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## International Gas Union (IGU)

News, views and knowledge on gas – worldwide



# Wholesale Gas Price Formation

- A global review of drivers and regional trends



# Foreword

Following the successful 24th World Gas Conference in Buenos Aires in October 2009, we have decided to convert some of the study reports presented at the conference into IGU publications, including the report “Gas Pricing” written by Study Group B2 of the IGU Strategy Committee (PGCB).

The IGU Strategy Committee is updating the review for the WGC in June 2012. Some interim findings have been published in the April 2011 edition of the IGU Magazine and are available on [www.igu.org](http://www.igu.org).

Historically, gas prices have not been in the news to the same extent as oil prices. This is changing. The share of gas in global energy and fuel consumption has increased and also the share of internationally traded gas globally is greater than before. LNG is providing intercontinental linkages that eventually could constitute a global gas market.

Natural gas is an abundant resource, it is clean and cost-competitive, and should therefore play an important role in the mitigation of climate change. However, the pricing of this valuable commodity is critical to a sustainable market growth.

It is our hope that this publication can serve as one example of how vital information related to gas pricing can be shared across borders to the benefit of the global gas industry and also to enable new gas regions to learn more about the different pricing models that are being used.

June 2011

Torstein Indrebø  
Secretary General of IGU



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# Table of contents

1. Executive Summary .....	4
2. Introduction .....	7
Mandate .....	7
Why this report? .....	7
Outline of report .....	8
Terms and concepts .....	8
3. Gas price drivers.....	10
Competitive markets.....	10
Short to medium term supply and demand drivers .....	10
Long term supply and demand drivers.....	11
Current scenarios.....	13
Other market organisation .....	13
OECD area .....	13
Non-OECD area .....	14
4. Key gas pricing mechanisms.....	15
5. Origins of individual pricing mechanisms .....	18
Origins of gas or oil market based pricing .....	18
North America .....	18
The UK.....	18
Continental Europe.....	19
Asia Pacific.....	19
Origins of regulated gas pricing .....	20
6. Recent gas price developments .....	23
OECD area .....	23
Rest of the world .....	24
7. Current extensiveness of individual pricing mechanisms .....	28
Introduction .....	28
Price Formation Mechanisms.....	30
Types of Price Formation Mechanism .....	30
Results .....	30
Format of Results .....	30
World Results .....	30
Regional results.....	34
Wholesale Prices .....	38
Changes between 2005 and 2007 .....	40
Conclusions .....	41
8. Trends in the extensiveness of individual pricing mechanisms .....	42
Towards a globalisation of gas pricing?.....	45
Bumps in the road toward globalised gas pricing .....	47
9. Price volatility .....	51
General .....	51
Causes of volatility.....	52
Volatility associated with gas price increases.....	53
Volatility associated with gas price declines .....	53
Volatility of oil indexed prices .....	54
Volatility and LNG .....	54
10. Towards further changes in the extensiveness of individual pricing mechanisms? .....	55
Appendix 1 – Price Formation Mechanisms 2005 Survey.....	58
Format of Results .....	58
World Results .....	58
Regional Results.....	61
Wholesale Prices .....	65
Conclusions .....	66

*“Gas Pricing”; Study group B2 of IGU Programme Committee B (PGC B). The work was coordinated by Runar Tjærslund, Study Group leader with contributions of Meg Tsuda, Mike Fulwood, Ottar Skagen and Howard Rogers.*

# 1. Executive Summary

Historically gas prices have not been in the news to the same extent as oil prices. This is changing. The share of gas in global energy and fuel consumption has increased. The share of internationally traded gas in global gas consumption has increased. LNG is providing intercontinental linkages that eventually could constitute a global gas market. With most gas producing OECD countries struggling to replace reserves and sustain production growth, the centre of gravity of gas production and exports has shifted towards the same regions and – to some extent – countries that for 40 years have dominated oil production and exports. Finally, gas prices have increased and become more volatile.

Gas prices are not determined but definitely influenced by individual markets' choices between available price formation mechanisms. The two main debates in this respect is the one that goes on in Europe and to an extent in Asia between proponents of continued indexation of gas prices to oil prices and proponents of gas-on-gas competition based pricing, and the one that goes on inside a number of Non-OECD countries – and between these countries' governments and entities like the EU Commission, the IEA and the multilateral development banks – on the sustainability of the more or less heavy handed price regulation that prevails in big parts of the Non-OECD world.

Arguably the former of these debates is the least important. Evidence from North America where gas prices are not contractually linked to oil prices suggests that gas prices nonetheless tend to track oil prices in a fairly stable long term relationship. Gas and oil prices are linked by interfuel competition in the industrial sector. They are also influenced in the same manner and to the same extent by the oil and gas industry's cost cycles. Finally price deviations may be arrested, eventually, by changes in oil and gas industry investment priorities.

In periods of ample gas supply, prices have delinked with gas becoming significantly cheaper than heavy fuel oil, not to mention crude oil or light fuel oil. But in periods of gas market tightness the link has re-emerged with oil product prices eventually putting an end to gas price rallies.

For the moment – by mid 2009 – the US gas market is exceptionally well supplied. As a result prices are softer than at any time since 2002 and well below crude oil and refined product prices in energy equivalence terms. Possibly this situation will last for a while due to the unexpectedly rapid growth in US unconventional gas production. But that does not need to apply to Europe or Asia. Consequently a radical replacement of oil linked contracts with gas linked contracts in any or both of these regions – had such a thing been politically and practically possible – would likely have increased gas price volatility but might not have materially changed long term price trends.

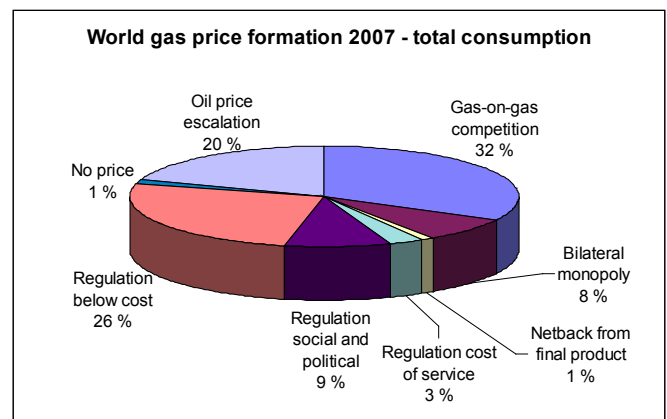
With respect to the latter debate, Non-OECD countries already supply high shares of the European and Asian OECD member

countries' gas demand, and the gas flows from Russia, the Middle East and Africa to the OECD are expected to further increase. Several gas exporting non-OECD countries are however struggling to sustain, let alone increase, their exports in the face of booming domestic gas demand. Domestic demand reflects among other things domestic prices. Consequently the outlook for domestic gas pricing in these countries is no longer of local interest only but of global importance.

This report examines the extensiveness in different parts of the world of the following gas pricing mechanisms:

- Gas on gas competition
- Oil price escalation
- Bilateral monopoly
- Netback from final product
- Regulation on a cost of service basis
- Regulation on a social and political basis
- Regulation below cost
- No pricing

*Chart 1.1: World gas price formation 2007 - total consumption*



Globally, in 2007 one third of all gas sold and purchased was priced according to the gas-on-gas competition mechanism. Regionally the share of gas transactions in this category varied from 99% in North America to zero in most of the developing world.

The second biggest category in 2007 was “Regulation below cost” (see Chapter 4 for definitions) with 26% of the global total. The share of gas supplied at prices contractually linked to oil product or crude prices – the dominant mechanism in Continental Europe and the Asia Pacific OECD countries – was 20%.

A comparison of the results for 2007 with those of a similar study carried out two years ago on 2005 data shows an increase in the “Regulation below cost” category in both absolute and relative terms. 85% of this change can be explained by robust gas consumption growth in the Former Soviet Union, particularly in Russia, where this pricing mechanism remains dominant. Only 15% was due to shifts from other pricing mechanisms to regulation below cost.

The share of gas transactions at prices reflecting “Regulation on a social and political basis” declined from 2005 to 2007 due mainly to changes in pricing mechanism in Brazil and Argentina and also to below average growth in gas production for the domestic market in Ukraine and in gas consumption in Malaysia, two countries where this type of regulation is widespread.

Gas-on-gas competition based pricing gained some ground, largely at the expense of oil price escalation – between 2005 and 2007 largely because of growth in Japan’s, Korea’s, Taiwan’s and Spain’s spot LNG imports, and in the trading on Continental Europe’s emerging gas hubs. Also less UK gas was sold into the UK market under oil linked contracts. The combined impact of these changes dwarfed Brazil’s shift towards oil price escalation, and China’s first LNG imports at oil linked prices, in this period.

A striking aspect of recent gas price developments is that prices seem to have become much more volatile. This impression may be slightly misleading. In absolute terms price gyrations have become stronger. In relative terms – i.e., if one takes into account that prices in recent years have fluctuated around higher averages – volatility appears to have been roughly constant during the 2000s.

Some short term price volatility is part and parcel of gas-on-gas competition based pricing. As such it is typical for North America, the UK and the short term trading around Continental Europe’s emerging hubs – but not for the bulk of Continental Europe’s and Asia’s gas transactions. A typical Continental European gas import contract links the gas price to a basket of oil product prices in an averaged and lagged way that significantly dampens the impact of oil price fluctuations. A typical Asian LNG import contract is structured the same way, only with the gas price indexed to a basket of crude oil prices.

However, if some price volatility is inevitable under gas-on-gas competition, strong volatility also requires market tightness. The last couple of years’ big gas price changes were due to supply and demand intersecting with each other at very steep segments of either the supply curve or the demand curve or both. For the moment markets are loose and volatility as well as prices are down.

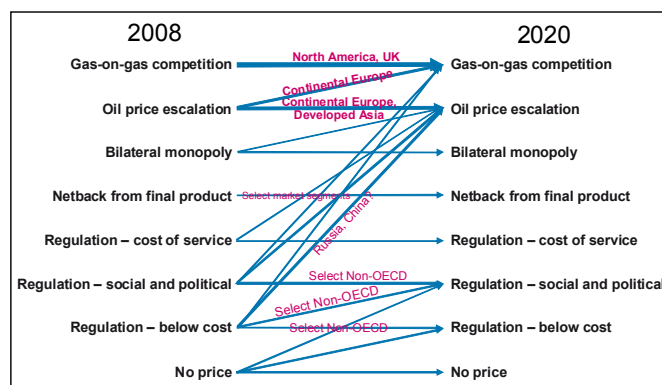
Another aspect of price volatility is that not everybody would agree that it is a bad thing that should be minimised. While some investors pursuing low risk activities with correspondingly low returns need stable, predictable prices, others thrive on price instability because of the arbitrage opportunities associated with a dynamic environment.

These findings beg the questions where gas prices and gas pricing mechanisms will go in the future. This study was never supposed to conclude with either another set of gas price scenarios or precise predictions of the changes in the extensiveness of individual pricing mechanisms that undoubtedly will occur <sup>1</sup>. Broad development directions may nevertheless be inferred

from the tensions that current pricing mechanisms have given rise to, and from the debates on gas pricing that these tensions have triggered.

The below figure is highly tentative and intended merely to facilitate a discussion.

**Chart 1.2:** Hypotheses on future changes in the extensiveness of individual pricing mechanisms in individual regions



In the countries where gas-on-gas competition based pricing prevails, there may be concerns about price volatility, and debates on how to deal with the harmful effects of price spikes and troughs. But there is little talk about a return to more regulation or a shift to some variation on the market value pricing theme. As such, gas-on-gas seems to be widely perceived as “the end game” without more efficient alternatives.

In Continental Europe the EU Commission is seeking to pave the way for a shift from oil price indexation to gas-on-gas competition based pricing. The Commission’s priorities are being shared to varying degrees by the EU member states’ governments depending on their ideological leanings and prioritisation between efficiency, environmental and gas supply security concerns, and by the region’s commercial actors depending on their status as incumbents or new entrants. The enthusiasm for this or that mechanism also tends to vary with the oil price and with outlook for the ratio between oil linked gas prices and hub gas prices.

Though oil price escalation is not going to disappear any time soon, gas-on-gas competition based pricing will likely gain ground as more hubs mature.

In the Asia Pacific region, the main LNG importers are sticking to crude oil indexation as the dominant imported gas pricing mechanism. Gas market based pricing is not yet an option since the Asian gas markets are characterised by limited competition and have almost no gas hubs. This could change with market reforms aimed at introducing third party access to LNG terminals and pipelines and competition at the wholesale level.

<sup>1</sup> A more thorough examination of the scope for changes could instead be the subject for a follow-up study in the next WGC triennium.

In addition to the political and regulatory push for liberalisation there has been much talk about Henry Hub or the NBP price becoming benchmarks also for Asian gas buyers. In 2007-08 when Japanese and Korean utilities had to dramatically increase their imports of Atlantic LNG, this prediction gained credibility. By 2009, however, with demand in decline due to the financial crisis and with a string of new Middle Eastern and Asian LNG trains at – or approaching – the commissioning stage, the Atlantic-Asian LNG trade looks set for an equally dramatic decline, potentially with a dampening impact on the pace of price globalisation.

In the longer term, internal and external forces may well combine to erode the position of oil price escalation also in the Asia Pacific area. For the time being, however, this region looks set to remain well behind Continental Europe in introducing alternative mechanisms.

Bilateral monopoly pricing remains important in the Former Soviet Union and characterises up to 8-9% of gas transactions in the other Non-OECD regions. Bilateral monopoly pricing may be expected to decline in importance – probably to the benefit of oil indexed pricing – as Russia is negotiating netback prices based on Western European border prices with its near neighbours.

The ‘netback from final product’ mechanism will likely prevail in certain market segments. For industrial gas users it represents a way to shift product market risk upstream. For gas sellers it represents a way to sustain industrial demand in times of potential market destruction. It is however difficult to see this mechanism making major inroads into the much bigger shares of gas transactions characterised by gas-on-gas pricing, oil escalation or regulation.

Outside the OECD area, gas subsidisation is taking an increasingly heavy toll. One trend seems to be for countries practicing below cost regulation to move towards ad hoc price adjustments with the purpose of keeping prices largely in line with supply costs – i.e. what we have termed regulation on a social and political

basis. Another trend seems to be for governments to liberalise prices to select, presumably robust, customers, and increasing remaining regulated prices to the extent politically possible. Typically, households and industries perceived as “strategic” such as the fertilizer sector continue to enjoy some protection.

Russia has embarked on a process of aligning domestic prices with opportunity costs, i.e., with the netback to the producers if they had exported the gas instead, and there is every reason to believe that this process will be completed, if not necessarily on schedule. Since Russia exports gas on oil linked contracts, this means an effective gradual introduction of oil price escalation in the domestic market.

Russia and other countries that have practiced gas price regulation are also experimenting with gas-on-gas competition. Gas exchanges intended to serve as safety valves for producers with surplus gas and consumers with extraordinary needs are being established. The volumes traded on such exchanges and their price impact will however be minor unless and until competition takes hold, and that could take some time.

China and India face challenges in incentivising the power sector to shift from cheap indigenous coal to gas, but there is significant industrial and household demand at much higher prices. The future will likely see price regulation with a view to both consumers’ ability to pay, supply costs and the prices of competing fuels. But increasing gas imports will expose these countries to gas-on-gas competition too, and affect the pricing environment for the consumers with the highest willingness to pay.

Middle Eastern countries face challenges in providing for development of non-associated gas reserves in the context of gas prices that reflect the very low costs of associated gas supply. But the need for countries like Kuwait, Abu Dhabi, Dubai and possibly Bahrain to start importing gas will introduce new benchmarks to the region and may eventually drive broader price reforms. To the small extent it still exists, the ‘no price’ category seems destined for phase-out.

## 2. Introduction

### Mandate

This report is as noted not an attempt to analyse in great detail gas price movements around the world in great detail, nor to provide another set of gas price forecasts. The mandate given to IGU PGC B/SG2 was:

- To carry out a comprehensive analysis of gas price formation models at regional level: price drivers, indexation, price arbitrage, demand elasticity;
- To investigate future trends and the factors which could help to minimize price anomalies and contribute to a sustainable market growth

The work group has on the basis of this mandate set itself the following targets:

- Identify the main gas price drivers and discuss how they operate in the short and longer term;
- Offer a categorisation of how gas is priced around the world;
- Discuss how individual pricing methods or models have arisen;
- Present the results of a global pricing method mapping exercise;
- Examine select trends in the use of individual pricing methods;
- Discuss the roots and consequences of gas price volatility;
- Offer some views on how the popularity and prevalence of individual methods may change in the years ahead.

### Why this report?

Ever since natural gas became a marketable good with an economic value, gas pricing principles and price levels have attracted producer, consumer, government and general interest. Gas prices have however not been in the news to the same extent as oil prices. This is because:

- Historically gas has been less important than oil in most countries' fuel mix;
- On balance gas border or hub prices has been lower, in energy equivalence terms, than crude oil border or hub prices;
- Unlike oil, gas has substitutes in its main applications, a fact that has served to check gas price fluctuations; also the way gas is indexed to oil in European and Asian contracts has smoothed the gas price curve;
- Gas has been a regional fuel and hence not in the same way as oil a matter of global importance;
- Gas reserves have been more widely distributed than oil reserves with OECD countries holding a major portion of the resource base; thus the divide between producing and consuming countries has been less clear-cut and gas prices less geo-politicised.

These differences between gas and oil are becoming less pronounced:

- The gas share of the fuel mix has increased world wide;
- Gas prices have increased;
- Gas prices have become more volatile;
- LNG is providing intercontinental gas price linkages that eventually could constitute a global gas market;
- With most gas producing OECD countries struggling to replace reserves and sustain production growth, the centre of gravity of gas production and exports has shifted towards the same regions and to some extent the same countries that for 40 years have dominated oil production and exports.

Gas prices in North America, Europe and developed Asia are being more closely monitored than prices in the rest of the world. This has several reasons:

- Historically the OECD area has accounted for the bulk of world gas consumption,
- The world's leading energy research institutions are located in the OECD area and sponsored by OECD area governments and companies,
- While prices in the OECD area are market driven and therefore amenable to standard economic theory and models, prices in the rest of the world are with a few notable exceptions politically determined and therefore essentially beyond forecasting.

The validity of the first reason is wearing thin. 2007 world gas use was split evenly between the OECD countries and the rest of the world, and since OECD area consumption is growing at a slower pace than non-OECD consumption, the latter area will soon have a lead on the former. Moreover, several non-OECD countries are already playing key roles in determining the supply of gas to world markets, and will only become more important in this respect in the future. Their domestic gas pricing decisions could therefore be strongly felt in the OECD area.

Russia is a case in point. Eurasian gas balance studies typically conclude that the call on Russian gas will increase significantly and that Gazprom, the Russian oil companies and Russia's independent gas producers need to invest massively in the upstream and midstream to stave off shortages. This from time to time prompts discussions on the adequacy of budgeted investments. However, if a gap exists it may be closed by dampening future demand as well as by boosting future supply. The bulk of Russian gas – currently almost 70% – is consumed at home. Thus if the pace of growth of Russian domestic gas use can be contained through for instance price increases, budgeted investments in supply may be more than adequate.

The Middle East is another case in point. Forecasters tend to vest high shares of the responsibility for supplying world gas demand in the decades ahead, with this region. But the Middle East's current and potential gas exporters are currently struggling to sustain or start exports in the face of stagnant production and booming domestic demand. The latter aspect of the region's

fuel situation is closely linked to its traditionally very low end user prices.

Estimates of the long term impact of gas price changes on gas demand vary across countries and time periods. And if it is difficult to reach consensus on price elasticities for OECD countries, it is even harder for regions like the FSU and the Middle East. However, although gas consumption per capita may be lower outside than inside the OECD area, gas consumption per unit of GDP produced in the sectors using gas in the first place, is typically higher. Hence the fuel switching and savings potential that could be released by gas price increases should not be underestimated.

## Outline of report

Chapter 3 of this report identifies the gas price drivers at work in different markets and offers some views on how they may develop in the years ahead.

Chapter 4 presents and briefly explains eight gas pricing mechanisms that together capture nearly all gas produced and consumed in the world.

Chapter 5 discusses the origins and history of each of these mechanisms, with an emphasis on those in use in the OECD countries.

The current interest in gas pricing models has a context, and this context is the gas price turbulence experienced since 2000 in big parts of the world. For this reason chapter 6 offers a brief overview of recent price developments inside and outside the OECD area.

Chapter 7 is the core of the report in that it presents the result of an empirical investigation of the prevalence of individual pricing models in individual markets in 2007, and also a comparison of the situation in 2007 to that in 2005. A sample of IGU member organisations were asked to estimate the shares of gas sales in their home countries that belonged to each of the eight pricing categories. The member organisations were selected so as to ensure that all regions and preferably all key countries were covered. The replies were then analysed by SGB2.

Chapter 8 addresses the tensions inherent in individual pricing mechanisms, the consequent challenges of sustaining the current pattern of methods, and the attempts being made by market players, politicians and regulators to introduce new methods, typically with a view to shifting prices to more efficient levels.

Chapter 9 addresses this issue of gas price volatility. Since the turn of the decade, gas prices have not only fluctuated around (until recently) rising trends, they have also gyrated more violently than typical for the 1980s and 1990s. The reasons for and nature of the post 2000 gas price instability, and whether the future will bring even more, or less, volatility, are questions on every gas market player's mind.

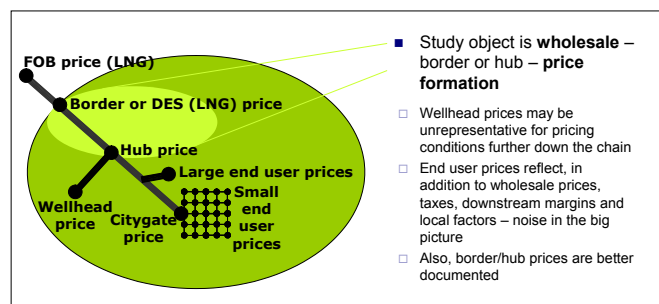
This chapter also addresses the issue of gas price globalisation. As noted, gas prices have historically been regional. Price formation in one region has largely reflected circumstances within that region only, and has in turn not impacted on price formation in other regions. This is changing, driven by the growth in flexible LNG, and at a more general level by the commoditization of gas, the better availability of global gas price information and a higher awareness in every corner of the world of the value of gas.

