerous to mention, who provided incisive comments on drafts of this report, and also the continued support he had from the Vice Chair, Ulco Vermeulen of Gasunie and the PGCB Secretary, Malek Salem Benabdallah of Sonatrach. Finally, thank you to all members of the IGU, who responded to the now annual surveys of wholesale gas prices, the conclusions of which form a key part of the report.

Fethi Arabi - Sonatrach
Chair - PGCB

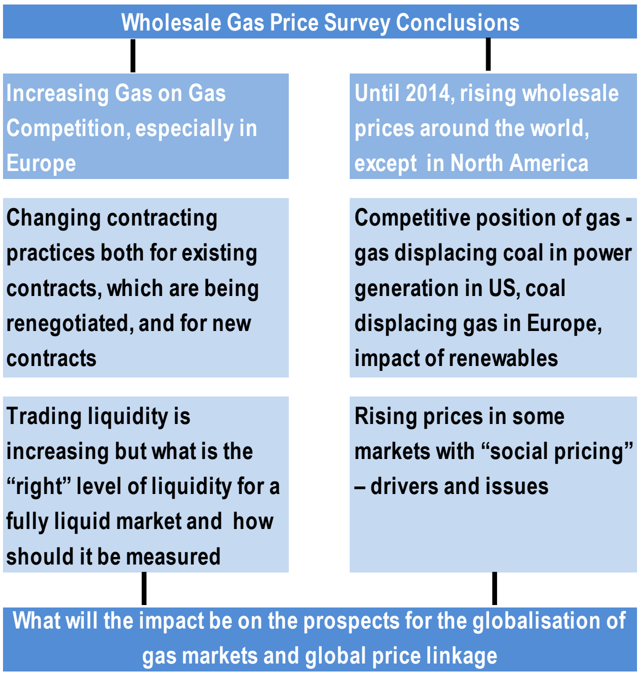
The 26th World Gas Conference (WGC) in Paris will be the third conference at which PGCB has presented a report on Gas Pricing. PGCB first established a sub-group on gas pricing for the 2006 to 2009 triennium culminating in the 24th WGC in Buenos Aires. The remit of the sub-group for Buenos Aires was to carry out a comprehensive analysis of gas price formation models at regional level and to investigate future trends and the factors which could help to minimize price anomalies and contribute to sustainable market growth.

The report to the 24th WGC reviewed the original bases for the pricing of gas, from the costs of exploration and production, competition with oil and, in many countries, price controls through to the development of gas-on-gas competition in liberalising markets. The sub-group also undertook the first two surveys of gas pricing mechanisms, covering the years 2005 and 2007.

For the 25th WGC in Kuala Lumpur, the remit was to build upon the work of the first report, specifically to continue the wholesale gas price survey; study the level and implications of gas market globalisation in terms of whether convergence differs when supply is tight or plentiful compared to demand, whether gas is different from other commodities, the future of oil price indexation and whether parallel pricing mechanisms can continue to co-exist globally or even regionally; study of the price drivers including an analysis if competing fuels to gas, price volatility and long run marginal cost as price drivers; and examine the impact of carbon tax or cap and trade policies on gas price formation.

For the current triennium, culminating in the 26th WGC in Paris, it was decided to continue the wholesale gas price survey and draw some conclusions from the changes in price formation mechanisms over successive surveys and use these conclusions to develop the report structure and specific sections of the report. The structure of this report, therefore, is illustrated in the figure below.

Figure 1.1 Report Structure[1]



The sections of the report are as follows:

- Section 2 covers the wholesale gas price survey;
- Section 3 covers changing contracting practices;
- Section 4 covers trading hubs and liquidity;
- Section 5 covers coal v gas v renewables in power generation;
- Section 6 covers social pricing;
- Section 7 covers the globalisation of gas prices and gas price convergence; and
- Section 8 is the conclusions.

[1] The report was largely written by early 2015 and the price survey results reflect the period to 2014, before the recent declines in oil prices and spot prices in some regions.

2.1 Background

The 2014 IGU Wholesale Gas Price survey is the seventh to be undertaken in a series which began at the start of the 2006 to 2009 triennium culminating in the World Gas Conference in Buenos Aires. Prior to the 2014 survey, previous surveys were undertaken for the years 2005, 2007, 2009, 2010, 2012 and 2013. The seven surveys are now indicating the changing trends in wholesale price formation mechanisms over a period of rapid and significant change in the global gas market. In the 2014 survey responses were received for some 71 out of 109 countries, but these responses covered 94% of total world consumption.

The focus of the gas pricing sub-group, and the surveys, was very much on wholesale prices, which can cover a wide range. In fully liberalised traded markets, such as the USA and the UK, the wholesale price would typically be a hub price (e.g. Henry Hub or the NBP). In many other countries, where gas is imported, it could typically be a border price. The more difficult cases are countries where all gas consumed is supplied from domestic production, with no international trade (either imports or exports) and the concept of a wholesale price is not recognised. In such cases the wholesale price could be approximated by wellhead prices or city-gate prices. Generally the wholesale price is likely to be determined somewhere between the entry to the main high pressure transmission system and the exit points to local distribution companies or very large end users.

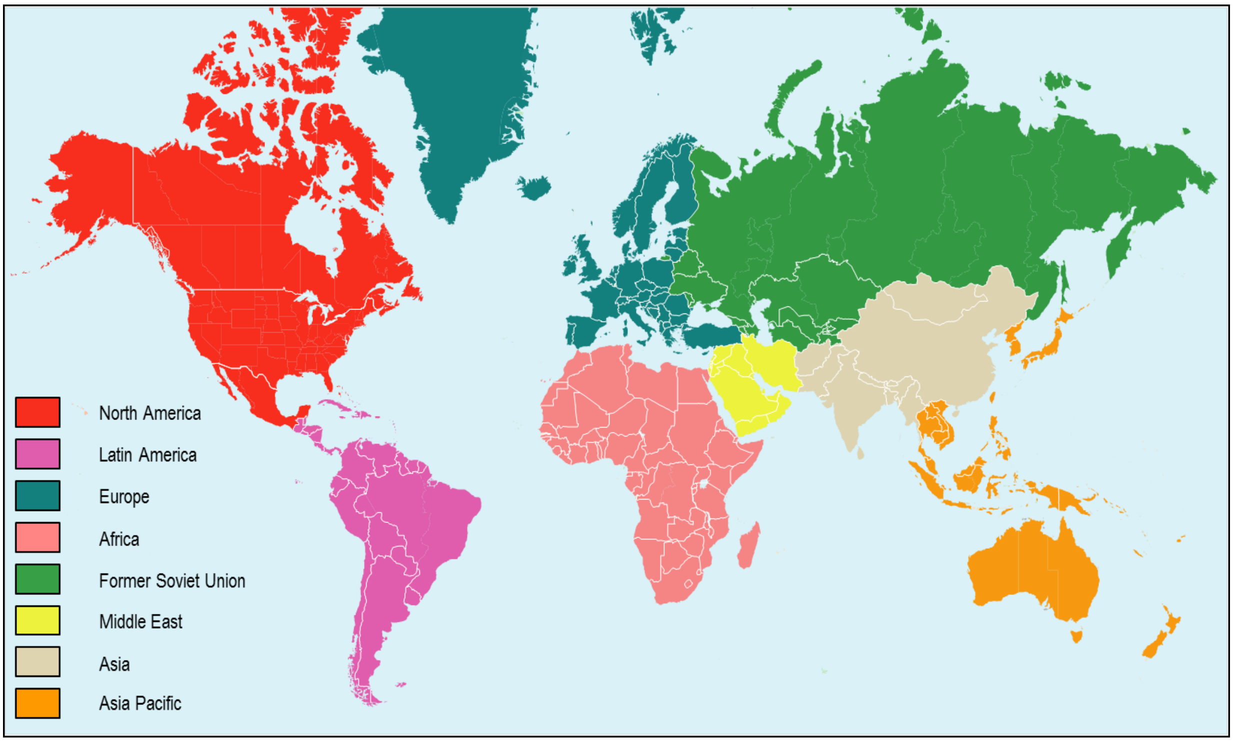
The initial data collection was done on a country basis. The data were then collated to a regional level using the standard IGU regions shown in the figure below. Most of the regions are defined along the usual geographic lines, although the IGU includes Mexico in North America, and divides Asia into a region including the Indian sub-continent[2] plus China[3], called Asia, and another region including the rest of Asia plus Australasia which is called Asia Pacific.

Data for each country were collected in a standard format. Individual country gas demand may be supplied from a combination of three sources – domestic production, pipeline imports and LNG imports (storage is ignored for the purpose of this analysis). For each of these three sources data was collected separately on what percentage of the wholesale price for that category is determined by each mechanism. In some countries, one single mechanism was found to cover all transactions and that mechanism, therefore, was allocated 100%. In many cases, however, several mechanisms were found to be operating, in which cases estimates were made of the percentages for each price mechanism. The only constraint is that the total for each source of gas – domestic production, pipeline imports and LNG imports – must add up to 100%.

Information was also collected on wholesale price levels. This covered the annual average price and the highest monthly average price and lowest monthly average price. All prices were converted to $ per MMBTU. A comments section was included to identify and acknowledge the source of the information and any other useful information.

[2] Afghanistan, Pakistan, India, Bangladesh, Nepal, Bhutan, Sri Lanka, Maldives, Myanmar
[3] Including Tibet, Mongolia, Hong Kong but excluding Taiwan

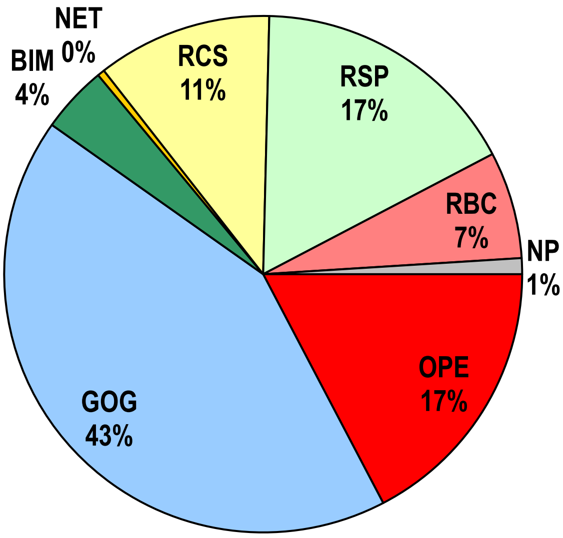
Figure 2.1 IGU Regions



2.2 2014 Survey Results

The 2014 survey showed again that gas on gas competition has the largest share in the world gas market. Out of total world consumption of some 3,520 bcm, gas on gas competition has a share of 43%, totalling around 1,495 bcm, dominated by North America at 936 bcm, followed by Europe at some 292 bcm and the Former Soviet Union at around 144 bcm (albeit a different type of GOG – see below). In all gas on gas competition can now be found in some 46 countries, in one form or another, and in all regions except Africa.

Figure 2.2 World Price Formation 2014



The different types of price formation mechanism are described below.

The share of oil price escalation or oil indexation stands at some 17%, and totals around 610 bcm and is predominantly Asia Pacific (230 bcm), Europe (153 bcm) and Asia (130 bcm). Oil price escalation is widespread being found in some 57 countries, including virtually every country in Europe, and in all regions except North America.

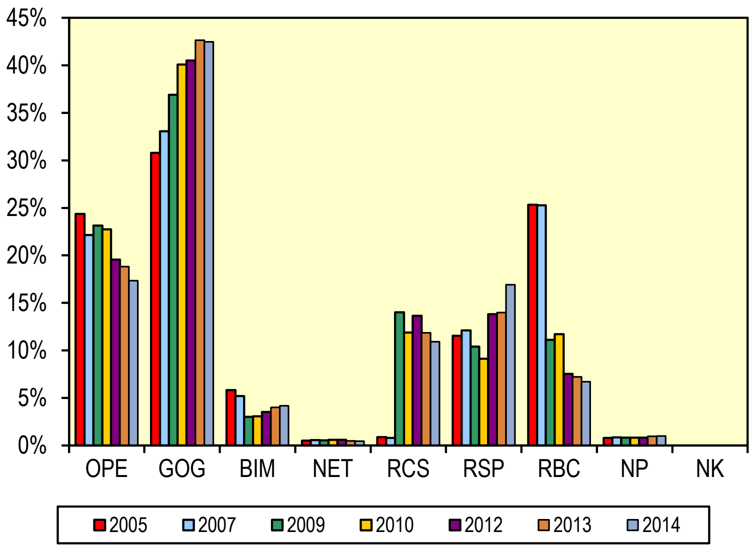
The three regulated categories – regulation cost of service, regulation social and political and regulation below cost – account in total for some 35%, or around 1,215 bcm; with regulation cost of service in 16 countries, mainly the Former Soviet Union (Russia) and Asia (China); regulation social and political in 26 countries, with the Middle East dominating – Iran, Saudi Arabia and the UAE; and regulation below cost in 13 countries, mainly the Former Soviet Union – Kazakhstan, Turkmenistan and Uzbekistan, Africa – Egypt and Algeria, and Latin America – Venezuela.

TYPES OF PRICE FORMATION MECHANISMS	
Oil Price Escalation (OPE)	The price is linked, usually through a base price and an escalation clause, to competing fuels, typically crude oil, gas oil and/or fuel oil. In some cases coal prices can be used as can electricity prices.
Gas-on-Gas Competition (GOG)	The price is determined by the interplay of supply and demand – gas-on-gas competition – and is traded over a variety of different periods (daily, monthly, annually or other periods). Trading takes place at physical hubs (e.g. Henry Hub) or notional hubs (e.g. NBP in the UK). There are likely to be developed futures markets (NYMEX or ICE). Not all gas is bought and sold on a short term fixed price basis and there will be longer term contracts but these will use gas price indices to determine the monthly price, for example, rather than competing fuel indices. Spot LNG is also included in this category, and also bilateral agreements in markets where there are multiple buyers and sellers.
Bilateral Monopoly (BIM)	The price is determined by bilateral discussions and agreements between a large seller and a large buyer, with the price being fixed for a period of time – typically this would be one year. There may be a written contract in place but often the arrangement is at the Government or state-owned company level. Typically there would be a single dominant buyer or seller on at least one side of the transaction, to distinguish this category from GOG, where there would be multiple buyers and sellers.
Netback from Final Product (NET)	The price received by the gas supplier is a function of the price received by the buyer for the final product the buyer produces. This may occur where the gas is used as a feedstock in chemical plants, such as ammonia or methanol, and is the major variable cost in producing the product.
Regulation: Cost of Service (RCS)	The price is determined, or approved, by a regulatory authority, or possibly a Ministry, but the level is set to cover the “cost of service”, including the recovery of investment and a reasonable rate of return.
Regulation: Social and Political (RSP)	The price is set, on an irregular basis, probably by a Ministry, on a political/social basis, in response to the need to cover increasing costs, or possibly as a revenue raising exercise.
Regulation: Below Cost (RBC)	The price is ***knowingly*** set below the average cost of producing and transporting the gas often as a form of state subsidy to the population.
No Price (NP)	The gas produced is either provided free to the population and industry, possibly as a feedstock for chemical and fertilizer plants, or in refinery processes and enhanced oil recovery. The gas produced maybe associated with oil and/or liquids and treated as a by-product.
Not Known (NK)	No data or evidence.

2.3 Changes in Price Formation Mechanisms 2005 to 2014

The share of gas on gas competition was virtually unchanged between the 2013 and 2014 surveys, reflecting a rise in the share in Europe, rising consumption in North America, offset by a decline in the share in Russia. The level of spot LNG imports was broadly unchanged. Oil price escalation declined again in 2014, largely in Europe, while the regulated categories increased share between 2013 and 2014 as a result of relatively faster consumption growth, rather than any change in price formation mechanisms

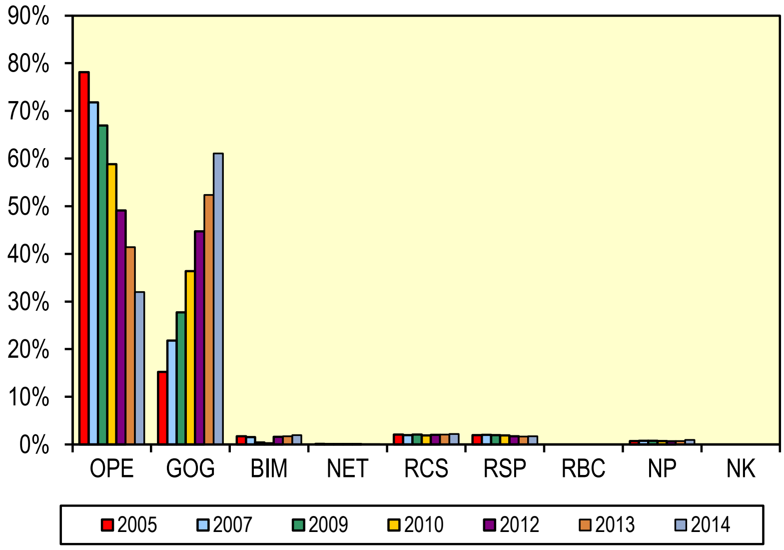
Figure 2.3 World Price Formation 2005 to 2014



Overall over the 2005 to 2014 period, the share of gas on gas competition has risen by 12 percentage points, while oil price escalation has declined by 7 percentage points. Bilateral monopoly has declined by 1.5 percentage points, while in the regulated categories regulation cost of service has risen by over 10 percentage points, regulation social and political has risen by almost 5 percentage points and regulation below cost has declined by 18 percentage points.

The major overall changes, in the 2005 to 2014 period, have been the continuous move away from formal oil price escalation to gas on gas competition in Europe, and also in Russia as the independents and Gazprom competed for sales to large eligible customers such as power plants. This is clearly a different kind of gas on gas competition from the liquid trading markets in North America and Europe but reflects the fact that there are multiple buyers and sellers, distinguishing it from the bilateral monopoly category, where there would be a single dominant buyer and/or seller.

Figure 2.4 Europe Price Formation 2005 to 2014



In Europe the move from formal oil price escalation to gas on gas competition, has seen the latter's share increasing from 15% in 2005 – when oil price escalation was 78% – to 61% in 2014 – when oil price escalation had declined to 32%. The changes have reflected a number of factors over the years; initially a decline in the volume of gas imported under the traditional oil indexed contracts, being replaced by imports of spot gas and increasing volumes traded at hubs, followed by the ending of contracts or the renegotiation of the terms to include a proportion of hub/spot price indexation in the pricing terms, or even a move to 100% hub price indexation, and in some cases, a reduction in the take-or-pay levels. The renegotiations have also seen the introduction of hybrid pricing formulas where oil indexation is partly maintained but within a price corridor set by hub prices.

The change in price formation mechanisms in Europe was not universal across the region. Northwest Europe[4] has seen the most dramatic change in price formation mechanisms, with a complete reversal from 72% oil price escalation and 28% gas on gas competition in 2005 to 12% oil price escalation and 88% gas on gas competition in 2014, as a result of increased hub trading and contract renegotiations, as noted above. Central Europe[5] has also, more recently, seen significant changes. Oil price escalation has declined from 85% in 2005 to 32% in 2014, while gas on gas competition has increased from almost zero in 2005 to over 50% in 2013, principally reflecting increased imports of spot gas, some re-exported from Germany, with some element of contract renegotiation. There has been much less change in other areas of Europe such as the Mediterranean[6], where oil price escalation has declined from 100% in 2005 to around 64% in 2014 and gas on gas competition rising from nothing to 27%, largely reflecting spot LNG imports with significant changes in pipeline imports into Italy in the last year, as a

[4] Belgium, Denmark, France, Germany, Ireland, Netherlands, UK
[5] Austria, Czech Republic, Hungary, Poland, Slovakia, Switzerland
[6] Greece, Italy, Portugal, Spain, Turkey

result of contract renegotiation. In Southeast Europe[7] there is only around 4% gas on gas competition.

While oil price escalation has lost share in Europe and, to a much lesser extent, in Asia Pacific, there have been gains in share in Asia with a rise from 35% to 45% between 2005 and 2014 as China began importing more LNG, pipeline gas from Turkmenistan together with domestic pricing reform in two Chinese provinces, plus India's pricing for LNG from Qatar changing.

Figure 2.5 Asia Price Formation 2005 to 2014

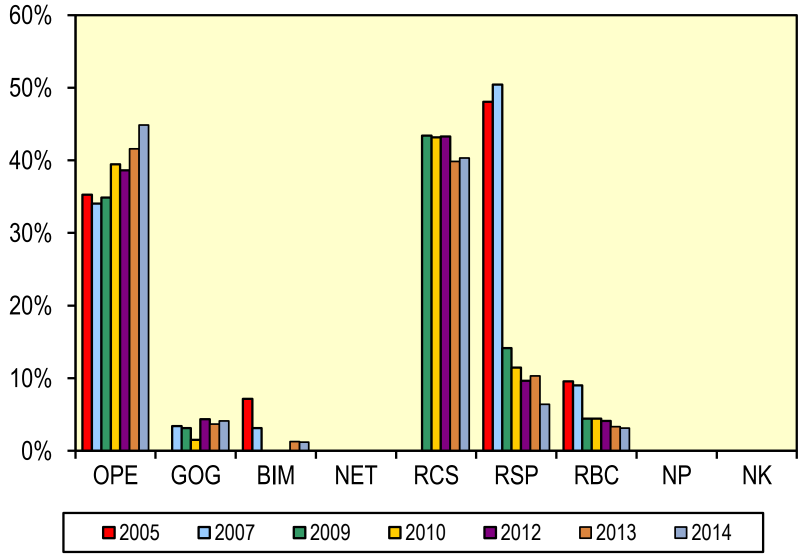
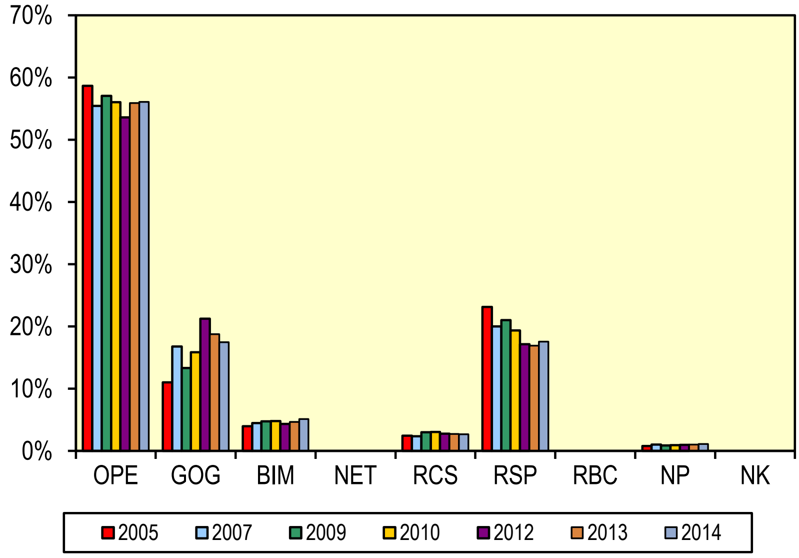


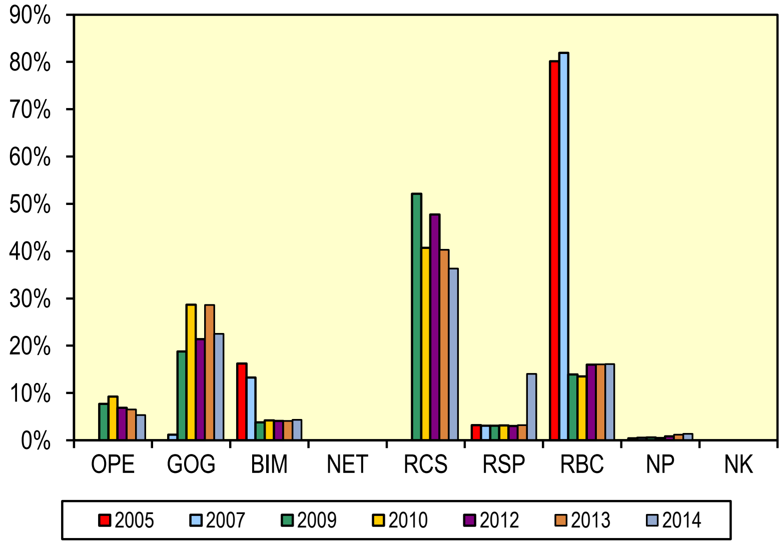
Figure 2.6 Asia Pacific Price Formation 2005 to 2014



[7] Bosnia, Bulgaria, Croatia, FYROM, Romania, Serbia, Slovenia

In the Former Soviet Union intra-regional trade, pricing had mostly switched from bilateral monopoly – effectively annual fixed price arrangements – to oil price escalation around 2009. Finally in the Middle East there have been very small amounts of oil price escalation since 2009 when pricing under the Turkmenistan to Iran contract changed.

Figure 2.7 Former Soviet Union Price Formation 2005 to 2014



Apart from the changes concerning gas on gas competition and oil price escalation in Europe and Asia Pacific, there have also been significant changes in the regulated pricing categories. The increases in regulated pricing and policy changes in Russia not only saw a switch towards gas on gas competition, but also a switch from the subsidised regulation below cost in 2009 to regulation cost of service as Gazprom finally stopped losing money on their domestic gas sales, although with the freeze in regulated prices in 2014, there was a partial switch back to regulation social and political.

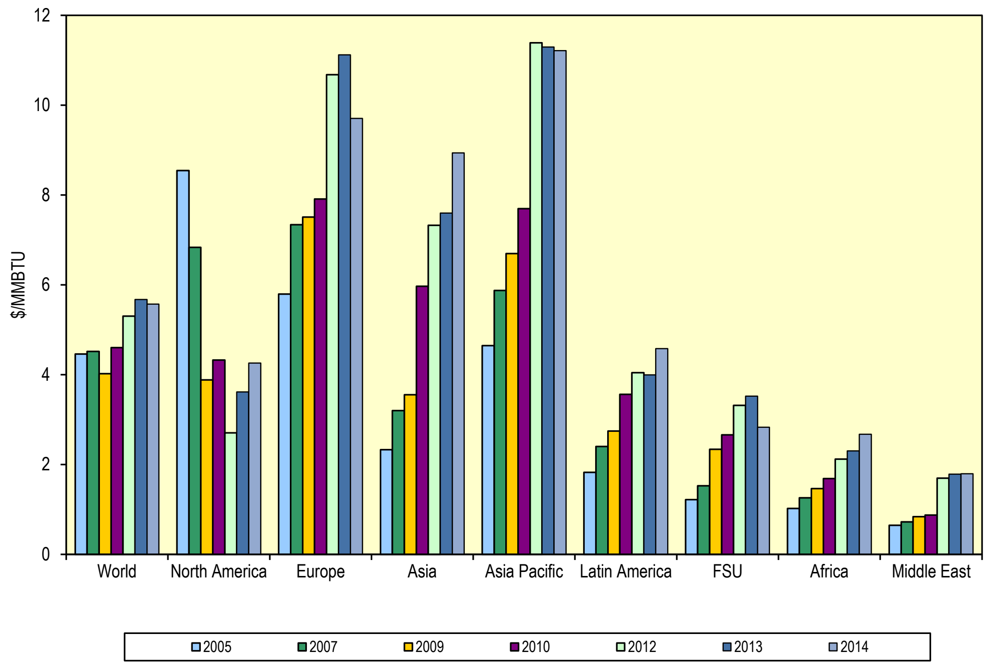
There were also significant changes in China as pricing reforms, again around the 2009 period, saw domestic production prices being more formally regulated and the price formation mechanism changing from regulation social and political to regulation cost of service. Similarly, and more recently, in Iran prices were raised significantly with the category changing from regulation below cost to regulation social and political in 2012, and a similar change in Nigeria in 2014, as prices increased.

2.4 Wholesale Price Levels

The rise in wholesale prices in Europe and Asia Pacific, over the last few years, and the decline in US prices, has been well documented and studied, but prices have also risen in Asia, largely due to increases in prices in China, particularly, and India, both as more gas was imported and regulated domestic prices were increased. The rise in Asia was especially significant in 2014.