Chapter 10 offers a view on the sustainability of individual pricing models, and a view on where we will most likely see changes and where we probably will not see much deviation from today's pricing habits.

Finally, Appendix 1 presents the full results of the 2005 mapping exercise in the same way as Chapter 7 presents the 2007 exercise.

## Terms and concepts

There are many prices along pipeline gas or LNG value chains. The focus in this study is on wholesale prices, that is, hub prices or – in the absence of hubs providing reliable price signals – border prices.



It is at the level of wholesale prices that battles over pricing principles are fought. It is this level that is subject to national or supranational regulation.

Moreover, wholesale pricing principles largely determine end user pricing principles. One cannot have, e.g., gas-on-gas competition based hub or border prices and at the same time competing fuel linked citygate or end user prices.

A third reason for focusing on wholesale prices is that city gate and end user prices are influenced by taxes and by local supply and demand conditions reflecting in turn local weather patterns, local infrastructural bottlenecks, the level of competition for local distribution rights, local regulators' ability to counteract attempts at monopoly pricing, etc.

A fourth, related reason is the inherent complexity of end user prices. Mature markets typically have extensive end user price matrices with prices varying by geography, end user segment, customer size and interruptibility of supply. Thus, end user prices studies require a degree of accounting for the local context that is beyond the scope of this study.



Finally, in many areas wholesale prices are as a rule better documented than other prices.

There are however exceptions from the latter rule. There are countries with immature gas markets, no hubs, no exports or imports and with state companies that do not publish much financial information in charge of gas supply – but where one can still find some anecdotal evidence of prices, typically at end user level. In such cases it is necessary to combine what little information exists into guesstimates of wholesale prices.

The following is an attempt to further define and explain the pricing terms to be used in this report.

### **Wellhead price**

- The value of gas at the mouth of the gas well
- In general the wellhead price is considered to be the sales price obtainable from a third party in an arm's length transaction
- Wellhead prices are well documented for the US, less so for other countries with less transparency in the upstream

### **Border/beach price**

- The price of gas at a border crossing or landing point
- US and European natural gas and LNG import prices are well documented by the US Department of Energy's Energy Information Administration (DOE/EIA) and Eurostat, and by the International Energy Agency (IEA) in its quarterly Energy

### **Prices and Taxes report**

- The reporting on European import prices is incomplete as the long term export-import contracts that determine these prices are as a rule not in the public domain
- Non OECD/IEA country border or beach prices are not systematically compiled and published, but a great deal of information on individual agreements exists
- Since so few countries have hubs providing reliable price information, border/beach prices will often be the best wholesale price proxies available

### **FOB and DES LNG prices**

- FOB (Free On Board) price
  - The price of LNG at the point of loading onto the vessel.
  - The FOB breakeven price needs to cover upstream costs (i.e., E&D, gas processing and field to plant transportation costs) and liquefaction costs, but not shipping and regasification costs.
- DES (Delivered Ex-Ship) price
  - The price of LNG at the point of unloading off the vessel.
  - The DES breakeven price needs to pay for the same cost components as the FOB price plus shipping costs

### **Hub price**

- The price of gas at a hub, typically a pipeline junction where a significant amount of gas sales and purchases takes place and where sellers and buyers can also purchase storage services
- A hub does not need to be physical, it can be virtual like the UK's National Balancing Point
- Serving as marketplaces, hubs are a prerequisite for gas pricing through gas-to-gas competition
- Hub prices are well documented as they underpin the world's gas futures markets
- The US' Henry Hub is the closest thing there is to a world gas pricing point
- Hub prices are optimal wholesale price indicators
- However, hubs liquid enough to convey reliable price signals exist for the moment only in the US, in the UK and to an extent in the Benelux area

### **Citygate price**

- The price of gas at a citygate, typically at the inlet to a low pressure pipeline grid owned and operated by a local distribution company
- US citygate prices on a monthly state-by-state and weighted average US basis are published by the DOE/EIA
- US citygate prices on balance reflect the prices on the hubs where the gas is sourced plus transportation costs, but may from time to time due to local supply and demand circumstances include substantial premiums or discounts
- Citygate prices are not systematically documented anywhere else

### **End user prices**

- End user prices are the prices charged to power sector, industrial, commercial or residential end users at the plant gate or the inlet to their individual pipeline connections
- End user prices for the OECD/IEA countries are published by the DOE/EIA, Eurostat and the IEA, and by select private market intelligence companies
- End user price information is available for a few non-OECD countries but not for most of them, and reliability is an issue
- End user prices are important insofar as it is at that level interfuel competition takes place
- However, publishers' aggregating and averaging make significant price differences disappear, limiting the conclusions that can be drawn from published end user price movements
- Moreover, taxes and local circumstances can distort the picture
- End user prices should be resorted to only when necessary due to a lack of wholesale price information

### **Netback price**

- Gas supply chains have multiple links, and for each point of transfer from one link to another a so-called netback price may be calculated by deducting from the end user price the unit costs of bringing the gas from that point to the end user

- The netback price to the upstream shows the value per unit of gas produced left for sharing between the producer and the state after distribution, transmission, storage and – in the event of LNG – regasification, shipping and liquefaction costs have been deducted from the end user price, and is as such a key indicator of project feasibility

### 3. Gas price drivers

In competitive markets, with multiple sellers facing multiple buyers, prices are driven by supply and demand. Price changes in turn feed back on supply and demand by providing signals that – in principle – ensures market equilibrium. Since supply and demand depend on more factors than price and since neither of these variables typically move smoothly and precisely between equilibrium levels but tend to undershoot or overshoot, the simultaneous price, supply and demand adjustment process never stops.

Due to the nature of gas as a commodity and to the different historical origins of national gas industries and markets, gas prices are not everywhere set under competitive conditions. But some markets have been liberalised, and others are at various stages of introducing gas-on-gas competition and competitively set prices. The factors that drive gas supply and demand, and how these factors will evolve and interact in the future, therefore need to be understood.

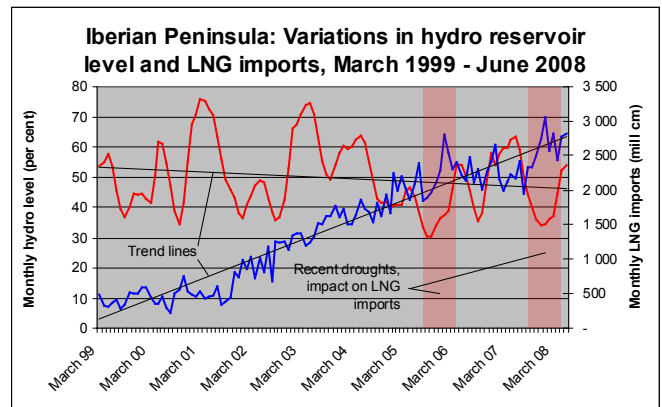
#### Competitive markets

##### Short to medium term supply and demand drivers

Even modest short term gas supply or demand disturbances may boost or depress prices significantly. The impact will depend on the state of the market at the outset. A tight market where either supply or demand or both are highly inelastic at intersection will deliver a stronger price response to the same disturbance than a relaxed market.

There are many examples of gas demand spikes leading to gas price spikes. Such spikes may occur because of temperature fluctuations. A cold spell during winter or – in places with much gas going into power generation and much power going into air conditioning – an unusually hot summer may boost seasonal gas demand and cause a price spike. Droughts may temporarily cut into hydro power generation capacity, boost demand for thermal power and as a result increase power sector gas demand. Spain’s drought problems since the middle of the current decade have impacted on Atlantic and world LNG demand (Chart 3.1).

**Chart 3.1: Iberian Peninsula: Hydro reservoir levels and LNG imports**

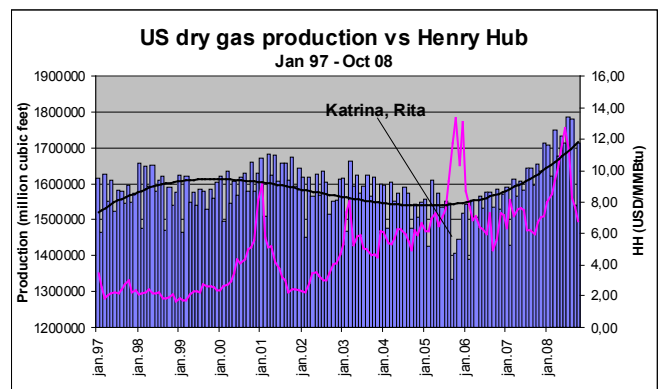


Sources: CERA, IEA

Business cycles affect gas demand – especially industrial gas demand – in the medium term.

There are also examples of gas supply interruptions boosting gas prices. Such interruptions may be due to extreme weather, accidents or political or commercial tensions. When hurricanes Katrina and Rita hit the US Gulf coast the result was a 13,5% drop in US dry gas production from August to September 2005, and a 26% increase in US gas prices as represented by the Henry Hub monthly average over the same period (Chart 3.2).

**Chart 3.2: US gas production vs Henry Hub, 1997-2008**

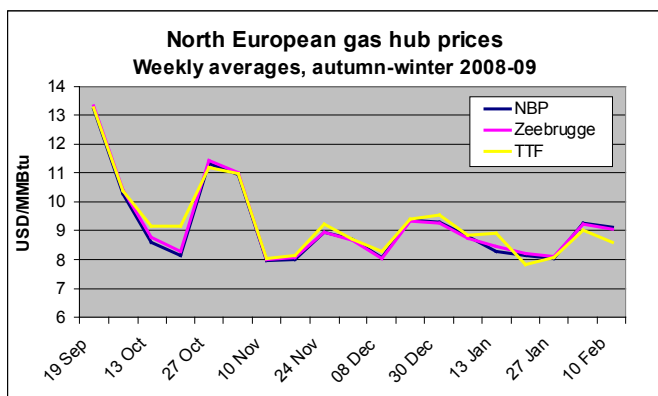


Source: US DOE EIA

Examples of accidents or commercial / political supply cut-offs driving price spikes are harder to find. Even an incident as serious as the explosion at the Algerian Skikda LNG plant in January 2004 that destroyed three trains with a combined capacity of more than 4 mtpa did not have noticeable consequences for buyer country prices as Sonatrach managed to quickly rearrange supply.

The Russian-Ukrainian gas conflicts in late 2005 – early 2006 and again in the beginning of 2009 caused some nervousness in European markets but apparently did not have much impact on spot prices. The former conflict occurred at a time when these prices had already increased significantly. The dip in Russian gas supply may have only marginally aggravated the price spike. The latter conflict apparently did not affect prices on the North European gas exchanges – which, it should be noted, are located far away from where the supply interruptions were most acutely felt – at all. Prices on these hubs kept fluctuating around a steadily declining trend during the final quarter of 2008 and into 2009 (Chart 3.3).

**Chart 3.3:** North European gas hub prices



Source: WGI

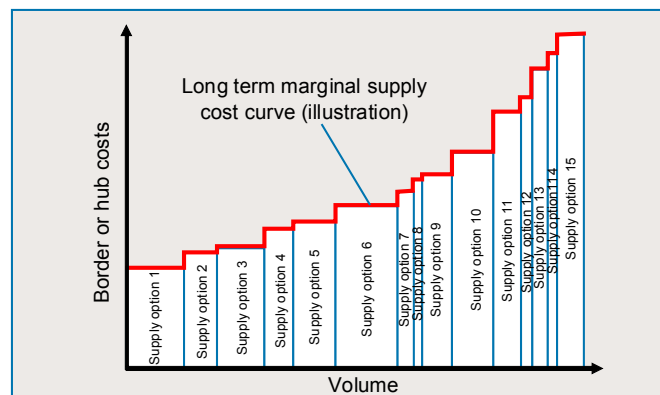
**Long term supply and demand drivers**

Gas prices in competitive markets fluctuate around long term trends determined by, graphically speaking:

- The shape of the long term marginal gas supply cost curve
- The extent to which the reserves on the marginal gas supply cost curve can actually be produced, given the regulatory, geopolitical and other constraints on oil and gas developments world wide
- Shifts in the demand curve

**Long term supply side drivers**

**Chart 3.4:** Long term marginal supply cost curve (illustration)



Long term marginal supply cost curves show – as Chart 3.4 seeks to illustrate – the incremental gas volumes that become available to a given market as supply costs are allowed to increase. Typically the cheapest supply is indigenous conventional gas delivered via amortised pipelines, and the most expensive supply high cost LNG, gas imported via long distance, not yet amortised pipelines and unconventional gas. There are however exceptions from this rule. In the US, the supply areas onshore or just offshore the Gulf of Mexico that for decades have constituted the backbone of the US gas industry no longer account for the cheapest portion of supply.

Snapshots of a given country’s long term marginal gas supply cost curve may be inaccurate. Unlike volume and to some extent price information, cost information is not easily available. Cost curves therefore tend to be based on assumptions and generic data as much as on solid project information. Moreover, the shape of the curve is bound to change over time. New upstream or midstream technologies may shift some supply options down the curve and, by default, other options up the same curve. New supply sources may displace existing supply sources. Examples of such developments abound. Tight gas, shale gas and coal bed methane used to be located on the uneconomic portion of the supply curve. Today unconventional gas is part of the mainstream supply in the US and is growing in importance in other countries. On the other hand, whereas LNG became much more competitive between the mid 1990s and 2004, since 2005 unit costs have rebounded and made new LNG that seemed economic by a wide margin a few years ago, look marginal.

For these reasons, basing price analysis on static supply curves is not recommendable.

Marginal cost curves are by definition sloping upwards and are normally becoming steeper as more supply is brought into the picture. However, new gas discoveries and technological progress can ‘flatten’ them and allow demand to shift out for much longer before hitting the steep portion. Past predictions of supply costs pushing prices outside their ‘normal’ range on

a permanent basis have generally proved wrong. Forecasters have failed to take the cyclical nature of the oil and gas business, with high prices dampening demand and stimulating E&D and thereby paving the way for another downturn, as well as the potential for technological improvements, fully into account. The gas price explosion all developed countries experienced in the years up to the financial crisis broke was widely assumed to be of a different, more structural and permanent nature. The price decline in late 2008 – early 2009 put a question mark at that assumption.

Access to the reserves on the long term marginal supply cost curve is another key gas supply determinant. Access may be constrained for a number of reasons. Host country governments may:

- Wish to reserve parts of their gas for future generations
- Wish to reserve their gas, or parts of it, for their national oil industries, which however may be unable for financial, technological or manpower reasons to take on complex developments
- Put up environmental restrictions so severe as to effectively block developments
- Present oil and gas companies with fiscal terms too onerous to allow projects to go forward

Independently of host government attitudes, countries or regions may be inaccessible for long periods of time for geopolitical reasons or because of local unrest and poor safety conditions

A related constraint which has slowed liquefaction plant projects in recent years is the limited capacity of key equipment vendors and the small number of engineering companies able to manage such projects. This problem is likely cyclical. Some problems may also be due to the industry pushing its borders with respect to project size (the Qatari megatrans) and climatic challenges (the Snøhvit and Sakhalin projects), and may go away as plant builders and operators gain experience. But by the autumn of 2008 project delays were undoubtedly aggravating gas price inflation and volatility world wide.

#### *Long term demand side drivers*

The price-volume curve representing a country's gas demand typically shifts to the right over time in response to economic growth, changes in the energy intensity of the country's economy, and changes in the fuel structure of the country's energy consumption.

#### **Economic growth**

Economic growth drives overall energy demand. The impact which is called the income elasticity of energy demand changes with the level of economic development. Emerging, industrialising economies are typically characterised by high elasticities. A 1% growth in such a country's GDP may require a 1+ % growth in energy use. Advanced, service based economies need less incremental energy to support a given economic growth.

However, no economy has managed to break the link over an extended period of time between economic growth and energy consumption growth.

#### **Energy intensity change**

The energy intensity of a country's economy refers to the energy and fuel consumed per unit of GDP produced in the country. Energy intensities change over time. Only in the unlikely events that the income elasticity of a country's energy demand is stable at exactly 1, and there is no impact from energy or fuel price changes, will its energy use per per unit of GDP be the same year after year.

Moreover, energy intensities tend to trend downwards, due to

- Normal structural changes, i.e. the transfer of resources from energy heavy to energy light sectors
- Autonomous energy efficiency improvements, meaning progress that happens by itself, so to say, not because of political signals
- Policy measures to make car manufacturers produce more fuel efficient cars, households insulate their houses better, etc.

This does not mean however that energy intensities cannot increase in certain periods due to for instance temperature fluctuations or the advent of new industries or products.

#### **Fuel structure change**

Companies and households switch between fuels mostly in response to changes in fuel price relationships. Such changes may in turn be market driven or policy – i.e., tax or subsidy – driven.

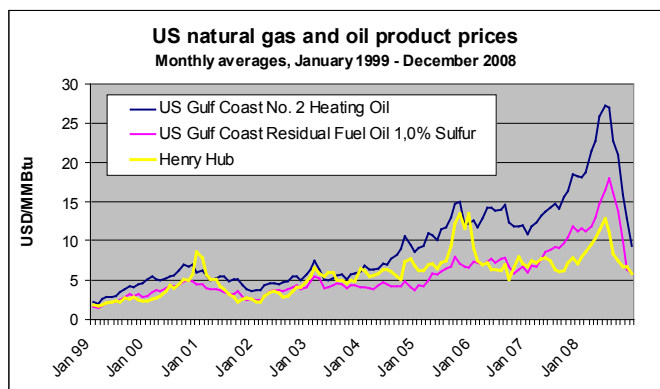
The ease with which consumers can switch between fuels in response to price signals, depends on the flexibility of their fuel using equipment. The more dual firing capacity, the more interfuel competition, and vice versa. Consumers that have to replace big parts of their equipment to capitalise on a change in relative fuel prices, need strong incentives and confidence that the new price relationship will last, to take action.

In the Atlantic markets gas initially competed mainly against select oil products. Gas prices have therefore tended to move in tandem with the regional light and heavy fuel oil prices. In Western Europe long term contract prices referenced to oil have provided an automatic link. In the US competition has provided a similar though looser link (chart 3.5). Normally gas in the US traded between heavy fuel oil and gasoil. But since the beginning of 2006 gas appears to have effectively decoupled from oil products.

A secondary reason why gas prices tend to shadow oil prices is that gas and oil is produced either in one and the same process or at least by the same actors employing the same rigs and other upstream equipment. Hence gas and oil projects are subject to joint feasibility evaluations and are exposed to the same input factor price upturns and downturns.

Today, with a growing share of world gas supply going to fire gas power plants, the coal price level is becoming another important reference.

**Chart 3.5: US natural gas and oil prices**



Sources: US DOE EIA

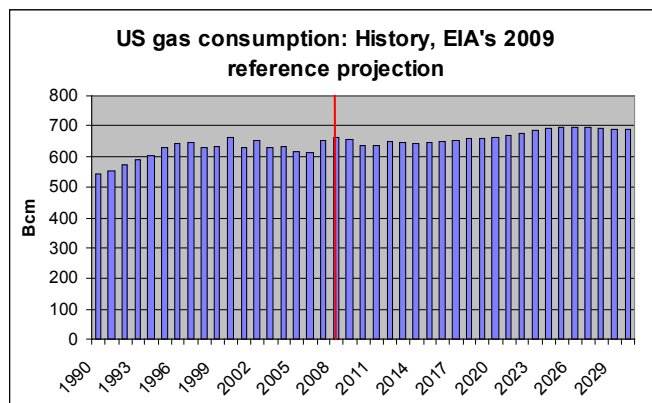
One development that should favour gas relative to other fossil fuels is the emphasis on curbing greenhouse gas emissions. Two key remedies are fuel consumption taxes differentiated by carbon contents, and emission trading schemes. Both will increase the costs to consumers of all fossil fuels, but leave gas relatively less affected. Whether the net effect on gas demand will be positive (because of substitution from other fuels to gas) or negative (because energy savings will wipe out the substitution gains) will depend on how these remedies are designed and implemented and how they come to interact with other policy measures and the forces of the market.

### Current scenarios

Will all these factors driving or dampening gas supply and demand growth sustain prices at or close to the levels observed in early-mid 2008, or has the financial crises deflated prices on a long term basis? There are as many answers to this question as there are market observers. However, the widely held view from a few years back that gas as the obvious bridging fuel between the oil intensive 20th century and a cleaner 21st century could look forward to several decades of robust supply and demand growth, is being challenged.

The International Energy Agency presents in its 2008 World Energy Outlook a business as usual scenario where world gas demand increases by some 1500 bcm between 2006 and 2030, or by 1,8% a year. The IEA sees US gas consumption peak at about 650 bcm a year in 2015 before declining to about 630 bcm a year by 2030. All in all this means a 0,1% a year growth in demand for the entire 2008-30 period.

**Chart 3.6: US gas consumption**



Source: US DOE EIA: Annual Energy Outlook 2009

The Energy Information Administration of the US Department of Oil and Energy expects in its 2009 Annual Energy Outlook US gas consumption to peak in 2026 (Chart 3.6). Though it implies an average demand growth expectation for the 2008-30 period of only 0,2% a year, this scenario is more optimistic in volume terms than its predecessor. The EIA has lowered its long term gas supply cost and price assumptions, with less demand destruction as a result.

### Other market organisations OECD area

A high share of world gas supply is not priced according to gas supply and demand. In Continental Europe and Developed Asia small numbers of importers / wholesalers have been dealing with small numbers of exporting countries typically represented by their national oil companies.

In Europe this structure is breaking up. New entrants are gaining access to the incumbents' infrastructure. Norwegian gas is no longer sold by a committee dominated by Statoil but by all the actors on the NCS in competition with each other. Gas hubs representing spot trading opportunities are popping up. Hubs need liquidity to be useful for pricing purposes and so far only the UK's NBP fulfil this criterion, but two or three others could be on their way. Existing and new LNG vendors are descending on a growing number of European LNG terminals, and new piped gas suppliers are awaiting access to Europe via new long distance import pipelines.