Less well documented, however, has been the general rise in prices in other regions, such as Latin America, where average prices have more than doubled and in the Former Soviet Union, where average prices have almost tripled, largely due to the rise in regulated prices in Russia, although in 2014 prices in US$ terms declined again. In Africa, where over 70% of prices are effectively subsidised, there have also been price increases, with the largest consumer Egypt raising prices, although remaining with subsidies, and more recently Nigeria. Also in the Middle East prices have risen slowly, with a significant increase in 2012 over 2010, as a result of the regulatory changes in Iran, maintained in 2014.

Figure 2.8 Wholesale Price Levels 2005 to 2014 by Region

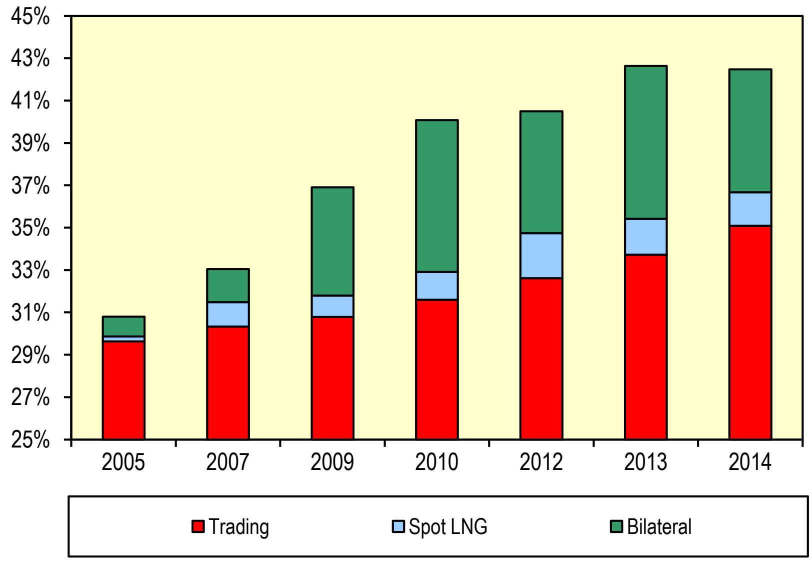


2.5 Analysis of Gas on Gas Competition

Gas on gas competition is not one homogenous category, and while the dominant mechanism can be considered as trading, as in the North American and European markets, there are also markets where there is no hub trading but there are multiple buyers and sellers entering into bilateral agreements – Australia, Russia and Argentina, plus spot LNG imports. Out of the increase in gas on gas competition of 12 percentage points between 2005 and 2014, 5 percentage points has come from the bilateral category, 5.5 percentage points from trading – entirely in the European market – and 1.5 percentage points from spot LNG. The changes in the bilateral category in Russia and Argentina are the principal examples of changes in pricing mechanisms away from "regulated[8]" pricing to "market[9]" pricing. Outside of these the changes have generally been *within* the larger groupings of "regulated" and "market" pricing.

Figure 2.9 Changes in GOG 2005 to 2014[10]

[8] Regulation Cost of Service; Regulation Social and Political; Regulation Below Cost; No Price
[9] Oil Price Escalation; Gas on Gas Competition; Bilateral Monopoly; Netback from Final Product
[10] In order to emphasise the changes the vertical axis starts at 25%



2.6 Wholesale Price Survey Conclusions

The trend in price formation mechanisms over the surveys between 2005 and 2014 shows the share of gas on gas competition rising by 12 percentage points (5.5% from trading hubs, 1.5% from spot LNG and 5% from bilateral negotiations), while oil price escalation has declined by 7 percentage points. Bilateral monopoly has declined by 1.5 percentage points, while in the regulated categories regulation cost of service has risen by 10 percentage points, regulation social and political has risen by over 4 percentage points and regulation below cost has declined by 18 percentage points.

In Europe there has been a broadly continuous move from oil price escalation to gas on gas competition since 2005, with the latter's share increasing from 15% in 2005 – when oil price escalation was 78% – to 61% in 2014 – when oil price escalation had declined to 32%.

While oil price escalation has lost share in Europe and, to a much lesser extent, in Asia Pacific, there have been gains in share in Asia with a rise from 35% to 45% between 2005 and 2014 as China began importing more LNG, pipeline gas from Turkmenistan and domestic pricing reform in two provinces, together with India's pricing for LNG from Qatar changing.

Apart from the changes concerning gas on gas competition and oil price escalation in Europe and Asia Pacific, there have also been significant changes in the regulated pricing categories. The increases in regulated pricing and policy changes in Russia not only saw a switch towards gas on gas competition, but also a switch from the subsidised regulation below cost in 2009 to regulation cost of service as Gazprom finally stopped losing money on their domestic gas sales, although with the freeze in regulated prices in 2014, there was a partial switch back to regulation social and political.

There were also significant changes in China as pricing reforms, again around the 2009 period, saw domestic production prices being more formally regulated and the price formation mechanism changing from regulation social and political to regulation cost of service.

Wholesale prices have increased consistently in all regions, except North America since 2005, with some respite in 2014 in Asia Pacific, Europe and the Former Soviet Union. The rise in wholesale prices in Europe and Asia Pacific, over the last few years, and the decline in US prices, has been well documented and studied, but prices have also risen in Asia, largely due to increases in prices in China, particularly, and India, both as more gas was imported and regulated domestic prices were increased.

Less well documented, however, has been the general rise in prices in other regions, such as Latin America, where average prices have more than doubled and in the Former Soviet Union, where average prices have almost tripled, largely due to the rise in regulated prices in Russia. In Africa, where over 70% of prices are effectively subsidised, there have also been price increases, with the largest consumer Egypt raising prices, although remaining with subsidies, and more recently Nigeria. Also in the Middle East prices have risen slowly, with a significant increase in 2012 over 2010, as a result of the regulatory changes in Iran, maintained in 2014.

In recent months, towards the end of 2014 and early 2015, gas prices have been declining in many regions, partly reflecting the supply – demand balance and partly the decline in oil prices and the subsequent impact on contract prices. In future surveys, therefore, we may be reporting different trends in prices.

3.1 Background

An important conclusion of the gas price survey (as discussed in the last chapter) is the change in contracting practices related to the transition from OPE to GOG price formation mechanisms. This chapter will discuss this transition in more detail. The change from OPE to GOG is most clear in Europe – Northwest and Central Europe especially – but also impacts other regions, such as Asia Pacific, Latin America and the FSU.

In this section, the pros and cons of the oil price escalation mechanism will be discussed (section 3.2). This provides background information to the changing contracting practices in Europe related to the gradual transition from the OPE to the GOG mechanism (section 3.3). In section 3.4 some developments related to changing contracting practices in other regions will be discussed.

3.2 Discussion Around Oil Price Escalation

There are advantages and disadvantages of each of the price formation mechanisms and there has been a lot of discussion around this. During the last years, especially, discussion surrounding oil price indexation has been intensive in the gas industry. There is no simple answer on the question whether oil price indexation is good or not. The answer depends on the interests of the parties involved. In the last triennium of the International Gas Union, arguments for and against oil price escalation were listed and discussed. These are included in table 1. For more detail, reference is made to the PGCB report of 2012 and the presentations on this subject at the World Gas Conference in 2012.

Table 3.1 Oil Price Escalation in Gas Contracts

Arguments For and Against

Arguments in favour of OPE	**Arguments against OPE**
• Competition between oil and gas (on the supply and demand side) • Resource value of hydrocarbons • Pricing via a third commodity • Oil prices have lower volatility • Higher confidence in the tradability of oil • Shareholders prefer oil price related risk • High level of acceptance • Easier to hedge oil prices due to more liquid oil derivatives (outside the US) • Easier to get financing with OPE LTCs • Investment decisions by producers more linked to oil prices than gas prices	• Oil and gas are separate markets • Oil and gas are no longer substitutes in many end user markets, especially power • Other alternatives to oil indexation are available • Political support for change • Political support for short term contracts • Better interconnection between regional gas markets • Reduced fear of market power as markets are more competitive

In the last 10 years, the arguments against OPE (and in favour of GOG) have gained ground in many areas of Europe, in part due to strong political support. The GOG pricing mechanism has increased market share in Europe from 15% in 2005 to 61% in 2014. The transition from OPE to GOG has led to contractual challenges in the existing long term contracts, further reinforcing the trend. This is discussed in the next paragraph.

Annex A to this report is a separate study on Oil Indexation as a Remedy for Market Failure in the Natural Gas Industry by Sergei Komlev from Gazprom.

3.3 Transition to GOG in Existing Contracts in Europe

Key elements of traditional long term contracts in Europe include the following:

- OPE pricing mechanism
- Long contract duration (often >20 years)
- Annual/ Daily Flexibility within limits
- Buyer: volume risk; Seller: price risk
- Delivery point: Border/Beach
- Security of supply/ Security of demand
- Price renegotiations based on market value/ competing fuels/ marketability (every 2/3 years)

With the transition to the GOG pricing mechanism, many of these elements are under discussion.

3.3.1 Commodity Pricing

In a few countries in Europe in 2014 the prices at liquid gas hubs were the only benchmark for wholesale contracts. In these countries (UK, Netherlands) market reflective contracts at the wholesale level were 100% on GOG). In many other European gas markets, the transition was still going on in 2014, gradually increasing the share of GOG pricing. Many long term contracts have changed from fully OPE to hybrid (partly OPE, partly GOG).

For the GOG pricing mechanism a common contract price is Month ahead and/or Day Ahead Index. However there are many alternative ways to include GOG pricing level in long term contracts. Some examples include:

- Price indexation (partly) based on longer term price indexes (e.g. Quarter Ahead, Season Ahead, Year Ahead, 2 year Ahead)
- Fixed pricing (partly) tuned at the gas hub forward price level
- Oil Price Indexation (partly) tuned at the gas hub forward price level (e.g. through P0 – base price – adjustments)
- Oil Price Indexation with a cap and floor around the gas hub prices
- Lump sum payments (partly) reflecting the difference between oil price and gas price levels

3.3.2 Contract Duration

Because of the presence of liquid markets, some parties do not feel the need for long term contracts. The liquid gas hubs provide a reliable outlet for producers or source for buyers. However, other parties still value the security of demand or supply provided by long term contracts. The existence of long term gas purchase and/or sales contracts, with oil indexation, can be a precondition for upstream and midstream project financing purposes. However, as trading hubs develop and start giving sound longer-term pricing signals, project financing practices may also change. A key factor here would be the availability and reliability of far-ahead price signals from hubs.

3.3.3 Flexibility

Many long term contracts provide flexibility, where the buyer has the possibility to change the volumes on an annual, monthly, daily and/or within day basis. Discussions on the value of contract flexibility in negotiations of traditional OPE priced long term contracts were mostly focused on the investment costs of gas storages, costs for additional transportation capacity, interest costs related to early/late payment, or published tariffs for gas storages in related markets. The customer paid an all-in price including commodity and flexibility services. Alternatively, in some cases flexibility was (partly) priced separately.

In liquid gas markets the value of flexibility is, at least to a certain extent, based on the possible value that this flexibility could generate when sold (or would cost when bought) on the liquid gas hub. The discussions around flexibility have changed to how to calculate this hub based value, the input parameters used for these calculations (e.g. volatility, market depth) and the extent to which the hub could be an alternative to the contractual flexibility.

In case parties cannot agree on the pricing of flexibility in the contracts, a solution could be to limit the flexibility in the contract, although formal contractual negotiation clauses might not cater for this option. As an example, there have been news articles about Statoil clawing back flexibility in their long term sales contracts in return for introducing more gas-on-gas indexation[11]. Flexibility for the buyer clearly has a price and to keep this with spot or hub indexation would require some sort of premium to be added to the base price.

3.3.4 Delivery Point

The delivery point of traditional long term contacts is at a border point or at the beach (e.g. at the location where pipelines cross borders or at LNG receiving terminals). In some negotiations, parties mutually agree not only to change the price to hub indexation, but also change the delivery point to gas hubs used as a base for the pricing of the contract (e.g. TTF price at TTF delivery point). Changing the delivery point to the hub changes the nature of long term contracts, where traditionally physical supply was an integral part. The discussion around this subject relates to opportunities for optimization of gas portfolios. If the delivery point is at a gas hub, the supplier could source the gas for delivery at the hub instead of physically delivering the gas. Delivery at the hub also facilitates onward selling for the buyer. At some border points there could be different possibilities for buyer and/or seller for sourcing or onward selling. When delivery is at a border point against hub prices, there can be discussion between buyer and seller about the allocation of the cost of transportation between the delivery point and relevant hubs. Due to contractual clauses, changing the delivery point generally is only possible if both parties agree. In the LNG market a lot of the contracting is changing from DES to FOB, with the new export contracts from the US leading the way.

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[11] E.g. in "Producers claw back flexibility" (Argus Gas Connections 13-2-13) or EU commends Statoil for contract changes" (Argus Gas Connections 13-3-13)

3.3.5 Security of Supply / Security of Demand

The argument is often put forward that efficient liquid hubs are the best way to warrant security of supply and security of demand. According to others the only guarantee for security of supply and demand are physical deliveries at physical delivery points backed by long term contracts. Where the truth lies in this discussion is different for every gas hub and is, amongst others, depending in the number of alternative physical sources (and destinations) for a certain hub (pipelines, LNG terminals, production sites, storages, customer base), and the relative size of these alternatives in relation to the total market served by this hub. The political environment could also have a determining influence. Clearly, there are more considerations to contract negotiations than only volume and prices, sometimes referred to as “the total value of the contract”.

3.3.6 Renegotiation Clauses

Some elements of negotiation clauses in long term contracts that could be under discussion when changing the pricing mechanism to hub indexation include:

- Interval of negotiation
- Trigger for negotiation
    - Market value principle – changes in market environment where oil products are no longer alternative fuels for gas
    - Marketability clauses/ Financial hardship
        - Relevant benchmark prices
        - Hardship

Depending on the delivery point, there could be discussion around the force majeure and maintenance clauses.

It can be argued that if pricing is based purely on hubs then there is no need for traditional type of price review at regular intervals, based on changes in market value, if the hubs are a true reflection of the “market”.

3.4 Other Developments Related to Changing Contracting Practices

In other parts of the world, the transition from OPE to GOG is less evident. The dynamics in contractual negotiations are quite different from Europe. There are, however, developments that support a gradual increase in GOG in some Asian countries as well. Some of these developments have been discussed in the IGU working group.

3.4.1 Price Transparency

Regular LNG spot price publications have been established for specific Asian countries, and also for larger regions, such as the Platts Japan Korea Marker Gas Price Assessment (JKM), the Argus Northeast Asian price assessment and the ICIS Heren East Asia Index. These publications could be used as reference for contractual pricing, although parties are still hesitant, mainly due to limited liquidity and questionable validity of these assessments if they do not represent actual transactions.

There are some efforts to create trading hubs and future markets in Asia. It will however take time before sufficient liquidity will have been developed for such markets. The Ministry of Energy, Trade and Industry in Japan have begun publishing monthly data on contracted and delivered spot prices based on actual cargoes delivered to Japan.

3.4.2 Further Globalization of Pricing

New gas export contracts from the USA based on Henry Hub pricing have been signed for Asian and European buyers[12]. There is discussion whether a gas price based on Henry Hub (+ premium) is better for Asian countries than a gas price based on oil prices. Some would say that one price is as (ir)relevant as the other. For some buyers, diversification in pricing is important, especially as it is hard to predict future price development.

Another example of globalisation of gas pricing is a new gas contract for export of LNG from Canada to Europe priced starting 2020 against European gas price indices[13]. Such development could further promote globalization which is discussed in more detail in section 7.

3.4.3 Buyers Going Upstream

One way for traditional buyers to ensure diversification and security of supply is to invest in gas liquefaction and production. Several Asian Buyers are taking upstream position in projects, for example in Australia, Africa and North America.[14] These upstream positions are also linked with offtaking rights from the liquefaction trains.

3.4.4 Unbundling in LNG Contracts

Traditionally LNG liquefaction terminals were developed by upstream parties directly as an outlet for their production for onward sale to customers. We now see more parties involved in development of liquefaction facilities without such close ties. This facilitates tolling agreements where buyers are purchasing the service of liquefaction instead of buying LNG as a commodity. Depending on the agreement, the purchase of natural gas to be liquefied could either be done by the facility operator or by the buyer. In tolling agreements, customers pay a fixed capacity charge. A variable fee is only charged when the liquefaction capacity is being used. For buyers of LNG and/or trading companies/ aggregators this provides flexibility in their supply portfolio and could reduce price risks.

3.5 Conclusions

The transition to GOG pricing away from OPE in Europe has led to changes in contracting practices. These include the introduction of hub prices into the price escalation clauses, possible reduction in contract duration, reduction in volume flexibility, changes to the delivery point from the border or beach to a hub and the potential removal of all or part of the renegotiation clauses.

The change in contracting practices in other regions is less developed. In the LNG markets in Asia, there is the lack of price discovery and transparency, although there have been efforts to improve this through the price reporting agencies and METI in Japan. With the advent of potential exports of LNG from the US, Henry Hub pricing is being introduced into future contracts and the LNG contracts are becoming unbundled into effective tolling agreements rather than traditional take of pay contracts. In addition, some LNG buyers are beginning to take upstream positions in projects.

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[12] E.g. http://business.financialpost.com/2013/03/27/asian-push-for-lower-prices-could-hurt-canadian-lng-projects/

[13] E.g. http://www.icis.com/heren/articles/2013/06/06/9675884/ e.on+seals+canadian+lng+on+European +natural+gas+hub.html

[14] E.g. http://www.gastechnews.com/lng/tokyo-gas-diversifying-to-adapt-to-a-new-energy-order/

4.1 Introduction

The gas-on-gas competition markets are largely characterised by active trading at physical and/or virtual hubs. This section considers how these hubs developed and what conditions are necessary for them to develop, using the US and UK as examples, a discussion of when a trading hub is liquid enough to provide reliable price discovery and transparency and, finally, assess the possible development of trading hubs in Asia, especially for LNG.

4.2 Development of Trading Hubs

The development of trading hubs in the US and the UK is a consequence of the move to competitive and liberalised gas markets and not a precursor or a causal factor in the development of competitive markets. The key factors in the drive to competitive markets can be categorised as follows:

- Market size and diversity
- Regulatory change
- Effective gas release
- Access to and availability of capacity
- Unbundling
- Harmonisation and Standardisation

4.2.1 USA

4.2.1.1 Market Size and Diversity

The sheer size of the US market, with consumption of over 20 tcf (560 bcm) during the period of competitive market development in the 1980s and 1990s was certainly a key factor. The diversity of the market as well with almost 7,000 producers, 1,400 gas utilities and upwards of 1,000 gas-fired power plants meant that the conditions of a multitude of buyers and sellers were easily met. When the gas marketers moved onto the scene, as deregulation took hold, this simply added to the diversity in the market. The market size, together with the available infrastructure, also meant that economies of scale could be realised by many players in the market and not just a handful. In 1996, for example, the top 20 gas marketers all traded more than 2 bcf per day which is more than enough to realize significant economies of scale.

4.2.1.2 Regulatory Change

The regulatory authorities in the US, certainly at the Federal level through FERC, responded to the problems faced by the natural gas industry of alternate surpluses and shortages, with major changes aimed at introducing more competition. However, it was hardly a gradual approach with Order 380 in 1984 and Order 436 in 1985 throwing the industry, especially the interstate pipelines, into an entirely new world all at once. The removal of the minimum bill requirements (Order 380) on the LDCs resulted in many pipelines facing potential bankruptcy and hence the necessity of the provisions in Orders 500 and 636 to allow pipelines to recover some of their restructuring costs in buying out the costly take-or-pay contracts. It has to be said, though, that FERC pursued the reform of the wholesale and producer markets, over which it had jurisdiction, with something approaching a "regulatory zeal".

4.2.1.3 Effective Gas Release

Prior to Order 380, almost all the sales of gas to LDCs were by interstate pipelines, who in turn bought gas from producers. High regulated gas prices and falling demand created a supply overhang which virtually overnight became available to the LDCs following Orders 380 and 436. The result was a sharp change in the structure of services provided by pipelines away from direct gas sales to transportation. In effect this was a gas release programme, with gas being released from the traditional high-priced sales contracts, and replaced with spot gas moved initially under interruptible transportation contracts.

4.2.1.4 Access to and Availability of Capacity

This effective gas release because of Orders 380 and 436 also opened up the availability of transportation to third parties. The capacity was no longer needed for sales by pipelines to LDCs and, following Order 436, pipelines could no longer discriminate against third parties requesting transportation in favour of their own merchant sales. For the pipelines to get at least some revenues, therefore, they had to sell transportation on an interruptible basis. Access to pipeline capacity, therefore, became relatively simple. This was also helped by the fact that gas demand had declined in the early 1980s, because of high gas prices, and there was spare capacity anyway on the interstate system.

4.2.1.5 Unbundling

The culmination of the restructuring of the wholesale and producer markets in the US in Order 636 involved the complete unbundling of transportation, supply and storage for the interstate pipelines. Gas sales had largely been unbundled anyway as a consequence of earlier FERC Orders, but Order 636 went as far as absolutely prohibiting sales by pipelines. Additionally, all the separate pipeline services such as transportation, gathering, processing and storage, which had previously been bundled together, now had to be unbundled and priced separately, giving equal non-discriminatory access to all parties including pipeline affiliates.

4.2.1.6 Harmonisation and Standardisation

With the increasing complexity of the deregulating and competitive gas industry it quickly became clear that harmonisation and standardisation of the rules and procedures of the pipelines were necessary. This ranged from mundane matters such as the timing of the gas day through to the exchange of information electronically. Immediately following Order 636, each pipeline had its own proprietary system for handling all the issues dealing with capacity booking, nominations, allocations, balancing etc. For the active gas marketer, therefore, this led to the requirement to have individual dedicated computers and lines for each and every pipeline . In September 1994, therefore, the Gas Industry Standards Board (GISB) was established as an "independent and voluntary North American organization to develop and promote the use of business practices and related electronic communications standards designed to promote more competitive, efficient and reliable gas service". In 2001 GISB took over responsibility for the electricity industry harmonisation of standards and became the North American Energy Standards Board (NAESB).

4.2.2 UK

4.2.2.1 Market Size and Diversity

While the UK was a significantly smaller market than the US, it was still the largest gas market in Europe, with annual consumption around 100 bcm in the 1990s. The key difference between the UK and the US was that prior to deregulation there was only one gas supplier and transporter – British Gas. On the production side, there were over 45 oil and gas producers in the North Sea, with the largest six producers accounting for 71% of gas production in the 1990s. The development of the competitive market was assisted by the willingness of large industrial customers to switch from British Gas to alternative suppliers and also the construction of new gas-fired power stations brought new buyers into the market. The UK also pushed ahead with retail competition and that brought in more players such as the regional electricity companies to compete with the supply arm of British Gas, now unbundled as Centrica. Centrica remained the dominant supplier of gas in the household sector but there was no evidence of any abuse of this dominant position.

4.2.2.2 Regulatory Change

As with the reform in the US, there was a very strong drive by Ofgas (and then Ofgem) for the introduction of competition in the market. Arguably the regulatory zeal was even greater in the UK than in the USA.

4.2.2.3 Effective Gas Release

As part of the early drive towards introducing competition, British Gas was forced first by the Monopolies and Mergers Commission (MMC) and then by the Office of Fair Trading (OFT) to embark on a gas release programme. The MMC enquiry in 1988 recommended that British Gas be required to contract for no more than 90 per cent of gas from new fields in the UK Continental Shelf. Producers were also given partial release from their obligations to supply British Gas, under 'swap' contracts involving fields already in production, with the volumes being repaid to British Gas at a later date once new fields came into production.

In 1991, the OFT concluded that the so called '90/10' rule had not been effective since much of the gas released had been sold into the newly emerging power generation market. The volume of gas acquired by non-British Gas buyers for use in the industrial and commercial market, other than power generation, represented only about 7% of the needs of that market.

As a result British Gas made undertakings to release gas from its contracted portfolio in order to allow the development of competition in advance of competitors having access to their own contracted gas. The release programme required British Gas to release stated minimum volumes of gas and such additional quantities as would be necessary to achieve the market share targets which had been set by the MMC. The minimum quantities were 500 million therms in each of the gas supply years 1992/3, 1993/4 and 1994/5 and 250 million therms in the supply year 1995/96. The undertakings included that British Gas would not be allowed to buy new gas for the express purpose of release.

The gas release programme was conducted as a series of 'auctions' in which the price was fixed and participants were invited to bid for volumes of gas. The price was fixed at the weighted average cost of gas (WACOG) which British Gas paid for gas from its suppliers, plus a small handling charge (0.25 p/them). This price was set to ensure that British Gas made neither a profit nor a loss from the release of gas.

The later MMC report in 1993 acknowledged that there had been a number of criticisms of the way in which the release gas programme had been implemented but concluded that it had achieved its purpose of pump priming competition. The other element in assisting gas release was the introduction of Accord into the UK market in 1994. At that time British Gas Exploration and Production had surplus uncontracted gas supplies and as part of the Joint Venture agreement between British Gas and NGC that set up Accord, these supplies were sold through Accord. Accord sold these volumes aggressively which led to a sharp decline in UK wholesale prices. Oversupply, therefore, can be of importance in the move to GOG.

4.2.2.4 Access to and Availability of Capacity

In the UK there was only one transmission and distribution company in contrast to the US with multiple pipelines and LDCs. In the US capacity was fairly easy to come by following Orders 380 and 436. British Gas, however, resisted third party access until they bowed to the inevitable and introduced the Network Code. One of the key elements of the Code was the entry-exit capacity booking and tariff system. In the early stages, any shipper that was willing to pay for entry capacity under a fixed tariff was allowed to book it and if capacity was overbooked then in the event of more gas being nominated than capacity available, there was a pro rata reduction. Exit capacity at the NTS offtakes was allocated based on the customer profile of each shipper in the LDZs.

4.2.2.5 Unbundling

The legal separation of British Gas transportation and supply businesses into separate subsidiaries was effected by the 1995 Gas Act and it went one stage further in 1997 when the supply business – Centrica – was demerged from the rest of the business. Also in 1997 the transportation and storage businesses were separated. Since then the storage business has been sold and resold to third parties. There has been clear and effective unbundling and separation in the UK.

4.2.2.6 Harmonisation and Standardisation

Since the UK had only one transmission and distribution company, all the standards were already applied to the whole country so harmonisation was not an issue. As the UK was set, in the late 1990s to become more heavily reliant on imported gas, issues of harmonisation with other European countries, particularly with respect to gas quality, became more relevant. These issues have been dealt with progressively through the European Commission and organisations such as GTE, GSE and GLE.

4.3 Liquidity at Trading Hubs

The conditions described above for the US and the UK led to the development of liquid trading hubs in these markets and, in the case of the US, multiple trading hubs. For participants to have confidence in the pricing of gas in spot markets and at hubs, the trading has to be liquid enough for price discovery to be reliable and pricing to be transparent. However, measuring and defining liquidity is much more difficult and there are a number of alternative approaches.

One popular measure it is so-called "churn" ratio which is the number of times a molecule of gas is traded before it is physically delivered. The table below, taken from the IEA's Medium Term Gas Market Report 2014, shows data for European hubs up to 2013.

Table 4.1 Traded and Physical Volumes on European Hubs (bcm)

	NBP	Zeebrugge	TTF	PSV	PEG's	GASPOOL	CEGH	NCG
Physical delivered volumes								
2007	66.8	7.9	7.4	6.8	5.1	2.2	6.9	4.1
2008	66.6	9.1	18.7	7.7	6.6	4.4	5.2	14.4
2009	74.6	12.9	25.0	11.0	8.1	12.9	7.6	25.0
2010	95.8	16.7	31.3	21.5	8.7	29.6	10.9	31.3
2011	79.6	14.3	35.6	23.0	12.8	29.6	11.6	35.5
2012	85.6	12.6	39.6	25.9	17.0	35.0	13.4	42.3
2013	85.4	16.8	42.5	25.3	16.3	40.0	9.7	47.4
Net traded/nominated volumes								
	NBP	**Zeebrugge**	**TTF**	**PSV**	**PEG's**	**GASPOOL**	**CEGH**	**NCG**
2007	902.6	40.2	27.6	11.5	11.1	4.8	17.7	6.6
2008	960.8	45.4	60.5	15.6	16.5	9.7	14.9	25.3
2009	1016.1	64.9	73.6	23.5	23.1	28.6	22.8	56.0
2010	1095.5	65.2	106.5	43.1	27.8	65.0	34.1	84.1
2011	1137.2	69.3	151.7	57.7	39.8	75.8	39.2	108.5
2012	1271.0	66.6	187.9	64.7	46.3	88.3	47.3	133.1
2013	1094.0	69.4	786.9*	65.8	55.5	112.6	35.4	152.7

Note*: As of January 2013, the Dutch TSO GTS began to report only total traded volumes, including OTC trades. As other TSOs still report the nominated volumes, an equal comparison between TTF and the other European hub could not be made with the data currently available.