Developed Asia is proceeding at a slower pace, but Kogas is no longer the only Korean LNG importer, and the Japanese gas market could see the introduction of competitive elements in the years ahead.

Continental Europe's and Developed Asia's long term gas import contracts index the price of the gas to the prices of oil and oil products. In Europe the indices are mostly light and heavy fuel oil, in Developed Asia it is crude oil. The contracts have a price clause that includes a base year price and a formula that regulates the gas price's tracking of the prices of the indices.

The clause also addresses the need for regular revisits to the formula in response to structural changes in the marketplace.

Continental European and Developed Asian border gas prices are thus driven by the prices of crude oil and refined products, and indirectly by all the factors that drive these prices, rather than by developments in Continental European and Developed Asian gas demand or in world gas supply.

This is a simplification insofar as the price signals coming from the spot markets around Europe, from the UK via the Interconnector and from the US via LNG do influence Continental European and Developed Asian contract prices. Long term import contracts always have some offtake flexibility. If spot prices fall significantly below contract prices, buyers will respond by offtaking as little as they can under their contracts, turning instead to the alternatives. This will lift spot prices but could also lead to contract renegotiations and eventually some realignment of contract prices with gas market realities.

The current trend is towards shorter, more flexible import contracts, so the influence from gas supply and demand on Continental European and Asian contract prices will likely increase. However, as we will revert to later in this report, there is currently little to indicate that either Continental Europe or Developed Asia will abandon oil linked pricing any time soon.

### Non-OECD area

Outside the OECD area there are many gas consuming countries that neither allow gas supply and demand to determine prices nor practice oil linked pricing. Instead they set prices administratively according to principles and procedures that are not always transparent.

Supply costs may be a consideration, but do not always receive systematic attention. If supply costs are taken into account, they may be defined so as to include both operating, depreciation and financial costs and a return on investments, but they may as well be defined so as to cover operating costs only, leaving nothing for maintenance not to mention system expansions. The more supply costs are ignored as a driver, i.e., the further below full cycle supply costs prices are set, the smaller is the role that sales revenues play in financing the country's gas supply. The state actor(s) involved then need to be funded directly from the state budget.

Social and political considerations are probably the most important regulated price drivers, with the regulators aiming to set prices so as not to hurt industrial consumers' competitiveness, overburden residential consumers and potentially trigger political unrest. These criteria are course ambiguous, reflecting what consumers have grown accustomed to rather than objective thresholds. The same gas bill as a share of a household's real disposable income may be acceptable in one country and intolerable in another.

In some countries gas prices are regulated at low levels to stimulate substitution from other fuels to gas. This is common

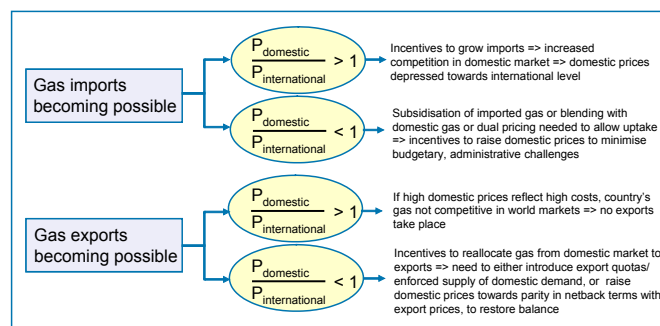
practice in oil exporting countries struggling to increase oil production and witnessing rapid growth in domestic oil use eroding the oil surplus available for exports.

Regulated gas prices may be adjusted according to some simple formula, e.g. by a certain percentage per year. More typical are ad hoc adjustments in response to typically conflicting calls for change from different sides – from the budget, from the macro economy, from companies involved in the supply of gas to the domestic market demanding higher prices, and from industrial and residential consumers demanding lower prices.

The different motives for gas price regulation at below economic levels are in no way mutually exclusive. More often than not governments that subsidise gas do it in the hope of killing several birds with one stone – attracting investments in petrochemical and other gas intensive industries, containing inflation, keeping the population happy and sustaining oil exports.

Participation in international and intercontinental gas trade inevitably plays a role in shaping market actors' views on the sustainability of different pricing models. Trade means the import and export of price signals. When a country decides to start importing or exporting gas, pressures to align domestic prices with import or export prices will inevitably start to build.

**Chart 3.7:** Impact on domestic pricing of opening for gas imports or exports



Gas price regulation that does not take costs fully into account and involves a degree of subsidisation typically becomes harder to sustain when international gas prices are high. This was the situation in 2008. Importing country governments needed if they wished to continue shielding their populations to accept increasing budget deficits. Producer country governments that could export the gas rather than keeping it at home had to accept increasing growth in export and tax revenues foregone. The latter governments were on the other hand typically also the biggest beneficiaries of the 2008 oil price escalation and therefore able to continue offering cheap gas to the domestic market.

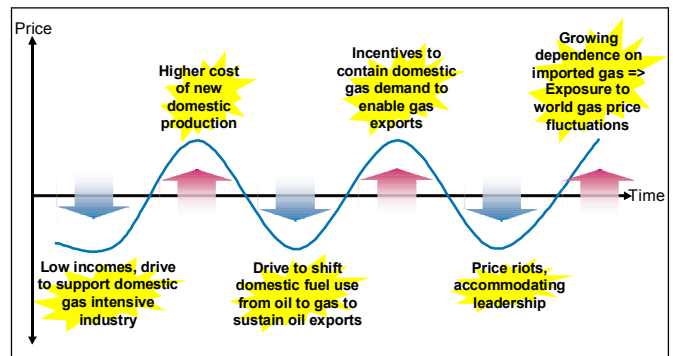
In response to such pressures governments typically deregulate prices to some market segments while retaining regulated prices to other, more vulnerable segments.

Deregulation may be a long and cumbersome process as the

pressures. Delayed responses to imbalances created by trying to keep too many people happy at the same time for too long may lead to draconian price hikes – and retreats, in response to popular protests and unrest.

Chart 3.8 seeks to illustrate how a government aiming to introduce gas initially may need to consider and trade off only a limited number of factors in a reasonably straightforward exercise. However, as time passes and situations change a consistent line on pricing may become increasingly difficult to define and support.

Chart 3.8: Challenges of price regulation



## 4. Key gas pricing mechanisms

We propose to distinguish between the following gas pricing mechanisms:

- Gas on gas competition
- Oil price escalation
- Bilateral monopoly
- Netback from final product
- Regulation on a cost of service basis
- Regulation on a social and political basis
- Regulation below cost
- No pricing

Gas-on-gas competition is the dominant pricing mechanisms in the US and the UK. It means that the gas price is determined by the interplay of gas supply and demand over a variety of different periods (daily, weekly, monthly, quarterly, seasonally, annually or longer). Trading takes place at physical hubs, e.g. Henry Hub, or notional hubs such as the NBP in the UK. Trading is likely to be supported by developed futures markets (NYMEX or ICE) and online commodity exchanges (ICE or OCM). Not all gas is bought and sold on a short term fixed price basis – there are longer term contracts but these rely on gas price indices rather than competing fuel indices for, e.g., monthly price determination.

Gas-on-gas competition does not mean that competing fuel prices play no role in determining the gas price. Key groups of gas consumers can switch between gas and oil products, or between gas and coal, in response to price signals. This substitutability of gas means that the prices of gas oil, HFO and at the low end coal typically frame the range within which gas prices may move. However, this market (as opposed to contractual) link between the prices of different fuels is neither stable over time nor able to prevent gas prices to move outside their prescribed corridor for long periods of time.

Chart 4.1: Pricing under gas-on-gas competition

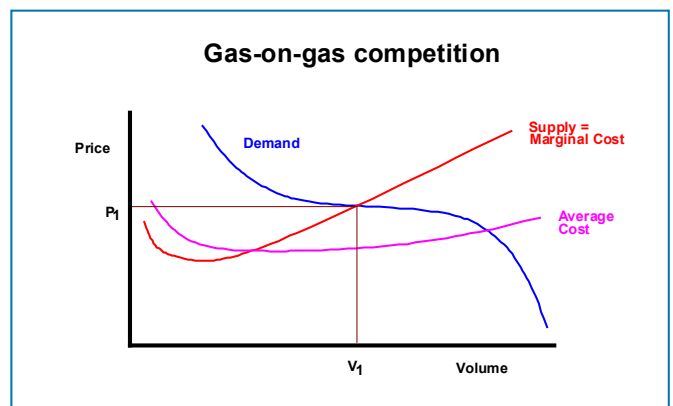


Chart 4.1 illustrates price formation under gas-on-gas competition. It is assumed that the price is set so as to clear the market.

- The demand curve is inelastic at high prices and low prices, where there is little scope for fuel-switching, and elastic in the middle range where demand for gas can change readily depending on relative fuel prices;
- The supply curve is identical to the long run marginal cost curve; and
- The average cost curve cuts the long run marginal cost curve at its low point, and then the demand curve at a lower price than the competitive market price.

Under gas-to-gas competition the price in any given period would presumably be at  $P1V1$ .

Oil price escalation is the dominant pricing mechanism in Continental Europe and Asia. It means that the gas price is contractually linked, usually through a base price and an

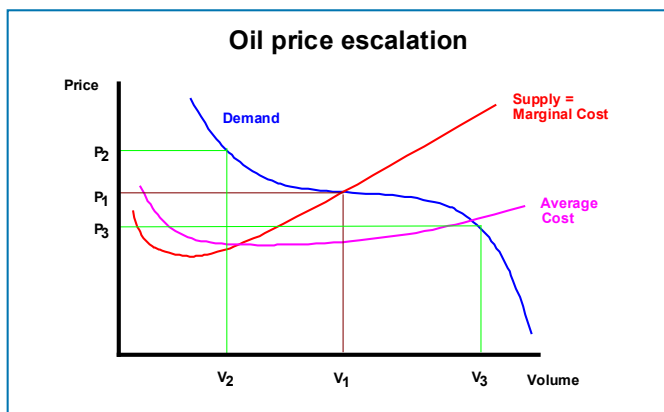
escalation clause, to the prices of one or more competing fuels, in Europe typically gas oil and/or fuel oil, in Asia typically crude oil. Occasionally, coal prices are part of the escalation clause, as are electricity prices. The escalation clause ensures that when an escalator value changes, the gas price is adjusted by a fraction of the escalator value change depending on the so-called pass-through factor.

In addition to the link to the prices of competing fuels, it is common to include a link to inflation in the escalation clause.

Oil price escalation does not mean that gas supply and demand play no role in determining the gas price. If Continental European or Asian buyers see the oil linked prices they pay for long term gas or LNG falling out of line with the supply and demand driven prices on the gas exchanges that are emerging, or on the global spot LNG market, customers will switch to short term gas to the extent they can, with contract price adjustments as a possible result.

Chart 4.2 shows the possible prices under the oil price escalation mechanism

**Chart 4.2: Pricing under oil escalation**



The gas price under oil price escalation will likely be above the market-clearing price if oil prices are very high, and below if oil prices are very low. Thus by summer 2008, when oil prices were in the \$120-130/bbl range, gas prices may have been close to P2, while at low oil prices they could be around P3. If oil prices are in the fuel-switching range, the oil indexed gas prices will presumably be close to P1.

Bilateral monopoly negotiations were the dominant pricing mechanism in interstate gas dealings in the former ‘East Bloc’ including the Former Soviet Union (FSU) and Central and Eastern Europe. The gas price was determined for a period of time – typically one year – through bilateral negotiations at government level. There were often elements of barter with the buyers paying for portions of their gas supply in transit services or by participating in field development and pipeline building projects.

The underlying valuation of the gas, the capital goods and the

services that changed hands in the intra-‘East Bloc’ gas trade was opaque, with politics playing a major role alongside economics.

Examples of gas pricing based on bilateral negotiations may still be found in countries where one dominant supplier, e.g., the national oil company, faces one or a couple of dominant buyers, say, the state owned power company and maybe 1-2 large industrial companies. A number of immature developing country gas markets have this structure.

Netback from final product means that the price received by the gas supplier reflects the price received by the buyer for his final product. For instance, the price received by the gas supplier from the power sector may be set in relation to, and allowed to fluctuate with, the price of electricity. Netback based pricing is also common where the gas is used as a feedstock for chemical production, such as ammonia or methanol, and represents the major variable cost in producing the product.

This mechanism should not be confused with contractual arrangements whereby the price to the producer/wholesaler is ‘netted back’ from the wholesale gas prices in countries further downstream. A netback arrangement such as this would be categorised depending on how the wholesale gas price in the downstream country is determined – through gas-on-gas competition, oil price escalation, etc.

Direct gas price regulation remains widespread. It would however be unhelpful to lump all kinds of regulation together. We need to distinguish between the principles applied by the regulator.

Under cost of service based regulation the price is determined, or approved, by a regulatory authority, or possibly a Ministry, so as to cover the “cost of service”, including the recovery of investment and a reasonable rate of return, in the same way as pipeline service tariffs are regulated in the US. Normally, cost of service based prices are published by the regulatory authority. Pakistan provides an example of cost of service based prices, with the wellhead price being the target.

Prices may also be regulated on an irregular social and political basis reflecting the regulator’s perceptions of social needs and/or gas supply cost developments, or possibly as a revenue raising exercise for the government. In all probability the gas company would be state-owned.

Many Non-OECD countries still practice below cost regulation, meaning that the gas price is knowingly set below the sum of production and transportation costs as a form of state subsidy to the population. Again the gas company would be state-owned.

In some countries where a substantial proportion of indigenous gas supply comes from oil fields with gas caps or gas-condensate fields, the marginal cost of producing this gas may be close to zero and as such it could be sold at a very low wholesale price and still be ‘profitable’. However, to the extent it is sold below the average cost of production and transportation it would still be included in the regulation below cost category.

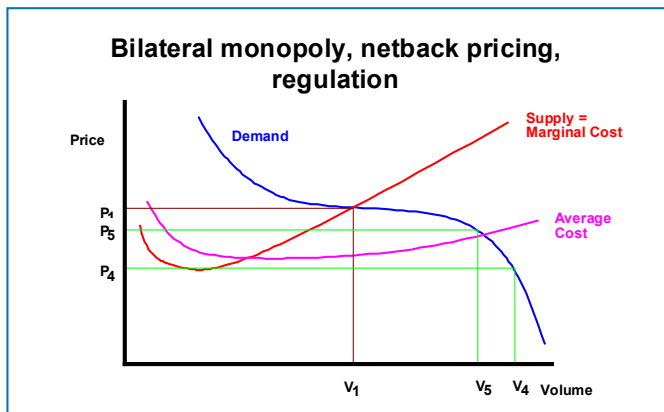


The extreme form of below cost regulation is to provide the gas free of charge to the population and industry, e.g., as a feedstock for chemical and fertilizer plants. Free gas is typically associated with gas treated as a by-product with the liquids covering the costs of bringing the gas to the wellhead. The gas supplier must still somehow finance transportation and distribution costs cross-subsidising local gas supply from his oil or gas export revenues, or the government must provide funding from the budget.

As hoc and below cost price regulation, and free gas supply, is only thinkable when domestic gas supply is in the hands of one or more state companies.

Chart 4.3 illustrates pricing under bilateral monopoly negotiations, with netback pricing and under various types of regulation.

*Chart 4.3: Pricing under regulation*



Under bilateral monopoly or netback pricing situations the price could, in theory, be higher or lower than the market-clearing price  $P_1$ . In practice, as will be shown later, prices under these mechanisms in 2005 were probably close to the  $P_5$  level, i.e. just above or below average cost.

With below cost regulation the gas price could be at  $P_4$ , that is, materially below the average cost. Under cost of service regulation the price would most likely be slightly above the average cost at  $P_5$ . Regulation on social and political grounds would likely lead to a price somewhere in the range between  $P_4$  and  $P_5$ . In all cases, the price is likely to be below the market-clearing price  $P_1$ .

## 5. Origins of individual pricing mechanisms

The main dividing line with respect to gas pricing runs between market based pricing where buyers are charged above or in line with supply costs, and regulated pricing where buyers may be charged below supply costs.

### Origins of gas or oil market based pricing

The countries that practice market based gas pricing have opted for different models because of differences in the level and degree of concentration of their gas resources, in addition to different historically and ideologically rooted preferences. Countries with significant gas resources dispersed in large numbers of fields typically saw the development of competitive industries and the early emergence of the physical and institutional preconditions for gas market based pricing. Countries with limited or zero gas resources of their own could not as easily develop gas industries with multiple sellers and buyers. These countries instead tended to encourage the emergence of national or regional import monopolies that could interact on an equal footing with a limited number of major foreign suppliers. Market value pricing was a response to the need for risk sharing to underpin the building of markets from scratch with the gas coming from major import contracts.

### North America

US gas production has always involved a number of companies, and US gas prices have as a rule been determined competitively by supply and demand. For decades prices were very low, reflecting producer competition for very limited local markets. After World War 2 rapid expansion of the US pipeline system enabled a gradual absorption of the surplus reserves.

The Supreme Court Phillips Decision in 1954 ushered in a period of wellhead price regulation that was to last for 24 years. The regulation applied only to gas traded across state borders. Gas produced and consumed in the same state was not affected by the decision.

The wellhead price controls were of the historic E&D cost plus type. They stimulated gas demand but not investment in the upstream and eventually led to gas shortages in those parts of the US that depended on other states for their gas supply. The Natural Gas Policy Act of 1978 sought to fix the imbalance by deregulating high cost gas prices while retaining most interstate gas under price control and placing also intrastate gas under price regulation so as to eliminate the particular shortage problems of the 'importing' states. These steps however paved the way for a further dismantling of price controls in the years that followed. Deregulation, and the impact of the first and second oil price

shocks, increased wellhead gas prices 15-fold between the beginning of the 1970s and 1984. US pipeline companies saw opportunities and contracted heavily for new long term supply. However, US gas demand proving unexpectedly sensitive to higher prices and sluggish economic growth dipped by more than one quarter in the in the 14 years between 1972 and 1986. The resulting gas 'bubble' arrested wellhead prices and pushed them back into the USD 1,60-1,70 per mcf range.

FERC Orders 380 and 436 in the mid 1980s completed the liberalisation of the US gas market by allowing first utilities and then other customers to contract directly with producers at market prices, and have the gas transported to their sites on pipelines subject to third party access regulation.

### The UK

The UK gas industry was nationalised in 1948. The UK at that time neither produced nor imported any natural gas. However, there were more than 1000 manufactured gas companies – some private, the other municipally owned – that were vested into 12 so-called area gas boards. In 1959 LNG imports commenced on a trial basis. In 1964 the government started to issue North Sea E&D licences. In 1965 the first natural gas discoveries were made. In 1966 the government decided to introduce natural gas into the UK fuel mix on a big scale.

The 1972 Gas Act paved the way for further centralisation of the industry with the creation of the British Gas Corporation (BGC). This entity was until 1986 the sole buyer of UKCS gas and the sole transmitter and distributor of this gas to UK customers. It was also a key upstream player.

Wellhead prices were in these years set through negotiations between BGC and the producers. BGC's legal monopsony on UKCS gas purchases, and good grasp on upstream costs thanks to its own UKCS interests, ensured prices that left little rent to the producers.

The Thatcher years saw a general, ideologically driven shift from state involvement through major public enterprises in the economy, towards private solutions. The gas sector exemplified this trend.

The 1982 Oil and Gas (Enterprise) Act permitted UKCS gas producers and major industrial customers to contract directly with each other, and ordered BGC to offer third party access to its pipelines. These first steps towards a liberalisation of the market failed to boost competition. The customers that producers could now approach directly were too few, and BGC's grip on the market remained too strong. The next steps were however more forceful. The 1986 Gas Act returned the gas industry to

the private sector, transformed BGC to British Gas Plc and created Ofgas to regulate the industry and protect the interests of consumers. In 1989 Ofgas limited British Gas' purchase of new UKCS gas supply to 90% of full capacity production. During the 1990s the right for producers and consumers to deal directly with each other was extended first to mid-sized industrial and commercial buyers, and then to the entire gas market.

Through the 1990s gas prices in the UK were generally lower than gas prices in Continental Europe. Proponents of liberalisation saw this as proof of the efficiency boosting effects of increased competition. However, prices were also influenced by a strong increase in UKCS gas production that came from new discoveries and steady, technology driven growth in depletion rates. The relative impact of each of these drivers on price developments is not easily calculated.

## Continental Europe

The market value pricing principle that dominates in Continental Europe originated in the Netherlands. The Groningen field discovered in 1959 and put on-stream in 1964 presented the Dutch government with a marketing challenge. Western European gas consumption in 1965 was about 21 bcm a year<sup>2</sup>. The Dutch themselves consumed a mere 1,8 Bcm a year<sup>2</sup>. Continental European cross border gas trade was negligible. Thus Groningen had to be sold into a small and immature market area. The government did not want to sell the field cheaply, thus giving away value. Delaying its development seemed an equally unattractive option. There was a perception of urgency stemming from the emergence of a new source of energy – nuclear – that conceivably could shorten the era of fossil fuels.

In 1962 the then Dutch Minister of Economic Affairs suggested to base prices not on production costs which were low for Groningen gas and would have left the government with limited revenues, but on the market or replacement value of the gas to individual market segment in individual countries.

Specifically, the idea was that the price of Groningen gas to a given customer should be based on the price of the best alternative to Groningen gas – typically heavy fuel or gas oil – for that customer.

The price of Groningen gas should not be mechanically aligned with the price of the best alternative. On the one hand rebates could be necessary to encourage customers that did not already use Groningen gas to start doing so, and discourage existing customers from switching back to competing fuels. The rebates to attract new customers might need to be substantial if switching would require investment in new heating systems. On the other hand, due consideration should be paid to the convenience of burning gas compared to oil products, potentially giving rise to a price premium.

Since it is not possible to price discriminate at individual

customer level, buyers in individual countries were split into individual market segments (typically the residential segment, the commercial segment, the industrial segment and the power segment), a single price was calculated for each segment in each country, a weighted average end user price was calculated for each country, and transmission, storage and distribution costs were factored in to arrive at an initial border price for each country.

The initial – or start-up year – border price would be continuously adjusted in response to changes the prices of the fuels assumed to be the closest competitors to gas, and the pricing formula itself would be renegotiated from time to time in response to changes in the relative importance of individual market segments and other deeper shifts in the market.