Sources: TSOs and regulators.

The table highlights the issues with measuring churn rates with the TTF calculation now being done on a different basis to other hubs, based on data provided by TSOs and regulators. The traded or nominated volumes are only the volumes reported by TSOs whereas there are other OTC trades and bilateral trades made which are not necessarily included. The NBP with churn rates consistently in excess of 10 is generally considered to be a truly liquid hub and TTF with its revised definition of traded volumes also exhibits a high churn rate suggesting a truly liquid hub. The churn rates on other hubs, however, are significantly lower.

The physical delivered volumes may not include all the volumes actually consumed or flowing on the pipeline system in a particular country. As noted in the PGCB report to the 2012 WGC in Kuala Lumpur a measure of total gas flows in a particular country or area (consumption plus exports or production plus imports) may be a better measure of physical volumes. This would not make much difference to the UK NBP numbers since the physical delivered volumes are reasonably close to total system flows, but would do for some other European countries where the delivered volumes are much lower than the total system flows.

The nominated or traded volumes also may not include trading on the futures markets, which would significantly impact the NBP volumes in particular, with the ICE futures contracts being actively traded. Again the 2012 PGCB report noted that traded futures volumes in the ICE were some 16 times the total system flows in 2010 significantly increasing the churn ratio. The inclusion of financial derivatives is even more marked in the US market. A FERC report from 2009 suggested a physical churn ratio (trades divided by system flows) of only 2.3 in the US but if you add the futures and options trades on NYMEX, the churn rate on these alone was estimated at over 35!

Churn rates are not the only way of trying to measure trading liquidity. Other assessments include the ability to trade very large quantities of gas, over and above the standard lots or contracts, which would require a lot of depth to the market, and looking at the bid-ask spread, with a narrower bid-ask spread implying the market has more liquidity. ICIS-Heren calculate a “tradability” score for the various European hubs, measuring the narrowness of bid/offer spreads across the curve, how easy it is to trade at the posted prices and the number of market participants. This tradability index still concluded that NBP and TTF were the most liquid hubs.

It is clear, however, that at the liquid hubs in Europe and the US, there is full price discovery and transparency, whether this comes from the futures exchanges – NYMEX and ICE – or the OTC exchanges where prices are posted and multiple transactions executed or to the various price reporting services on both sides of the Atlantic where the price assessments are based in reported actual physical transactions. These prices can, therefore, be trusted as being the “market” price and give confidence that contracts can then link their prices to these respective indices.

Annex B to this report includes a presentation on the Potential for a Gas Hub in Southeast Europe and Turkey by Zeyno Elbasi of BP and Stelios Bikos of DEPA.

4.4 Development of Trading Hubs in Asia

The growth of hubs in North America and Europe and the growing flexibility in the LNG market combined with the prospect of US LNG exports bringing Henry Hub pricing to the Asian LNG importers, has led to much discussion of the possible development of trading hubs in Asia. The authorities in Japan have been looking at a possible LNG futures market and METI have started publishing a monthly series on prices of spot cargoes into Japan. In addition, the price reporting publications – Platts, Argus and ICIS – are all publishing assessments of spot prices in North East Asia.

4.4.1 IEA 2013 Report

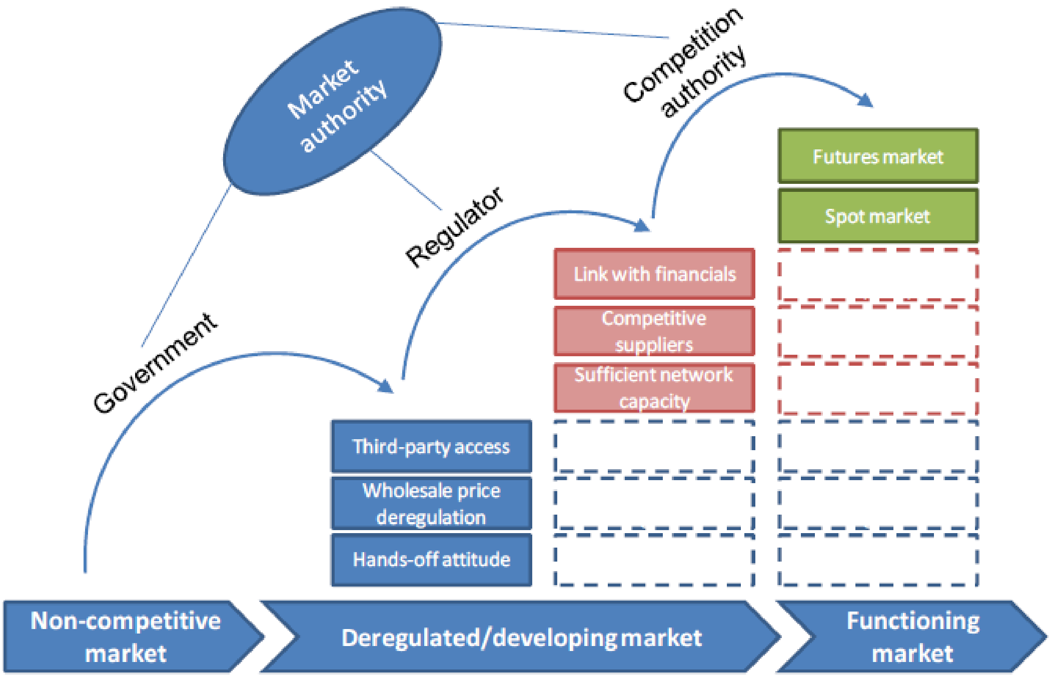
In 2013 the IEA published a report on Developing a Natural Gas Trading Hub in Asia[15]. The report included the figure below which neatly illustrated the steps to creating a competitive wholesale natural gas market.

The figure identifies the key role played by a market authority and the key steps are in line with those we have identified above in respect of how the markets developed in the US and the UK. Regulatory change is consistent with the key role of the market authority, unbundling, market diversity and effective gas release fit with wholesale price deregulation and competitive suppliers, and access to and availability of capacity are the same as third party access and sufficient network capacity.

The IEA report concluded that the prospects for a functioning wholesale gas market in the region were limited, with the respective government’s emphasis on security of supply leading to government interference along the supply chain in market such as Japan and Korea while China remains heavily regulated and dominated by the 3 big wholesalers. Singapore was identified as the best-suited candidate for a regional natural gas trading hub because of the role of the government but the size of the market is a limiting factor on the number of potential players, from the perspective of developing a trading hub.

[15] IEA (2013), *Developing a Natural Gas Trading Hub in Asia,* Partner Country Series, OECD/IEA, Paris

Figure 4.1 Creating a Competitive Wholesale Natural Gas Market



4.4.2 Obstacles to the Development of a Trading Hub in Asia

Many of the identified obstacles to the development of a trading hub in Asia can be overcome if there is a willingness to accept and implement regulatory change. However, the countries and the region have fundamental differences from both the US and UK / European markets:

- Both the US and the UK are large integrated markets and crucially had significant quantities of domestic production from multiple suppliers. In addition they were exposed to international influences through the ability to both import and export gas, especially via pipeline. Only China comes close to replicating these market characteristics.
- The spread of competition and trading from the UK to the rest of the EU was built on increasing interconnectivity and crucially the common rules and objectives as outlined in the EU directives which were then transposed into the laws of each country. The Asian market lacks any overarching governmental authority to push through reforms which would be required if a larger transnational single market was to be developed.
- The Asian market, outside China, is fundamentally a LNG market. The US and UK trading markets were built on pipeline gas where trades can be done in homogenous relatively small quantities on a daily or monthly basis. Trading LNG is a very different proposition given the volume of gas involved and the financial commitments required. Only the relatively large players can actively trade LNG.

It could be that these obstacles will remain insurmountable but that does not mean that trading will not develop in the region. It is difficult to see there being a "Henry Hub" in Asia, but the establishment of pricing reference points, price discovery and transparency are achievable, maybe with some regulatory push, enabling increasing confidence in the ability to price LNG cargoes against a local index, as opposed to a non-local index such as Henry Hub. Increasing numbers of traders and companies are establishing LNG operations in Singapore which with its openness and trading culture is a natural home for trades to be concluded for delivery all over the region.

Annex C to this report included a report on Challenges and Opportunities in Asia's Future LNG Pricing by Hiroshi Hashimoto of IEEJ.

These issues will be discussed further in the section on the globalisation of gas prices.

4.5 Conclusions

The development of trading hubs has been a consequence of changes in gas markets and regulation. This is exemplified by the experience in the USA and UK, spreading to other neighbouring countries. The governmental and regulatory drive to liberalise gas markets has been a key factor. Reforms have included regulated third party access to infrastructure, effective unbundling of supply from transportation and release of gas supplies from long term contractual arrangements. However, the market conditions have also been important. A large and diverse gas market, in terms of the numbers of producers, suppliers and buyers, helps foster competition, as does the emergence of surplus gas supply and infrastructure.

As trading hubs develop, the question is asked whether they are liquid enough to provide confidence in pricing transparency and discovery at the hubs and the ability to buy and sell gas. A number of measures can be made of liquidity including churn rates, the narrowness of bid-offer spreads, market depth and "tradability" indices. There is no single agreed measure of adequate liquidity in markets and while it is clear that the US market and the UK and Dutch markets in Europe seem to exhibit more than adequate liquidity on any measure, it is less clear when the threshold between too little and adequate liquidity is passed.

The development of a trading hub in Asia and the LNG market in particular is some way behind the North American and European markets. The regulatory and gas market conditions do not yet exist in Asian countries as they did in North America and Europe and the dominance of LNG in international trade in the Asian region, with the large volume of gas in a single trade, is a further obstacle to overcome. However, there appears to be progress being made towards the establishment of pricing reference points, maybe with increasing price discovery and transparency and Singapore is where LNG players are increasingly locating their businesses, making it an important trading centre for Asia, even if it does not have the conditions to become a physical trading hub.

5.1 Background

Gas competes against other fuels in many end-user markets but it is especially true in the power generation market, which is where the largest proportion of gas is consumed. The competition in the power sector can be divided into long run and the short run. The long term competition concerns the decision to install generating equipment and what "fuel" is used. It can be a commercial or government policy decision to install a particular type of power generation e.g. gas against coal or renewables against fossil fuels.

Once the equipment is installed then the competition turns to the short run which concerns the dispatching of power generators. In respect of gas against coal this can depend on relative prices of gas to coal, including the impact of any carbon prices or taxes and the relative efficiencies of the plants. For gas and renewables, the issue is not price but the intermittency of renewables which may require gas to be the load balancing generation source.

This section considers broad long term trends in generation by fuel and then considers the short term issues, focussing on price in the gas v coal market and intermittency in the gas v renewables market, using Iberia as a case study.

5.2 Gas v Coal in Power Generation

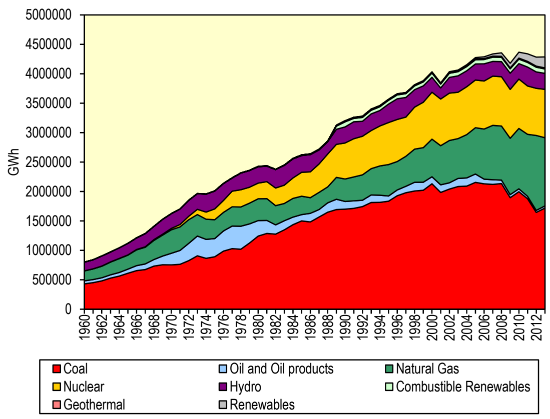
This section discusses the "competition" between gas and coal in the power generation market and uses 5 major countries – USA, Germany, Japan, China and the UK – as examples. A more exhaustive study would include more countries but very broad conclusions can be drawn from these 5. At the end of this section data on Spain is included as an introduction to the next section which looks at the impact of renewables on gas.

5.2.1 Overall Trends in Power Generation

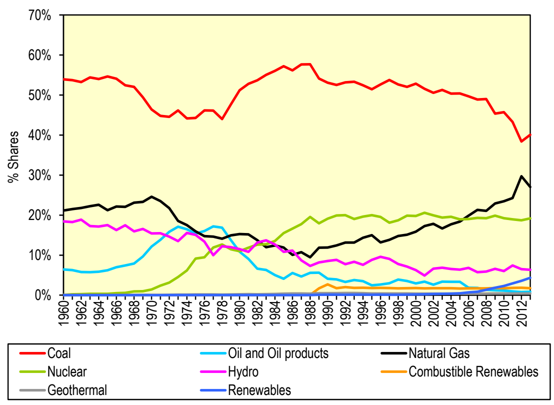
Using IEA data the figures below show the long term trends in electricity generated and the respective shares by fuel used to generate.

Figure 5.1 USA: Generation (GWh) and Shares (%)

GWh



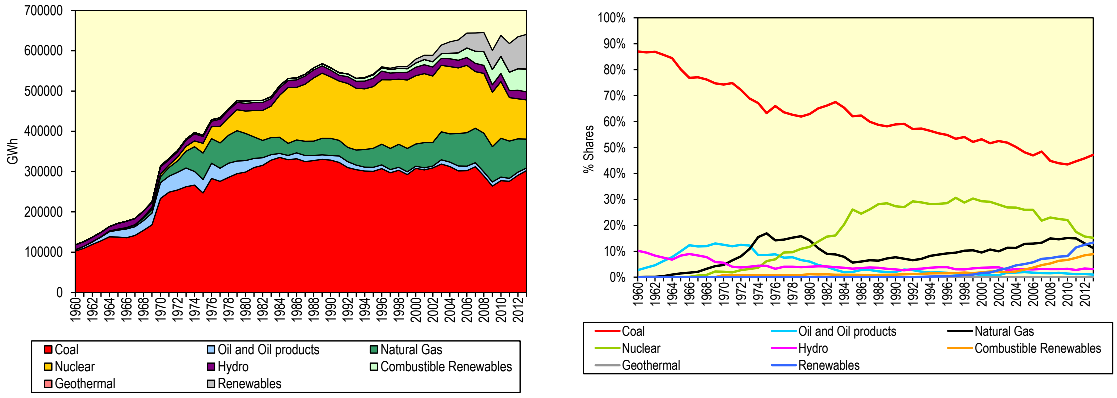
% Shares



Gas has always played a significant part in power generation in the USA, but coal has dominated the market since 1960. Hydro has had a consistent level of generation and nuclear has grown since the early 1970s and then stabilised. Generally the USA has a diversified range of fuels used in power generation, although the share of oil is now down to less than 1%, while the share of renewables (solar and wind) is now at just under 4% having been less than 1% in 2007. This has resulted in a rise in the share of non-fossil fuel generation from 28% in 2007 to 32% in 2013. Prior to 2007 the shares had not changed materially since the introduction of nuclear in the late 1970s.

Figure 5.2 Germany: Generation (GWh) and Shares (%)

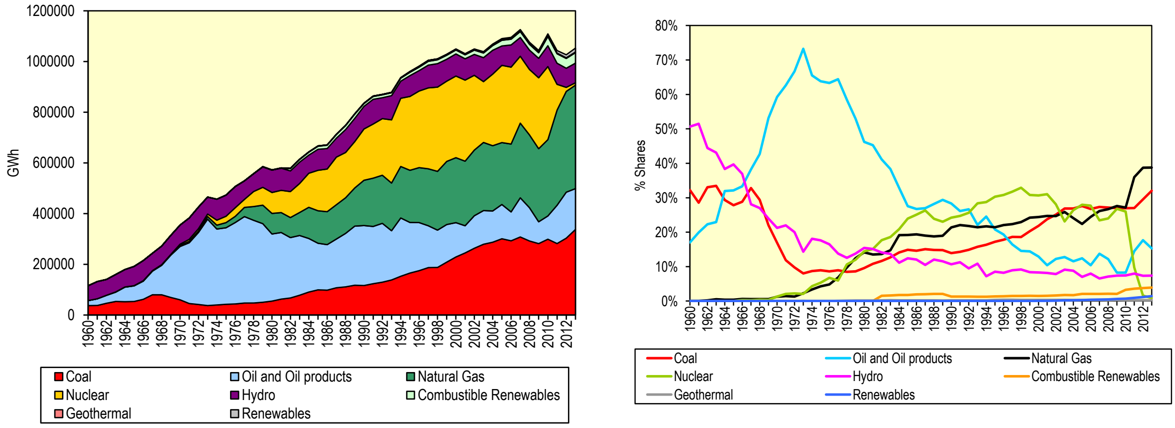
GWh *% Shares*



Coal remains the dominant fuel in German power generation, its share only declining over time as the demand for electricity grew. The share of gas has generally grown over time, reaching almost 15% in 2010 before falling back to 11% in 2013 as coal regained share – this is discussed further below. The share of nuclear has dropped sharply from 30% in 1999 to 15% in 2013, reflecting the closures of plants. The share of renewables increased from 1% in 1999 to over 13% in 2013 – a share which was slightly larger than the share for gas. However, it is only since 2007 that the share of non-fossil fuel generation has risen from just under 37% to almost 41% in 2013. This also reflects the increased share of combustible renewables (biomass) to some 9% in 2013 from less than 2% in 1999. Similar to the USA, oil plays virtually no part in the generation of electricity in Germany.

Figure 5.3 Japan: Generation (GWh) and Shares (%)

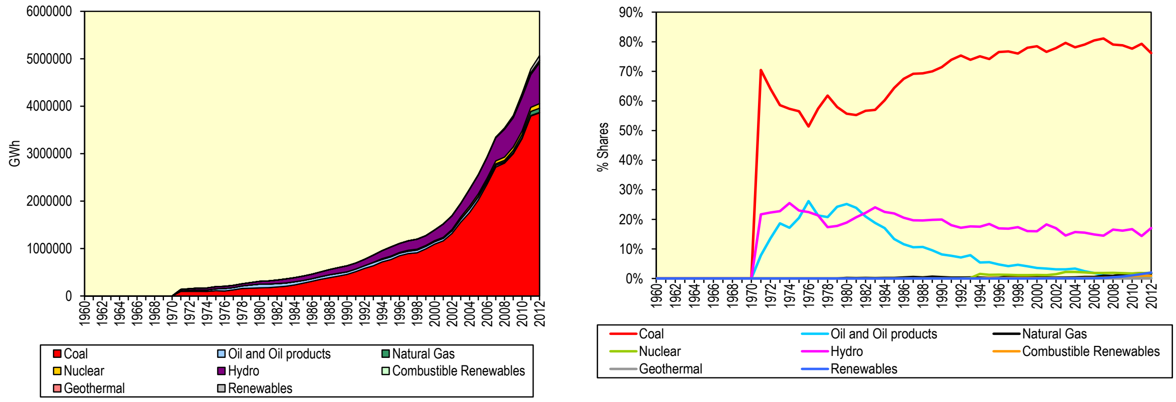
GWh *% Shares*



For many years in Japan, oil was the dominant fuel used for generation, but was gradually displaced by coal, gas and nuclear. By 2010, just before the Fukushima disaster, oil's share had dropped to some 8.5% with coal, gas and nuclear with broadly similar shares around 26 to 27%. The impact of Fukushima in closing the nuclear plants can be seen with, nuclear generation falling to 1% in 2013, with gas rising to 39% and oil back to 15%. There were small rises in shares for other fuels, not because they generated more but because demand declined. Unlike the USA and Germany, oil still plays an important role in Japan's electricity generation. Despite the closure of the nuclear plants, coal generation did not increase as it is thought they were already running as a base load and close to capacity. Combustible renewables (biomass) has also shown some increase in share but renewables (solar and wind) share is only 1.5%.

Figure 5.4 China: Generation (GWh) and Shares (%)

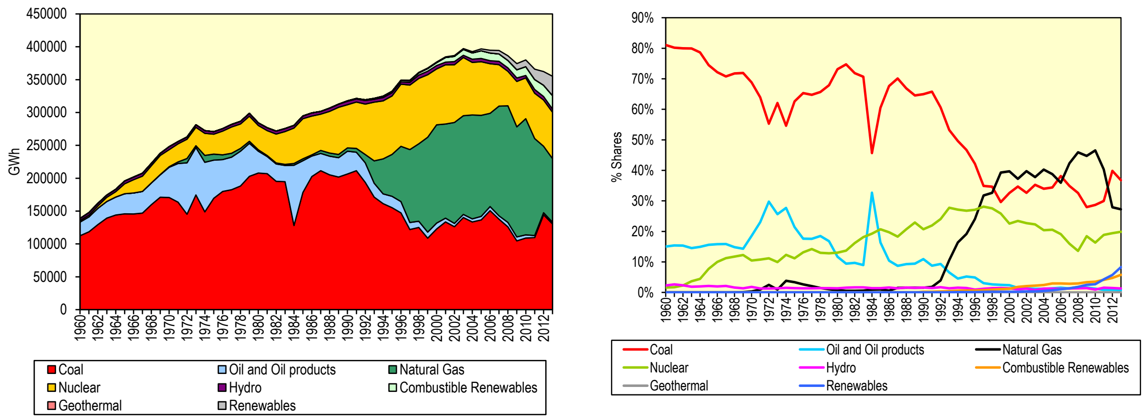
GWh *% Shares*



Coal dominates the Chinese market for electricity generation, with a share that has been consistent between 75% and 80% since the mid-1990s. Hydro is the other significant source, while oil has almost disappeared as a generating source. The share of gas has risen from 0.5% in 2006 to 1.7% in 2012, a similar share as nuclear. Renewables share was 2% in 2012 from almost zero in 2000.

Figure 5.5 UK: Generation (GWh) and Shares (%)

GWh *% Shares*



Coal was the dominant fuel for power generation in the UK until the "dash for gas" in the 1980s. Gas not only replaced coal in the generation mix but also led to the decline in oil-fired generation, which has now virtually disappeared from the generation mix, as in the USA and Germany. Nuclear's share has declined since 2000 with the closure of some plants and is now down to just under 20%. Since 2000 the respective shares of gas and coal have mirrored each other, with particularly dramatic changes in the last 7 years. In 2006 the share of coal was 38% and gas at 36%. From then until 2010 coal declined to 29%, while gas rose to 46.5%, but by 2013 coal had risen back to 37% while gas was back to 27%. These trends are discussed further below. The share of renewables has increased from less than 1% in 2005 to over 8% in 2013, with combustible renewables (biomass) reaching almost 6% in 2013 from just over 1% in 2000. The share of non-fossil fuel generation, at over 35% in 2013, is at its highest level ever, and is up from less than 20% in 2008, assisted by the rise in nuclear, as well as other renewables.

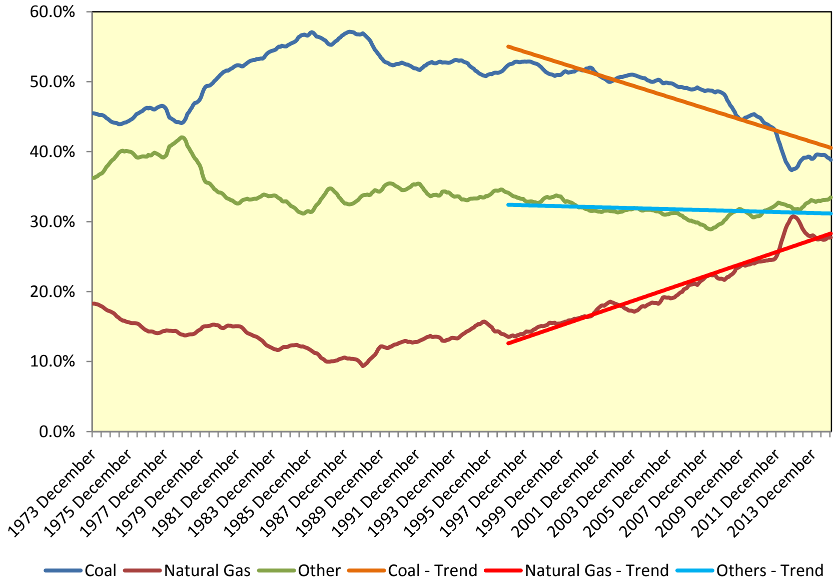
5.2.2 Impact of Relative Coal / Gas Prices

The long term trends presented above on generation by fuel type are determined largely by the installed generation capacity. This will often be driven by government policy in some countries, including subsidies to renewables, as well as the long run economics of power generation by different types of fuel. However, the year-to-year fluctuations in fuel shares are more likely the consequence of short term impacts of plant shutdowns for maintenance – especially in nuclear – intermittency issues with hydro and renewables and response to short term relative price changes, especially between gas and coal. It is this latter issue that will be addressed in this sub-section, and it will be seen that some markets are more price responsive than others

The USA is one market where the impact of relative price changes, on short term market changes, between gas and coal can be seen. The figure below uses monthly data from the EIA, on a 12 month moving total basis to eliminate seasonality and shows the percentage market shares for coal, natural gas and other – which aggregates all the other fuels together. Also plotted on is a trendline in the market shares calculated from 1997 onwards.

Figure 5.6 USA: Power Generation Market Shares by Fuel

Source: EIA and Nexant analysis



Comparing the actual shares with the estimated trend shows that between 2005 and around 2008 the coal share was above trend and the gas share below trend but that this has reversed dramatically in the last year or two and especially in 2012.

These movements are highlighted in Figure 5.7 below which plots the gas use in power generation relative to the calculated trend – the actual volume of gas used in million standard cubic metres less the quantity that would have been consumed if the trend market share had been maintained. The trend, which corresponds to axis on the right, shows the ratio of the Central Appalachian Coal Price to Henry Hub Gas Price, with the coal price being adjusted for relative efficiency.

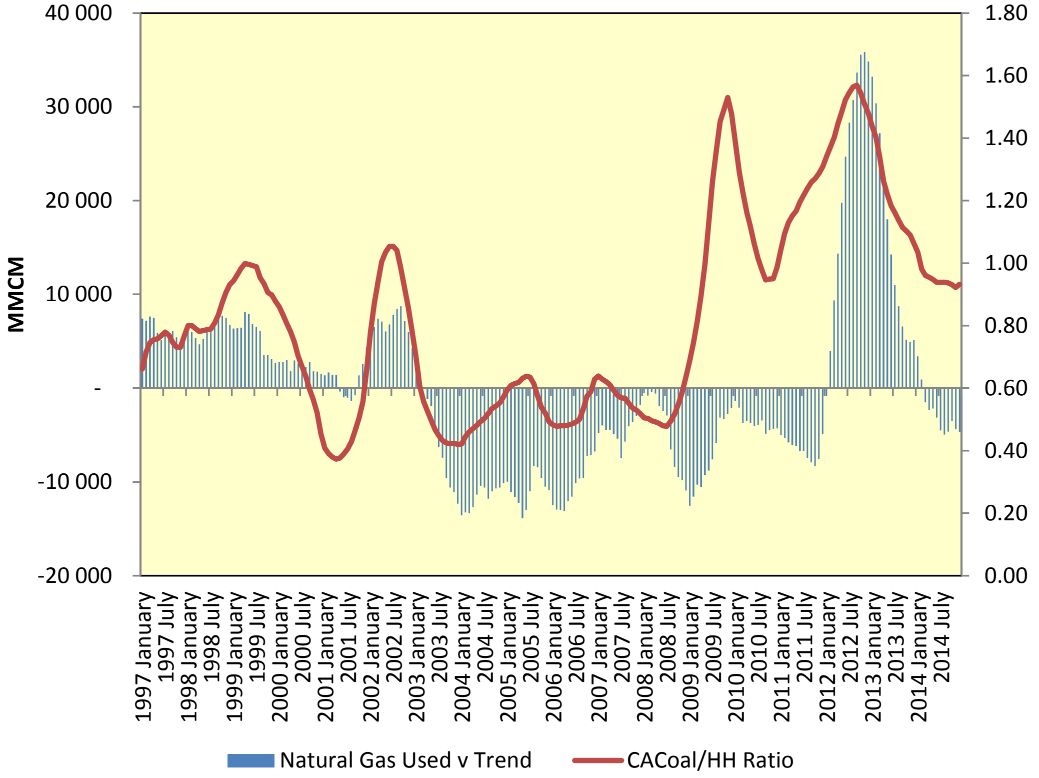
The powerful effect of relative coal and gas prices on the amount of gas consumed in power stations is apparent from the figure. As coal becomes more expensive relative to gas – the ratio rises – then gas consumption increases relative to the trend, and vice versa. The relatively high gas prices from 2003 through 2008 saw gas consumed below trend and the sharp fall in gas prices since mid-2011, even though coal prices were also weakening albeit more slowly, coincided with a sharp surge in gas use in power. This was reversed in 2013 as gas prices rose relative to coal.