While the market value principle placed the price risk in the Groningen gas sales contracts with the seller, the take or pay principle – another feature of these contracts – placed the volume risk with the buyer. These provisions on risk sharing paved the way for rapid growth in Dutch gas exports and for a rapid maturation of European gas markets. The latter effect was accentuated when Algeria, Russia and Norway adopted both market value pricing and the TOP principle in their contracting with European gas buyers. .

## Asia Pacific

Japan was a 2 bcm a year gas market until 1970 when imported (Alaskan) LNG entered the fuel mix. Import growth accelerated in the 1970s and 1980s in response to the first and second oil price shock. South Korea and Taiwan started to import LNG in 1986 and 1990 respectively. Australia and New Zealand – the two developed economies in the region with indigenous gas reserves – started to exploit these reserves around 1970.

The Asian countries that do not have significant domestic natural resources and access to international pipeline networks and underground storages like Europe and the US, have come to rely almost 100% on imported LNG for their natural gas supply. The largest importers, Japanese LNG buyers, are gas and power companies carrying out business in an integrated manner, from procurement and imports to transmission, distribution, downstream gas and power supply and marketing. When they first initiated discussions on potential LNG imports, they had to emphasize long-term security of supply to make sure that they would be able to fulfil their supply obligation to end-users. At the same time, since LNG projects require enormous initial investments on the seller's side, the latter needed security of demand, meaning long-term and stable offtake by buyers. Sellers and buyers thus had a common interest in long-term and stable relationships. Commercial LNG projects have been developed based on cooperative arrangements, and this is reflected in the history of LNG pricing as well.

In 1969 when LNG was first imported into Japan, and through the early 1970s, the price was fixed. This suited the suppliers since they could recover their huge initial investment with certainty. Fixed prices also enabled them to lock in the economics of their

<sup>2</sup> BP Statistical Review of World Energy, 2008

LNG project, which was an immature business at that time. Since the price of oil – the main alternative fuel to Japanese buyers – was rather stable, a fixed pricing system was acceptable to Japanese LNG buyers as well.

After the first oil shock in 1973, however, the oil price surge left the price of LNG significantly lower than that of oil. In response to requirements from suppliers, the price of LNG were gradually raised in line with the price of oil. These LNG price increases were, after the second oil shock in 1980, codified into a formula based on the concept of “oil parity pricing”. At that time, the Government Selling Price (“GSP”) was applied as index in the formula. Although different crudes were utilized, most LNG prices were 100% indexed to the GSP price.

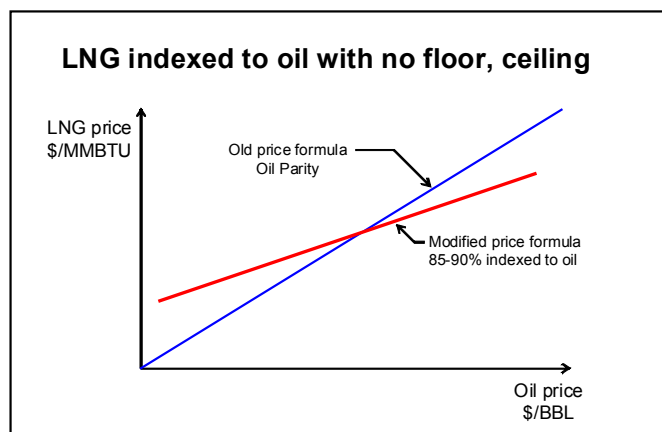
As the OPEC countries’ share of global oil production went into decline, oil turned from a strategic product into a commodity. In response to that change, some countries started to sell oil at prices that differed from the GSP, and market prices were gradually established. Since the GSP was left unmodified, the LNG price indexed to the GSP fell out of line with market realities. Furthermore, after the 1986 oil price collapse, suppliers selling LNG at oil parity prices ran into difficulties securing the economics of their LNG projects. In order to cope with that problem, the LNG pricing formula was modified again through negotiations into a new price formula, which became the basis for the current formula.

Today, most Asian LNG transactions except those that involve Indonesian LNG apply the weighted average price of oil imported into Japan (the Japanese Crude Cocktail, JCC) as index. The price formula is generally as follows:

$$Y \text{ (LNG price : \$/MMBtu)} = A \times \text{(oil price : \$/bbl)} + B$$

By applying this type of formula, the LNG price is indexed to the realized oil price (import price). The exposure to the oil price (JCC) is reduced to 80 to 90% through “A”, and a constant “B” makes the LNG price more stable than the oil price (Chart 5.1). It also enables suppliers to secure economics of LNG projects since a certain amount of income are secured even when the oil price is low.

**Chart 5.1: LNG pricing with no floor or ceiling**

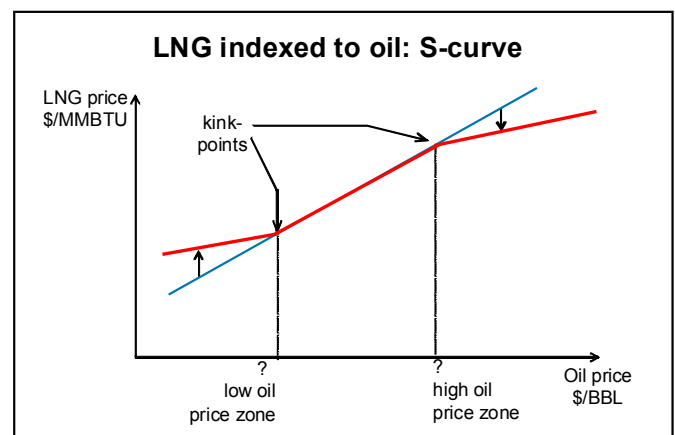


In Japan, LNG was introduced in order to reduce an at that time excessive dependency on oil. Japanese power companies

relied on oil thermal power plants for 70% of their power supply. Therefore, it was a reasonable decision for them to make LNG pricing competitive against oil. For Japanese gas companies, the main competing fuels were oil products such as kerosene for heating and fuel oil for industrial use. Hence indexation to oil was to an extent acceptable to them too. JCC is used as index since it is calculated from data in Japan Exports & Imports Monthly published by Japan Tariff Association, and therefore can be considered a credible, transparent and neutral index.

In the 1990s, the generally low oil price environment caused LNG suppliers to suffer from deteriorating project economics. In response to suppliers’ call for a helping hand, a new pricing mechanism with lower slopes at very low or very high oil prices – the so-called S-curve – was introduced (Chart 5.2). Later, when the LNG industry started to suffer from the impact of sluggish demand related to the Asian currency crisis in the late 1990s, some buyers obtained price floors and ceilings as an extension of the S-curve mechanism.

**Chart 5.2: LNG pricing with S-curve**



As oil prices rebounded, LNG contracts with a lower slope became hugely advantageous to buyers. At the same time, however, LNG market tightness resulted in sellers’ market conditions and in the abolishment of the S-curve in some contracts.

### Origins of regulated gas pricing

Regulated gas pricing may mean cost of service based pricing as well as political pricing where costs may be considered but generally play second fiddle to political and social concerns.

Regulated gas pricing with long term marginal supply costs playing a minor role requires as a rule state companies in the lead, at least from the start. Building a gas industry dominated by private players on the basis of below cost prices would likely be challenging. There are examples of state oil and gas companies being part privatised with gas prices to end users remaining under below cost regulation, but such combinations tend to create tensions and lead to calls – from, among other quarters, the part privatised companies in charge – for price reform. Cost-plus pricing is practiced in different ways in different countries. Cost-plus pricing and market based pricing may exist

side by side with households and vulnerable industries benefiting from regulations while industries with a bigger choice of fuels and suppliers are exposed to market based prices. Another recurrent feature is that wellhead prices are set on a competitive basis while transmission and distribution tariffs are regulated.

Cost based pricing shifts the rent in the affected links of the value chain to the consumers and may as such boost gas market growth – at least for a while. But cost based pricing tends to discourage efficiency improvements along the supply chain, and even households and vulnerable industries may be offered alternatives to regulated gas. Thus sooner or later the insensitivity of cost based pricing to changes in the competitive landscape may leave the gas priced this way unmarketable.

On the other hand, since cost based pricing may not provide very strong incentives to invest in fields and pipelines, growth in gas supply may fall behind growth in gas demand at regulated prices.

Both these developments may pave the way for awarding a bigger role to market based pricing, and have indeed triggered a number of price reform efforts around the world.

China is not one integrated gas market. China has multiple regional markets that traditionally have received supply from different production areas at different costs, with different prices as a result. These characteristics are gradually giving way to those of a more integrated market. Rapid construction of new long distance pipelines will give sellers access to a bigger variety of buyers and buyers access to a bigger variety of sellers.

In China as in other centrally planned economies, gas prices were historically used for accounting purposes rather than for resource allocation purposes. Gas produced under the national plan was priced differently from gas produced outside the national plan. End user prices differed not only by region but also by consumption sector; thus the fertiliser industry paid less than other industry. Neither the complexity and rigidity of the gas price structure nor the fact that many prices did not cover supply costs encouraged gas E&D. On the other hand, gas was much more expensive in energy equivalence terms than coal. This prevented gas penetration into the power sector and other sectors where coal was an option.

Cost plus pricing is still the rule but procedures are being streamlined and standardised. Also an element of competitive pricing is introduced. Wholesale buyers are allowed to negotiate directly with suppliers.

In India decision makers started to take an interest in gas only in the mid 1980s. Consumption was by then around 4,5 bcm a year. In 1984 the Gas Authority of India Ltd. (GAIL) was established to manage the development of a genuine gas market. In 1986 GAIL began the construction of the 2688 km Hazira-Bijapur-Jagdishpur pipeline to give major fuel users in the interior of the country access to gas discovered along the west coast. Supply via this pipeline fell short of demand almost from the start. In response the government established

the so-called Gas Linkage Committee to ensure that sufficient gas was allocated to priority consumers – namely the fertiliser industry and the power sector – at subsidised prices.

The Gulf war seriously weakened the Indian economy and forced the government to turn to the IMF, the World Bank and the Asian Development Bank for support. These institutions typically request policy reform in return for loans, and in the case of India they made support conditional on the state reducing its involvement in select sectors, among them the hydrocarbons sector. In response the government introduced the new Exploration and Licensing Policy (NELP) and – eventually – the multi-tiered pricing system described in chapter 3. In the beginning, however, the producer price was fixed on the basis of a particular committee's estimate of the long run marginal costs of gas production. The decision to index the price of gas at landfall points to a basket of fuel oil prices was made in 1990.

In Latin America cost based pricing was the rule until the early 1990s. Argentina then de-controlled wellhead prices with regulator Enargas continuing to regulate transmission and distribution tariffs. These were originally set to ensure a fair return on investments in pipelines and other facilities, but emergency legislation passed in the wake of Argentina's economic crisis in the early 2000s authorised the government to re-impose price and exchange controls, with the result that tariffs and prices in dollar terms dropped significantly.

In 2004 Argentinean authorities and the country's main gas producers agreed on a schedule for partially lifting the price freeze, but progress has been limited, although more recently producers and large industrial and power sector end users have been free to negotiate prices.

Brazil in 2002 liberalised gas prices but continues to regulate prices to qualifying gas power plants. Regulator ANP sets transportation tariffs on a cost of service basis. Petrobras' dominating role in the upstream and continued hold on the transmission link limits the role of competition in gas price formation, with wholesale gas prices now increasingly following oil prices.

Below cost pricing was a hallmark of the 20th century's centrally planned economies. In the FSU, prices served accounting purposes only. They were not supposed to carry signals between market actors and drive resource allocation decisions. Instead hierarchies of plans provided volume targets reflecting the prevailing prioritisation between society's different needs, and the planners' attempts to optimise under all kinds of constraints related to the unwieldiness of the productive sectors. The centrally planned economies' bias towards heavy, energy intensive industries favoured low accounting prices. Ordinary people were offered a meagre selection of consumer goods but in return received free education and health care, and cheap housing and other goods including gas.

The former 'East Bloc' included a string of countries that received Russian gas in return for pipeline construction or transit services under the division of labour within the Comecon area,

or cheaply for political reasons. In general terms, constructions like the Comecon area need arrangements for their sustainability, and one arrangement underpinning Russia's authority within this area was Moscow's provision of cheap gas and other commodities to its neighbours.

East Europe has moved away from below cost pricing and the FSU republics are implementing price reform. The countries that have opted to retain gas price regulation at below cost levels, at least for now, are the North African and Middle Eastern oil producers and exporters.

Oil producers typically have associated gas at their disposal. In the past associated gas was vented, flared or at best reinjected. Though flaring continues in some countries, globally much of the gas that was wasted is now harvested, processed and marketed. As a free good at the wellhead, associated gas is low cost gas. It can be supplied economically at prices covering only transmission and distribution costs. Alternatively it can be supplied at even lower prices or for free with an (at least initially) manageable subsidisation burden falling on the state. Problems arise only when gas demand starts exceeding associated gas supply, i.e., when need arises for much more expensive non-associated gas.

Iran began harnessing associated gas in the 1960s and Saudi Arabia followed suit with the construction of the Master Gas System in the late 1970s. Both countries, and eventually others in the region, funded gas infrastructure investments from their oil export revenues. The rulers' main motivation was to contain the growth in domestic oil consumption. This could have been done in different ways, probably most efficiently by raising domestic oil product prices. Oil price reform could however have triggered political and social unrest. The nature of the

legitimacy of rentier state governments dictates generosity in the provision of basic goods and services including fuels and electricity. Positive price and availability incentives to switch to gas appeared much safer.

Though Iranian gas use (net of reinjection) increased by 10,5% a year between 1991 and 2006, domestic oil consumption growth continued to outpace oil production growth. The country's position as a major oil exporter came under increasing pressure. Iranian rulers have therefore since the 1990s intensified efforts to make fuel users switch from oil products to gas by providing for continuous growth in the gas grid and keeping domestic gas prices at very low levels.

Saudi Arabia has also maintained the domestic gas price at a very low level for a very long time. Between 2001 and 2008 no material adjustments have taken place. Saudi Arabia has come under pressure internationally for its highly subsidized prices. Trade partners have protested that the country – now a full member of the WTO – is unfairly supporting Saudi industries and utilities.

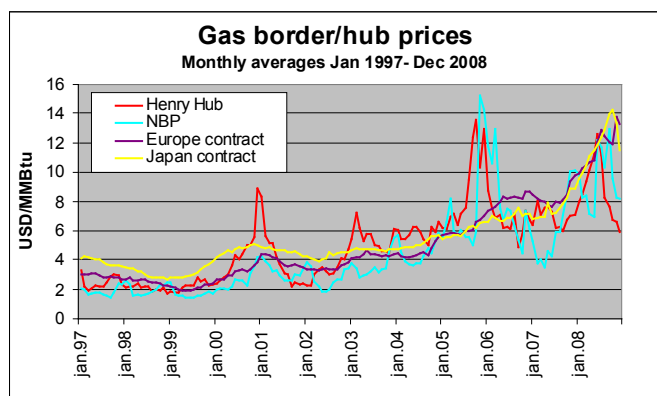
In an attempt to address the main distortions in the domestic gas sector, Saudi Arabia recently adopted a new pricing policy that could herald real price reform. In 2006, the local Eastern Gas Company was awarded a two-year contract to become Aramco's gas distributor to consumers in the Dhahran industrial area. According to industry reports, its purchase price from Aramco will be USD 1,12 per MMBtu and its sale price USD 1,34/MMBtu. In Riyadh, the Natural Gas Distribution Company was granted a license to supply small-scale manufacturing plants under a similar pricing structure. For the time being, the price for foreign investors and other consumers remains unchanged.

## 6. Recent gas price developments

### OECD area

After 6 to 7 years of gas price fluctuations around a rising trend, by mid 2008 there was broad agreement across OECD countries that prices had shifted up on a permanent basis (Chart 6.1). The financial crisis in the autumn of 2008, the steep oil price and spot gas price declines towards the end of the year and the outlook for oil linked gas prices to come down in 2009 have highlighted the risks of jumping to conclusions. There will likely be many revisits to the question of the structural or cyclical nature of gas price movements in the 2000s. Will permanently higher supply costs restore prices to USD 10 or 12 per MMBtu once the crisis peters out and demand picks up? Or will the price history of the first three quarters of 2008 prove to be a one-off event?

Chart 6.1: Gas border and hub prices



Source: PIRA

Prices firmed in the 2002-08 period for two main reasons:

- Gas supply-demand balances tightened, affecting prices through gas-on-gas competition,
- Oil prices went up, affecting gas prices in Europe and Asia through the price clause in European and Asian gas import contracts, and gas prices elsewhere through the substitution mechanism, i.e., by raising the price thresholds where consumers can save money by switching from gas to competing fuels.

Gas market tightening became an issue in late 2000 when US prices quadrupled. US gas demand increased by more than 4% in 2000, and the power sector's dash for gas promised further growth. US gas production had been flat for some years, but few had bothered to look for structural reasons; consumption had also been flat so there had been no need for more supply than was available at the prevailing prices. In 2000, however, it became clear that the surplus production capacity that had ensured low prices through the 1990s was gone. The US gas supply curve had steepened and prices responded accordingly to the increase in demand.

Prices reverted to the USD 2-3/MMBtu range in late 2001

thanks to weather and other circumstances that wiped out the previous year's demand growth, but started to climb again in 2002, and Henry Hub peaked at close to USD 14/MMBtu on a monthly average basis in the wake of hurricanes Katrina and Rita in the autumn of 2005. Following a period of relative normality Henry Hub in the summer of 2008 again touched the USD 13-14/MMBtu range, this time because of a combination of factors including high demand, record high oil prices, a lack of LNG for the US and below average storage levels. Indigenous production has however staged an unexpected recovery with high prices and new technology making shale gas and other unconventional gas economic.

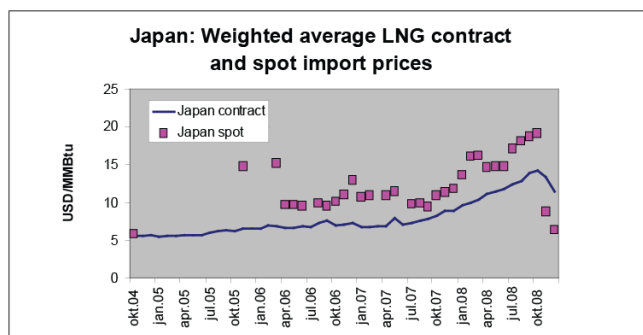
Continental European gas buyers had after 2007 to cope with the impact of sharply rising oil prices. Gas import prices more than doubled between June 2007 and January 2009.

The UK's growing gas import dependence and recurrent need to compete with other importers for supply constitute a strong link between UK and Continental European gas import prices. Thus the NBP price was by mid 2008 forecast to climb at an even faster pace than Continental prices to ensure British competitiveness during the winter.

Because of the averaging and lagging nature of the gas price-oil price link, Asian import prices are like Continental European import prices less volatile than US and Northwest European hub prices. They have also on balance been 1-2 dollars per MMBtu higher than US and European prices. This relationship has however become less clear cut since 2005. Asian buyers still tend to pay more for their supply than other buyers, but the differences have recently narrowed somewhat and occasionally the relationships have reversed.

Chart 6.1 does not show the wide range of prices paid for spot cargos by Japanese, Korean, Spanish and other buyers that for various reasons have needed to top up their term imports. Asian buyers in early-mid 2008 frequently offered USD 15-20/MMBtu for additional supply (Chart 6.2).

Chart 6.2: Japanese LNG import prices



Source: PIRA

Japanese contract prices in 2004-08 fell out of line with spot prices due to the S-curve formulae typical for Japanese LNG import contracts. These formulae flatten the LNG price-oil price curve above and below certain oil price levels. The upper level is typically around USD 30 a barrel which was considered a robust price at the time of contract signature but corresponded to only 20-25% of spring-summer 2008 oil prices. The levels are not set in stone – most contracts state that buyers and sellers should get together and negotiate new terms if it appears that the existing ones no longer reflect market realities. However, buyers have ways to put off settlements, and many have done so. With respect to new contracts, Asia’s main LNG suppliers in 2008 took advantage of the prevailing market tightness to demand price parity with crude oil. A JCC price of USD 150/b would then translate into an LNG price of some USD 25-26/MMBtu. Asian LNG buyers resisted full parity with no S-curve protection against extreme oil prices as a basis for long term contracts. As of early 2009 full parity seems some time off. There is evidence that S-curves are beginning to regain their popularity with sellers fearful of crude oil prices in the USD 30-40/b bracket and LNG prices in the USD 5-6/MMBtu range.

The global financial crisis hit spot gas prices in the autumn of 2008, reducing Henry Hub from more than USD 12/MMBtu in June to around USD 5,50/MMBtu by end December, and the NBP price from USD 12,90/MMBtu in September to around USD 8,20/MMBtu three months later (Chart 3.1). Long term contract prices held up through 2008 but were by early 2009 caught up by tumbling crude and oil product prices and looked set to plummet in the second and third quarters.

Independently of the financial crisis, US gas prices have since 2007 fluctuated in a range making US buyers unprepared to compete with Asian and European buyers for spot LNG. The US has since the beginning of 2006 experienced a boom in unconventional gas production which, in combination with flat demand, has allowed for declines in both piped gas and LNG imports and still left the country with adequate gas in storage. Since unconventional gas is relatively costly to produce, prices lower than those prevailing by the end of 2008 may be unsustainable. The number of gas rigs in operation is already down in response to the July-December 2008 price downturn. Whether the US gas supply-demand balance will drive, and sustain, a price recovery any time soon is however equally questionable.

A wide range of possible development paths for US gas production is adding to the uncertainty whether oil and gas prices world wide will decline even further, remain depressed for a long time or recover fairly quickly. This confusion reflected the impossibility in the midst of a crisis, with no distance to the subject matter, of forecasting its depth and duration.

However, it needs to be remembered that:

- Gas prices are still robust in comparison to those prevailing as recently as in 2003,
- The gas price levels of 2007 and early-mid 2008 pointed

towards demand destruction on a significant scale; the price decline has dampened if not eliminated this risk,

- Gas development costs have exploded leaving a fair share of future supply marginal at early 2009 prices,
- Though a world wide economic setback will dampen cost inflation,
  - The cyclical component of this inflation (booming raw material, engineering service and skilled labour prices) will not disappear overnight,
  - The structural component related to the oil and gas industry’s turn to developments in more remote locations, deeper waters and harsher climates will not disappear at all.

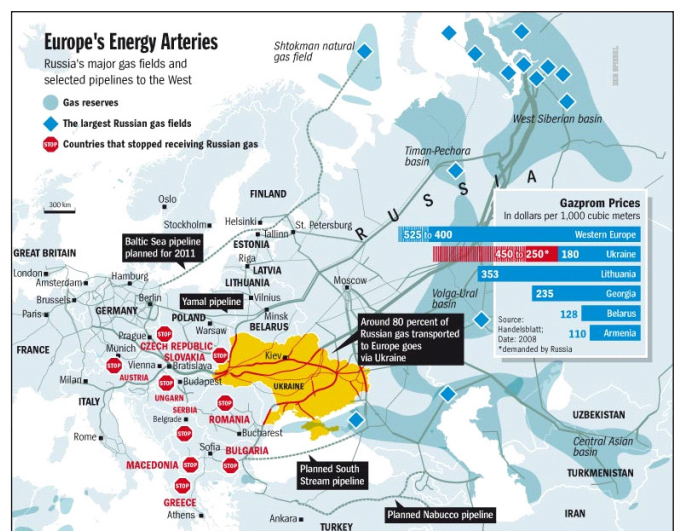
Thus, while the jury is still out, it seems a fair hypothesis that gas prices will recover – perhaps not in the medium-short term to levels comparable to their recent peaks, but to levels that will support continued growth in supply and demand.

## Rest of the world

Prior to the financial crisis gas prices increased also outside the OECD area, though not everywhere, and certainly not at uniform rates.

Central and Eastern Europe and the FSU countries that rely on Russian gas have had to undertake major price adjustments. Soon after the break-up of the FSU, the Central and Eastern European countries that had come to rely on cheap Russian and Central Asian were presented with similar price formulas as those underpinning Western Europe’s Russian gas imports. More recently the other FSU republics have had to cope with similar sea-changes in the pricing of Russian gas, although different countries have been granted different transition periods and were still by 2008 paying significantly different prices (Chart 6.3)

Chart 6.3: Gazprom prices



The Russian-Ukrainian dispute over gas prices, transit tariffs and payment arrears that has received special attention due to Ukraine’s role as transit country for nearly two thirds of Russia’s

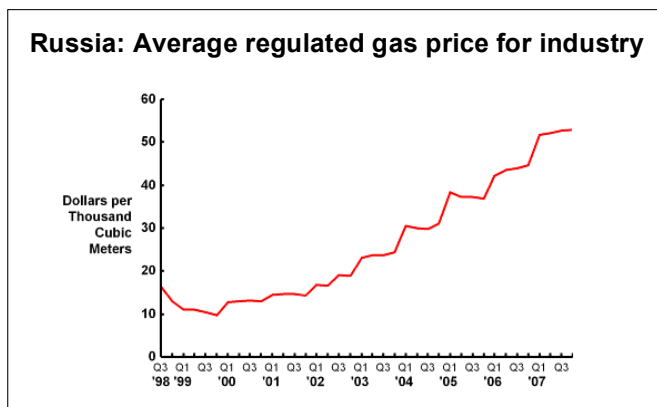


gas exports to Europe. Ukraine by 2005 paid a nominal price of USD 50 per 1000 cubic metres or USD 1,38/MMBtu for Russian gas. Russia raised the gas price first to USD 160/1000 cm and then to USD 230/1000 cm. Ukrainian payment problems have on two occasions – in 2006 and again in 2009 – led Gazprom to cut its supply of gas to Ukraine and indirectly to Europe. An agreement concluded in January 2009 commits Ukraine to pay the “European standard” price minus 20% in 2009, and the full “European standard” price from 2010 onwards, against receiving market based transit tariffs for the roughly four fifths of Russia’s gas exports to Europe that transit Ukraine. The financial crisis will lower Russia’s oil linked export prices – but will evidently also reduce the importing countries’ ability to pay.

Gazprom continues to adjust the existing agreements with CIS countries step by step in order to move to contractual terms and conditions and pricing mechanisms similar to those effective in the European countries beginning from 2011. Finally export prices will reflect fuel market conditions and the prices of the best alternatives to gas.

Russia is also implementing domestic price reform. Although quite impressive in nominal terms (Chart 6.4), the price adjustments made between the mid 1990s and 2005 only kept up with inflation. Gas became steadily cheaper compared to oil and coal. Gazprom reported a loss of USD 25 billion on its domestic sales between 1999 and 2003. Concerns about the sustainability of Russia’s gas balance with prices that favoured rapid consumption growth but did not generate the funds needed for the development of the next generation of giant gas fields, were raised.

**Chart 6.4:** Russian regulated gas prices to industry



Source: CERA

In 2006 the government responded by presenting a plan to increase prices to industrial consumers to parity with European border prices adjusted for transportation costs, by 2011. Observers noting the strains that exposure to ‘world level’ gas prices would put on the Russian economy, greeted the timeline with scepticism, and the oil driven escalation of European border prices that started in 2007 made the reform pace required by the 2006 plan even faster. The government in mid 2008 acknowledged all this by postponing the deadline for full alignment of domestic industrial

prices with export netback prices, to 2014-15, and announcing a revised schedule for the 2008-11 period according to which prices will increase by 25% in 2008, 25% in 2009, 30% in 2010 and 40% in 2011.

The fact that Russian industrial and residential consumers in 2008 paid only USD 1,89/MMBtu and USD 1,44/MMBtu<sup>3</sup> (net of VAT) for gas indicates that the country has a long way to go to reach parity in netback terms with European prices.

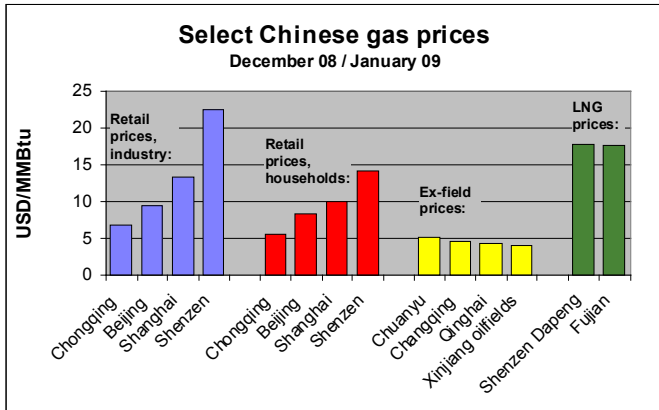
The Russian government’s embrace of this pricing principle probably inspired – and has in turn been bolstered by – the Central Asian republics’ more aggressive pricing of their gas sales to Russia. Back in 2000 Gazprom typically paid a border price of around USD 40/1000 cm, or USD 1,10/MMBtu, for Turkmen and other Central Asian gas. In the first half of 2008 Turkmenistan received USD 130/1000 cm or USD 3,59/MMBtu for its gas. At the same time the heads of Turkmenistan’s, Kazakhstan’s and Uzbekistan’s state oil and gas companies announced that from 2009 on Gazprom would need to pay the price of gas on Europe’s eastern border netted back to the delivery points for Central Asian gas on Russia’s southern border.

In addition to raising regulated prices, the Russian government is encouraging growth in the hitherto tiny part of the gas market with unregulated prices. A gas exchange is established and placed under Gazprom subsidiary Mezhhregiongas. It remains embryonic, and exchange prices have to date not differed much from the regulated prices. However, it is a start.

The leading Asian Non-OECD economies, China and India, share a desire to boost gas consumption, and a need to complement indigenous gas production with imported gas supply. Both countries already have pockets of domestic gas demand ready for international gas prices. Market growth requires however the active participation of the power sector and key industries used to burn cheap coal or price regulated domestic gas. The difficulties of accelerating gas penetration in such an environment have stimulated indigenous gas E&D in both countries. Recent discoveries may enable a more gradual alignment of Chinese and Indian prices with the Japanese and Korean import prices that define the alternative costs to suppliers – but will not eliminate the need for price reform.

<sup>3</sup> Gazprom reports on its home page regulated prices in 2008 at RUB 1690 per 1000 cubic metres for industrial consumers and RUB 1290/1000 cm for households. The average RUB/USD exchange rate in 2008 was 0,04039.

**Chart 6.5: Select Chinese gas prices**



Source: ICIS Heren China Gas Markets

Chinese gas prices are regulated by central and provincial authorities and have traditionally varied across locations and sectors. In late 2005 a nation-wide price reform – the first in eight years – was implemented, and in late 2007 the government announced further price hikes (with special, subsidised rates remaining in place for the fertilizer industry). As of 2008 ex-field prices were in the USD 4-5/MMBtu range, the ex-terminal price of imported LNG USD 17-18/MMBtu and retail prices between USD 5,50 and USD 22,50 per MMBtu depending on location and customer class (Chart 6.5).

China’s willingness to pay today’s market prices for imported LNG was long in doubt. CNOOC’s contracts for NWS and Tangguh LNG were signed under the buyers’ market conditions that prevailed in the early 2000s and lay down DES prices in the USD 3,00-3,70/MMBtu price range reflecting oil price ceilings of USD 25 and USD 38 per barrel respectively. However, CNOOC’s and Petrochina’s more recent deals with Petronas, Woodside and Qatargas are comparable to the established Asian importers’ recent contracts, with the Chinese side accepting Qatar’s 2008 insistence on crude oil parity pricing. The Chinese buyers presumably hope to make expensive LNG marketable through blending with much cheaper indigenous gas.

In India gas supply has three components, each of which is priced differently. Gas produced by the state oil companies ONGC and OIL is subject to the so-called Administrated Price Mechanism (APM). In 2006-07 this gas made up about 65% of total supply. The APM price is indexed to a basket of fuel oil prices in such a way that the markets segments eligible for APN gas in 2008 paid wholesale prices in the USD 2,00-2,40/MMBtu range plus transmission and distribution charges and taxes. Customers in the northeast paid less as part of a regional support policy package. Gas produced by private companies is sold at negotiated prices with no linkage to oil and no caps; recently prices have varied between USD 3,50 and USD 5,70 per MMBtu. Finally, regasified imported LNG is sold at prices set on a cost plus basis and subject to government approval.

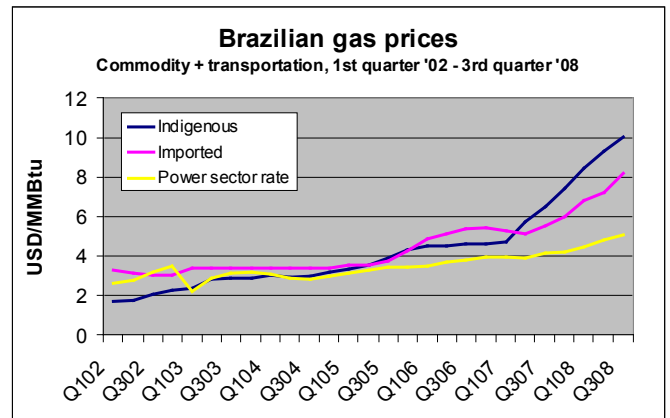
As China, India signed its first LNG import contracts – with RasGas II – at a time when buyers had the upper hand. Thus

Petronet between 2004 and 2009 received Qatari LNG at a constant price of USD 2,53/MMBtu. From 2009 the price will be linked to oil, but for several years the pass-through factor will be much lower than normal for newer contracts. India has not since 20XX signed any long term LNG import contracts reflecting the 2008 price environment and also the outlook for rapid growth in indigenous – Krishna Godavari basin – gas production. But Indian buyers have at times been active in the spot market.

Also in Latin America, countries experiencing gas demand pressure and relying on imported gas for significant shares of their supply, are struggling to cope with increasing prices of internationally traded gas.

One example is Brazil where gas prices in nominal USD terms increased significantly in 2003 and again in 2005. An attempt in 2004 to boost market growth by freezing prices was abandoned due to its negative impact on E&D. The price of locally produced gas jumped from about USD 3/MMBtu by mid 2004 to USD 10/MMBtu by late 2008 (Chart 6.6).

**Chart 6.6: Brazilian gas prices**



Source: Petrobras

In 2006 Brazil which sources more than 40% of its gas supply from Bolivia, was presented with a request for a 120% increase in the price of Bolivian gas. La Paz based its claim on, among other things, the steep increase in international gas prices between 1999 when Bolivia started selling gas to Brazil, and 2006. Eventually, the two countries settled for a smaller increase, but the episode showed how international gas prices can enter intra regional gas price negotiations as benchmarks without the exporting country having the option to export gas outside the region or the importing country having the option to import gas from outside the region, i.e., without the international prices having any real significance as alternative costs to any of them.

**Argentinean** producers receive only about USD 1,50/MMBtu for indigenous gas. This low price reflects decisions made in the wake of the Argentinean economic crisis in the beginning of this decade. It is about one fifth of what Argentina pays for Bolivian gas and is not encouraging gas E&D, which is one reason why Argentinean gas production has stagnated and shortage problems have emerged.

In March 2008 the government authorised higher prices for gas produced from new, remote or tight fields with above normal development costs. But this so-called ‘Gas Plus’ plan does not introduce new pricing principles, it only amounts to a modernisation of the cost plus approach.

Several Latin American countries have opted for LNG as a means to reduce their dependence on piped gas imports from their neighbours. Exposure to the volatility of world LNG prices apparently seems a lesser evil than the risk of supply cut-offs in the event that the upstream country needs the gas for itself. Petrobras in 2008 commissioned terminals at Pecém in Ceará and at Baía de Guanabara near Rio de Janeiro. Both terminals are LNG tankers modified for onboard regasification and will operate mainly during the Brazilian winter season. Argentina’s Enarsa in 2008 commissioned a terminal of the same type at the port of Bahia Blanca, 400 miles southwest of Buenos Aires, partly in response to warnings that Bolivia would not be able to meet its supply commitments to Argentina in 2008-09. In Chile construction of one terminal at Quintero near Santiago and another at Mejillones further north is ongoing with a view to commissioning in 2009-10, partly in response to the risk of Argentinean gas supply shortfalls.

**Venezuela** also practices price regulation. Since 2001 private producers have been allowed to sell gas directly to end-users, bypassing PdVSA, but because of limited access to PdVSA’s pipelines the state company remains the main market for private gas. Moreover, the Ministry of Energy and Petroleum caps prices at levels supposedly reflecting Anaco or Lake Maracaibo hub costs and transportation costs but clearly reflecting other, political and social considerations as well. As importantly, maximum prices are quoted in Bolivares, and provisions for adjusting them in response to inflation and changes in the exchange rate did not prevent a significant drop in the dollar value of gas in the Venezuelan local market between 2000 and 2004.

Africa and the Middle East are lagging the other Non-OECD regions in reforming their domestic gas prices. In **Algeria** and **Libya**, Sonatrach and NOC provide gas to big industrial and power sector customers at prices that are not publicly available but apparently low by international standards. Algeria also has a significant number of smaller scale, residential and commercial customers, and Sonelgaz in 2006 supplied these customers at a fraction of what Mediterranean European residential and commercial gas consumers pay. In **Egypt**, EGAS purchases gas from various upstream consortia at a price linked to oil but until recently capped at a low oil price; for the 2006 licensing round EGAS put the maximum gas price at USD 2,57/mcf for oil prices at or above USD 22/b. However, warnings from key upstream players that EGAS needed to pay more to enable companies to cover escalating costs and sustain E&D in 2007 brought results with BP and RWE managing to negotiate a ceiling of USD 4,84/mcf. At the same time hikes in select end user gas prices were announced, reflecting government worries about its fuel subsidy burden as well as with the sustainability of the pace of growth of domestic gas use.

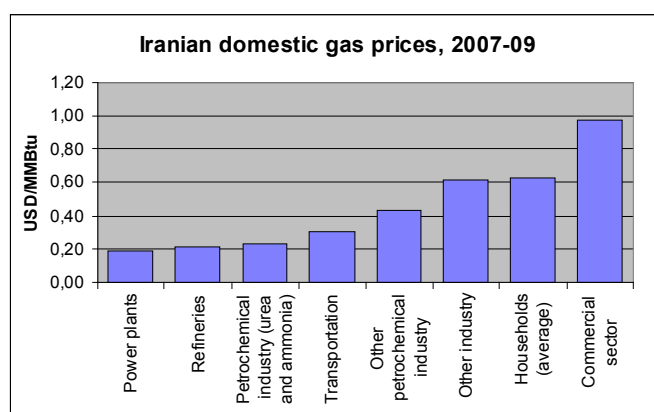
In **Nigeria**, as yet the only significant gas producer south of Sahara, select industrial customers reportedly pay prices that cover supply costs, but the country’s biggest gas user, state power utility PHCN, in 2005 paid only a reported 11 US cents per MMBtu.

Nigerian authorities in 2008 presented companies looking for opportunities in Nigerian LNG with a request to get involved also in domestic gas and power supply. A new Gas Master Plan promises efforts to turn the currently badly mismanaged domestic gas and power sectors into attractive targets for foreign investment. However, the plan remains short on specifics on key preconditions like domestic gas price reform, and the current political situation in Nigeria does not bode well for consistent implementation of policies to fix the country’s problems.

The Middle East has seen even fewer attempts at domestic gas price reform. In many Middle Eastern countries gas has historically been considered a free good, and as high oil prices have boosted national oil company and state revenues across the region, the appetite for fuel subsidy cuts that one could detect in the late 1990s has waned.

**Iran** has kept domestic gas prices low with the purpose of encouraging substitution from oil products to gas wherever possible, and also for social and political reasons. The reporting on Iranian end user gas prices is not particularly consistent. The highest estimate available – from Facts – puts the prices charged to different market segments in the USD 0,20-1,00/MMBtu range (Chart 6.7).

*Chart 6.7: Iranian gas prices*



Source: Facts Global Energy

Fuel subsidies represent a major burden on the Iranian budget. But with oil being more valuable than gas, and with NIOC struggling to sustain Iran’s oil exports, until spring 2008 no one suspected the government of planning gas price reform initiatives.

Nevertheless, in May 2008 government officials did announce a plan to hike domestic gas prices to encourage energy conservation and free up gas for exports.

Apparently the announcement – which could be related to Turkmenistan’s decision to double the price of Turkmen gas to Iran – included neither details on the planned extensiveness of the reform nor a timeline, and it remains to be seen whether and when adjustments with sufficient bite to have an impact on demand patterns, will be enacted.

**Saudi Arabian** gas sales prices are not public but are presumably consistent with the gas purchase price announced in 2003 in

the context of the ‘gas opening’, of USD 0,75/MMBtu at the inlet to the Saudi Master Gas System, minus a tariff for use of this system for onward transportation. Saudi Arabia sticks to its policy of offering cheap gas to attract investments in petrochemical and other gas intensive industries, even in the face of a gas shortage so severe that power plants intended to run on gas recently have burned crude oil instead.

## 7. Current extensiveness of individual pricing mechanisms

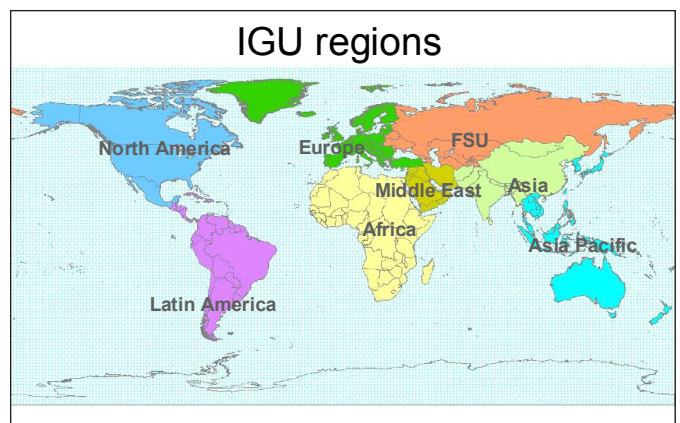
### Introduction

This section considers current practice with respect to wholesale contract price formation for both pipeline gas and LNG. We proceed from a mapping of current pricing mechanisms around the world, not only for gas traded internationally, but also for gas produced and consumed within countries. IGU members have provided data for almost 100 countries, and Nexant have collated and analysed them. The mapping of price mechanisms was first undertaken for the year 2005 and was repeated for 2007. This section reports largely on the 2007 results with some comparisons against the 2005 results.

We focus as noted on wholesale prices. Wholesale prices can cover a wide range of prices. The only prices which are clearly not included are the prices of gas to end users. In 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 indigenous 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 Chart 7.1. 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 plus China, called Asia, and another region including the rest of Asia plus Australasia which is called Asia Pacific.

Chart 7.1: IGU regions



Data for each country were collected in a standard format. As an example, a data collection form for the UK is shown in the chart below. Individual country gas demand may be supplied from any one combination of three sources – indigenous production, pipeline imports and LNG imports (storage is ignored for the purpose of this analysis). For each of these three sources separately data was collected 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 must add up to 100%.

Information was also collected on wholesale price levels in 2007 and 2005. This covered the annual average price and the highest monthly average price and lowest monthly average price. All prices were converted to \$/MMBtu. A comments section was included to identify and acknowledge the source of the information and any other useful information.

All data in the IGU study on gas volumes for consumption, production, imports and exports is taken from the IEA database, supplemented where necessary by the US Energy Information Administration and any specific country and/or regional knowledge.