This analysis considers data at the level of the whole of the USA which averages information from all the states. The ability to switch between coal and gas fired power differs greatly from state to state. A detailed analysis of this is beyond the scope of this report but the IEA have recently published a report which addresses this in more detail.[16]

[16] IEA (2013). Gas to Coal Competition in the US Power Sector, IEA Insights Series 2013.

Figure 5.7 USA: Natural Gas / Coal Use and Relative Prices

Source: EIA and Nexant analysis



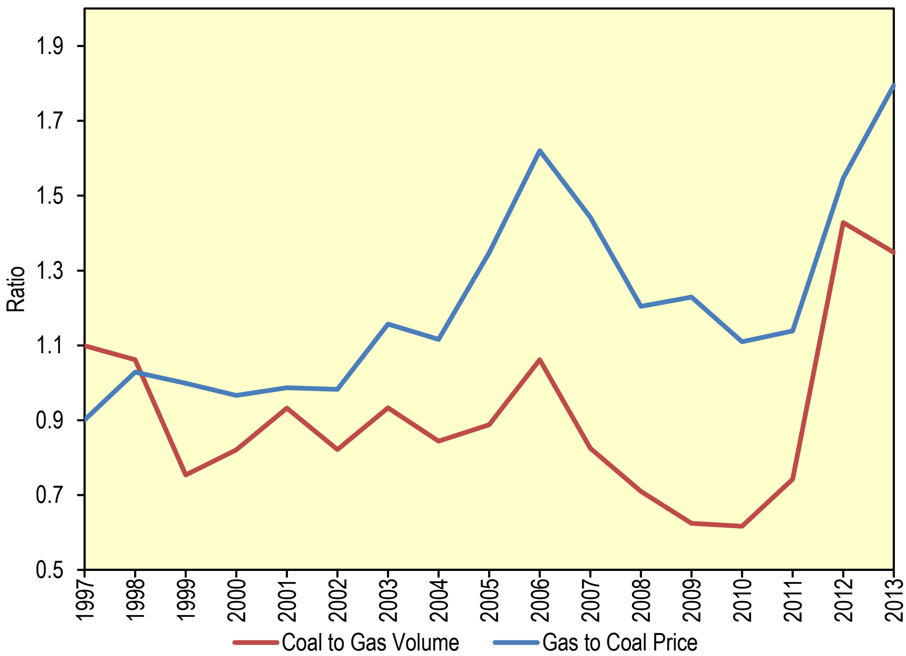
On the US power market, the *Energy Information Administration* derived short run elasticities by power district from 2005 to 2010. This suggested that, in the FRCC area, a 1% increase in the relative price of natural gas led to a relative increase of 0.43% of coal consumption compared to gas on the switchable power market, while a 1% increase in the price of coal in the RFC area led to a 0.48% increase in gas consumption compared to coal.

A similar effect can be seen in the UK market as shown in Figure 5.8 below.

The red line shows the ratio of electricity generation by coal to that by gas while the blue line shows the ratio of gas price to the efficiency adjusted coal price – both delivered prices to power plants. As the gas price rises relative to the coal price, there is more coal fired generation and vice versa.

Figure 5.8 UK: Natural Gas / Coal Use and Relative Prices

Source: IEA and DECC

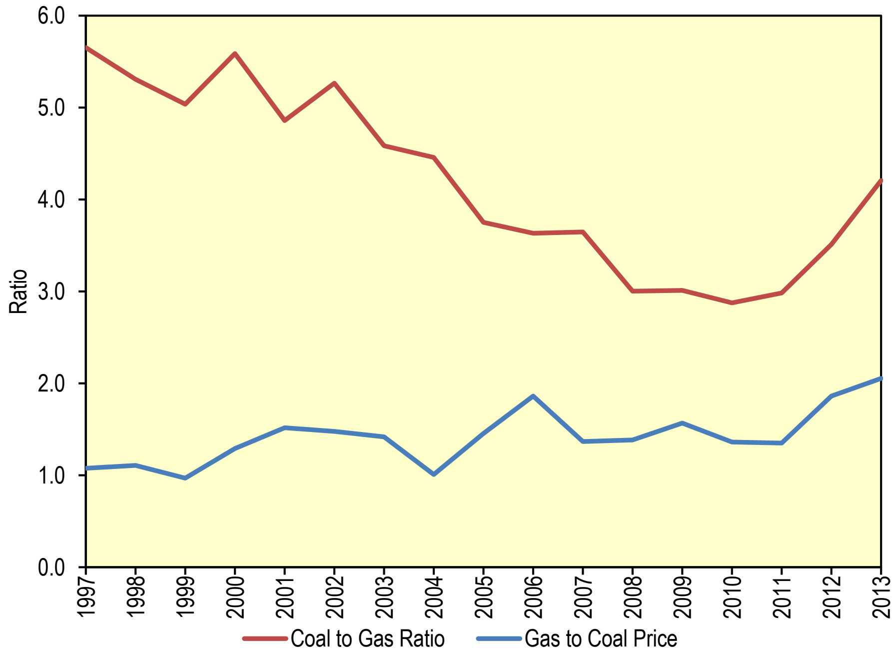


The responsiveness of changes in the gas to coal mix is somewhat less obvious in other countries. Figure 5.9 below shows the same parameters for Germany.

Post 2005 some relationship is discernible but not as strong as in the UK or USA. Prior to that gas was increasing market share as more gas-fired power capacity came onstream.

Figure 5.9 Germany: Natural Gas / Coal Use and Relative Prices

Source: IEA

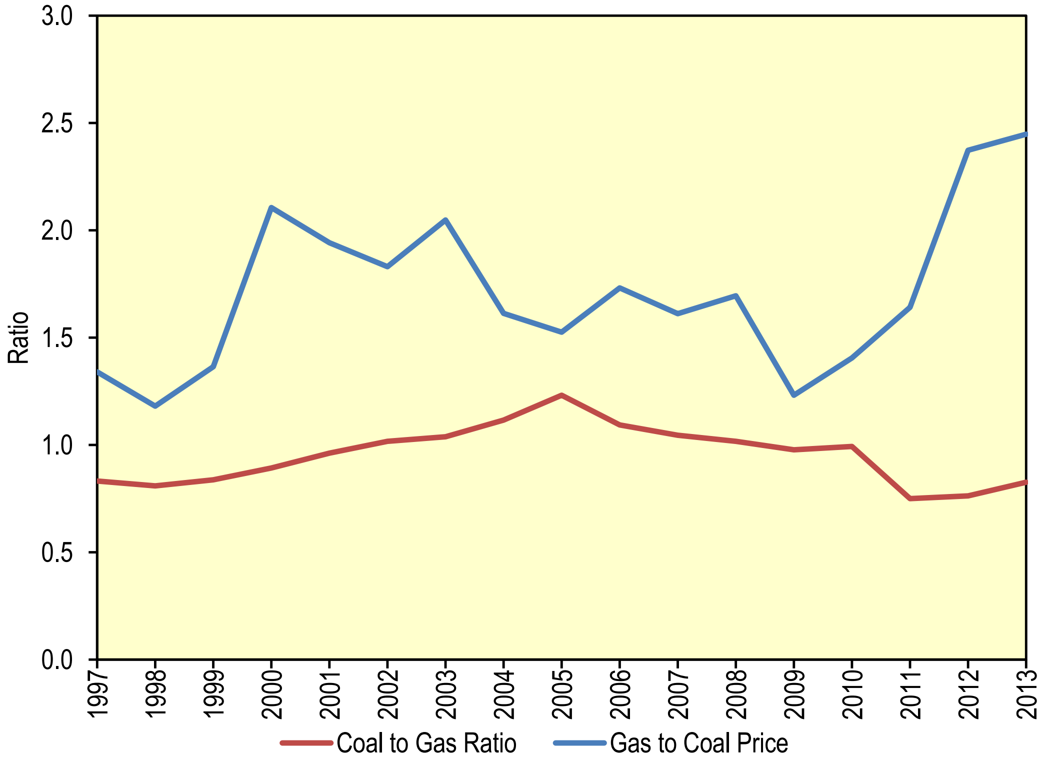


The situation in Japan is shown in Figure 5.10 below. The changes in the coal to gas ratio would appear to be independent of the gas to coal price. As noted above, the use of coal in power generation has not even risen as a result of Fukushima, suggesting that there is a constraint on coal generation capacity. In fact, there is probably more competition between gas and oil in the generation market in Japan than between gas and coal.

In China gas is just beginning to increase its share but from almost nothing and this is not related to price but to policy and environmental conditions.

Figure 5.10 Japan: Natural Gas / Coal Use and Relative Prices

Source: IEA



5.2.3 CO2 Prices and Competition Between Coal and Gas

The relative price analysis in the previous sub-section did not include the impact of carbon prices or taxes. In terms of actual carbon prices or taxes there is little or no actual evidence of the impact since carbon prices or taxes are either very low or non-existent. Most studies of the impact are based on theoretical calculations rather than actual empirical evidence.

Both gas and coal contain carbon, but coal emits some 43% more CO2 per unit of heating value so any carbon price or tax will impact coal relatively more. A rough estimate is that for every $1 per tonne of carbon price / tax, this increases the price of coal relative to gas by some 4 US cents per MMBtu[17].

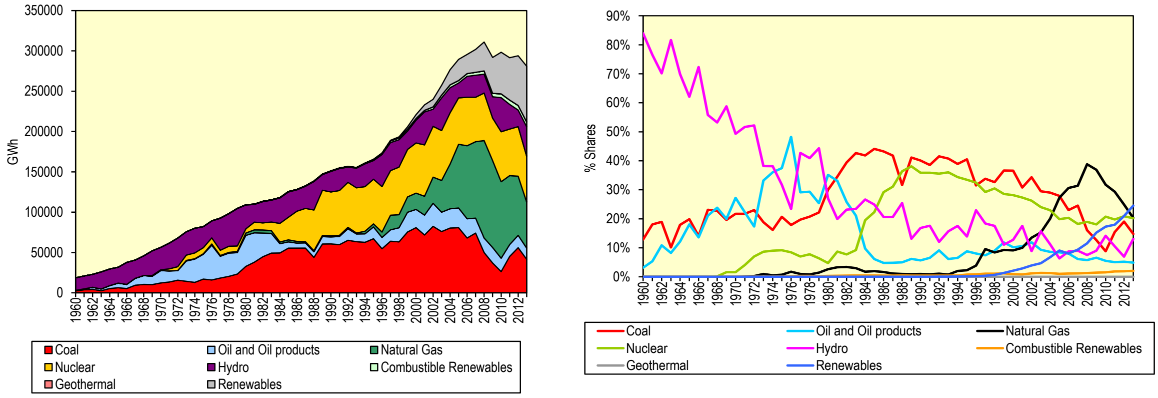
5.2.4 Spain

As an introduction to the next section which looks at gas and renewables in the power sector, the IEA data on Spain is discussed.

[17] Nexant calculation based on coal emitting 210lb of CO2 per mmbtu and gas 117 (US EPA assessement)

Figure 5.11 Spain: Generation (GWh) and Shares (%)

GWh *% Shares*



The figure shows the rapid rise in the share of gas since the late 1990s, effectively providing the growth in power generation, together with the more recent rise in renewables to almost 25% in 2013, with gas being displaced by both renewables and coal. The intermittency issues of hydro in the past are also highlighted, with coal providing the balancing in the early years.

5.3 Gas v Renewables in Power Generation

5.3.1 Iberian Power and Gas Markets

Portugal and Spain have quite integrated power and gas wholesale markets. The power market is a single one, with all wholesale sellers and buyers bidding hourly in a unique pool with a transparent public price. For gas, there is no formal wholesale market, but the Iberian players, Portuguese or Spanish, are able to buy or sell on a wholesale basis in either side of the border and are able to manage their portfolio in an optimized way between both countries.

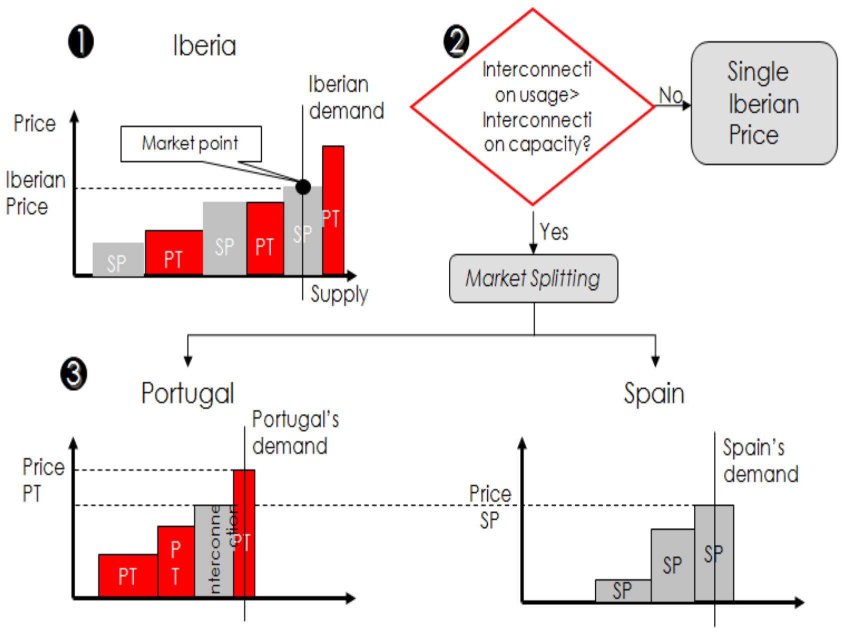
Portugal and Spain have both quite diversified portfolios of power generation, including large and small hydro, CCGTs, renewable such as wind or solar, nuclear (only in Spain), cogenerations, biomass, waste and oil products. By the end of 2013, total installed capacity was 108.148 MW in Spain and 17.790 MW in Portugal. Neither country had capacity restrictions, both with a reserve margin against peak load above 1.3 against firm capacity. Table 5.1 below details the structure of the Iberian power market.

Table 5.1 Iberian Power Market

Technology		Portugal [MW]	Portugal [%]	Spain [MW]	Spain [%]
Nuclear		-	-	7.866	7%
Hydro		5.239	29%	17.766	16%
Thermal	CCGT	3.829	22%	27.206	25%
	Coal	1.756	10%	11.641	11%
	Fuel/Gasoil	165	1%	3.498	3%
Ordinary Regime		10.989	62%	67.977	63%
Hydro		413	2%	2.058	2%
Wind		4.368	25%	22.900	21%
Solar		282	2%	6.981	6%
Thermal		1.738	10%	8.232	8%
Special Regime		6.801	38%	40.171	37%
Total Capacity		17.790	100%	108.148	100%
Anual Peak Load		8.322		40.277	

On what concerns market operation, both countries share a single integrated power market with two price zones, one for each country. Normally, those two prices will be the same, but if there are interconnection restrictions between Portugal and Spain, different prices will result, as is illustrated in the example in the figure below.

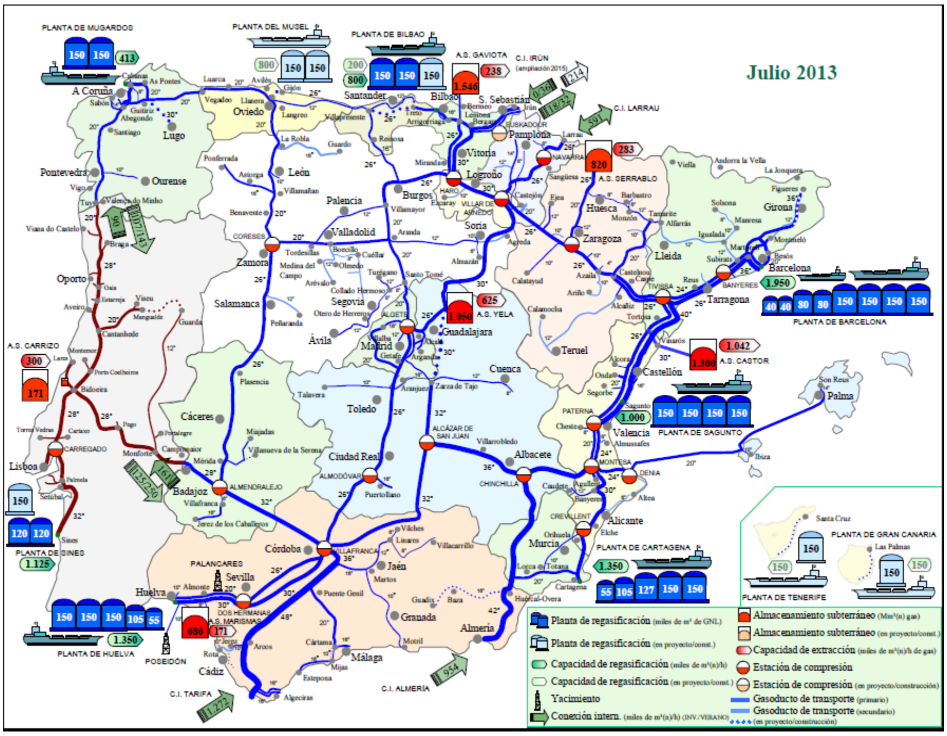
Figure 5.12 Iberian Price Setting



This pool market is a physical hourly based day-ahead and intra-day market. Additionally, players have access to an organized forward exchange and they also trade financially over-the-counter. In 2013, 310 TWh were consumed in Iberia, 49 in Portugal and 261 in Spain. In the wholesale markets 273 TWh were traded spot and 86 TWh were traded forward. Average pool prices were 43.6 €/MWh in Portugal and 44.2 €/MWh in Spain.

On what concerns natural gas, Iberia has insignificant local production and relies basically on imports. Import capacity is more than 60 bcm/year, far above actual Iberian consumption, and includes 8 LNG terminals, two pipeline connections with Algeria (GME and Medgaz) with 18 bcm/year import capacity and two interconnections with the south of France with capacity of 4 to 5 bcm/year. The figure below shows the Iberian gas grid and relevant importation infrastructures.

Figure 5.13 Iberia Gas Infrastructure



Iberian gas consumption was 381 TWh (ca. 32.5 bcm) in 2013, 48 TWh in Portugal and 333 TWh in Spain. Both countries are mainly supplied through long-term take-or-pay contracts. No formal wholesale markets exist, but wholesale operations are carried out among a number of players in the centre of gravity of the Spanish system (called “AOC”), in-tank in the terminals or in the Portuguese-Spanish and French-Spanish interconnections. Such wholesale market has moderate liquidity. Deal prices are not public, though, and no Iberian price index currently exists.

5.3.2 Renewables Relevance in the Power Portfolio and Impact on CCGT Usage

As can be seen in table 5.1, above, Portugal and Spain have an important installed CCGT capacity (25% of total Iberian generation portfolio). However in the last decade, CCGT load factors have experienced a systematic downward trend, as the figures below illustrate.

Figure 5.14 CCGT Load Factors

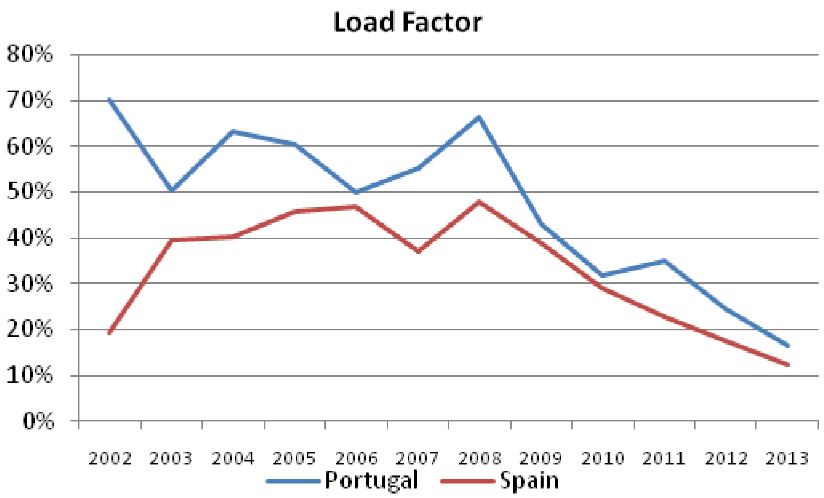
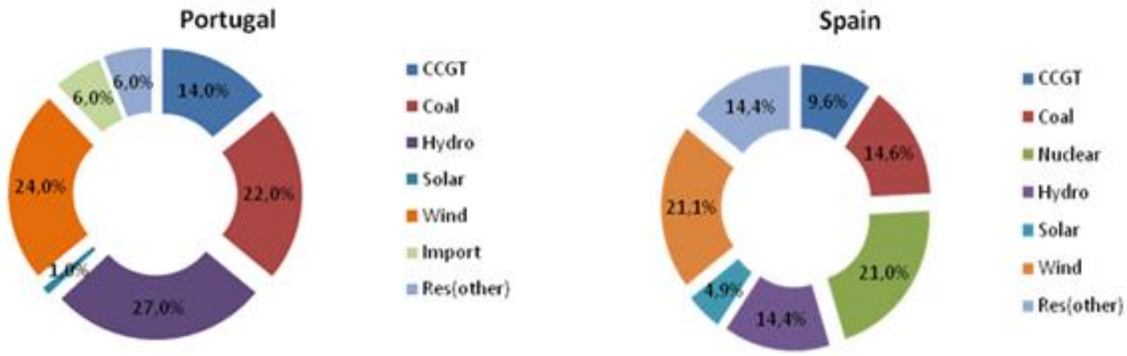


Figure 5.15 Market Shares by Fuel



What has caused this behaviour?

On one side, there was a spectacular development of CCGTs in Iberia, since the end of the 1990s. This was motivated by the competitiveness of the combined cycle gas turbine technology, the strong growth in consumption that was expected by then to occur, the liberalization of generation activities in both countries that led each player to develop its portfolio according to its own individual business logic and, finally, the introduction of the CO2 market that was supposed to help gas displace coal in thermal generation.

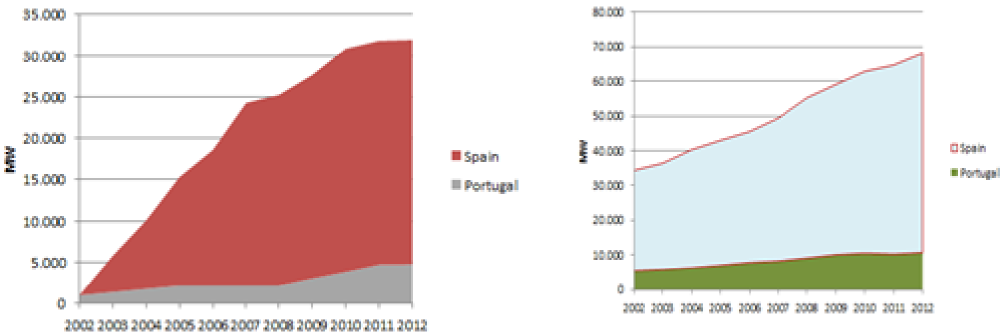
On the other side, and at the same time, both countries have experienced a spectacular renewable capacity development, especially in the form of on-shore wind generation. This development resulted from important European and national incentives that resulted in the introduction of support schemes such as guaranteed tariffs and preferential balancing or dispatching regimes. These incentives resulted of the will of both countries authorities to fulfil the European Union's 2020 Climate and Energy Package, also known as EU20/20/20, by which by 2020 20% of the energy produced in each member state should be based on renewable sources, emissions should be reduced by 20% as compared to those that occurred in the year

1990 and indirectly, energy efficiency should reach 20% of the projected business-as-usual energy consumption of 2020.

As a consequence of these two trends, CCGT capacity in Iberia grew 40% a year from 2002 to 2012, from 990 MW in 2002 to 31993 MW in 2012, only stabilizing in recent years (see figure 5 below). Simultaneously, in the same period, renewable energy sources (RES) generation capacity doubled in Iberia, from 34.327 MW to 68.071 MW, specially through the addition of on-shore wind (see figure 6 below).

Figure 5.16 Growth in Gas and Renewables Generation

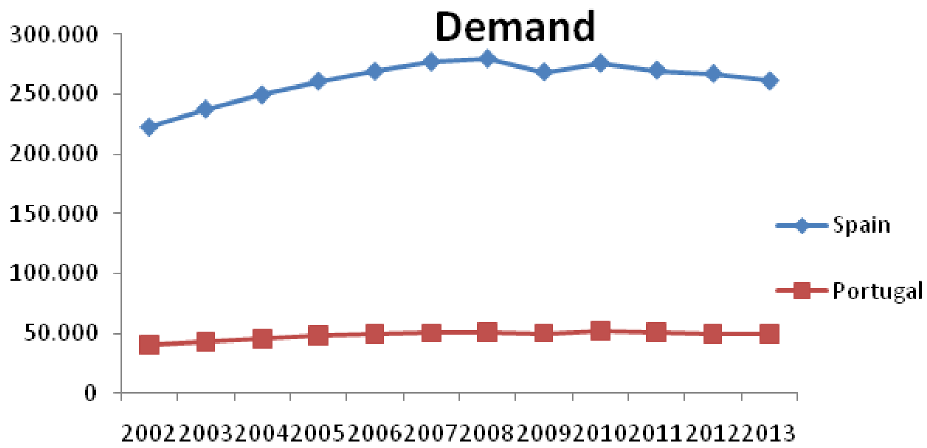
Gas **Renewables**



In a marginalistic market like the Iberian power pool, RES generation, with nearly zero variable cost, does have an advantage over CCGTs, which for every MWh generated have to pay for the gas, the CO_2, the variable grid access costs and variable operational costs. But even with RES competition, CCGTs would be able to sustain important load factors if it wasn't for two issues unexpected in 2002.

First, electricity demand did not grow as foreseen because of the financial and economic crisis that struck Europe at the end of the 2000 decade and caused huge demand destruction in Portugal and Spain. After years of consistent growth, power demand in both countries stagnated and even declined, returning to 2005 levels (see figure below). As compared to 2002 projections, 70 TWh/year of demand were destroyed in Iberia, which is 20% of the expected market.

Figure 5.17 Demand



Then, CO2 prices didn't behave as expected. Oversupply in a poorly calibrated European Trading Scheme (ETS), together with reduced demand, led to a CO2 price crash (see figure below). Coal prices (API 2) also fell about 30% since 2011 to about 80$/ton, because of lower demand and additional USA exports caused by coal displacement induced by shale gas. At current gas and coal prices in Iberia, only CO2 prices above 40 €/ton would displace coal generation in favour of gas-fired generation. But even after a 900 million tonnes of CO2 back-loading recently decided by the European Union (after a very long technical and political process), prices linger at 4 €/ton, 10% of the value required to invert the dispatching merit order in favour of CCGTs and against coal generation.

Figure 5.18 EU ETS CO2 Prices

In this context, what happens today in the Iberian power pool is quite straightforward. Let's suppose that in a specific hour the demand is X MWh. Nuclear, non-stockable hydro and renewable generators will bid their capacity at very low prices (even at zero prices). If the sum, Y, of the capacities of these "low variable cost" generators is above X, market will sell at those very low prices and coal and gas plants will not work. If X-Y>0, the difference between X and Y will be the "thermal gap", T, and to fill it some coal plants will work, setting the market price in such a way that the clean-dark spread is positive, that is above the variable production cost of coal-fired generation. If coal-fired generation is not enough to fill the thermal gap, combined cycle gas-fired plants will work setting the market price in such a way that the clean-spark spread is positive, or eventually slightly negative if other factors, like take-or-pay pressure or revenues from ancillary services (described below) , are at work.

The impact of these situations for gas plants is then double: reduced load factors and very irregular operation profile.