Chart 7.2: Data collection form  
Data Collection Form

### Data Collection Form

<b>Country</b>	<b>United Kingdom</b>					
<b>Region</b>	<b>Europe</b>					
<b>Volumes 2007: BCM</b>	<b>Consumption</b>	<b>Production</b>	<b>Imports</b>		<b>Exports</b>	
			<b>Pipeline</b>	<b>LNG</b>	<b>Pipeline</b>	<b>LNG</b>
	91.4	72.4	28.0	1.5	10.4	0.0
<b>Wholesale Price Formation</b>	<b>Domestic Production</b>		<b>Imports</b>			
			<b>Pipeline</b>		<b>LNG</b>	
<b>Oil Price Escalation</b>	23.5%					
<b>Gas-on-Gas Competition</b>	76.5%		100.0%		100.0%	
<b>Bilateral Monopoly</b>						
<b>Netback from Final Product</b>						
<b>Regulation: Cost of Service</b>						
<b>Regulation: Social and Political</b>						
<b>Regulation: Below Cost</b>						
<b>No Price</b>						
<b>Not Known</b>						
<b>Total</b>	100.0%		100.0%		100.0%	
<b>Estimated 2007 Wholesale Price Range (\$/MMBTU)</b>	<b>Average</b>		<b>High</b>		<b>Low</b>	
	\$5.89		\$10.57		\$3.35	
<b>Comments</b>	The EU Energy Sector Inquiry found that in the UK around 40% of long term contracts use a market based gas price index as the escalator. The remaining 60% predominantly use oil price indexation with some inflation element. However, less than 40% of domestic UK production is under long term contract with the other 60% being traded on the spot market and therefore automatically priced on the NBP index (source for this information was an OIES study on the UK gas market updated for recent data from IEA and Heren). It is thought that all pipeline and LNG imports are priced against the NBP. UK imports pipeline gas from Norway, Netherlands, Belgium and Germany and LNG from Trinidad, Qatar, Egypt and Algeria.					
<b>Completed By</b>	Mke Fulwood - Nexant					

## Price Formation Mechanisms

### Types of Price Formation Mechanism

In preparation for the initial data collection exercise for 2005, a series of discussions were held at the PGC B2 sub group meetings on the range of different types of possible price formation mechanisms.

It was decided to use for categorisation purposes the eight wholesale pricing mechanisms outlined above. For the remainder of this section the following abbreviations will be used:

GOG	Gas-on-Gas Competition
OPE	Oil Price Escalation
BIM	Bilateral Monopoly
NET	Netback from Final Product
RCS	Regulation Cost of Service
RSP	Regulation Social and Political
RBC	Regulation Below Cost
NP	No Price
NK	Not Known

In addition to categories 1-8 it proved necessary to have a 'not known' category for those instances where no information was found on how a particular component of gas consumption in a particular country is priced.

## Results

### Format of Results

In looking at price formation mechanisms, the results have generally been analysed from the perspective of the consuming country. Within each country gas consumption can come from one of three sources, ignoring withdrawals from (and injections into) storage – domestic production, imported by pipeline and imported by LNG. In many instances, as will be shown below, domestic production, which is not exported, is priced differently from gas available for export and also from imported gas whether by pipeline or LNG. Information was collected for these 3 categories separately for each country and, in addition, pipeline and LNG imports were aggregated to give total imports and adding total imports to domestic production gives total consumption. For each country, therefore, price formation could be considered in 5 different categories:

- Indigenous production (consumed within the country, i.e. not exported)
- Pipeline imports
- LNG imports
- Total imports (pipeline plus LNG)
- Total consumption (indigenous production plus total imports)

Each country was then considered to be part of one of the IGU regions, as described in the Introduction, and the 5 categories reviewed for each region. Finally the IGU regions were aggregated to give the results for the World as a whole.

In terms of the presentation of results, the World results will be

considered first, followed by the Regional results for the separate regions – North America, Latin America, Europe, Former Soviet Union, Middle East, Africa, Asia and Asia Pacific.

As well as collecting information on price formation mechanisms by country, information was also collected on wholesale price levels in each country. These results on a country and regional basis are also presented together with an analysis of price trends.

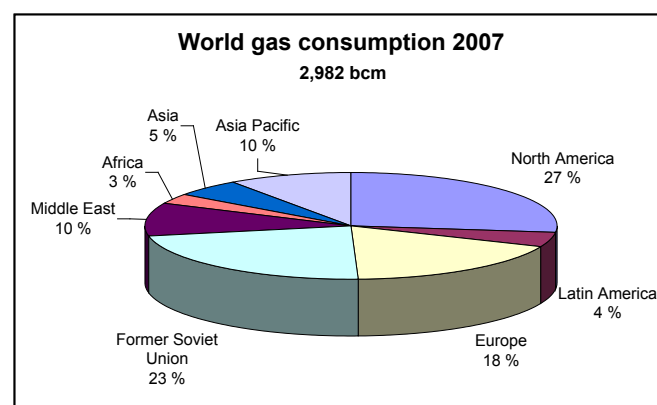
## World Results

Before considering the results on price formation mechanisms, the regional patterns of consumption and production will be considered. The discussion of the results on price formation mechanisms will show comparisons between 2007 and 2005 for the World and where relevant for regions but there is an additional sub-section which explains directly the reasons for the changes.

### World Consumption and Production

In 2007 total world consumption and production was of the order of 2,980 bcm. Chart 7.3 below shows the distribution of world consumption.

Chart 7.3: World gas consumption 2007

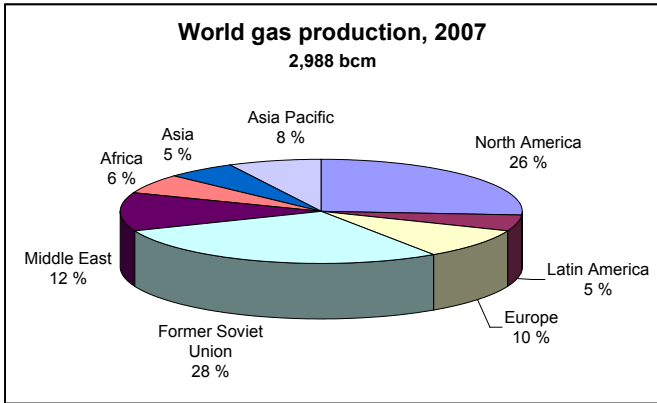


Sources: BP, IGU

North America and the Former Soviet Union, followed by Europe are the main consuming regions, and it is these regions, therefore, which will have the greatest influence on the results on price formation mechanisms at the World level. The Middle East and Asia Pacific will also have an important, but smaller, influence.

With respect to world gas production, the largest consuming region – North America – was largely self-sufficient in 2007. The Former Soviet Union was a net exporter, principally to Europe, which was a net importer. Asia Pacific was a net importer, principally from the Middle East, while Africa was a net exporter, mainly to Europe. Asia and Latin America were largely self-sufficient.

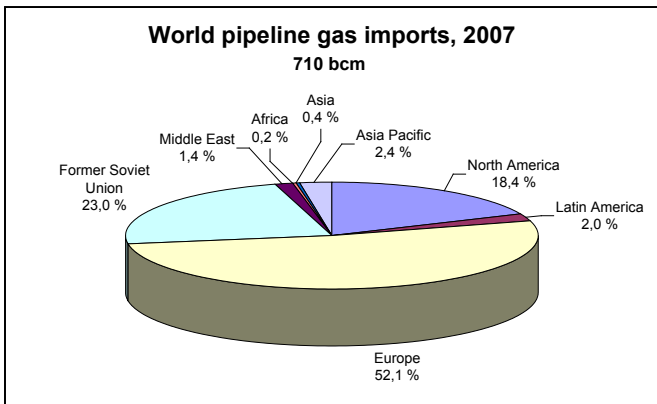
**Chart 7.4: World gas production, 2007**



Sources: BP, IGU

Concerning imports by pipeline (both intra- and inter-regional), Europe accounts for more than half of the world total. Both European intra-regional gas imports (Norway to various countries) and Europe’s imports of gas from outside Europe (Russia and Algeria) are very significant. In the other regions, pipeline imports are all intra-regional.

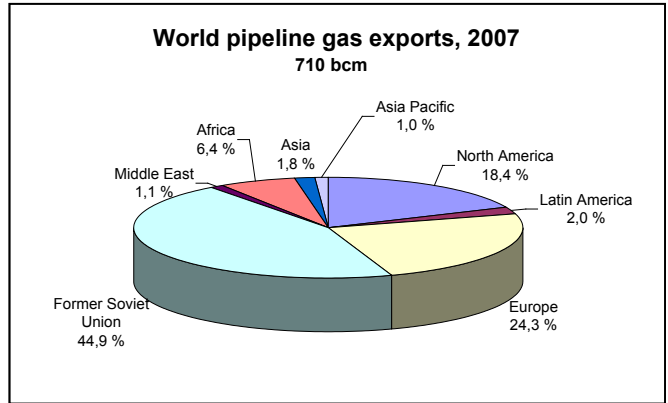
**Chart 7.5: World pipeline gas imports, 2007**



Sources: BP, IGU

With respect to gas exports via pipeline, the Former Soviet Union in 2007 accounted for some 46% of the world total. Africa, meaning in this case Algeria, is also a significant exporter to Europe, while any trade in the Asian and American regions is intra-regional.

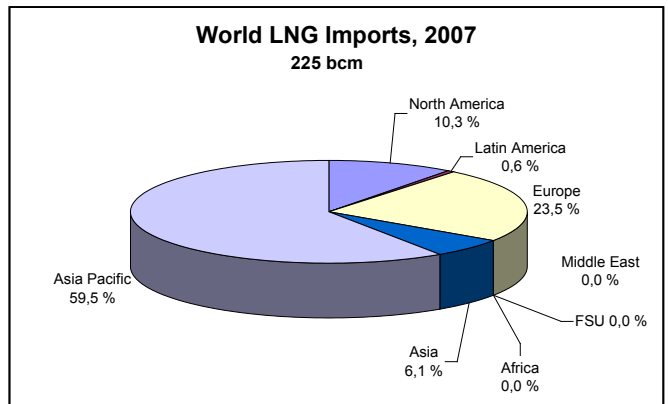
**Chart 7.6: World pipeline gas exports, 2007**



Sources: BP, IGU

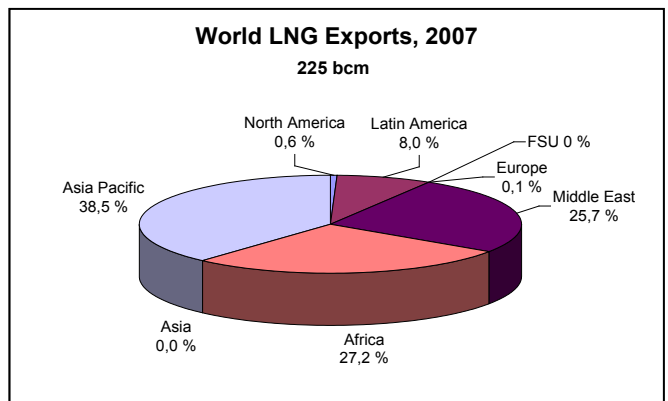
LNG imports are dominated by Asia Pacific – principally Japan, Korea, and Taiwan, with Europe being the second largest importing region. When compared with the LNG Exports chart, much of the Asia Pacific trade is intra-regional, but the region also imports significant quantities from the Middle East, while Africa and Latin America (Trinidad) are key exporters to Europe and North America.

**Chart 7.7: World LNG imports, 2007**



Sources: BP, IGU

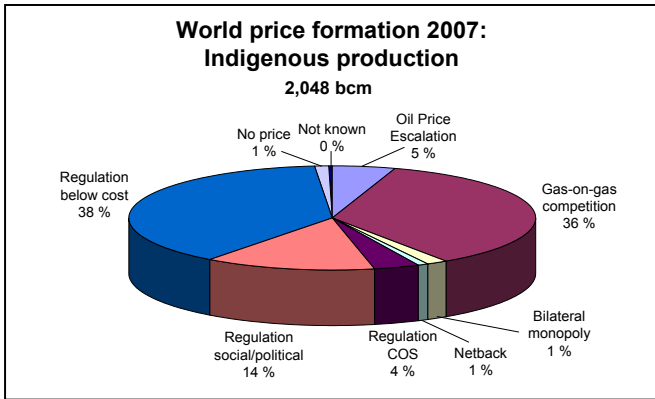
**Chart 7.8: World LNG exports, 2007**



Sources: BP, IGU

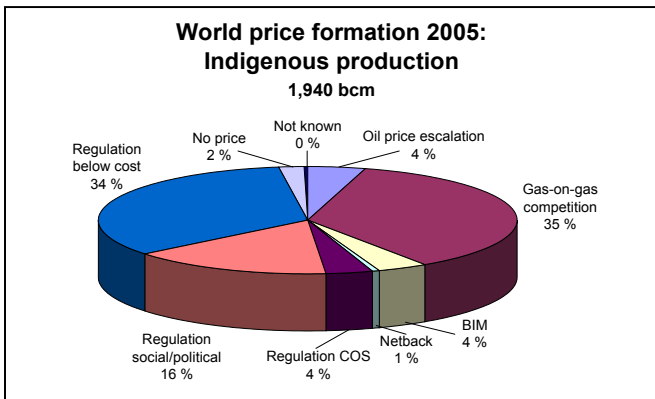
**Price formation: Indigenous production**

*Chart 7.9: World price formation 2007 – indigenous production*



Indigenous production, consumed in own country, accounted for just over 2,000 bcm in 2007, slightly less than 70% of total world consumption. The two largest price formation categories were GOG – accounting for some 36% mainly in North America, UK in Europe and Australia in Asia Pacific – and RBC – accounting for 38%, largely the Former Soviet Union and Middle East with some in Africa. RSP at 14% is spread through all regions apart from North America. RCS, at 4%, is principally in Africa and Asia. There is a small amount of OPE in Europe and Asia. Compared to 2005 the changes have been minor – marginal increases in GOG and RBC.

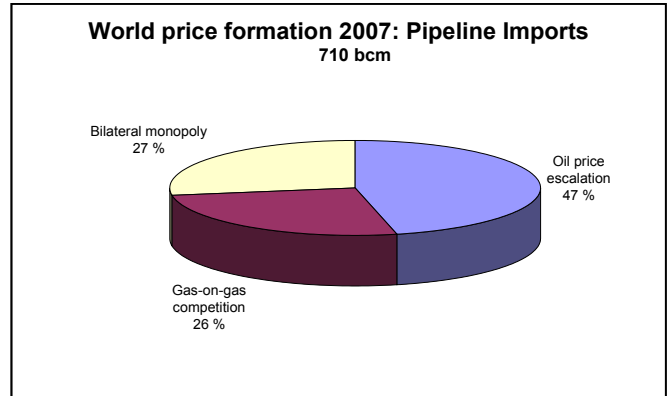
*Chart 7.10: World price formation 2005 – indigenous production*



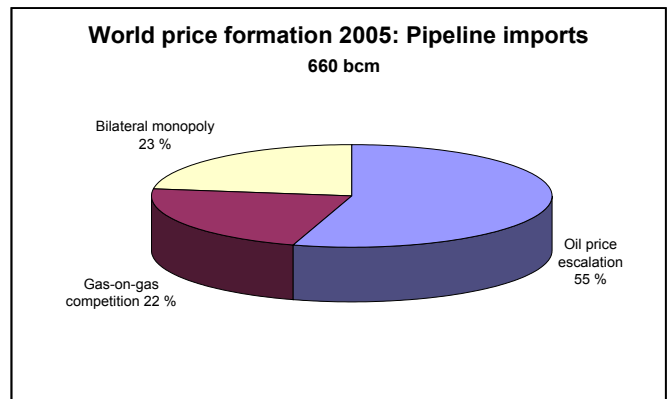
**Price Formation: Pipeline Imports**

Pipeline imports at 710 bcm account for some 24% of total world consumption. Three categories account for internationally traded pipeline gas – OPE almost all in Europe; GOG in North America with small amount in Europe into UK and BIM almost all intra-Former Soviet Union trade. Compared to 2005, there have been increases in GOG and BIM at the expense of OPE.

*Chart 7.11: World price formation 2007 – pipeline imports*



*Chart 7.12: World price formation 2005 – pipeline imports*



**Price Formation: LNG Imports**

LNG imports at 225 bcm account for some 7,5% of total world gas consumption. Internationally traded LNG is largely dominated by OPE into Europe and Asia Pacific. GOG is mainly North America with some spot LNG cargoes into Europe and Asia Pacific, while the small amount of BIM is in Asia reflecting the LNG cargoes to India. Compared to 2005, GOG has gained significantly at the expense of OPE, largely reflecting the increase in spot LNG cargoes.

*Chart 7.13: World price formation 2007 – LNG imports*

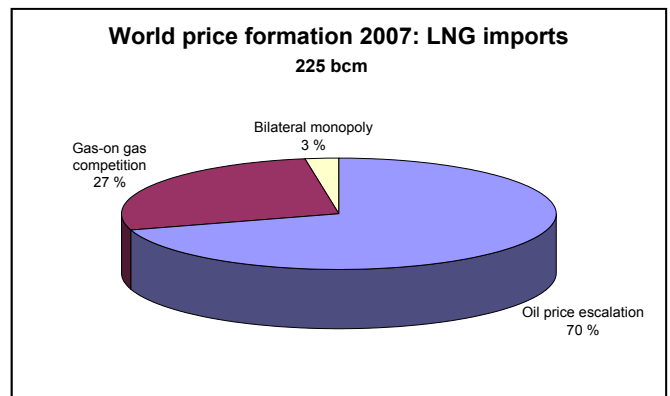
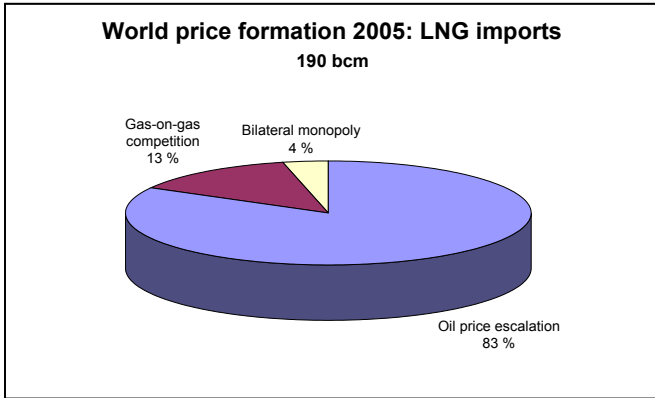




Chart 7.14: World price formation 2005 – LNG imports



**Price Formation: Total Imports**

Total imports at 935 bcm account for some 32% of total world consumption. 53% is OPE with Europe (pipeline mainly) and Asia Pacific (LNG) dominating. GOG is both pipeline and LNG imports, with BIM largely intra-Former Soviet Union pipeline trade. GOG and BIM have gained significantly at the expense of OPE comparing 2007 and 2005.

Chart 7.15: World price formation 2007 – total imports

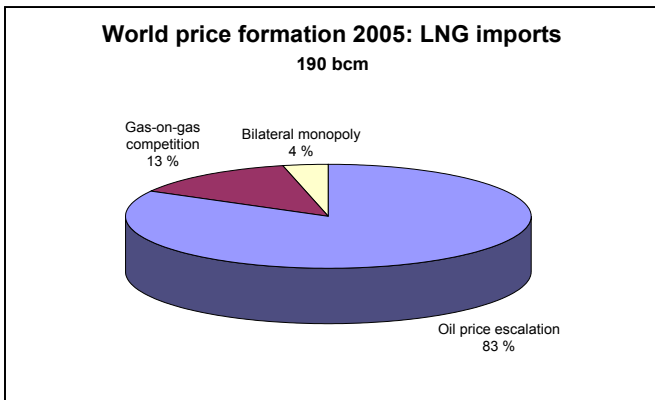
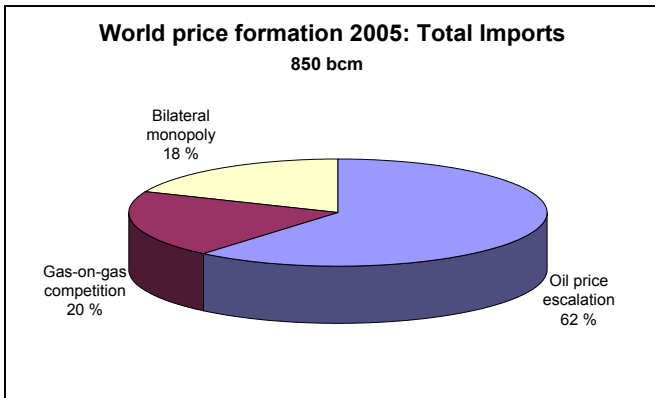


Chart 7.16: World price formation 2005 – total imports



**Price formation: Total consumption**

The respective shares of total world consumption for each price formation mechanism reflect largely the dominance of domestic production consumed in own country. OPE becomes more important because of its dominance in gas traded across borders.

Just over 50% of total consumption is either OPE or GOG, while just under 40% is subject to some form of regulatory control including RBC, where it could be said gas is effectively subsidised. Regulation of wholesale prices occurs in all regions apart from North America.

The small amount of NET pricing is in Latin America (Trinidad to methanol plants) while NP (gas effectively given away) is principally in the Former Soviet Union (Turkmenistan), Middle East and North America (in Mexico, where Pemex refineries and petrochemical plants use gas as a “free” feedstock).

Compared to 2005, GOG and RBC have increased their respective shares, largely at the expense of OPE and RSP.

Chart 7.17: World price formation 2007 – total consumption

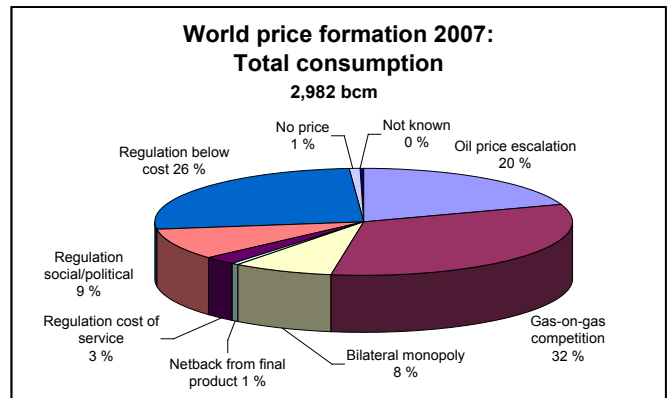
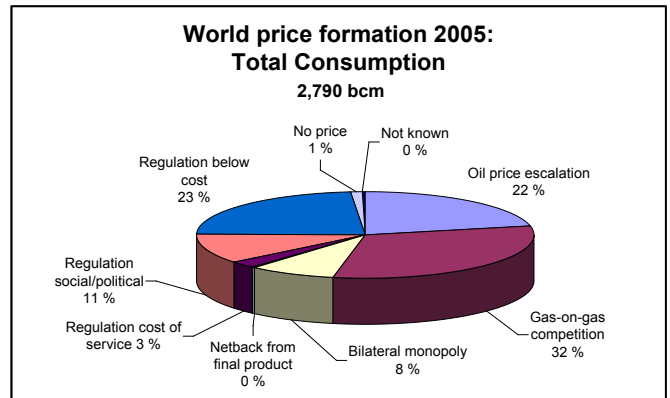


Chart 7.18: World price formation 2005 – total consumption



## Regional results

In presenting the World results all 5 identified categories – Domestic Production, Pipeline Imports, LNG Imports, Total Imports and Total Consumption – were reviewed and analysed, and also compared with 2005. At the regional level not all the categories will be relevant, for example, there may be little or no LNG imports into a region, and there may be no material changes from 2005. The data and charts presented for each region, therefore, will differ depending on the relevance of each consumption category, and any changes since 2005.

### North America

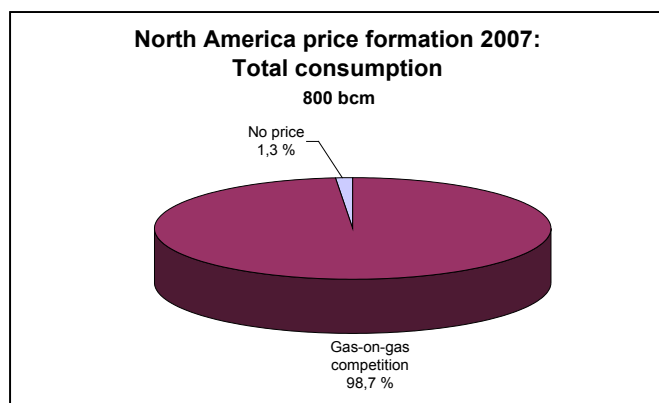
In terms of an IGU region, North America consists of only 3 countries – Canada, USA and Mexico – but it is the largest consuming region.

**Table 7.1: North America consumption and production 2007 (BCM)**

Country	Consumption	Production	Imports		Exports	
			Pipeline	LNG	Pipeline	LNG
USA	652.9	545.9	108.9	20.7	22.0	1.2
Canada	94.0	183.7	13.2		107.3	
Mexico	54.1	46.2	8.8	2.5	1.6	
<b>Total North America</b>	<b>801.0</b>	<b>775.8</b>	<b>130.9</b>	<b>23.2</b>	<b>130.9</b>	<b>1.2</b>

Consumption is dominated by the USA, which is also by far the region’s largest producer. All pipeline trade is intra-regional with the USA importing from Canada, but also exports to both Canada and Mexico. USA LNG exports are from Alaska to Japan, while LNG imports are principally from Trinidad but also significant amounts from the Middle East and Africa.

**Chart 7.19: North America price formation 2007 – total consumption**



The gas market in the USA is completely deregulated and all prices are effectively set by gas-on-gas competition. Imports, whether by pipeline or LNG are effectively price-takers. The market in Canada is linked to the USA markets and the price formation mechanism is the same. Mexico imports gas from the US at US prices. For domestically produced gas, a reference price is set, which is based on the US price at the US-Mexico border, plus the cost of transportation to the Los Ramones “hub”. From the Los Ramones “hub” further south the reference price gets reduced based on transportation costs. However, some 10 bcm of gas is estimated to be used by Pemex for its own internal

consumption, related to feedstock for petrochemical plants, fuel for equipment in refineries and plants and for secondary oil recovery. This gas is not priced and has been allocated to the No Price category.

### Latin America

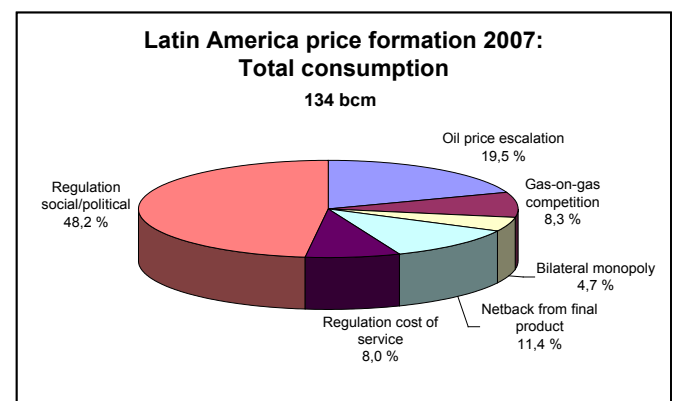
**Table 7.2: Latin America consumption and production 2007 (BCM)**

Country	Consumption	Production	Imports		Exports	
			Pipeline	LNG	Pipeline	LNG
Argentina	44.1	44.8	1.9		2.5	
Bolivia	1.8	13.5			11.7	
Brazil	22.0	11.3	10.0			
Chile	4.4	2.0	2.4			
Colombia	7.7	7.7				
Dominican Republic	0.6			0.6		
Ecuador	0.3	0.3				
Peru	2.7	2.7				
Puerto Rico	0.7			0.7		
Trinidad	20.9	39.0				18.2
Uruguay	0.1		0.1			
Venezuela	28.5	28.5				
<b>Total Latin America</b>	<b>133.6</b>	<b>149.8</b>	<b>14.3</b>	<b>1.2</b>	<b>14.2</b>	<b>18.2</b>

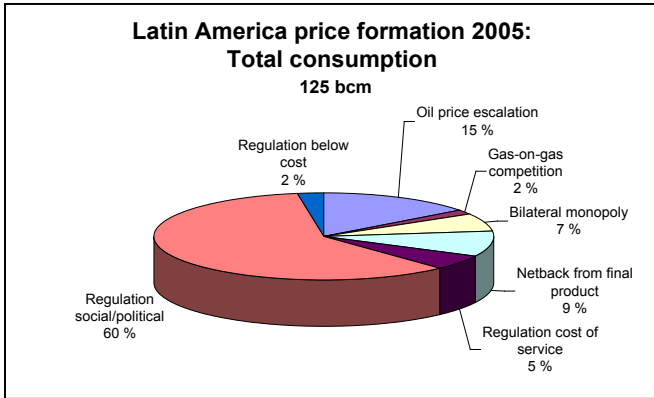
Latin American gas is largely produced and consumed within each individual country with Venezuela, Colombia and Peru being completely domestic markets. All pipeline trade is intra-regional with Argentina importing from Bolivia but also exporting to Chile. Bolivia also exports gas to Brazil. Even then almost all of Argentina’s consumption is domestically produced and half of Brazil’s.

Latin America consumption at 134 bcm accounts for less than 5% of total world consumption. The traded pipeline gas to Brazil and Chile mainly account for most of the OPE. Wholesale prices in the two largest consuming countries, Argentina and Venezuela, are largely determined by regulatory and/or government control (RSP). Some large customers in Argentina are free to negotiate directly with competing suppliers (GOG), as are power generators in Trinidad (BIM). NET is in Trinidad where gas is provided to Methanol plants. Compared to 2005 the main changes are increasing shares of GOG (in Argentina) and OPE (in Brazil) at the expense of RSP.

**Chart 7.20: Latin America price formation 2007 – total consumption**



**Chart 7.21: Latin America price formation 2005 – total consumption**



**Europe**

**Table 7.3: Europe consumption and production 2007 (Bcm)**

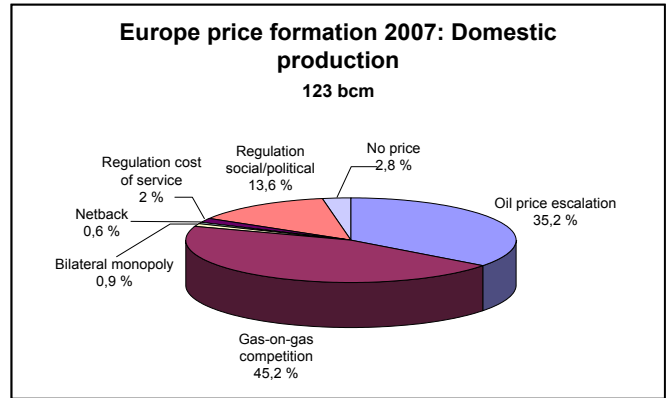
Country	Consumption	Production	Imports		Exports	
			Pipeline	LNG	Pipeline	LNG
Austria	8.9	1.4	7.5			
Belgium & Luxembourg	16.9		19.3	3.2	4.5	
Bosnia-Herzegovina	0.4		0.4			
Bulgaria	3.1		3.1			
Croatia	3.1	2.0	1.1			
Czech Republic	8.9	0.3	8.6			
Denmark	5.0	10.4			5.3	
Estonia	1.0		1.0			
Finland	4.3		4.3			
France	43.2	1.0	29.1	12.6		
FYROM	0.1		0.1			
Germany	82.7	14.3	83.7		16.4	
Greece	4.0		2.9	0.8		
Hungary	11.8	1.3	10.5			
Ireland	4.8	0.6	4.2			
Italy	84.9	9.7	71.5	2.4	0.1	
Latvia	1.6		1.6			
Lithuania	3.8		3.4			
Netherlands	37.2	64.5	18.9		50.1	
Norway	4.3	89.7			86.1	0.1
Poland	13.7	4.3	9.3			
Portugal	4.2		1.9	2.3		
Romania	16.4	11.6	4.8			
Serbia & Montenegro	2.3	0.2	2.1			
Slovakia	5.9	0.1	5.8			
Slovenia	1.1		1.1			
Spain	35.1		11.0	24.2		
Sweden	1.0		1.1			
Switzerland	2.9		3.0			
Turkey	35.1		30.6	6.0		
United Kingdom	91.4	72.4	28.0	1.5	10.4	
<b>Total Europe</b>	<b>539.2</b>	<b>283.8</b>	<b>369.8</b>	<b>53.0</b>	<b>172.7</b>	<b>0.1</b>

Europe is highly dependent on imported gas both by pipeline and LNG. Of the largest consumers, only the UK produced the majority of its gas requirements, and this situation is rapidly changing. Norway and the Netherlands provided a significant proportion of the rest of Europe’s pipeline supplies, but Europe remained heavily dependent on Russian and Algerian pipeline supplies. The major importers of LNG were Spain and France with Algeria being the principal supplier, but significant quantities of LNG were also sourced from West Africa and the Middle East.

Out of the total European consumption in 2007 of 539 bcm, only 117 bcm (22%) was produced and consumed within the country and half of this was in the UK market. The chart below shows the price formation mechanisms for this indigenous production with GOG at 44% and OPE at 35% dominating. This was in the UK, where some of the older contracts still retain key elements of OPE, but also in the Netherlands and Italy where domestic production is largely on an OPE basis.

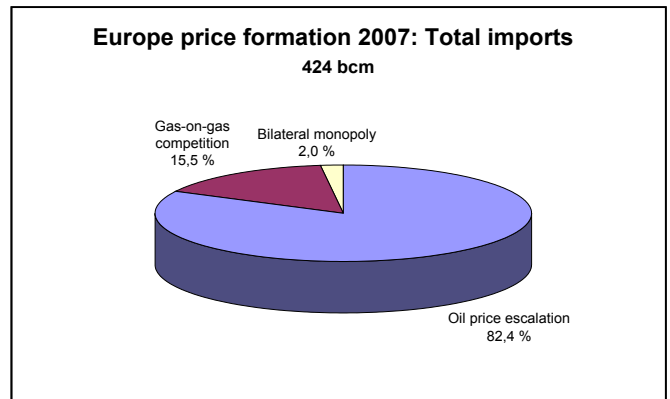
Wholesale prices for domestic production remained regulated on a RSP basis in Poland and Romania. There were small elements of NET in Norway and BIM in Denmark. NP was in Norway reflecting reinjected gas.

**Chart 7.22: Europe price formation 2007 – indigenous production**



The situation for total imports (both pipeline and LNG, comprising 424 bcm or 78% of total consumption) is markedly different, with OPE dominating at 82%. GOG at 16% is predominantly the UK, plus Ireland, but also in other major European countries where trading hubs are developing and in Spain, reflecting spot LNG cargoes. The BIM category (2%) is largely accounted for by imports into the Baltic States (Estonia, Latvia and Lithuania) and Bulgaria from Russia.

**Chart 7.23: Europe price formation 2007 – total imports**



In total, at 540 bcm, Europe accounts for around 18% of world consumption. The dependence in imports, most of which are priced on an OPE basis, is illustrated in the chart above, with OPE at 72%. GOG is largely the UK market, plus the developing trading hubs in continental Europe. Compared to 2005, GOG has gained at the expense of OPE as trading hubs developed and spot LNG cargoes increased.

Chart 7.24: Europe price formation 2007 – total consumption

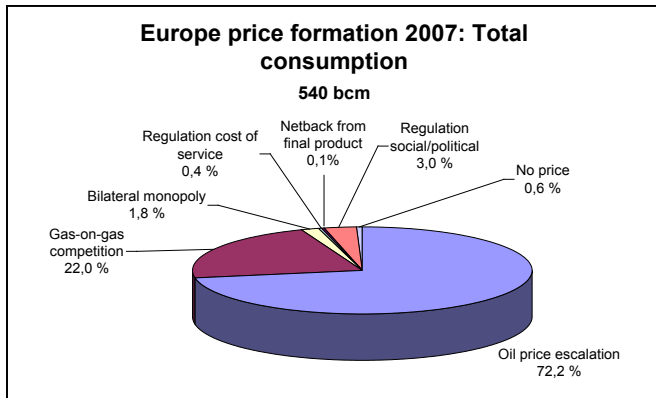
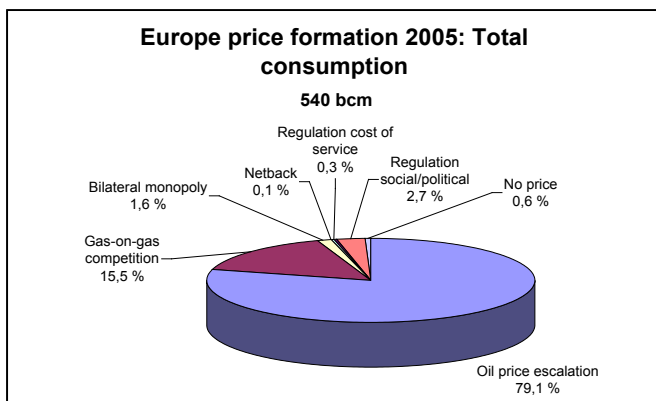


Chart 7.25: Europe price formation 2005 – total consumption



### Former Soviet Union

Table 7.4: FSU consumption and production 2007 (BCM)

Country	Consumption	Production	Imports		Exports	
			Pipeline	LNG	Pipeline	LNG
Armenia	2.1		2.1	0.0		
Azerbaijan	8.3	10.3			2.0	
Belarus	20.8	0.2	20.6			
Georgia	1.7		1.7			
Kazakhstan	13.3	29.6	7.2		15.2	
Kyrgyzstan	0.8	0.0	0.8			
Moldova	2.8	0.1	2.7			
Russian Federation	481.5	647.0	68.1		233.7	
Tajikistan	0.7	0.0	0.6			
Turkmenistan	23.5	72.3	0.0		48.8	
Ukraine	69.8	20.6	59.2		5.1	
Uzbekistan	50.6	65.3	0.0		14.7	
<b>Total FSU</b>	<b>675.9</b>	<b>845.5</b>	<b>163.0</b>	<b>0.0</b>	<b>319.5</b>	<b>0.0</b>

The Former Soviet Union region is dominated by Russia, both as the largest consumer and producer of gas. All the imported gas within the region is intra-FSU trade i.e. no imports come from outside the region. Russia exports gas to almost all its neighbouring countries but Kazakhstan, Turkmenistan and Uzbekistan are also exporters, including to Russia. Russia is also a major importer of gas, together with Ukraine.

At 675 bcm the Former Soviet Union accounts for around 23% of world consumption. All imported gas is priced on a BIM basis. The dominant price formation mechanism, however, is RBC in Russia, Turkmenistan, Uzbekistan and Kazakhstan.

However, this situation in Russia, at least, is beginning to change with increased prices to domestic consumers raising levels above the average cost of production and transportation. Domestic production in Ukraine is the RSP category and NP in Turkmenistan. Compared to 2005 RBC has increased its share, in part due to changing consumption patterns within the region.

Chart 7.26: FSU price formation 2007 – total consumption

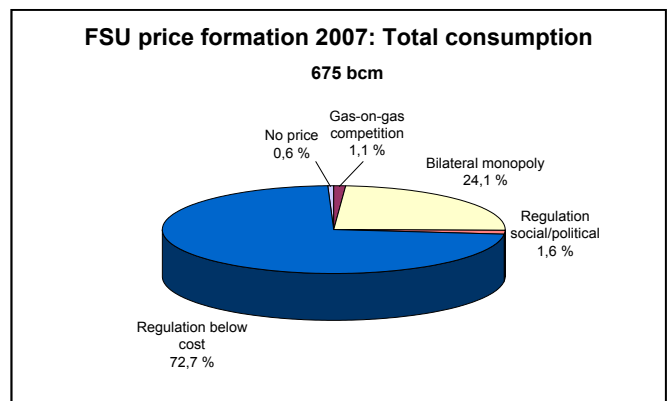
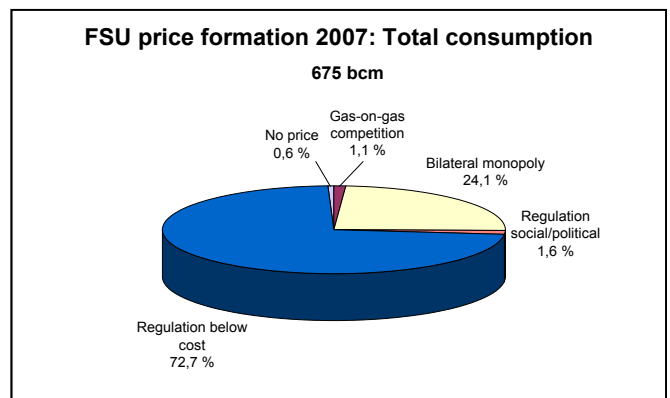


Chart 7.27: FSU price formation 2005 – total consumption



### Middle East

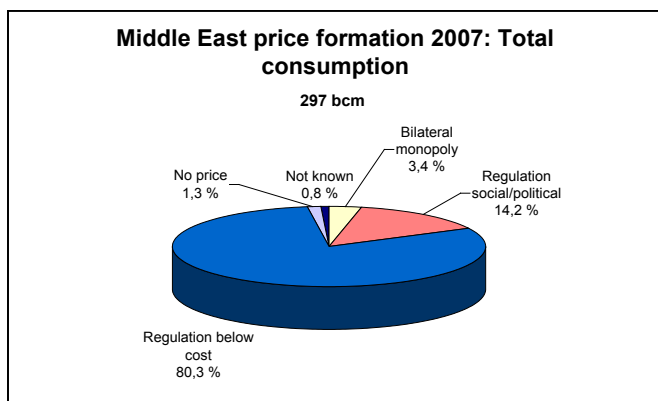
Table 7.5: Middle East consumption and production 2007 (BCM)

Country	Consumption	Production	Imports		Exports	
			Pipeline	LNG	Pipeline	LNG
Bahrain	11.5	11.5				
Iran	111.8	111.9	6.1		6.2	
Iraq	2.5	2.5				
Israel	0.7	0.7				
Jordan	2.4	0.2	2.4			
Kuwait	12.6	12.6				
Oman	10.9	24.1			1.0	12.2
Qatar	20.5	59.8			0.8	38.5
Saudi Arabia	75.9	75.9				
Syria	5.3	5.3				
United Arab Emirates	43.2	49.2	1.8			7.6
<b>Total Middle East</b>	<b>297.3</b>	<b>353.7</b>	<b>10.2</b>	<b>0.0</b>	<b>7.9</b>	<b>58.2</b>

The Middle East region is largely an insulated market in terms of gas consumption with very little gas being traded (excluding exports) across borders. Small quantities of gas are imported by Iran from Turkmenistan and Jordan from Egypt.

Middle East consumption at 297 bcm accounts for around 10% of total world consumption. The dominant price formation mechanism in the region is RBC in largely Iran, Saudi Arabia, Kuwait and Qatar. The RSP category is accounted for by the UAE, where price is regulated by each emirate. The BIM category relates to Iranian imports from Turkmenistan and the trades from Egypt to Jordan and Oman to the UAE. Chart for 2005 is not shown as there has been almost no change.

Chart 7.28: Middle East price formation 2007 – total consumption



## Africa

Table 7.6: Africa consumption and production 2007 (BCM)

Country	Consumption	Production	Imports		Exports	
			Pipeline	LNG	Pipeline	LNG
Algeria	24.4	83.0			34.0	24.7
Angola	0.8	0.8				
Egypt	32.0	46.5			2.4	13.6
Equatorial Guinea	1.3	2.7				1.4
Ivory Coast	1.3	1.3				
Libya	5.2	15.2			9.2	0.8
Nigeria	14.8	35.0				21.2
South Africa	2.2	2.2				
Tunisia	4.3	2.5	1.3			
<b>Total Africa</b>	<b>86.3</b>	<b>189.2</b>	<b>1.3</b>	<b>0.0</b>	<b>45.6</b>	<b>61.6</b>

Excluding its export trade, Africa has virtually no traded gas, with only Tunisia importing some gas from Algeria via the pipeline to Italy.

In terms of consumption, Africa is the smallest region at 86 bcm, or 3% of total world consumption. Wholesale prices are highly regulated, with RBC accounting for just over half, in Egypt and Nigeria. RCS is predominantly Algeria and RSP in Libya and South Africa. The OPE category reflects the only traded gas with Tunisia importing from Algeria. Compared to 2005 RBC has increased its share largely at the expense of RCS, reflecting changing consumption patterns.