5.3.3 CCGT's Response

Reduced load factors and higher intermittency of usage had a number of consequences on CCGT management. On what concerns gas supply, take-or-pay management became even more important and pressure by buyers to review gas supply contracts, both on price and on take-or-pay levels, increased. Optimization of the cost chain, particularly of the grid access costs, implied the demand for a higher diversification of third party access offered by system operators, through short-term access products. Participation in the ancillary services market became paramount to the economics of CCGTs; this (and also take-or-pay management along the year) implied the need for a more accurate price forecasting. Operationally, CCGTs had to learn to live with the unpredictability of running programs, cold starts (leading to higher operation and maintenance costs) and unstable regimes that reduce the lifetime of the turbines.

CCGTs in Iberia represents 28.7 GW of installed capacity, almost all supplied by long-term, oil-indexed, ToP contracts. Annual contracted quantities of those contracts are for nearly base load usage, between 5500 to 6000 hours per year, that is 0.4 bcm/year per 400 MW unit installed. In fact, plants are working 20 to 30% of these hours. So, of nearly 30 bcm/year of take-or-pay contracted, the CCGTs are only able to consume 7 to 10, leaving to the utilities a problem of more than 20 bcm/year to solve. Several levers were used to solve this problem:

- CCGT gas buyers used the clauses for price review in their contracts to try to reduce acquisition prices and thus improve the number of hours worked by the CCGTs; since the application and the outcome of these review clauses are confidential under the supply contracts, it is impossible to know the extent of their application; however it may be assumed that some price reductions existed, but not enough to significantly increase the average number of hours of positive clean spark spread.
- Annual contracted quantities reductions, take-or-pay level reductions or sales of gas back to the suppliers were negotiated by CCGT gas buyers with their suppliers; those three mechanisms are equivalent, amounting to a reduction in off-take obligations.
- CCGT gas buyers deviated gas contracted for CCGTs to the wholesale and retail Iberian markets; though this policy prevented take-or-pay at the CCGT levels, it momentarily flooded the Iberian market with excess gas, causing a drop in prices in the wholesale and B2B segments, sometimes clearly below the acquisition levels.
- Several agents used the available capacity in LNG regasification terminals to organize reloads of LNG aimed at such markets as Asia and Latin America; a significant quantity of gas was taken out of the market in this way; in 2013, an estimated 40 cargoes were reloaded from Iberia, amounting to 3.1 bcm of LNG.

Another important consequence of the growth of RES based generation, and its higher intermittency, was the increase in the need, of the electrical systems for ancillary services.

Ancillary services are rendered by power plants that make themselves available to increase or decrease load as compared to the load resulting from market equilibrium, in exchange of an economic reward. They may take several forms (having automatic regulation, being available to remote operation by the system operator to modify load for balancing purposes, being mobilized as a result of this remote operation, being mobilized to solve a physical restriction, etc.). The figures below show the positive relation between wind power and the mobilization by the system, in Spain, of secondary and tertiary energy.

Figure 5.19 Mobilised Secondary v Eolic Production

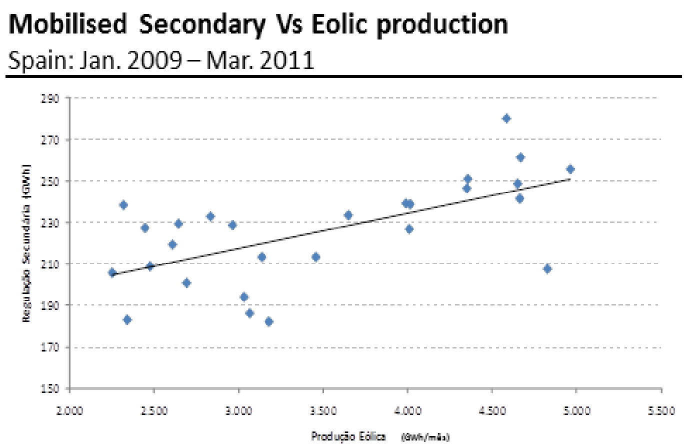
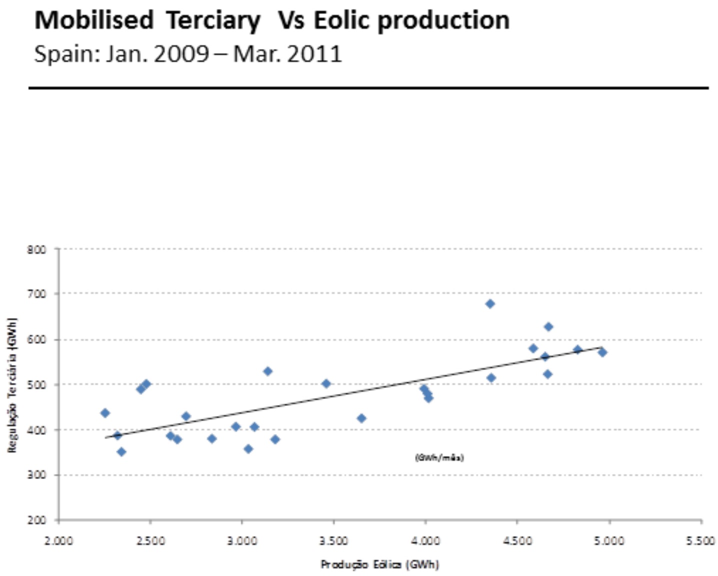


Figure 5.20 Mobilised Tertiary v Eolic Production



Gas fired power plants can generally adapt production faster, further and more reliably than other thermal plants. So CCGTs have become an important player in the Iberian ancillary services markets. In fact, in Spain, in 2012, 12% of the hours worked by CCGTs were due to the selling of ancillary services. This trend was being reinforced in 2013: up to July, those services made viable up to 26% of electricity production in CCGTs. In many of those hours, CCGTs made a loss in the sale of energy to the pool, but were able to break even with the revenues of the ancillary services.

As a consequence of this new way of functioning of the CCGTs, gas transmission systems have to face sudden and multiple ramping up and down of large number of gas plants to back up wind generation. That means that both transmission systems and gas supply contracts will have to evolve and adapt to the growing flexibility needs of CCGTs.

This was made obvious in December 2013 in Iberia, when below-the-average hydro and wind availability, associated with some technical outages of nuclear and coal plants caused CCGTs to be called upon as never before during the year to fill the thermal gap. This sudden spike in demand caused the natural gas prices to peak and consequently pool prices too.

However, in spite of this higher gas prices, short-term supply was scarce because of time needed to divert LNG back to Iberia and because of poor interconnection between the north and the south of France: during these days, PEG Nord prices were below 30 €/MWh, PEG Sud prices were way above 40 €/MWh but even so gas was still not flowing!

This event showed not only the importance of solving physical restrictions inside the European area but also the need for higher resiliency of the systems if CCGTs are working as back-up for renewables, with less stringent rules for strategic storage withdrawals and an eventual assumption by the systems of a small part of the take-or-pay risk, either directly or through an adequate remuneration of ancillary services.

5.3.4 Final Considerations

RES and CCGTs are bound to live together in the Iberian power market. They were decided by corporate or political decisions, they have been built and they are yet at the beginning of their working lives. RES, especially on-shore wind generation, are today competitive on a total cost basis with conventional hydro, nuclear, coal or CCGTs, but they need to be backed-up and CCGTs are particularly well-suited for this role. This means that the power systems have to adapt to the joint role of these two forms of power generation. Such adaptation implies that capacity remuneration mechanisms are put in place to guarantee that CCGTs are not mothballed or are built if needed, that a considered view exists on new capacity needs, in order to avoid catastrophic over-capacity and that market rules account for the intermittency and unpredictability of RES power production.

The natural gas system and market will have to evolve as well. The development of an efficient and liquid gas hub and of market based balancing regimes will certainly be a part of this evolution, but flexible access to transport capacity and to gas storage and a flexible capacity secondary market are also required.

In fact, the Iberian gas system will have to take in account, in its evolution, that it has to serve an important portfolio of CCGTs, working as peak or mid-merit units, which are fundamental to the security of the power system and, also very important, to keep bringing important revenues to remunerate the investment made in the gas network. So it can't just copy models from markets were CCGTs' role is not important and has to address CCGTs needs, namely:

- On balancing, daily balancing with no within-day obligations and higher tolerance levels for CCGTs in terms of imbalance and line-pack;

- On nomination rights, flexible nomination and re-nomination rules in order to cope with daily and within-day program changes and the alignment of nomination schedules with the electricity market planning;
- On what concerns the capacity market, and as referred, the development of liquid and robust primary and secondary markets with clear rules that permit CCGTs to buy and sell capacity to accommodate cargo variation regimes;
- On storage, a flexible and effective access to storage capacity, important to accommodate volumes of gas necessary for CCGTs to face fast variations of consumption.

5.4 Conclusions

The price competition between gas and coal in power generation is not universal in all markets. There appears to be a considerable degree of actual and potential load switching, based on relative prices, in markets such as the US, UK and to some extent Germany, However, this is less evident in Japan, where oil fired generation still has a significant market share, and not at all evident in China, where coal still dominates the generation mix.

In terms of gas and renewables, the example of the Iberian market is that the strong increase in renewables installed capacity and power production in the Iberian Peninsula in the last years has led to a significant increase in price volatility and instability of the system, reducing the space for CCGTs functioning. Moreover, the decrease of CO2 prices also contributed for the loss of competitiveness of CCGTs, that have production costs higher than coal plants at current CO2 price levels. This new market reality strongly reduces CCGTs usage and induces costs or inefficiencies related with the management of gas supply contracts, operation & maintenance, lower lifetime, etc. CCGTs have now to operate in an unstable environment, with lower load factors and highly variable operation regimes; these changes are structural and are here to stay. Issues like the design of ancillary markets and/or capacity payment mechanisms will be fundamental for CCGTs viability.

6.1 Introduction

The wholesale price survey, as described in Section 2 identifies many different price formation mechanisms. Three regulated categories are identified – Regulation Cost of Service (RCS), Regulation Social and Political (RSP) and Regulation Below Cost (RBC) – plus there is also a No Price (NP) category, with relatively small volumes. The survey is only concerned with prices at the wholesale level and in some cases subsidies can be applied after the wholesale level to reduce prices to end users.

The RCS category implies that the prices are set at a level which covers all costs, including providing a reasonable rate of return, so almost by definition these prices are set at an economic level and could not, therefore, be said to include any element of social pricing. The key social pricing categories, therefore, are RSP and RBC plus NP.

This section identifies the regions and countries where social pricing is most prevalent and considers changes over the 7 surveys.

6.2 Social Pricing: Survey Results

The table below shows the regional and category breakdown for total world consumption for the 2014 survey.

Table 6.1 World Price Formation 2014 – Total Consumption (BSCM)

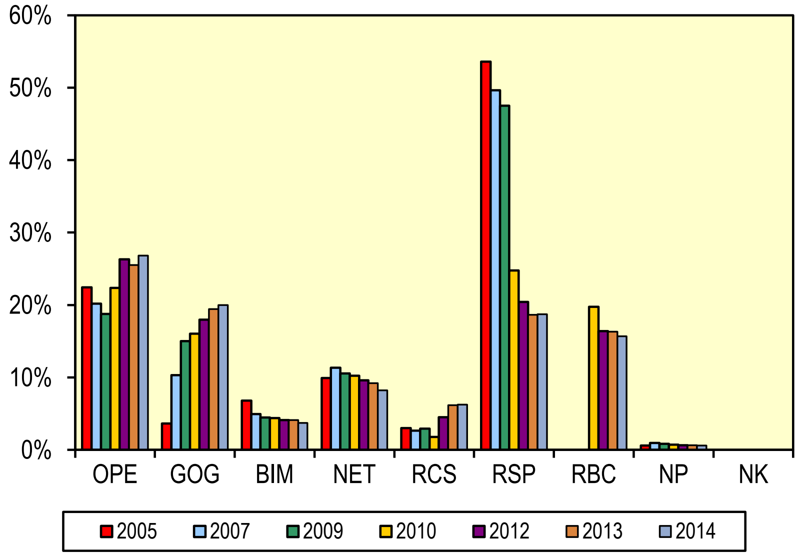
Region	Total Consumption									
	OPE	GOG	BIM	NET	RCS	RSP	RBC	NP	NK	TOT
North America	0.0	936.0	0.0	0.0	0.0	0.0	0.0	6.0	0.0	942.1
Europe	152.9	291.9	9.5	0.4	10.6	8.3	0.0	4.4	0.0	478.1
Asia	130.4	12.0	3.4	0.0	117.3	18.6	9.1	0.0	0.0	290.9
Asia Pacific	229.5	71.5	20.9	0.0	10.9	71.8	0.0	4.5	0.0	409.1
Latin America	46.1	34.4	6.4	14.2	10.7	32.2	27.0	1.0	0.0	172.1
FSU	34.2	144.4	27.8	0.0	233.1	90.0	103.3	8.8	0.0	641.6
Africa	8.4	0.0	6.4	1.3	1.5	16.8	86.0	0.8	0.0	121.1
Middle East	8.1	4.0	73.1	0.0	0.0	357.6	10.3	9.5	0.0	462.6
Total	609.6	1 494.3	147.5	15.8	384.2	595.4	235.7	35.0	0.0	3 517.5

The four main regions where RSP and RBC have significant shares are Latin America, FSU, Africa and Middle East. Asia has some in the Indian sub-continent while in Asia Pacific it is mainly Indonesia and Malaysia. In considering changes over time it is the four main regions that will be reviewed.

6.2.1 Latin America

The changes in price formation mechanisms in Latin America have seen a rise in GOG from 4% to 20%, a decline in RSP from 54% to 19%, comprising domestic production in Argentina, Peru and Bolivia and a rise in RBC from 0% to 16% - the latter all in Venezuela. The rise in GOG in part is due to rising spot LNG imports in Argentina, Brazil and Chile, and a switch away from RSP to GOG in Argentina, and to a lesser extent from RCS to GOG in Colombia. In Argentina, this reflected producers and marketing entities, being allowed to sell gas at unregulated prices to large eligible customers, such as power plants.

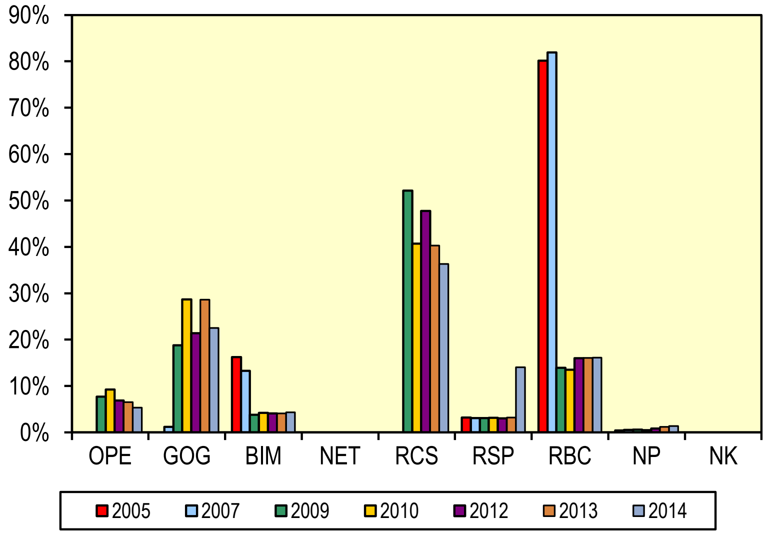
Figure 6.1 Latin America Price Formation 2005 to 2014



6.2.2 Former Soviet Union

The Former Soviet Union has seen significant changes in price formation mechanisms, largely based around Russia. From having domestic production completely in the RBC category in 2005, there was a switch to GOG as the independent producers began to compete with each other and Gazprom to sell gas to the power sector and large industrials, and the rising Gazprom regulated prices saw a switch from RBC to RCS. The other change was in intra-FSU trade where pricing switched from BIM to OPE, particularly in the Russia to Ukraine trade. The remaining RBC is domestic production in Turkmenistan, Kazakhstan and Uzbekistan while RSP is Russia and Ukraine domestic production.

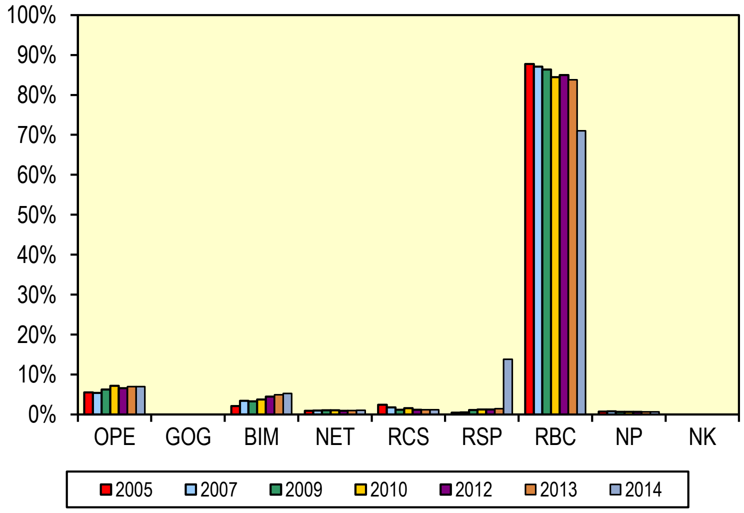
Figure 6.2 Former Soviet Union Price Formation 2005 to 2014



6.2.3 Africa

There have been almost no changes in price formation mechanisms in Africa, between 2005 and 2014, apart from the move in Nigeria from RBC to RSP in 2014. The region remains dominated by RBC, with gas prices largely subsidised, and is predominantly domestic production in Egypt and Algeria.

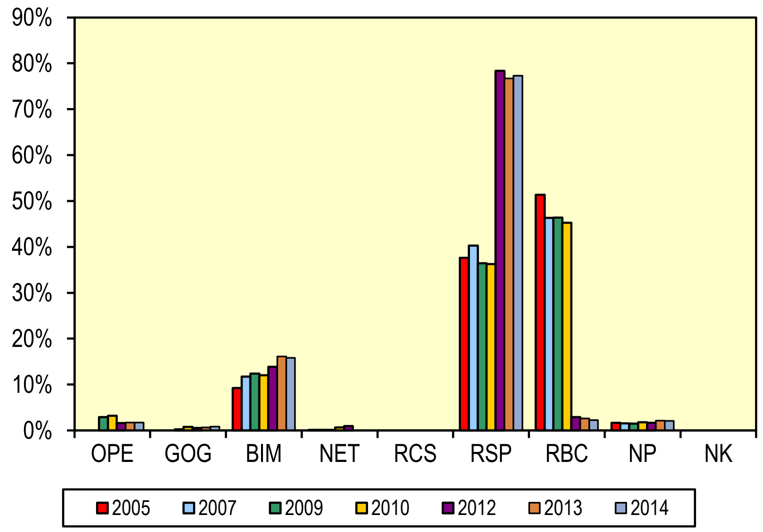
Figure 6.3 Africa Price Formation 2005 to 2014



6.2.4 Middle East

The changes in price formation mechanisms in the Middle East, the biggest region in the world for social pricing, have almost totally taken place between 2010 and 2012, when prices were increased significantly in Iran, moving from the RBC category to the RSP category. The RSP category is now largely domestic production in Iran, Saudi Arabia and the UAE with smaller amounts in Oman, Bahrain and Kuwait. The other change was in small quantities of OPE and GOG as LNG began to be imported into Kuwait and UAE. The rise in BIM, which is more market pricing, in 2013 reflects rapid consumption growth in Qatar.

Figure 6.4 Middle East Price Formation 2005 to 2014



6.3 Price Changes in Key Social Pricing Countries

The key social pricing countries (those mainly with RSP and RBC) by region are:

- Asia Pacific – Indonesia and Malaysia
- Latin America – Argentina, Peru, Bolivia and Venezuela
- FSU – Turkmenistan, Uzbekistan and Kazakhstan
- Africa – Algeria, Egypt and Nigeria
- Middle East – Iran, Saudi Arabia, UAE, Oman, Bahrain and Kuwait

The figures below look at how average wholesale prices have changed in these countries.

Figure 6.5 Social Pricing Changes: Asia Pacific, Latin America and FSU

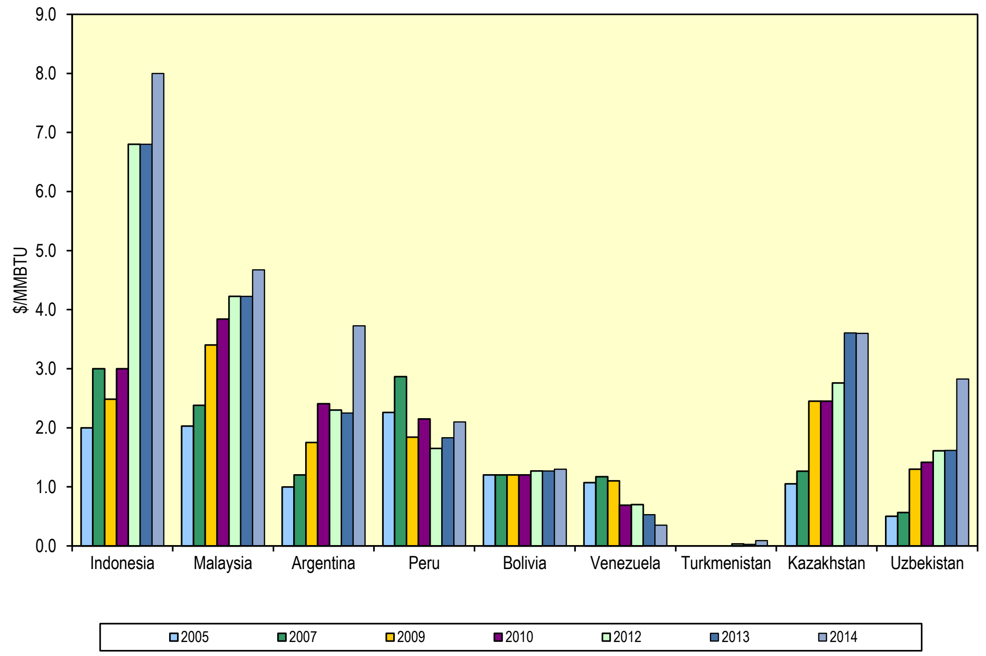
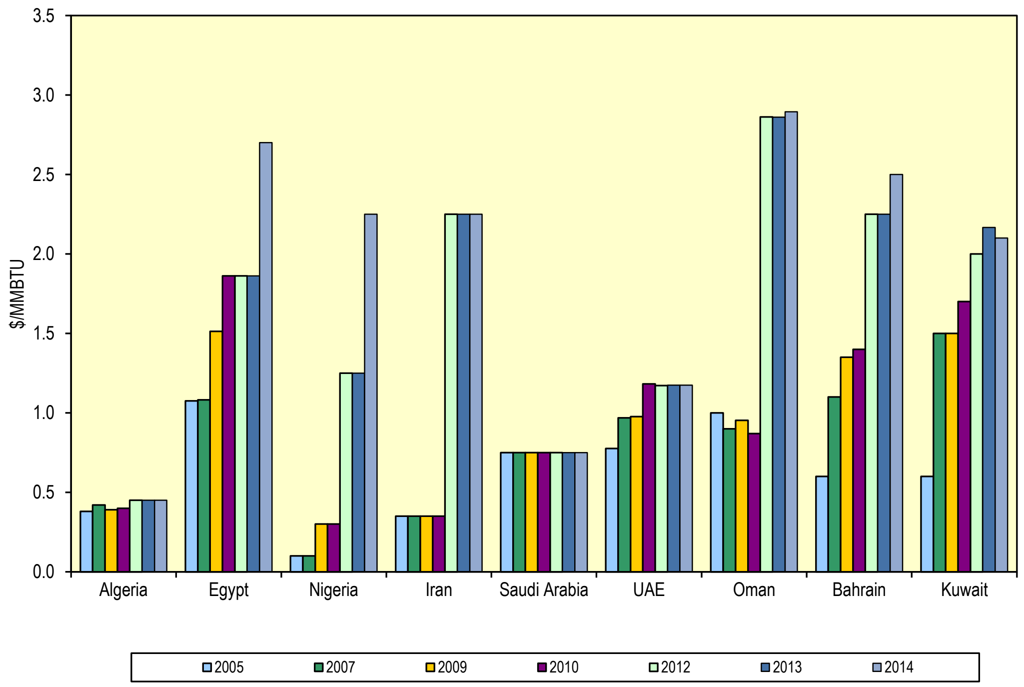


Figure 6.6 Social Pricing Changes: Africa and Middle East



These figures illustrate the significant differences between countries which have raised prices and those countries which have not. A number of countries, which were traditionally large producers and exporters of gas, have seen rising demand coinciding with declining or stagnating production, leading to the need or potential need for imports. These countries include:

- Indonesia, Malaysia, Argentina, UAE, Bahrain and Kuwait

Other countries which have raised prices have done so for budgetary reasons, to reduce the impact of subsidies on their finances, and/or to encourage the development of new reserves at higher cost. These countries include:

- Kazakhstan, Uzbekistan, Egypt, Nigeria, Iran and Oman

Some countries, however, have not raised prices and these have tended to be those who remain completely self-sufficient and export in significant quantities. These countries include:

- Peru, Bolivia, Turkmenistan, Algeria and Saudi Arabia

Finally, Venezuela has not raised prices despite having significant budgetary issues and the need to increase prices to encourage new developments, and is also importing gas. This reflects the policies and politics of successive governments.

What has not been covered in this analysis at purely the wholesale price level is where there are specific policies of cross subsidy, providing lower prices to certain sectors at the expense of others. This can often be to the benefit of the residential or household sector against the industrial sector e.g. Russia or sometimes the power and fertilizer sectors versus other sectors e.g. India.

6.4 Targeted Policies on Energy Poverty

The other area which could be deemed as social pricing is where there are targeted policies on energy poverty. These are more likely to be seen in the wealthier countries where the wholesale price of gas is a “market price” – most likely GOG and/or OPE. The report of PGCB3 discusses the survey that has been undertaken of energy poverty policies to protect poorer consumers in developed markets.

The survey noted that measures are mainly designed to protect residential customers and especially those on low incomes or low consumption levels. Some of these policies include reducing the energy bill, through social tariffs or rebates, measures to reduce energy consumption through efficiency and assistance with modern more efficient energy equipment. More detail on the survey is contained in the PGCB3 report.

6.5 Conclusions

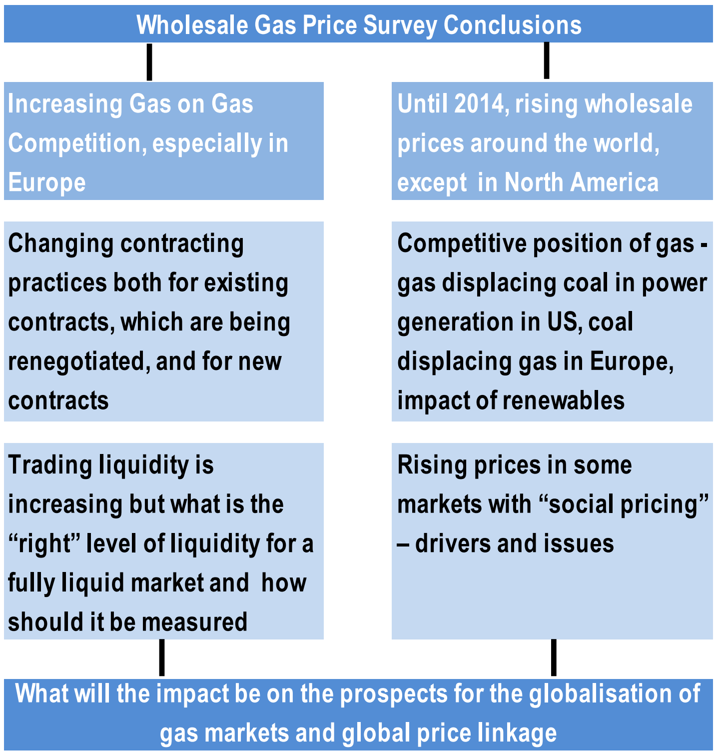
The four main regions where Social Pricing (the RSP and RBC categories from the survey) have significant shares are Latin America, FSU, Africa and Middle East. Asia has some in the Indian sub-continent while in Asia Pacific it is mainly Indonesia and Malaysia.

Many countries with Social Pricing have been increasing prices over time because they were traditionally large producers and exporters, who have been caught with rising demand and stagnating or declining production, leading to the need or potential need for imports – Indonesia, Malaysia, Argentina, UAE, Bahrain and Kuwait. Other countries which have raised price have done so for budgetary reasons, to reduce the impact of subsidies on their finances and/or to encourage the development of higher cost reserves – Kazakhstan, Uzbekistan, Egypt, Nigeria, Iran and Oman. On the other hand some countries have not raised prices and these have tended to be those who remain completely self-sufficient and export in significant quantities – Peru, Bolivia, Turkmenistan, Algeria and Saudi Arabia.

7.1 Introduction

This section brings together the preceding sections in line with the report structure outlined in the Introduction section and summarised in the figure below.

Figure 7.1 Report Structure



In summary this section will discuss the impact of changing contracting practices, increasing trading liquidity, the competitive position of gas against coal and renewables and rising prices in some markets with more regulated / social pricing, on the prospects for the globalisation of gas markets and global price linkage.

In the 2012 publication The Pricing of Internationally Traded Gas[18], the chapter by Howard Rogers[19] identified three factors which might lead to greater globalisation of gas prices:

- Existence of infrastructure to enable gas to move between regional markets and of sufficient volumes of flexible or divertible gas;
- Creation of supply chains which allow the diversion of flexible gas supply between regional markets in response to supply-demand imbalances and price disparities (arbitrage); and

[18] *The Pricing of Internationally Traded Gas*, Oxford Institute for Energy Studies, Ed Jonathan P. Stern
[19] Chapter 12, *The Interaction of LNG and Pipeline Gas Pricing: Does Greater Connectivity equal Globalization,* Howard Rogers

- Motivation and ability of one or more of the three key agents - producer, midstream utility, end user - in an existing regional gas supply chain to move away from oil indexed contracts to hub based pricing.

These factors largely relate to internationally traded gas and factors which are largely external to individual country markets. There may be other factors which are required which are internal to the domestic markets within countries and there is also the issue of what specific actions are needed for change to occur.

This section will consider these factors in the context of categorising the issues into three areas relating to:

- Infrastructure;
- Contractual arrangements (including regulation); and
- Pricing

Furthermore these categories can also be divided into internal factors – i.e. within a country's market – and external factors – i.e factors impacting external trade. The framework for analysis, therefore, can be considered as a matrix – see figure below – and the rest of this section will consider each of the "boxes" in the matrix and review the key factors.

Figure 7.2 Analytical Framework

	Internal	External
Infrastructure		
Regulation / Contractual		
Pricing		

However, before moving on to each of these categories, the next section will consider what we mean by globalisation and price convergence.

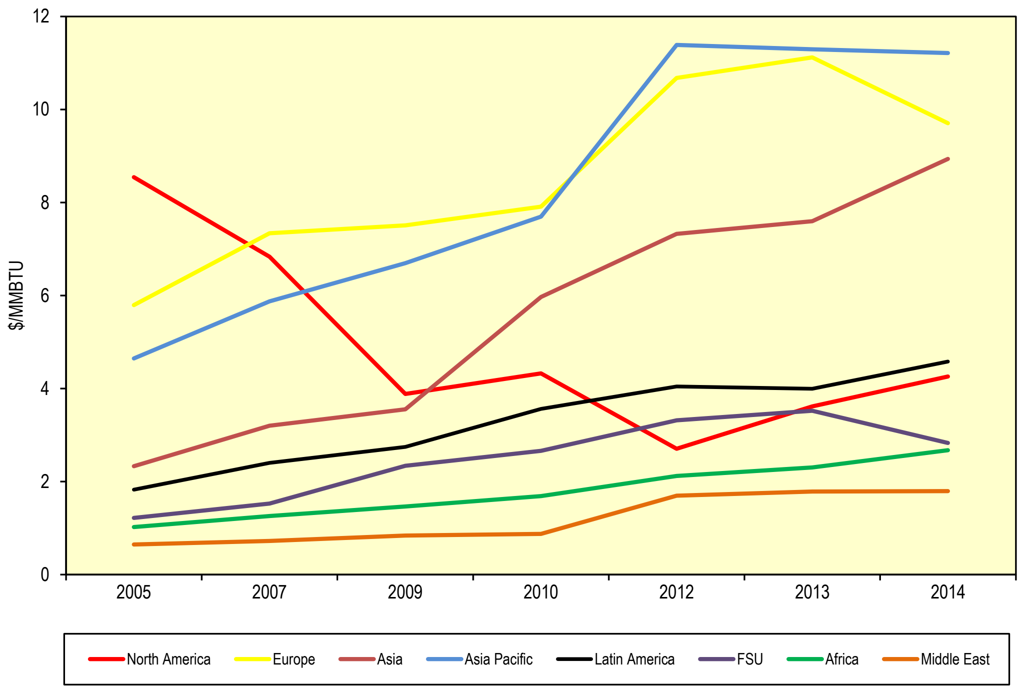
7.2 Globalisation and Price Convergence: What do we mean?

Price convergence does not mean that prices have to be the same in all global markets but that ultimately they will reflect basis or transportation differentials. Even then because of short term infrastructure constraints and localised periods of tight and/or surplus supply relative to demand, prices might converge by much more than the usual basis or transportation differentials, as has been seen in the North American markets in recent years, at least on a temporary basis before adequate infrastructure is constructed to reflect changing supply patterns in particular. The changing differentials in the North American market were reviewed in some detail in the PGCB

Sub Group 2 report at the 2012 World Gas Conference in Kuala Lumpur. It was concluded that the diverging prices served as an attractive motivation to invest in the incremental capacity needed to equalize prices, and create a more complete and free-flowing natural gas infrastructure network to accommodate production growth for years to come. This was the case for the gas producers in the Rockies in the 2007 to 2010 period and is now being repeated with the boom in Marcellus shale gas production and the pressing need to build infrastructure to move the gas out of Pennsylvania and West Virginia.

What has happened in the North American market could be transferred to the global market but the question remains how and over what timescale. However, what we are really talking about is not necessarily price convergence but "price connectivity" between regions of the world. The figure below illustrates the changing price levels between the IGU regions, in a slightly different layout to the figure in Section 2.

Figure 7.3 Wholesale Price Levels 2005 to 2014 by Region

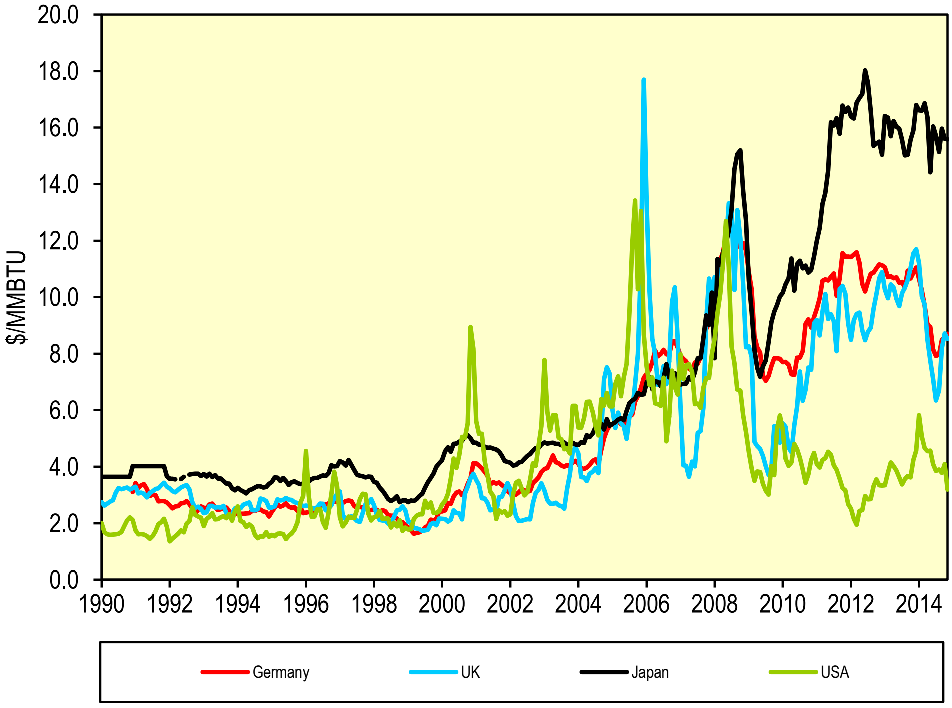


Section 2 noted that wholesale prices have largely increased consistently across all regions, except for North America, since 2005, and the recent easing of prices in Europe and Asia Pacific in 2014. However, as the successive wholesale price surveys have demonstrated, the price mechanism and drivers in the respective markets have been very different and there has been little or no "price connectivity" between the regions in reality. Price connectivity is only likely to arise where there is gas traded between countries and regions and the dominant internationally traded regions have been North America, Europe and Asia Pacific, very recently joined by Asia. The other regions – FSU, Latin America, Africa and the Middle East – are where prices have been predominantly regulated and price connectivity would be unlikely.

The figure below illustrates the history of key wholesale prices in the main internationally traded regions.

Figure 7.4 International Wholesale Prices

Source: Argus



The figure shows wholesale prices in the US (Henry Hub), UK (NBP), Germany (BAFA) and Japan (average LNG import price). As is well known, prices diverged in 2009, and there has been little sign on any convergence since then, or even any connectivity between the markets. The BAFA price in Germany is now increasingly a spot or hub based price with an increasing proportion of hub indexation in the contracts and more pure spot imports, so it is now tracking NBP more closely. The Japan average LNG import price is largely linked to oil price through JCC. Japan spot prices have also traditionally been close to the contract prices but in 2014, Japan spot prices declined before contract prices, much in line with NBP prices, reflecting supply – demand fundamentals. At the spot level therefore, there appears to be increasing connectivity. However, if price formation mechanisms differ – oil indexation against spot / hub pricing – any convergence of prices or connectivity is only likely to happen through coincidence rather than any fundamental forces.

7.3 Infrastructure

7.3.1 Internal

Internal infrastructure within a country can mean the domestic pipeline infrastructure connecting the various regions. This has already been identified in the North American market where changing supply patterns led to widening price differentials and incentivising additional investment. However, it is more problematic in less liberalised more regulated markets. Japan, for example, is effectively largely a series of regional markets, which are either not, or are poorly, interconnected. While in theory there are a number of buyers of imported LNG they do not, by and large, interconnect with each other. The level of pipeline capacity also has to be sufficient to allow for the free flow of gas in response to price signals – an element of over-building of capacity can be desirable.

Importing infrastructure is also important whether it is by pipelines to neighbouring countries or LNG regasification capacity. The UK, for example, has import pipeline capacity from Norway, Belgium and the Netherlands amounting to around 90 bcma and LNG import capacity of around 50 bcma, in addition to domestic production of just under 40 bcm in 2013. This compares with total consumption and exports (to Ireland and Belgium) of just under 90 bcm in 2013. While there is clearly more than enough import capacity to supply the UK market there is considerable diversity of capacity as well.

A recent example of diversifying capacity is in Lithuania which was 100% dependent on imported pipeline gas from Russia but has just commissioned a FSRU to import LNG and has contracted with Statoil to do so. Even before Lithuania had taken FID on the FSRU the price of imported gas from Russia fell by some 25%, as a result of a price renegotiation. The mere threat of diversifying infrastructure and supply, therefore, can apparently change pricing.

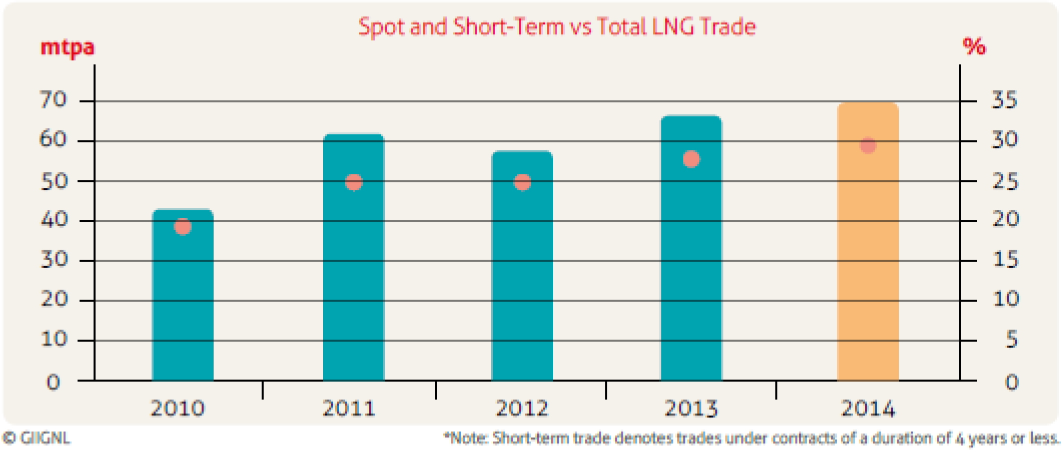
3.5.1 External

As noted in his chapter in the Oxford Institute book – see footnote 2 above – Howard Rogers identified as one of the conditions for the potential creation of global price linkage was the existence of infrastructure to enable gas to move between regional markets and of sufficient volumes of flexible or divertible gas. The examples he gave of the infrastructure included the construction of LNG import capacity in North America in anticipation of a potential need to large volumes of imported gas – which was clearly made obsolete by the shale gas revolution. Europe also has large amounts of import pipeline capacity from outside Europe – GIE data put this at some 370 bcma in 2012, of which 280 bcma was from Russia – plus some 190 bcma of LNG regasification capacity. The Asian LNG importing countries of China, India, Japan, Korea and Taiwan had effective regasification import capacity of some 500 bcma in 2013, far above the imported LNG volumes of some 230 bcm in that year.

However, in terms of global price linkage, this infrastructure can only be effective if there are sufficient volumes of flexible or divertible gas. As shown in the figure below from GIIGNL, the volume of spot and short term LNG sales has been rising while in the European markets, more gas has been moving on cross border pipelines on an effective spot basis.

Figure 7.5 Long and Short Term LNG Sales

Source: GIIGNL



The effect of flexible and divertible gas is addressed further in 7.4.2 below.

7.4 Regulation and Contractual

7.4.1 Internal

Having sufficient internal and external infrastructure is, however, only a partial contribution to global price linkage and connectivity. All the markets where gas trading has developed have followed the path of market liberalisation with regulated third party access – at least to the pipeline infrastructure – together with the unbundling of the gas supply function from the transportation function. Third party access may also be desirable for LNG import infrastructure and gas storage, although to the extent there are multiple competing facilities, this may be less of an imperative. The initiatives for market liberalisation, however, more often than not come from governments or regulators and there generally has to be the political push to ensure there are the necessary reforms.

A further element in terms of the market structure which is likely to encourage price connectivity is the existence of demand flexibility and fuel switching capability. This is particularly true of the power generation market. If gas has to compete with other fuels, especially on a short term basis for example with coal, then this encourages price and supply flexibility which in turn helps with fulfilling the conditions for price linkage and connectivity. Gas could compete with coal, and possibly oil, in the power generation market and maybe oil in the industrial market. The USA and the UK markets in particular exhibit strong competition between gas and coal in the power markets – see section 5.

7.4.2 External

The second condition Howard Rogers identified was the creation of supply chains which allow the diversion of flexible gas supply between regional markets in response to supply-demand imbalances and price disparities (arbitrage). The examples used here included the UK market with gas flows on the Interconnector pipeline – which is bi-directional – changing direction according to the relative UK spot price and the continental European oil-indexed price. The second example was in the LNG market where the tight Asian market attracted cargoes away from the Atlantic Basin between 2006 and 2008.

For this arbitrage to be achieved the contractual conditions have to be right. The removal of so-called destination clauses in contracts which restricts the onward trading of gas, is particularly important in this respect. In European pipeline contracts, the EU has effectively outlawed destination clauses. In the LNG market many older contracts still include destination clauses, which is why LNG re-exports have become more important, but new contacting practices in the LNG market are introducing greater flexibility. The primary example of this has been the forthcoming LNG export contracts from the developing US export terminals, which are largely in effect tolling agreements – see section 3 – with the only obligation on the part of the offtaker of LNG is to pay a monthly liquefaction tolling fee. Once the offtaker has lifted the LNG – paying a Henry Hub related price for the gas – then the delivery is solely at the offtakers' discretion.

The other element in the LNG supply chain relates to the physical ability of suppliers to move LNG to different markets, particularly switching between the Atlantic Basin and Pacific Basin markets. In theory many LNG suppliers can switch between markets, but in practice the costs of shipping can inhibit the economics. Of the 4 largest LNG exporters in 2014 – Qatar, Malaysia, Australia and Indonesia – only Qatar can realistically be said to supply all the main LNG markets in volumes of any size. The other 3 all supply almost totally the Pacific Basin market. Of the other large LNG exporters, Algeria is predominantly Europe now, while Nigeria and Trinidad, while focussing on the Atlantic Basin, also have a wide range of countries supplied in the Pacific Basin on a spot or short term basis.

However, once the US starts to export LNG in substantial volumes they are likely to rival Qatar in terms of the wide geographical spread of their deliveries, with the growing Australian volumes destined for the Pacific Basin.

7.5 Pricing

7.5.1 Internal

In the sub-section above on Contractual the role of market liberalisation was seen as key to the development of the right conditions for trading and hence price linkage and connectivity. As part of this market liberalisation, at a minimum, wholesale prices should be deregulated to allow the development of liquid trading hubs – these have been discussed in more detail in section 4. These have been developed in the North American and European markets, as well as in Australia, but have not yet developed in the Asian LNG market, which may be needed if global price linkage and connectivity is to be achieved.

Competition at the retail / end user level may also be helpful in price deregulation and encourage the right conditions for trading. Competition in the large end user market – industrial customers as well as the obvious power generation market – is clearly likely to help. At the small user, largely residential customer, it is less obvious that competition necessarily helps trading. In the US for example, many states do not have residential competition, yet there is clearly a well-functioning wholesale market. However, if retail competition at the residential level brings in new suppliers who can then compete in the wholesale market, then that is likely to help the development of trading.

7.5.2 External

The third condition Howard Rogers identified was the motivation and ability of one or more of the three key agents - producer, midstream utility, end user - in an existing regional gas supply chain to move away from oil indexed contracts to hub based pricing. This has largely already happened in the European markets with the EU market liberalisation packages pushing through the reforms with contracts being renegotiated to included increasing proportions of hub pricing depending on the renegotiations with the suppliers. However, there has been little change in the Asian markets for current contracts but with the new LNG supplies coming on from the US in particular, the buyers – midstream utilities and end users – are increasingly looking at including Henry Hub into the pricing formula plus tolling fee and shipping costs. It is also reported that other non-US suppliers may also be looking at the inclusion in part at least of an element of hub pricing in their proposed contracts.

The other factor which may promote the move to more hub based pricing is the emergence of portfolio / trading companies in the LNG market who aggregate both LNG supplies as well as LNG markets and then can supply the various markets with supplies from different sources. This flexibility in supply sourcing and destination is likely to promote more flexible pricing.

7.6 Conclusions

The analytical matrix below summarises the key factors identified to lead to the globalisation of gas prices and increased connectivity.

Figure 7.6 Analytical Matrix

	Internal	External
Infrastructure	Widespread domestic pipeline capacity. Diversified import capacity - pipeline and LNG.	Infrastructure to move gas between regional markets. Supply of divertible and flexible gas
Regulation / Contractual	Market liberalisation - TPA, Unbundling Demand flexibility and fuel switching	Supply chains allowing the diversion of flexible gas. Physical ability of suppliers to move LNG between regional markets
Pricing	Wholesale price deregulation. Liquid trading hubs	Motivation to move from OPE to GOG pricing. Emergence of portfolio / trading companies

It seems clear from the summary table above and the discussion in this section that many factors need to come together if gas prices globally are to become more connected. Ultimate connectivity would seem to require the development of liquid trading hubs in all the key markets. Such hubs are widespread in North America and Europe but less so in Asia, where the markets are relatively more reliant on LNG.

Infrastructure, both within and between markets, has been crucial as it enables gas (pipeline or LNG) to move freely. However, if the infrastructure is contractually constrained then effectively that prevents competitive utilisation of that infrastructure. This leads to the need to proper market liberalisation including regulated TPA and unbundling. In terms of the gas supply contracting the elimination of point to point contracts, allowing gas or LNG to be diverted to alternative markets in relation to pricing signals is also of key importance.

Finally, the introduction of new participants such as portfolio / trading companies into the key markets and the changing pricing mechanisms to spot / hub pricing (GOG) away from oil indexation (OPE) should ultimately result in increasing price connectivity.

Wholesale Price Survey

The trend in price formation mechanisms over the surveys between 2005 and 2014 shows the share of gas on gas competition rising by 12 percentage points (5.5% from trading hubs, 1.5% from spot LNG and 5% from bilateral negotiations), while oil price escalation has declined by 7 percentage points. Bilateral monopoly has declined by 1.5 percentage points, while in the regulated categories regulation cost of service has risen by 10 percentage points, regulation social and political has risen by over 4 percentage points and regulation below cost has declined by 18 percentage points.

In Europe there has been a broadly continuous move from oil price escalation to gas on gas competition since 2005, with the latter's share increasing from 15% in 2005 – when oil price escalation was 78% – to 61% in 2014 – when oil price escalation had declined to 32%.

While oil price escalation has lost share in Europe and, to a much lesser extent, in Asia Pacific, there have been gains in share in Asia with a rise from 35% to 45% between 2005 and 2013 as China began importing more LNG, pipeline gas from Turkmenistan and domestic pricing reform in two provinces, together with India's pricing for LNG from Qatar changing.

Apart from the changes concerning gas on gas competition and oil price escalation in Europe and Asia Pacific, there have also been significant changes in the regulated pricing categories. The increases in regulated pricing and policy changes in Russia not only saw a switch towards gas on gas competition, but also a switch from the subsidised regulation below cost in 2009 to regulation cost of service as Gazprom finally stopped losing money on their domestic gas sales, although with the freeze in regulated prices in 2014, there was a partial switch back to regulation social and political.

There were also significant changes in China as pricing reforms, again around the 2009 period, saw domestic production prices being more formally regulated and the price formation mechanism changing from regulation social and political to regulation cost of service.

Wholesale prices have increased consistently in all regions, except North America since 2005, with some respite in 2014 in Asia Pacific, Europe and the Former Soviet Union. The rise in wholesale prices in Europe and Asia Pacific, over the last few years, and the decline in US prices, has been well documented and studied, but prices have also risen in Asia, largely due to increases in prices in China, particularly, and India, both as more gas was imported and regulated domestic prices were increased.

Less well documented, however, has been the general rise in prices in other regions, such as Latin America, where average prices have more than doubled and in the Former Soviet Union, where average prices have almost tripled, largely due to the rise in regulated prices in Russia. In Africa, where over 70% of prices are effectively subsidised, there have also been price increases, with the largest consumer Egypt raising prices, although remaining with subsidies, and more recently Nigeria. Also in the Middle East prices have risen slowly, with a significant increase in 2012 over 2010, as a result of the regulatory changes in Iran, maintained in 2014.

In recent months, towards the end of 2014 and early 2015, gas prices have been declining in many regions, partly reflecting the supply – demand balance and partly the decline in oil prices and the subsequent impact on contract prices. In future surveys, therefore, we may be reporting different trends in prices.

Changing Contracting Practices

The transition to GOG pricing away from OPE in Europe has led to changes in contracting practices. These include the introduction of hub prices into the price escalation clauses, possible reduction in contract duration, reduction in volume flexibility, changes to the delivery point from the border or beach to a hub and the potential removal of all or part of the renegotiation clauses.

The change in contracting practices in other regions is less developed. In the LNG markets in Asia, there is the lack of price discovery and transparency, although there have been efforts to improve this through the price reporting agencies and METI in Japan. With the advent of potential exports of LNG from the US, Henry Hub pricing is being introduced into future contracts and the LNG contracts are becoming unbundled into effective tolling agreements rather than traditional take of pay contracts. In addition, some LNG buyers are beginning to take upstream positions in projects.

Trading Hubs and Liquidity

The development of trading hubs has been a consequence of changes in gas markets and regulation. This is exemplified by the experience in the USA and UK, spreading to other neighbouring countries. The governmental and regulatory drive to liberalise gas markets has been a key factor. Reforms have included regulated third party access to infrastructure, effective unbundling of supply from transportation and release of gas supplies from long term contractual arrangements. However, the market conditions have also been important. A large and diverse gas market, in terms of the numbers of producers, suppliers and buyers, helps foster competition, as does the emergence of surplus gas supply and infrastructure.

As trading hubs develop, the question is asked whether they are liquid enough to provide confidence in pricing transparency and discovery at the hubs and the ability to buy and sell gas. A number of measures can be made of liquidity including churn rates, the narrowness of bid-offer spreads, market depth and “tradability” indices. There is no single agreed measure of adequate liquidity in markets and while it is clear that the US market and the UK and Dutch markets in Europe seem to exhibit more than adequate liquidity on any measure, it is less clear when the threshold between too little and adequate liquidity is passed.

The development of a trading hub in Asia and the LNG market in particular is some way behind the North American and European markets. The regulatory and gas market conditions do not yet exist in Asian countries as they did in North America and Europe and the dominance of LNG in international trade in the Asian region, with the large volume of gas in a single trade, is a further obstacle to overcome. However, there appears to be progress being made towards the establishment of pricing reference points, maybe with increasing price discovery and transparency and Singapore is where LNG players are increasingly locating their businesses, making it an important trading centre for Asia, even if it does not have the conditions to become a physical trading hub.

Gas v Coal v Renewables in Power Generation

The price competition between gas and coal in power generation is not universal in all markets. There appears to be a considerable degree of actual and potential load switching, based on relative prices, in markets such as the US, UK and to some extent Germany, However, this is less evident in Japan, where oil fired generation still has a significant market share, and not at all evident in China, where coal still dominates the generation mix.

In terms of gas and renewables, the example of the Iberian market is that the strong increase in renewables installed capacity and power production in the last years has led to a significant increase in price volatility and instability of the system, reducing the space for CCGTs functioning. Moreover, the decrease of CO2 prices also contributed for the loss of competitiveness of CCGTs, that have production costs higher than coal plants at current CO2 price levels. This new market reality strongly reduces CCGTs usage and induces costs or inefficiencies related with the management of gas supply contracts, operation & maintenance, lower lifetime, etc. CCGTs have now to operate in an unstable environment, with lower load factors and highly variable operation regimes; these changes are structural and are here to stay. Issues like the design of ancillary markets and/or capacity payment mechanisms will be fundamental for CCGTs viability

Social Pricing

The four main regions where Social Pricing (the RSP and RBC categories from the survey) have significant shares are Latin America, FSU, Africa and Middle East. Asia has some in the Indian sub-continent while in Asia Pacific it is mainly Indonesia and Malaysia.

Many countries with Social Pricing have been increasing prices over time because they were traditionally large producers and exporters, who have been caught with rising demand and stagnating or declining production, leading to the need or potential need for imports – Indonesia, Malaysia, Argentina, UAE, Bahrain and Kuwait. Other countries which have raised price have done so for budgetary reasons, to reduce the impact of subsidies on their finances and/or to encourage the development of higher cost reserves – Kazakhstan, Uzbekistan, Egypt, Nigeria, Iran and Oman. On the other hand some countries have not raised prices and these have tended to be those who remain completely self-sufficient and export in significant quantities – Peru, Bolivia, Turkmenistan, Algeria and Saudi Arabia.

Globalisation of Gas Markets and Gas Price Convergence

The analytical matrix below summarises the key factors identified to lead to the globalisation of gas prices and increased connectivity.

Figure 8.1 Analytical Matrix

	Internal	External
Infrastructure	Widespread domestic pipeline capacity. Diversified import capacity - pipeline and LNG.	Infrastructure to move gas between regional markets. Supply of divertible and flexible gas
Regulation / Contractual	Market liberalisation - TPA, Unbundling Demand flexibility and fuel switching	Supply chains allowing the diversion of flexible gas. Physical ability of suppliers to move LNG between regional markets
Pricing	Wholesale price deregulation. Liquid trading hubs	Motivation to move from OPE to GOG pricing. Emergence of portfolio / trading companies

It seems clear from the summary table above and the discussion in this section that many factors need to come together if gas prices globally are to become more connected. Ultimate connectivity would seem to require the development of liquid trading hubs in all the key markets. Such hubs are widespread in North America and Europe but less so in Asia, where the markets are relatively more reliant on LNG.

Infrastructure, both within and between markets, has been crucial as it enables gas (pipeline or LNG) to move freely. However, if the infrastructure is contractually constrained then effectively that prevents competitive utilisation of that infrastructure. This leads to the need to proper market liberalisation including regulated TPA and unbundling. In terms of the gas supply contracting the elimination of point to point contracts, allowing gas or LNG to be diverted to alternative markets in relation to pricing signals is also of key importance.

Finally, the introduction of new participants such as portfolio / trading companies into the key markets and the changing pricing mechanisms to spot / hub pricing (GOG) away from oil indexation (OPE) should ultimately result in increasing price connectivity.

Oil Indexation as Remedy for Market Failure in Natural Gas Industry

By Sergei Komlev, Head of Contract Structuring and Pricing, Gazprom Export LLC, Russia

Background

Market failure is a concept within economic theory describing when the allocation of goods and services by a free market is not efficient. That is, there exists another conceivable outcome where a market participant may be made better-off without making someone else worse-off. (The outcome is not Pareto optimal.). In essence market failure is about mismatch between supply and demand of the traded commodity, its dearth or abundance compared to the situation when private and social welfare are maximized.

Typically market failure reveals itself in suboptimal free market prices which lead to shortages of a traded commodity compared to the wiliness of buyers to consume more or in oversupply of a commodity compared to wiliness of a producer to deliver it. Although the concept of 'market failure' looks purely theoretical, in fact it has important practical implications for the global gas industry.

I am not aware of any dedicated research on market failure in natural gas industry and therefore this study is a first endeavour. There are several types of market failure. I will focus on only those of them that have strong impact on gas industry and primarily on its wholesale markets. For these considerations as example I left 'asymmetry of information' market failures out of scope of this analysis because it manifest themselves on the retail prices while the subject of my study are wholesale prices.

Aim

The common wisdom these days is that major global producers are stubbornly and irrationally standing in the way of progress in gas markets by resisting hub-based pricing in there long-term contracts. Oil-indexed pricing for natural gas is now portrayed as an "anti-market" policy. My view is that natural gas is a special kind of commodity whose market price is best maintained through linking it to oil prices in order to prevent market failures. The position I took in this essay is that at least in Europe and Asia the replacement value principle brings us closer to a resource allocation optimum than that which would be achieved through real world under-reformed "free" markets. Just as I consider natural gas to be a practical bridge fuel to a carbonless future economy, I believe that oil-indexation is the best type of cost-based market signal in our imperfect current markets on the way to something better.

Methods

Economic analysis

Results

Our analysis has shown that the 'no rational' argument against oil indexation is based on an exaggerated and flawed understanding of the market as a whole. I have shown that in Europe competition between natural gas and oil is still strong in industry, commercial and residential sectors. Looking towards Asia, oil products remain a viable substitute to natural gas in power generation. Under these circumstances, oil-indexed natural gas prices are far from outmoded and retain the rational core purpose for which the Dutch formulated them originally.

In general, events that are the sources of market failure are different and stem out of 1) the nature of the good being traded, 2) the nature of the market, and 3) the exchange itself. 'Free' hub prices on the European exchanges are an example of market failure representing the last case. Dependence on oil-indexed prices of the long-term contracts is a more powerful force than supply and demand interplay in setting baseline trend for hub prices behavior. Prior to 2009 contract oil-indexed prices were setting the central tendency price for the European hubs. Hub prices were drifting above and below the oil-indexed price based on seasonal trends and underlying fundamentals. After 2009 with the emergence of liquid hubs oil-indexed prices formed a hard ceiling for European gas balances.

Despite differences of behaviour patterns in the hybrid system of price formation they have one common feature: solid and enduring link to oil prices is embedded in hub prices. As a result of the oil link we have an equilibrium market price on the hubs which are not an indication of the total supply and demand for the whole market. In addition to that on the liquid hubs we see dysfunctional mechanisms of adjusting supply to demand as a result of financialization or monetization of the firm delivery obligations of the suppliers under long-term contract arrangements. Midstreamers have found ways to go around take-or-pay obligations in these long-term contracts by selling their firm obligations on a forward curve and buying back as much of these obligations on the hubs as needed by the end-user clients. Volumetric risks are vested on another party, brokers and financial institutions holders of the forward contracts.

Due to the overcontraction resulting from the overblown expectations for demand growth in Europe there is a permanent disconnect between the volume of paper gas sold and bought back that leads to a situation of enduring oversupply on the hubs. That oversupply modifies term and spot price interaction but does not rule out the dominance of oil peg in their relationship. Oil peg is not an symptom of 'market failure' It is the long-lasting Inability of hubs to rebalance European gas market on their own that is an obvious case of 'market failure'.

Price dysfunction indeed is in place on the liberalized American market. In principle price anomaly in the USA has the same nature as on the liquid hubs in Europe – permanent oversupply of natural gas. The mechanism of oversupply though is different – in the USA gas natural became a spin-off of production of shale oil and gas liquids. Oversupply here is of physical nature. As it was mentioned above oversupply on the European liquid hubs is an outcome of a different reason – overcontraction. Overcontraction leads to mismatch between the volumes of 'paper' gas sold on hubs by the holders of long-term supply contracts and the volumes bought back by them to meet physical demand of their customers.

Low prices have already brought dry gas production in the USA into a state of coma. Drilling for dry gas has nearly halted. From the economically non-performing dry wells drilling relocated to the wet wells and, as result of this transformation, shale gas turned out to be-a by-product of shale oil and gas liquids production. Indeed it is NGL-weighted production that tilts economics of Mercellus play, which is known as a major producer of dry gas too.

Mechanism of adjusting supply to price in gas got completely broken, because from the point of view of a shale oil/NGL producer methane it is not a self-sufficient commodity anymore but rather an 'added bonus' to the price of core products. In worst case when there are no pipelines around, dry gas becomes an unwanted waist product of shale oil extraction that has to be disposed of anyway. It is destined to flaring or pumping back into the well. Dysfunctional market in natural gas is a clear indication of a 'market failure'.

Although there are many parties that benefit from the depressed prices on the USA gas market, oil and gas producers are the losers because they have to sell two valuable products at a price on one.

Under a present state of the American market reaction of supply to depressed pricing is delayed or even absent at all because gas became a spin-off of shale oil and liquids production. Although producers of shale oil and NGLs do their best to adjust supply of these commodities to the demand in order to be profitable, they do not care about a balance on the natural gas market. To them revenues from natural gas sales is an added bonus to that of selling the core products. Supply of natural gas is therefore a function of production of other associated commodities rather than demand for methane itself. In that respect a sharp decline in the oil price which made shale oil production unprofitable in many locations may have a more profound influence on the supply of natural gas cut downs than any changes in the fundamentals of the gas market over the last several years.

Prices set by supply and demand are formally de-linked from oil and should be driven by the fundamentals of their own market. Irony of the situation on the most advanced and liberalized market is that dry gas production became here a function of another commodity output, shale oil. My study brings me to a conclusion that prices for dry shale gas in the USA are distorted and could not be considered as indication of a true value of this commodity.

Are there ways to fix the problem of a ‘market failure’?

Government intervention in a ‘failure market’ is a customary way of resolving the problem. But it is also a common knowledge that government intervention although indispensable in many instances creates the problems of its own named a ‘government failure’.

Global natural gas industry has developed its own unique and purely market response to ‘market failure’ based on a replacement value principle. This response of natural gas industry is unique because there is no other commodity that has relied on replacement value pricing on any significant scale. Under this principle, price of a given commodity is not determined by the fundamentals of its own market but by a price of a basket of its substitutes. These substitutes are competing commodities that originate from the markets that are a way more efficient (although perfect markets exist only in the textbooks) than market for a commodity that is subject to a replacement value pricing.

Global natural gas industry 50 year history of success is largely due to taking advantage of the replacement value of oil and/or oil products in price setting. In that sense dependence on oil/products prices is a problem and its solution at the same time. Oil indexation is definitely a surrogate or an ersatz of market pricing based on supply and demand. But it turned out to be an efficient tool to overcome several types of ‘market failure’ that are characteristic of the free market price setting in natural gas.

Chart 1. Advantages of oil Indexation over government intervention in ‘market failure’ fix

Type of Market Failure	Negative Outcome	Treatment	Remedy Efficiency
Lack of mechanisms of adjusting supply to price signals leads to a wrong level of output	Gas as byproduct of oil is not a self-sufficient commodity	O –I	For decades O-I and long-term contracts served as efficient instrument of matching supply and demand
Instability of prices undermines long-term investments	Inability to plan revenues makes projects difficult to finance	O-I and gov. guarantees	O-I makes projects financeable while gov. guarantees raise risk of antitrust actions
Price manipulation by dominant suppliers	High prices for buyers	O-I and gov. intervention	O-L is a hedge against price manipulation. Poor track record of competition enhancement in gas market by governments
Externalities in gas	Free markets do not address security of supply	O-I and ‘Too big to fail’ policies’	Competition promotion leads to ‘free riding’ while O-I provides security of supply

Source: Gazprom Export

In addition to addressing the ‘small brother of oil syndrome’ described above, oil-indexation in natural gas pricing turned out to be a remedy to the monopoly power abuse by the dominant suppliers. Almost all gas markets outside of North America lack the level of competition to create market mechanisms to fairly price gas as an independent commodity. Global gas markets are dominated by the large national companies that can potentially exercise their market power to distort prices in their own favour by limiting supply. With oil indexation in place this does not happen.

Price manipulation by the dominant or even monopolistic supplier becomes impossible because none of these suppliers is capable of affecting one way or another prices of the replacement value basket made of oil and/or the oil products. And even more to it, daily nominations in the long-term oil indexed contracts comes from the buyers making it impossible for a seller to restrain supply. There is a lot that importing nations can do with enhancing competition on their own domestic markets but they are not capable to overhaul a “god blessed” situation with the gas reserves concentrated in the hands of a few supplier nations.

Another ‘market failure’ in natural gas is traditionally associated with the long investment cycle and a necessity for the financial institutions to bear risks related to the lengthy, from 20 to 50 year, reservoir and gas infrastructure development projects. Liberalized gas markets with their unstable, unpredictable, or even negative hub prices do not provide for a steady cashflows over the life span of such lengthy projects. Long-term hedging instruments, if available, could somewhat mitigate these risks but to a limited extend only. Oil indexation in the dry gas development projects offers a solution as the oil price long-term predictability is a grade higher and fully meets the project bankability criteria.

For decades oil indexation was providing support to the investment cycle in the global gas industry but the joint attack on the oil peg by the British liberal academics and the IEA officials has modified somewhat the mindset of the Asian buyers as they start showing reluctance to sign for the long-term oil indexed projects. In 2013 there were only 7 final investment decisions (FIDs) in the gas industry on the back of growing long-term demand for gas in Asia. That is not enough to meet the growing global demand for LNG.

It is not a surprise that all the seven FIDs were gas liquefaction projects in the USA. Isn’t it a signal that the banks start to except free market price risks in gas? Do not be misled. Banks do not take the Henry hub price risks, these risks are fully transferred to the buyers.

‘Market failure’ in gas has its externalities too. Pricing of gas based on supply and demand reflects short-term gas value and is not fully reflective of the security of supply aspects. LNG supply contracts linked to the hub-based pricing are usually not firm, as they include a redirection clause. When prices do not meet the supplier expectations gas could be without any fines redirected to the premium markets. By enforcing directly or indirectly pricing based on supply and demand instead of oil-indexation European politicians and regulators put at risk the existing long-term supply contracts that are a cornerstone of the supply security in the Continent.

Conclusions

I want to emphasize that the replacement value principle can perform an efficient market fixer role because it has market origin. It is much more efficient than any form of government intervention. This pricing mechanism means that pricing of a commodity in a malfunctioning market is conducted via another substitutive commodity that has a relatively better performing market. The principle conclusion of this essay is that natural gas markets in Europe and Asia operate in malfunctioning markets with potential for severe ‘market failures’ of various kinds and therefore, these ‘market failures’ can be avoided by determining natural gas prices linked to prices for oil/oil products.

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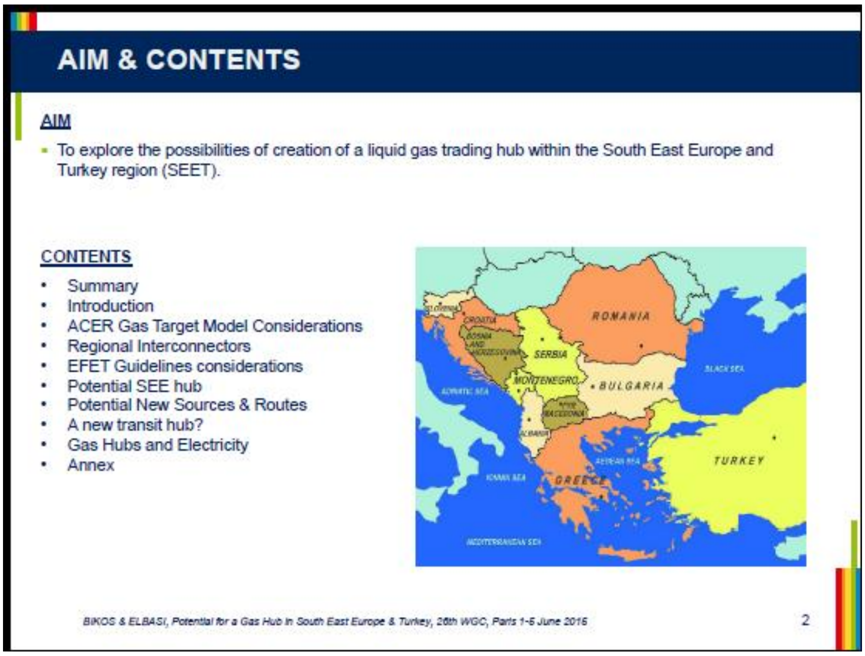
POTENTIAL FOR A GAS HUB IN SOUTH EAST EUROPE AND TURKEY

STELIOS BIKOS – DEPA
ZEYNO ELBASI – BP


26th World Gas Conference
1 – 5 June 2015 – Paris, France
THEMATIC SESSION PGC B-2
Potential for a Gas Hub in South East Europe & Turkey
Stelios BIKOS, DEPA
Zeyno ELBASI, BP
WGCPARIS2015
WORLD GAS CONFERENCE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AIM
To explore the possibilities of creation of a liquid gas trading hub within the South East Europe and Turkey region (SEET).
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SUMMARY

- North West European have already developed gas hubs with reliable pricing signals driven by market forces
- SEET Region (South East Europe and Turkey) gas markets are not yet developed to form a liquid trading hub. Countries in the region have started showing intentions for hub creation driven mainly by supply security concerns.
- Templates for roadmap to hub creation have been developed by ACER[1] and EFET[2]. SEET Region is behind in meeting the requirements of these templates.
- This study scores the SEET region against ACER and EFET criteria and discusses further action to achieve progress.

[1] Agency for the Cooperation of Energy Regulators
[2] European Federation of Energy Traders

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INTRODUCTION

- Starting from the late 90s, North West European countries have developed gas hubs where gas trading started to take place in transparent, increasingly liquid platforms generating reliable price signals.
    - British NBP stated operations in 1997 followed by Dutch TTF in 2003. Belgium, Germany, France, Austria and Italy followed the trend. These trading points are examples of functional gas markets in Europe, albeit of variable success.
    - Combination of fundamentals (large gas surplus), governmental, regulatory and Infrastructural factors have been the key drivers behind creation and strength of these gas hubs.
    - By 2013, 53% of total amount of gas sold in Europe (a lot more in NWE) is done so under gas-to-gas competition, mostly on trading hubs. This shows a significant change from 2005 where only 15% of gas was priced on gas-to-gas. *(Source: Wholesale Gas Price Formation Report, IGU 2015).*
- **SEET has not yet developed liquid gas trading hubs** and compared to NW Europe, is still at early stages of market liberalization. Countries in the Region signal aspirations for further market liberalization and hub creation. (i.e. Turkey based on market size and regional role as a new supply corridor to Europe and each of Greece, Bulgaria and Romania based on specific competitive advantages)
- **Templates for operational gas hubs have been created** and are kept up to date: the Gas Target Model (GTM) by ACER on the regulators' side and the Guidelines for European Gas Hubs by EFET on the traders' side.
- **Potential hub development in SEET will be assessed in this study with reference to ACER and EFET templates.**

SEET: Far from European Gas Hubs

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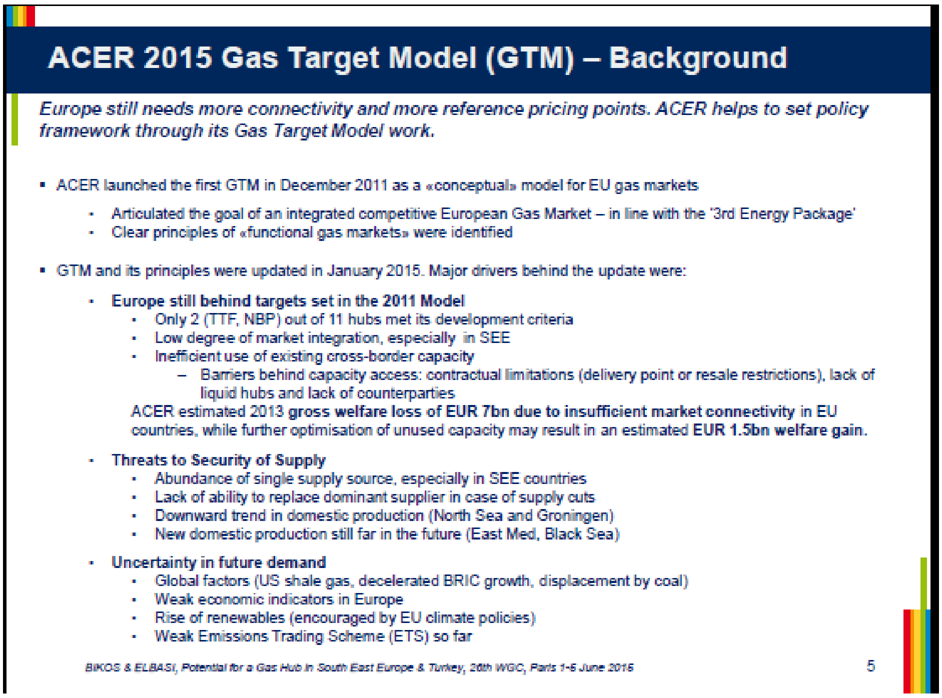
ACER 2015 Gas Target Model (GTM) – Background
Europe still needs more connectivity and more reference pricing points. ACER helps to set policy framework through its Gas Target Model work.
ACER launched the first GTM in December 2011 as a «conceptual» model for EU gas markets
Articulated the goal of an integrated competitive European Gas Market – in line with the '3rd Energy Package'
Clear principles of «functional gas markets» were identified
GTM and its principles were updated in January 2015. Major drivers behind the update were:
Europe still behind targets set in the 2011 Model
Only 2 (TTF, NBP) out of 11 hubs met its development criteria
Low degree of market integration, especially in SEE
Inefficient use of existing cross-border capacity
Barriers behind capacity access: contractual limitations (delivery point or resale restrictions), lack of liquid hubs and lack of counterparties
ACER estimated 2013 gross welfare loss of EUR 7bn due to insufficient market connectivity in EU countries, while further optimisation of unused capacity may result in an estimated EUR 1.5bn welfare gain.
Threats to Security of Supply
Abundance of single supply source, especially in SEE countries
Lack of ability to replace dominant supplier in case of supply cuts
Downward trend in domestic production (North Sea and Groningen)
New domestic production still far in the future (East Med, Black Sea)
Uncertainty in future demand
Global factors (US shale gas, decelerated BRIC growth, displacement by coal)
Weak economic indicators in Europe
Rise of renewables (encouraged by EU climate policies)
Weak Emissions Trading Scheme (ETS) so far
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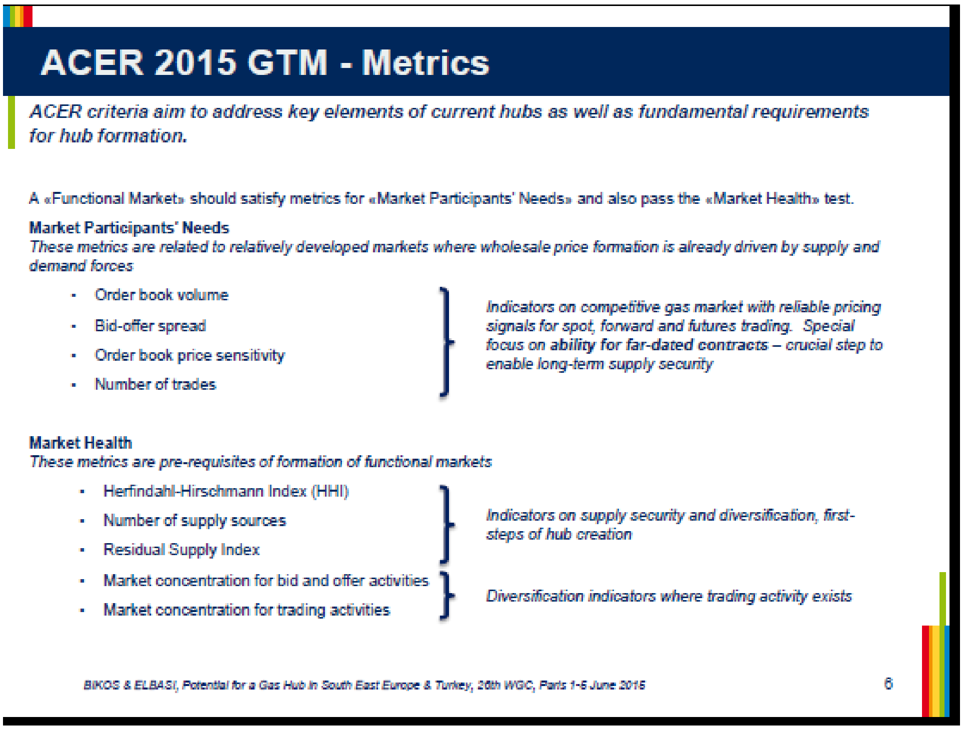
ACER 2015 GTM - Metrics
ACER criteria aim to address key elements of current hubs as well as fundamental requirements for hub formation.
A «Functional Market» should satisfy metrics for «Market Participants' Needs» and also pass the «Market Health» test.
Market Participants' Needs
These metrics are related to relatively developed markets where wholesale price formation is already driven by supply and demand forces
Order book volume
Bid-offer spread
Order book price sensitivity
Number of trades
Indicators on competitive gas market with reliable pricing signals for spot, forward and futures trading. Special focus on ability for far-dated contracts – crucial step to enable long-term supply security
Market Health
These metrics are pre-requisites of formation of functional markets
Herfindahl-Hirschmann Index (HHI)
Number of supply sources
Residual Supply Index
Indicators on supply security and diversification, first-steps of hub creation
Market concentration for bid and offer activities
Market concentration for trading activities
Diversification indicators where trading activity exists
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ACER 2015 GTM - Metrics

As SEET does not yet have a trading hub, some GTM metrics do not apply. The analysis will concentrate on the remaining metrics related to Market Health.

- **Herfindahl-Hirschmann Index (HHI) - Target: below 2000**
  - An indicator for market concentration or degree of competition.
  - Fully monopolized market – one player, 100% share, HHI of 10000.
  - Extreme of high competition – say 100 players, 1% share each, HHI of 100.
  - Particularly useful to show status of monopolistic structures in SEET.
  - HHI = $\sum(\%\ market\ share\ of\ each\ player)^2$

- **Number of Supply Sources – Target: at least 3**
  - Refers to number of supplying countries rather than commercial entities
  - Most SEET countries rely on a single source for imported pipeline gas. (Turkey and Greece are exceptions)
  - Increased number of supplying countries reached by LNG spot sources

- **Residual Supply Index - Target: at least 110% @ 95% of days**
  - Ability of market to replace its largest external supplier in case that supplier fails to deliver
  - RSI = (Total Supply – Supply by Largest Supplier) / Total Demand
  - Challenging in traditional contractual environment (may be invalidated due to significant systemic local oversupply)
  - Subject to 'common mode failure' if say largest supplier failure leads to simultaneous failure of other suppliers.

- **Ideally, a market will feature:**
  - **Many small market participants** helps meet the HHI criterion
  - **Many supply sources** helps meet the Number of Supply Sources criterion
  - **Balanced supply portfolio** helps meet the RSI criterion

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ACER 2015 GTM - Metrics

Current Market Situation and Assessment:

Metrics values for SEE countries

	Number of Sources	HHI	RSI
Greece	9	5181	131%
Bulgaria	2	7587	13%
Romania	4	3270	104%
Croatia	5	5987	125%
Slovenia	5	5027	74%
TARGET	≥ 3	≤ 2000	≥ 110%

Source: ACER, 2012 data
9 sources for Greece represent multiple spot LNG sources

Degree of Dependence on Single Supplier

Country	Consumption (bcma)	Net Imports (bcma)	2012 RU% on Imports
Romania	18	2	100
FYROM	0,1	0,1	100
Bulgaria	2,6	2,48	100
Bosnia & Herzegovina	0,4	0,4	100
Serbia	2,4	2,0	99
Croatia	3,2	0,6	96
Montenegro	0	0	90
Greece	3,5	3,5	57
Slovenia	1,1	1,0	47
Turkey	35	34	46
Albania	0,03	0	-

Source: V. Tsachevsky, Energy Mgt in S.E.Europe, E-Publications of Pan-European Institute, 2/2013. RU: Russia

Notes:

- None of the SEE countries comply with the criteria because of high degree of dependence on a single supplier
- Turkey has the greatest number of pipeline suppliers (Russia, Azerbaijan and Iran)
- Diversity within the SEE mostly driven by LNG (i.e. Greece) and interconnections with adjacent markets (i.e. Hungary, Turkey)
- However **high market concentration (high HHI)** and **low capability to replace dominant supplier (low RSI)** indicate barriers for hub creation.

Each metric addresses current market barriers:
- High degree of dependence on single supplier. *SEE countries are proven to be most affected in case of prolonged supply cuts from Russia (source: ENTSOG 2013 simulation results) (low RSI)*
- Low level of interconnection with adjacent markets (so fewer supply sources)
- Lack of transparent market structures / markets dominated by incumbents *(High HHI)*

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Interconnections / Infrastructure I

Fundamental barriers identified by GTM criteria are lifted through increased interconnection capacity and access to new supply sources as interconnections increase size of market zone and expand supply options.

Projects of Common Interest (PCI)

- EC has identified PCIs which should:
  - Serve for further integration of gas markets (by connecting market zones or improving existing interconnections)
    - De-bottlenecking flows will lead to arbitrage opportunities and result in strong price connectivity. **Potential gross welfare gains are the appropiate measure for project selection.**
  - Increase competition in the markets
  - Strengthen supply security through supply diversification (increased number of supply sources)
- A PCI would benefit from fast- track permitting and adequate financial resources
- **Limited availability of project funding in the region is the major challenge behind realization of PCIs**
  - Initial PCI list includes 107 gas projects with total investment cost of 53bn euros (source: EC)
  - CEF (Connecting Europe Facility) allocated a total of 5.8bn euros for all PCIs (gas and electricity)
  - **CEF funding represents only about 3% of the total investment needed** – *but may help to attract other funds*
- Specific focus to Priority Projects that serves for security of supply, especially in SEE markets where the connectivity is weak, may help materialize the identified projects with the funding available.

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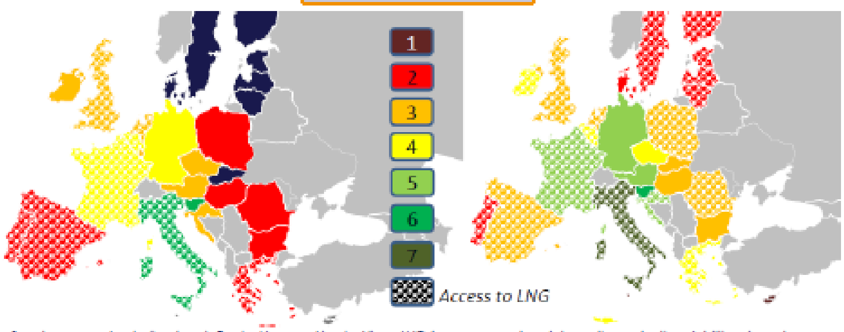
Interconnections / Infrastructure II

Once implemented, PCIs will diversify supply sources to the SEE countries and Turkey.

- **Southern Gas Corridor** increases supply diversity in the Region – Greece, Bulgaria and Romania will have access to at least 3 pipeline gas resources each on a continuous basis.
- New **LNG terminals** in North East Greece and Croatia will provide a fourth (at least), independent source of gas, especially if accompanied by fully functional regional interconnections.

Current situation | ***Number of supply sources*** | **After completion of PCIs - 2022**



Supply sources: Azerbaijan (new), Russia, Norway, Algeria, Libya, LNG (as one source) and domestic production. Additional supply sources would at least cover 5% of country demand
Source: EC, ENTSOG

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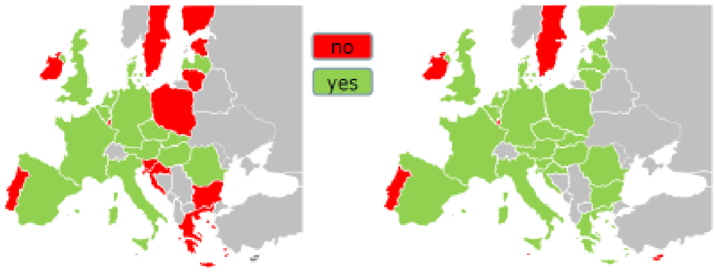
Interconnections / Infrastructure III

Once implemented, PCIs will also strengthen security of supply through increased redundancy of supply routes

- **Interconnectors**
  - New: Greece-Bulgaria, Turkey-Bulgaria, Bulgaria-Serbia, Bulgaria-Romania, Ionian Adriatic Pipeline
  - Retrofit: More capacity Bulgaria-Greece, reverse flow Romania-Hungary

- Finalisation of these projects will result in more supply routes - SEE countries will meet **N-1 Infrastructure Standard**
  - **N-1 Infrastructure Standard is complementary to GTM RSI metric**
  - Defined as enough capacity to meet 1-in-20-year peak demand when the capacity of the largest infrastructure is deducted *(2010 Supply Security Regulation No 994)*
  - Expresses infrastructural resilience, whereas RSI represents contractual resilience

Compliance with the N-1 infrastructure standard – before and after (2022)



Source: EC, ENTSOG

All SEE countries will meet N-1 criterion if PCIs are implemented

EFET Guidelines – Roadmap to Hubs I

Interconnections / infrastructure are necessary but not sufficient. Structural market changes supported by regulation are also needed.

- **EFET provides a practical delivery roadmap applicable to SEET complementing the fundamental requirements addressed by ACER's GTM**
- EFET has been developing best practices for hub creation and assessing, through them, the progress in current and towards potential gas trading hubs in Europe. A scoring mechanism has been devised and market assessments made (see **Annex 1**).

- EFET's European Gas Hub Development Guidelines
  - Set out a roadmap of milestones on the way towards the ultimate: a liquid gas trading exchange
  - Clearly define the roles and responsibilities in achieving these milestones of
    - National Regulatory Authorities (NRA),
    - Transmission System Operators (TSO) and
    - Market Participants (traders)

- However, **paramount to success is the dedication of Governments to mobilize stakeholders, in a quest for social welfare gains.**

- We concentrate on key SEET countries (**Turkey, Greece, Bulgaria and Romania**):
  - All seek to fulfill the institutional requirements towards a functional liquid gas trading hub
  - All are analyzed against EFET's Guidelines

EFET Guidelines II

EFET roadmap starts with establishment of a Virtual Trading Point and ends with the establishment of a liquid gas trading Exchange. Several reforms contribute along the way.

Establishment of Entry-Exit System with Virtual Trading Point(s)

Balancing Market

Structural Market Reforms

Establishment of an Exchange

Reliable Hub Price Index

This first step has already been taken by GR, RO, TR and about to be taken by BG

Consultation

- First and foremost, steps must be discussed and implemented through **consultation with stakeholders** for each hub.

Steps include:

- Establishment of an Entry-Exit system with VTP(s) and clear access terms, title transfer and imbalance transfer services by the TSO is key to facilitate a hub.
- **Resolution of structural market issues** to foster liquidity and competition. Liquidity provider / market maker roles would be introduced and encouraged by the NRA.
- Establishment of a Hub Operator (HO) and definition of its governance rules by the NRA.
- Firmness of hub would be achieved after a while through a liquid balancing market facilitated by TSO/HO and reference prices for imbalance would thus be established.
- Development of standard contracts by market participants (i.e. EFET master trading agreements), availability of price reporting agencies and the coming of brokers would then facilitate an exchange.

EFET work is an excellent starting point setting clear steps that need to be taken by institutions. High level of market commitment is required to implement these steps. ***SEET countries should show full commitment supported by Governments.*** *Otherwise, it will not be possible to achieve such a goal.*

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EFET Guidelines - TURKEY

Turkish institutions and market players are capable of ensuring hub formation

Steps to meet EFET guidelines:

- NRA should start holding consultations with the effective participation of stakeholders.
- TSO should establish daily pricing at the existing VTP based on supply/demand
- NRA should define transparent rules of governance of an HO, most probably the existing TSO.
- Government / NRA should engage in resolving the known structural market issues, to the benefit of strategic goals in the region. Examples include
    - deregulation of prices, transparent rules for cross-border trade, establishment of the incumbent – along with others - as a market maker and liquidity provider.
- As a consequence:
    - As balancing market at VTP develops and structural reforms supported by regulations are achieved, firmness of hub would be strenghtened further through liquidity
    - Traders would adopt standard contracts, easing trades at the VTP.
    - PRAs would be attracted to cover transactions at the VTP, so adding transparency
    - As traded volumes increase, individual trades would be aggregated by credible brokers, acting as a risk buffer between the HO and small traders.
- The establishment of a gas trading Exchange would follow, most probably by one of the existing exchanges.
- **Price Index at the Exchange would then be recognized as a reliable price signal for the country and the region.**

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EFET Guidelines - GREECE

Greek institutions and market players are already on course to a hub formation

Steps to meet EFET guidelines:

- TSO should establish an intraday market at the existing Virtual Nominations Point, starting with a Balancing Platform and evolving into a full Virtual Trading Point for physical and non-physical trades.
- TSO should be guided by the NRA to harmonize Nominations and Matching practices with neighboring countries, notably Bulgaria and Turkey (depending on regulatory progress there), for cross-border trade.
- NRA should define transparent rules of governance of an HO, most probably the existing TSO.
- Government / NRA should encourage players other than the incumbent to participate actively in the market. Examples include
    - Encouragement of the incumbent and other wholesalers to act as market makers and liquidity providers
    - Help to gas consumers (power producers, industry, distributors) to exploit the market at the VTP
- As a consequence:
    - As balancing market at VTP develops, firmness of hub will be strenghtened through liquidity
    - Traders will adopt standard contracts, easing trades at the VTP.
    - PRAs would be attracted to cover transactions at the VTP, so adding transparency
    - As traded volumes increase, individual trades would be aggregated by credible brokers, acting as a risk buffer between the HO and small traders.
- The establishment of a gas trading Exchange would follow, most probably by one of the existing exchanges.
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Potential SEE Hub – I

However diligently Greece develops a hub, its domestic market could do with more volumes. A joint SEE hub could be the solution.

- With the completion of planned infrastructure projects, GR, BG, RO would hit the GTM targets through access to multiple resources.
- Moreover, Greece, Bulgaria and Romania will be well-integrated among them to exercise cross-border gas trade.
- There is value in integration of these countries (compared to a single hub in each) as
    - The overall market size will be larger than otherwise, encouraging liquidity
    - The upstream and downstream connections of the new market will be many and diverse, including LNG
    - Competition will exist overnight, as players in each country (including incumbents) will compete against players in the other two countries.
    - The share of each incumbent will instantly reduce to a lower level, simply because of enlargement of their target market.
    - Prices will inevitably converge to a sustainable level.
    - Through price convergence, consumers are likely to enjoy a unified energy-cost environment, reducing mobility obstacles for people, business and goods within the new market.
- After creation of a SEE pricing hub:
    - Other markets, (Serbia, BH, Albania, FYROM, Montenegro) could act either as «satellite markets» (see ACER GTM Annex 6), when further necessary IC projects would be made operational and regulation would permit or follow their own path to national hubs. Eventually, one regional hub is likely to prevail. Croatia and Slovenia are most likely to attach themselves to the Italian PSV and the Austrian CEGH hubs.
- **Main prerequisite** of integration is to convince all countries involved that integration is the safest route to a welfare gain through:
    - Reduced energy poverty
    - Competitive industry (energy costs "in the market")
    - More cost effective power production

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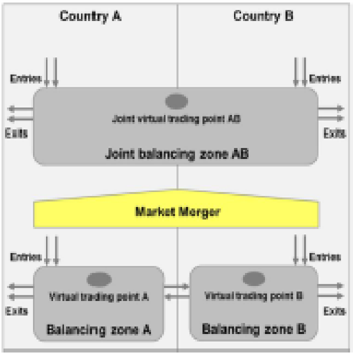
Potential SEE Hub – II

A joint SEE hub would need stable steps and constant assessment of feasibility along the way.

- Annex 6 of the GTM provides valuable guidance on how to pursue integration. Depending on progress on either side of each SEE border and on lowering non-gas related barriers (cultural, historical, political etc), integration may proceed in steps:
  - First, use **Market Coupling** to increase liquidity in each national hub.
  - Then, move by establishing a **Trading Region**.
  - Finally, go for full **Market Merger**.
- Variations and ad-hoc deviations to match the case might prove necessary.
- Though long in time, this sequence of steps is likely to provide a stable transition towards a robust regional SEE gas market, comparable to those of Central Europe if not Western Europe.
- This new SEE market is bound at some point along the way to link up with the Turkish market. Then, the whole SEET will have achieved its potential in enjoying healthy price signals and efficient investment allocation.



GTM Market Merger Model

- The final step towards a joint SEE hub would resemble the scheme above, albeit for three countries.
- Interim steps and additional work (regulatory and technical) would be required for such a result.

Potential New Sources & Routes

Multiple projects are considered in the region.

These projects would further bring supply and route diversification which should help liquidity in future hub(s) once implemented.

A new Transit Hub?

If regulation either side of the Turkish-Greek border allowed, a new transit hub could emerge.

Such a hub would:

- Resemble CEGH and ZEE in relying on transit flows rather than local markets
- Add liquidity to regional VTPs
- Allow arbitrage among VTPs
- Cement energy cooperation in SEET and beyond

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Gas hubs and electricity

Whereas gas and electricity may be traded at separate hubs, it may make economic sense for joint exchanges to be set up, when hubs mature.

- A number of national players in the region promote the creation of national "energy exchanges" where both gas and electricity will be traded.
- Such combined exchanges are justified where a significant portion of a country's physical gas flows end up as fuel for power generation; otherwise, such exchanges merely house two largely independent commodities with significant synergies only in the financial part.
- In SEET, gas has a significant role to play in power production and is significant in shaping the Marginal System Price of power.
- Moreover, significant amounts of power are traded among the countries of the region,
    - mostly cheap hydro- and nuclear power of the North flowing South
    - bidirectionally in some of the interconnection points between adjacent countries.
- In short, the emergence of gas pricing hubs among Greece-Bulgaria-Romania and separately in Turkey may trigger the emergence of similar regional exchanges of electricity
    - Either at the same location(s) with those of gas
    - Or totally independent.

	BU	GR	RO	SEE	TR
PowerGen from Gas	5%	22%	14%	14%	43%
Gas into PowerGen	38%	59%	24%	33%	48%

Source: EC DG Energy, 2014 Country Factsheets V.3, TEIAS, EMRA

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Annex
EFET European Gas Hub Development Guidelines & Country Analysis

Source: BIKOS & ELBASI, *Potential for a Gas Hub in South East Europe & Turkey, 26th WGC, Paris 1-5 June 2015*

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EFET Scoring Mechanism

Developed hubs score 20 (i.e. UK NBP)

Responsible party	What should be done	Scoring mechanism
NRA	Establish a consultation mechanism	1 if group set up and English language
TSO	Entry-exit system established	½ for Entry Exit; 1 if a single VTP
TSO	Title Transfer	
TSO	Cashout rules	
TSO	Accessible to non-physical traders	1 if trade without signup to physical rules
TSO	Firmness of hub	0 if not firm; ½ if firmness "managed" by TSO; 1 if BUBD; 2 if fully market-based
TSO	Credit arrangements non-punitive	
NRA	Resolve market structural issues (defined role for historical player)	½ for release etc; 1 if market maker
NRA	Role of Hub operator	1 – role defined; 2 – gov'nce addressed
NRA	Agree regulatory jurisdiction if cross border	0 if cross border and no agreement; 1 if not cross border or does have agreement
Market	Establish a reference price at the hub for contract settlement	1 if price always available; ½ if deemed
Market	Standardised contract	1 if specialised contract – EFET or equivalent (or standard is sufficient)
Market	Price Reporting Agencies at the hub	1 if several' ½ if only one PRA
Market	Commercial / Voluntary market makers	
Market	Brokers	1 if voice or few ; 2 if systems and many
NRA	Establishment of exchange	1 if exchange appointed and hub is liquid; ½ if exchange appointed and hub illiquid
Market	Index becomes reliable and used as benchmark	1 if Market parties frequently requested

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EFET Scoring Mechanism BULGARIA

Bulgaria – Score 1½

EFET

Responsible party	What should be done	Comments	Score
NRA	Establish a consultation mechanism	Document released in Bulgarian language	½
TSO	Entry-exit system established		0
TSO	Title Transfer		0
TSO	Cashout rules		0
TSO	Accessible to non-physical traders		0
TSO	Firmness of hub		0
TSO	Credit arrangements non punitive		0
NRA	Resolve market structural issues (defined role for historical player)		0
NRA	Role of Hub operator		0
NRA	Agree regulatory jurisdiction if cross border		1
Market	Establish a reference price at the hub for contract settlement		0
Market	Standardised contract	Being discussed	0
Market	PRAs at the hub		0
Market	Market makers		0
Market	Brokers		0
NRA	Establishment of exchange		0
Market	Index becomes reliable and used as benchmark		0

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EFET Scoring Mechanism GREECE

Greece– Score 5

EFET

Responsible party	What should be done	Comments	Score
NRA	Establish a consultation mechanism		
TSO	Entry-exit system established	Under discussion	½
TSO	Title Transfer		1
TSO	Cashout rules		1
TSO	Accessible to non-physical traders		0
TSO	Firmness of hub	Allocated as nominated	½
TSO	Credit arrangements non punitive	Not established	0
NRA	Resolve market structural issues (defined role for historical player)	Gas release 10% of imports – prob at VTG	½
NRA	Role of Hub operator	Desfa runs VTP; HO not defined	½
NRA	Agree regulatory jurisdiction if cross border		1
Market	Establish a reference price at the hub for contract settlement	Imbalance published with 3 month delay	0
Market	Standardised contract		0
Market	PRAs at the hub		0
Market	Market makers		0
Market	Brokers		0
NRA	Establishment of exchange		0
Market	Index becomes reliable and used as benchmark		0

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EFET Scoring Mechanism ROMANIA

Romania – Score 2½

EFET

Responsible party	What should be done	Comments	Score
NRA	Establish a consultation mechanism		0
TSO	Entry-exit system established		0
TSO	Title Transfer		1
TSO	Cashout rules		0
TSO	Accessible to non-physical traders		0
TSO	Firmness of hub		0
TSO	Credit arrangements non punitive		0
NRA	Resolve market structural issues (defined role for historical player)		0
NRA	Role of Hub operator		0
NRA	Agree regulatory jurisdiction if cross border		1
Market	Establish a reference price at the hub for contract settlement		0
Market	Standardised contract	Being discussed	0
Market	PRAs at the hub		0
Market	Market makers		0
Market	Brokers		0
NRA	Establishment of exchange		½
Market	Index becomes reliable and used as benchmark		0

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EFET Scoring Mechanism TURKEY

Turkey – Score 5½

EFET

Responsible party	What should be done	Comments	Score
NRA	Establish a consultation mechanism	Petform+EFET	1
TSO	Entry-exit system established	Under discussion	0
TSO	Title Transfer		1
TSO	Cashout rules		1
TSO	Accessible to non-physical traders	?	
TSO	Firmness of hub	?	
TSO	Credit arrangements non punitive	?	
NRA	Resolve market structural issues (defined role for historical player)	?	
NRA	Role of Hub operator	BOTAS	½
NRA	Agree regulatory jurisdiction if cross border		1
Market	Establish a reference price at the hub for contract settlement		
Market	Standardised contract	Proposed, unclear if adopted	½
Market	PRAs at the hub	Limited	½
Market	Market makers		0
Market	Brokers		0
NRA	Establishment of exchange		0
Market	Index becomes reliable and used as benchmark		0

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26

Challenges and opportunities in Asia's future LNG pricing

At a major turning point

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Background

The global LNG industry is relatively young, just celebrating its 50 year anniversary in October 2014. Thus it is quite natural for it to continue changing its shape and evolving.

In the past the global LNG market has doubled its size every ten years - from 50 million tonnes in 1990, 100 million tonnes in 2000, and 220 million tonnes in 2010. Now it is expected to have 400 million tonnes per year by 2020.

The latest phase of expansion, starting in the 51st year of the industry, is expected to be unprecedented. We also saw huge expansion of the industry from 2009 to 2011. And it was also unprecedented at that time and the expansion caused a lot of changes.

During the latest phase of expansion, significant transformation in trading patterns is expected. This phase is even more unprecedented as two production centres are expected to increase presence: Australia and the United States. This is also expected to bring about another layer of flexibility and liquidity into the market.

In this always evolving industry, it has been often difficult to predict the future. Players act based on some specific perspectives and assumptions, and they often lead to unintended consequences.

Just ten years ago many people thought that the United States would be short of gas and importing a lot of LNG. But the expectation of higher gas prices over there encouraged huge domestic gas production, not only LNG production projects around the world targeting the United States.

Then during the past year we saw declining oil prices, partly caused by expansion of liquid production in the United States, which in turn was caused by expectation of widening gaps between dry gas and oil prices.

While some people may expect an amply supplied LNG market for some years to come, others may be worried about slowing investment leading to supply shortage years later.

At the beginning of 2015, the LNG industry was already facing another new set of challenges caused by the declining oil and gas prices.

In the short-term, while lower prices mean smaller revenues for sellers, they offer some relieves to LNG buyers, especially in North Asia, who have suffered financial pains from expensive LNG prices in the past five years or so, in both contract and spot and short-term purchases. The lower prices may also encourage those potential buyers who have been hesitant to decide to introduce LNG because of expensive prices.

At the same time, the relatively rapid change in pricing environment has made it more difficult for buyers to establish procurement strategies than in the past, as they may find it more difficult to predict future pricing environment.

Japanese and Asian LNG long-term contract prices have been linked with crude oil prices for decades. It is because oil was considered to be the main competing fuel against LNG and there was not, and has not been, a better indicator to represent the general energy market trend in the region. The linkage was in general accepted as a reasonable practice until around 2008 although the percentages of linkage had been contentious issues in price negotiations between LNG sellers and buyers from time to time.

Since 2008, however, in the wake of rapid increase of gas production in the United States, price gaps between Asia and North America have been widened and so apparent, especially after the 2011 nuclear crisis in Japan. Many LNG buyers have realized that it would be structurally very difficult to reduce the gaps if they continue relying mostly on the linkage.

General public, especially in Japan, are also now well aware of high costs of LNG, as electricity prices have been raised for both residential and industrial uses, although there have been some misunderstandings that LNG has been expensive because it is LNG - if gas had been supplied via seaborne pipeline it would have been even more expensive in the past.

In order to keep energy prices affordable and maintain industrial competitiveness, every possible measure should be taken, including energy savings and boosting renewable energy capacity, as well as (re)starting nuclear reactors which are confirmed safe (according to the new safety standard, in case of Japan).

In terms of LNG procurement, buyers should try to obtain reasonably lower prices for both long-term contract deals and short-term and spot LNG transactions.

While majority of LNG is traded under long-term contracts, spot and short-term cargoes are playing a more important role in recent years.

Some information service companies have provided spot price assessments. Those have not established as reliable price benchmarks yet, as the market is not yet liquid enough. As actual transactions are still not so many and companies do not make transaction details disclosed, the assessments are mostly based on notified offers and bids.

However, they can still be viewed as some indications of market sentiments. In 2014 it was expensive, hitting 20 dollars per million Btu in February. One year later in 2015 it was less than 7 dollars.

Growth of short-term trades is accompanied with the growth of the overall market, as well as diversification of sources and markets. More than 60 million tonnes or 1/4 of the total LNG is traded under short-term arrangements.

Aim

The buyers in the region have been trying to obtain better terms and conditions in LNG procurement, by diversifying their supply sources, contract terms - including both long-term and short-term contracts - and pricing methodologies.

They also want to improve restrictive clauses in traditional sale contracts to make procurement more flexible so that they can be more resilient in the more variable market environment in the wake of anticipated more market opening policies.

This flexibility is expected not only to mitigate risks of downstream market fluctuation but also enhance opportunities to bring upside benefits to LNG buyers in the international LNG market.

This could also be good for LNG sellers as this could provide with them expand greater LNG markets as a whole than otherwise.

Methods

Around the turn of the century some utility buyers from Japan started considering minority equity participation in the upstream, liquefaction and ocean transportation segments of the LNG value chain.

They initially started modest investment into those segments. After seeing more proliferation of LNG production projects in the Asia Pacific region, some buyers have become more proactive in equity participation. And this has not been confined to Japanese players, but also included LNG buyers in other countries.

In most cases Japanese players' equity participation is accompanies by project financing deals organized by the Japan Bank for International Corporation (JBIC) and biggest commercial banks, leading to stable and competitive capitals employed.

Because LNG projects have been capital intensive and needed several years to construct, even after several years of conceptual and planning stages, long-term reliable sources of financing have been very important.

Several such project financing deals were concluded in 2014 for LNG projects, which were major factors of those project sanctions.

In addition to those familiar names in this business some new financial institutions are entering LNG project financings. Appetite from those Japanese banks is expected to be strong in the years to come. The loans provided by private banks are insured by Nippon Export and Investment Insurance (NEXI). Those financing arrangements ensure stable project development.

For those volumes allocated in proportion with equity participation, buyer-partners have certain degree of discretion in pricing the commodity. This type of flexibility is expected to have positive influence on other portions from the same project, as well as trends in the industry as a whole.

Another important aspect of changing trends in recent years has been a pursuit of introduction of different indices in LNG pricing - notably Henry Hub and other North American ones.

Some indirect impacts had been briefly felt even before the recent wave of LNG export projects in the United States (notably regulatory approvals and project activities in 2014), as some volumes of LNG originally proposed to be sold into the United States had been diverted to the Asian markets - some of them were priced at a discount to the Henry Hub at their FOB points with additional transportation elements.

But in most cases it was intermediary players that pocketed arbitrage profits and those diverted cargoes did not translate into hugely more competitive prices in the end-use markets in Asia. The cargoes were priced arbitrarily referring to either NBP plus transportation elements or prevailing Asian long-term contract prices, rather than the Henry Hub.

From those LNG export projects in the United States, expected to become online from 2016, several Asian players have made long-term lifting commitments with prices linked to Henry Hub prices, rather than crude oil.

Some commitments have been made in the form of liquefaction tolling arrangements rather than straight-forward sale-and-purchase agreements (SPAs) at the planned plants, meaning that the offtakers are responsible in procuring feedgas and pipeline transportation to the plants as well as ocean transportation of resulting LNG.

From those LNG export projects planned in other countries, Asian LNG buyers also seek diversification in pricing, as well as more flexible terms and conditions.

The G7 energy ministers' meeting in May and summit meeting in June 2014 confirmed their further efforts to promote flexible LNG markets, including relaxation of destination clauses and producer-consumer dialogue.

At the annual LNG Producer - Consumer Conference in November 2014 in Tokyo, as well as other international industry conferences - including the Gastech conference in March - the Japanese and other government officials and company representatives also called for greater flexibility in LNG trades.

Many people in the industry used to say, especially until early 2014, that the LNG market would be tight until 2015. They often fail to distinguish between the global LNG market as a whole and the short-term LNG market. The notion of tightness itself may have had effects to raise negotiated prices. Because of this, the notion of market tightness is part of the structural problem of expensive LNG prices.

Such arguments of tightness of short-term LNG markets, often found in commercial media and sellers' comments, could have given undue supports to such LNG sellers, leading to unrealistically high offering prices.

The overall balance in the LNG market did not show any signs of tightness, even though some supply disruptions are observed from the Atlantic region producers. Lost LNG volumes in European markets in recent years have been more than offset by Russian pipeline gas supply, as well as reduction of overall gas demand.

Some decreasing liquidity of short-term LNG cargoes is sometimes observed leading to seasonal imbalances.

Even though major expansion is expected to begin, the past few years have been quite an unusual time of lower growth for the LNG industry caused by combination of factors of supply disruptions in some Atlantic region sources and more importantly disappeared LNG demand in Europe. Part of this demand destruction in Europe has been also caused by the illusive notion of LNG market tightness and higher prices.

Results

Later in this decade LNG from the United States is expected to start flowing into the Asian LNG markets. There remains uncertainty over whether it would lead to lower prices of LNG in the region, while it is certain that this would bring pricing diversification of LNG.

When landed prices in Asia for LNG from the United States are expected to be more expensive than oil-linked LNG prices in Asia, some of the American LNG, or the gas before liquefaction, may be diverted to other markets, either in the United States or other LNG/gas consumers.

If persistently lower oil prices are also assumed, there could be a convergence of those LNG prices linked with oil and those determined according to gas indices. Resulting narrower bands of LNG prices and increasing liquidity out of more flexible lifting arrangements from the United States and other supply sources as well could lead to improved transparency and active trading in the Asian LNG markets. This would facilitate development of Asia's own active market places.

Conclusions

In conclusion, in order to mitigate expensive LNG costs, Japanese and Asian LNG players are trying to be more proactive in their procurement activities, notably in equity participation and acquiring volumes with competitive pricing and other conditions. And they should continue doing so. This is expected to lead to Asia's own competitive and transparent market place.

A larger and more flexible LNG market is expected with capacity expanding to 400 million tonnes per year globally by 2020. Demand for the fuel is expected to grow but with significant uncertainty. Therefore greater flexibility is not only expected but is necessary.

Although the market is accompanied with more uncertainty and is expected to be more difficult to manage, the greater market is expected to provide more reward. New reality of lower crude prices and market calls for more competitive LNG prices pose challenges - but they should be overcome through cooperation between parties.

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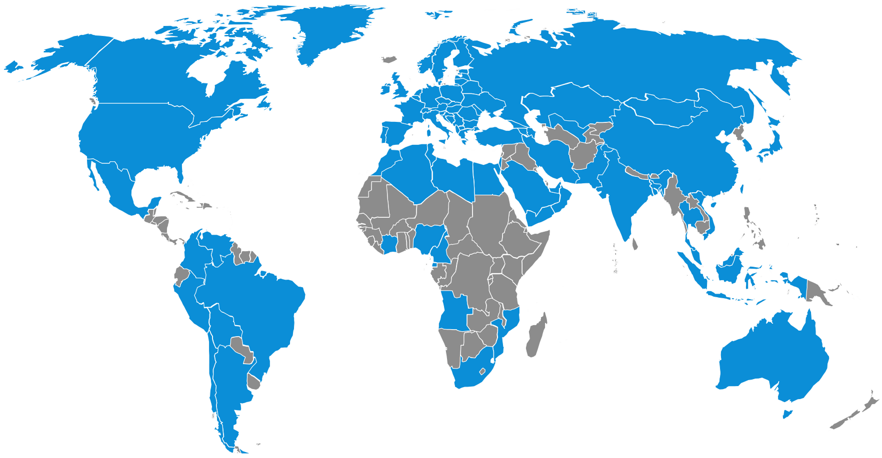
"Significant events in the LNG industry in 2014 and their future implications" Hiroshi Hashimoto and Seishi Fukuoka, Institute of Energy Economics, Japan - IEEJ, March 2015

NOTES



The International Gas Union (IGU) was founded in 1931 and is a worldwide non-profit organisation promoting the political, technical and economic progress of the gas industry with the mission to advocate for gas as an integral part of a sustainable global energy system. The IGU has more than 142 members worldwide and represents more than 97% of the world's gas market. The members are national associations and corporations of the gas industry. The working organisation of IGU covers the complete value chain of the gas industry from upstream to downstream. For more information please visit **www.igu.org**

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