Chart 7.29: Africa price formation 2007 – total consumption

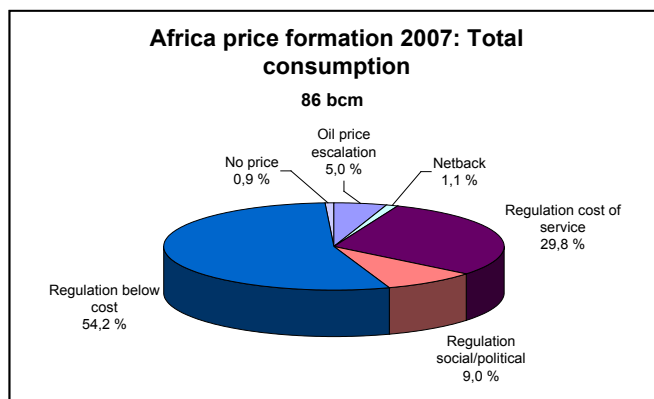
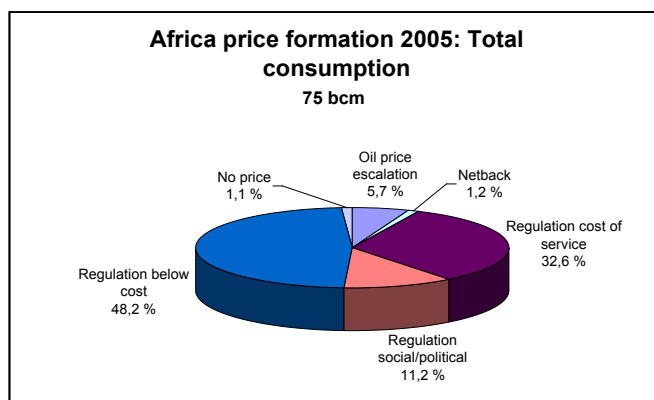


Chart 7.30: Africa price formation 2005 – total consumption



## Asia

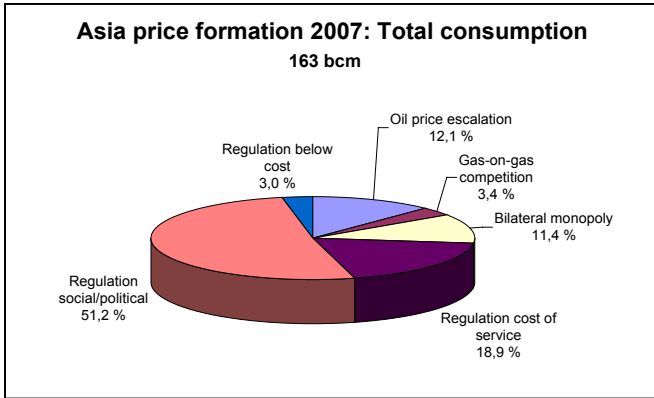
Table 7.7: Asia consumption and production 2007 (BCM)

Country	Consumption	Production	Imports		Exports	
			Pipeline	LNG	Pipeline	LNG
Afghanistan	0.2	0.2				
Bangladesh	16.3	16.3				
China	67.3	69.3		3.9	3.0	
China Hong Kong	3.0		3.0			
India	40.2	30.2		10.0		
Myanmar	4.8	14.7			9.9	
Pakistan	30.8	30.8				
<b>Total Asia</b>	<b>162.6</b>	<b>161.5</b>	<b>3.0</b>	<b>13.9</b>	<b>12.9</b>	<b>0.0</b>

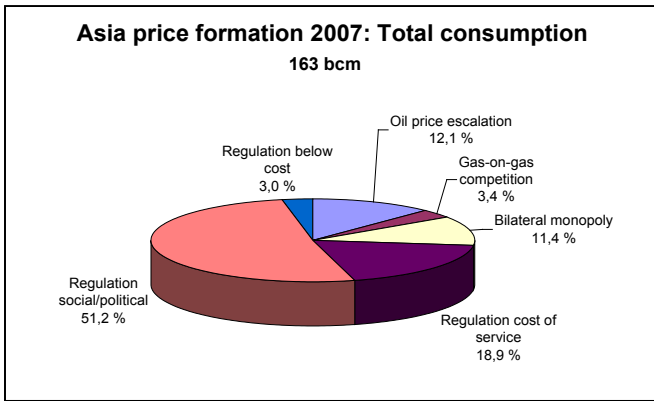
Again there is not a large amount of traded gas within this region – China Hong Kong imports from China, while India imports LNG, principally from Qatar. China, India and Pakistan are the largest consumers. China and India are expected to increase gas consumption significantly from both indigenous resources and imports.

Asia accounts for just over 5% of world consumption at 163 bcm. Regulation of wholesale prices is widespread. RSP at 51% is predominantly China and India, RCS in Pakistan and RBC in Myanmar. OPE at 12% is in Bangladesh and LNG into China. The BIM category is Indian LNG imports, and private gas production in India, plus Hong Kong imports from China. GOG is spot LNG cargoes into India. Compared to 2005, RSP and RCS have declined with OPE, GOG and BIM gaining, in part reflecting changing consumption patterns.

**Chart 7.31: Asia price formation 2007 – total consumption**



**Chart 7.32: Asia price formation 2005 - total consumption**



**Asia Pacific**

**Table 7.8: Asia Pacific consumption and production 2007 (BCM)**

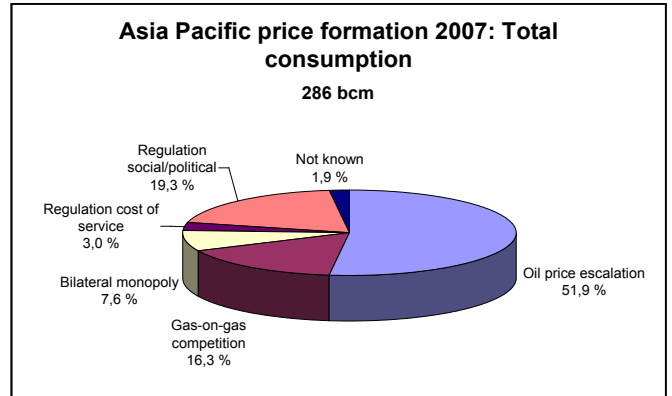
Country	Consumption	Production	Imports		Exports	
			Pipeline	LNG	Pipeline	LNG
Australia	25.1	40.0				20.2
Brunei	2.9	12.3				9.4
Indonesia	33.8	66.7			5.4	27.7
Japan	90.2	1.4		88.8		
Malaysia	28.3	60.5			1.8	29.8
New Zealand	3.7	4.0				
Philippines	3.4	3.4				
Singapore	7.2		7.2			
South Korea	37.0	2.6		34.4		
Taiwan	11.8	0.9		10.9		
Thailand	35.4	25.9	9.9			
Vietnam	7.7	7.7				
<b>Total Asia Pacific</b>	<b>286.5</b>	<b>225.4</b>	<b>17.1</b>	<b>134.1</b>	<b>7.2</b>	<b>87.1</b>

After Europe, Asia Pacific is the region most heavily dependent on internationally traded gas, principally LNG into Japan, Korea and Taiwan, although much of the LNG comes from within the region together with imports from the Middle East. A distinguishing feature of Japan, Korea and Taiwan is that they are virtually totally dependent on LNG imports for all their gas consumption, leading to what some might argue are the premium prices paid for the gas. The pipeline imports are into Singapore from Indonesia and Malaysia and Thailand from Myanmar.

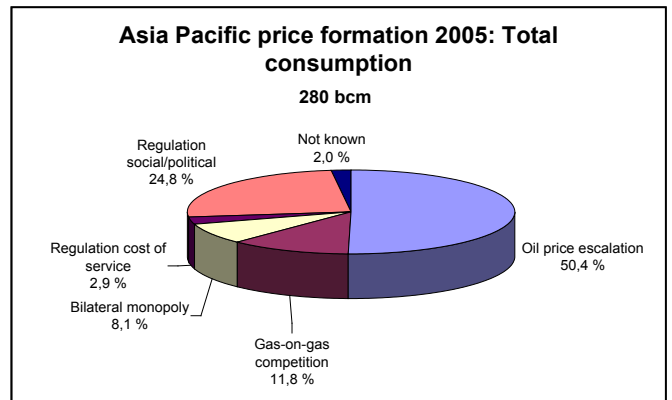
At 286 bcm, Asia Pacific accounts for just under 10% of total world consumption. Over 50% of gas is imported by countries.

OPE at 52% is the largest category and comprises LNG imports into Japan, Korea and Taiwan, pipeline into Singapore and domestic production in Thailand. GOG is Australia and spot LNG trade. BIM is mainly imports into Thailand and some in Indonesia and New Zealand. RSP is the majority of wholesale gas in Indonesia and Malaysia. RCS is Vietnam. Compared to 2005, GOG and OPE have gained shares, principally at the expense of RSP.

**Chart 7.33: Asia Pacific price formation 2007 - total consumption**



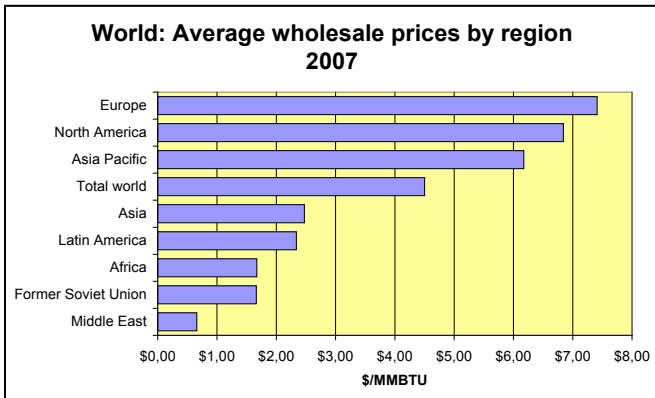
**Chart 7.34: Asia Pacific price formation 2005 - total consumption**



**Wholesale Prices**

As well as collecting data on price formation mechanisms the IGU study also collected information on wholesale price levels in 2007. As noted in the Introduction, the results here should be treated as broad orders of magnitude, since the definition of wholesale prices is quite wide. It is typically a hub price or a border price in the case of internationally traded gas, but could also easily be a wellhead or city-gate price.

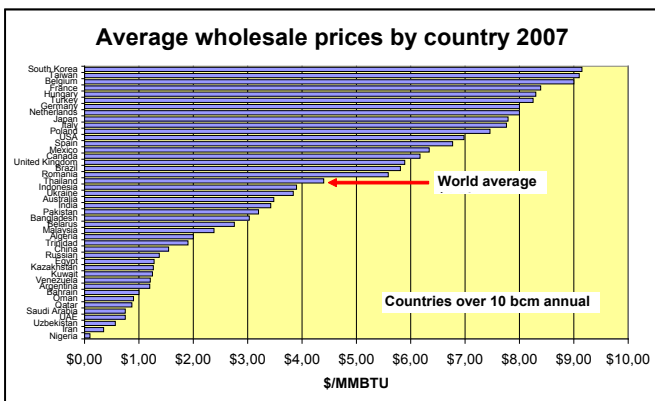
**Chart 7.35: World average wholesale gas prices by region**



The chart above shows a snapshot of price levels for 2007. From year to year, wholesale prices can change significantly, as discussed below. Generally the highest wholesale prices are in regions where, it could be said that, there is more “economic” pricing – GOG and OPE – in North America, Europe and Asia Pacific. The lowest wholesale prices are generally where regulation dominates in the Middle East and Former Soviet Union, particularly RBC.

These conclusions are illustrated more clearly in the chart below which considers wholesale prices at the individual country level, at least for those countries with more than 10 bcm annual consumption. Only Turkmenistan is missing with over 10 bcm consumption. The highest wholesale prices in 2007 were found in the LNG dependent countries in Asia Pacific (South Korea and Taiwan). These were followed by a whole host of European countries headed by Belgium and France, and then North America. At the bottom of the chart were generally countries where wholesale prices were subject to some form of regulation, typically RBC – Iran, Nigeria, Saudi Arabia, Russia and Egypt – plus Argentina and Venezuela.

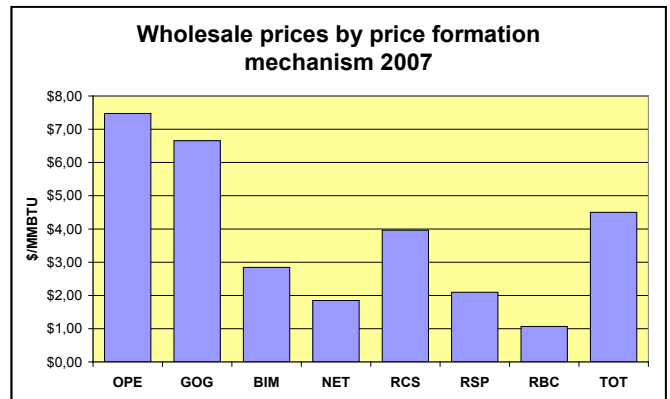
**Chart 7.36: World average wholesale gas prices by country**



An alternative way of analysing the data is to categorise by price formation mechanism. The highest wholesale prices are OPE followed by GOG. At the bottom end, as might be expected, wholesale prices determined by RBC are less than RSP which,

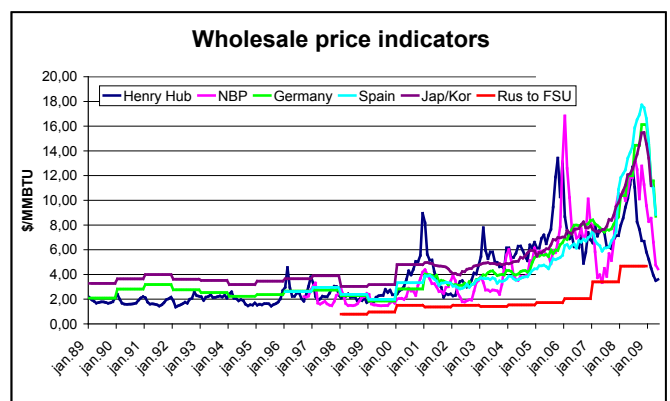
in turn, are less than RCS. The low level of wholesale prices for NET are presumably affected by low commodity prices for the final products – almost all Trinidad and some in Norway. The result for BIM is largely impacted by the lower levels of wholesale prices in intra-Former Soviet Union trade.

**Chart 7.37: Wholesale prices by price formation mechanism, 2007**



The charts above are for 2007 only and present, therefore, only a snapshot of price levels. The chart below shows prices over time for Henry Hub and NBP (both GOG markets) and Germany, Spain, Japan/Korea (all OPE markets) and for Russian exports to Former Soviet Union countries (BIM). In 2005 GOG prices were above OPE prices but since 2006 GOG prices have generally been below the OPE market prices. Through the 1990s Henry Hub / NBP prices were generally below Japan/Korea, Germany and Spain prices. Prices of Russian exports to Former Soviet Union countries have very recently started to rise as Russia moves towards more “market” pricing.

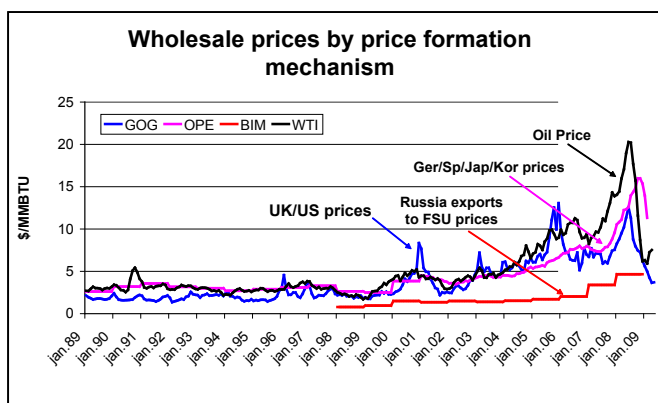
**Chart 7.38: Wholesale price trends 1989 - 2008**



The next chart simplifies the last one, using specific countries as proxies for different price formation mechanisms. Countries are weighted together using their annual gas consumption as the weights. GOG is the weighted average of UK and US (US only prior to 1997); OPE is the weighted average of Germany, Spain, Japan and Korea; and BIM is Russia exports to Former Soviet Union countries. The oil price (WTI) is also shown as the black line, converted to \$/MMBTU. It is clear here how

GOG prices dropped below OPE prices from the beginning of 2006. OPE prices would appear to track oil prices pretty closely for much of the period, although the sharp increase in oil prices from the beginning of 2007 was only partly passed through into OPE prices with a lag, and the recent falls have not yet been translated into lower wholesale prices. In the case of Japan and Korea the effects of the “S” curve clauses in the LNG contracts, may be responsible for the wholesale price not fully reflecting the rise in oil prices.

**Chart 7.39: Wholesale price trends by price formation mechanism 1989 - 2008**



### Changes between 2005 and 2007

Details of the 2005 price formation mapping, were in part included in the Results section but full details are contained in Appendix 1. Changes in the relative importance of the different price formation mechanisms can occur either because of differential growth in consumption between countries or because price formation mechanisms themselves change. The table below shows the growth in consumption by region between 2005 and 2007.

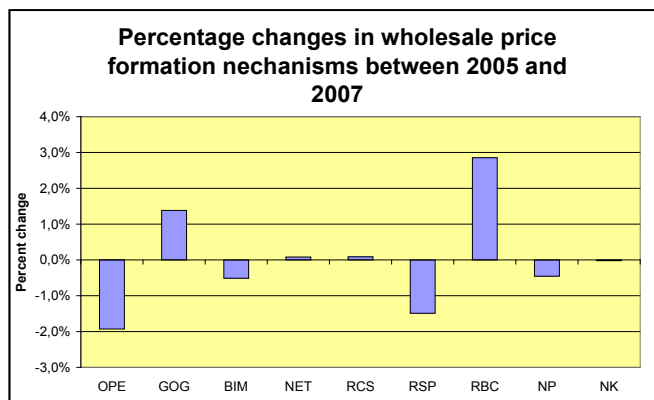
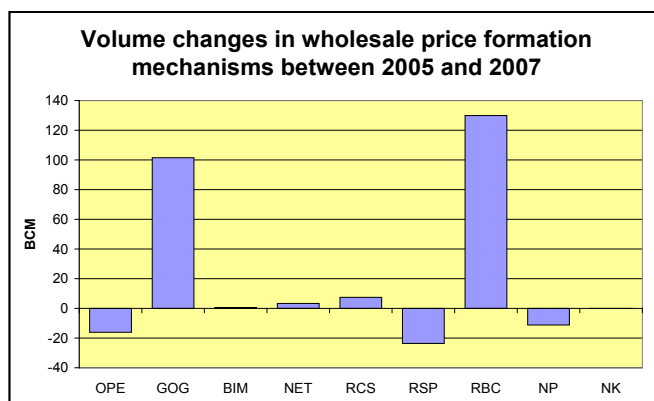
**Table 7.9: Growth in gas consumption 2005 to 2007**

Region	Consumption		Changes	
	2005	2007	BCM	%
North America	768.8	801.0	32.2	4.2%
Latin America	125.7	133.6	8.0	6.4%
Europe	534.6	539.2	4.6	0.9%
Former Soviet Union	593.8	675.9	82.1	13.8%
Middle East	276.6	297.3	20.7	7.5%
Africa	75.1	86.3	11.2	14.9%
Asia	134.7	162.6	27.9	20.7%
Asia Pacific	279.3	286.5	7.2	2.6%
<b>Total World</b>	<b>2,788.5</b>	<b>2,982.3</b>	<b>193.9</b>	<b>7.0%</b>

World gas consumption grew by 7% between 2005 and 2007, with faster than average growth in the Former Soviet Union, Africa and Asia. The RBC price formation category is relatively more important in these regions so, other things being equal, the share of RBC might be expected to rise between 2005 and 2007.

The charts below show the changes in the volumes attributable to each price formation mechanism and the changes in percentage shares. It appears that the share of RBC has risen between 2005 and 2007, both in absolute volume terms and in its percentage share.

**Chart 7.40: Changes in wholesale price formation mechanisms 2005 to 2007**



In addition to the RBC category increasing its share, the GOG category also increased its share. These categories gained largely at the expense of the RSP and OPE categories. The changes can be explained as follows:

- The increase in the RBC category of 130 bcm (2.9% increase in share) was mostly as a result of the faster consumption growth in the FSU, particularly in Russia. Some 110 bcm out of the 130 bcm reflects consumption growth, with only the balance of 20 bcm reflecting changes in price formation mechanisms (largely in Russia);
- The decline in the RSP category of some 24 bcm, largely reflects changes in price formation mechanisms in Brazil (towards OPE), Argentina (towards GOG), lower domestic production in Ukraine (which is all RSP) and declining consumption in Malaysia (again all RSP);
- The increase in the GOG category of some 100 bcm and the decline in the OPE category are largely related. The switch to GOG away from OPE reflected relatively more spot LNG cargoes to Japan, Korea, Taiwan and Spain, together with increased spot volumes in Europe delivered from trading hubs in Belgium, France, Germany, Italy and the Netherlands together with a decline in production from traditional long

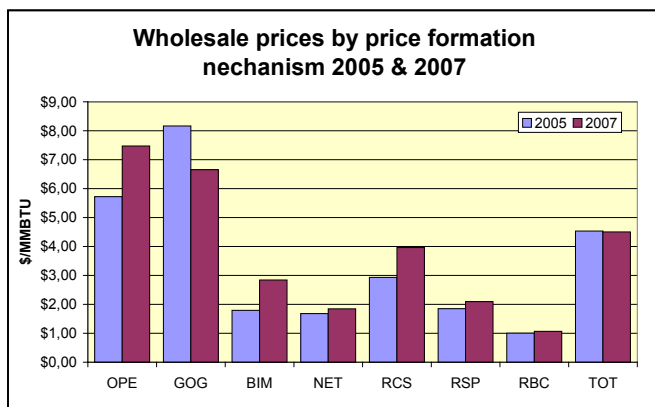


term contracts in the UK. The decline in the OPE category was partly offset by the change in Brazil towards OPE and consumption growth in Asia, particularly LNG imports into China.

Overall much of the change in relative importance of the different price formation mechanisms was due to changing consumption patterns with the main switching between categories occurring with moves away from OPE to GOG as spot LNG trade increased and trading hubs developed in Europe.

In respect of the levels of wholesale prices, the average wholesale price was little changed between 2005 and 2007 - \$4.50 per MMBTU in 2007 against \$4.53 per MMBTU in 2005. However, as the chart below shows, in every price formation category, apart from GOG, prices rose, sometimes significantly. In GOG prices declined as a consequence of the falls in the USA and the UK from the peak levels in 2005.

Chart 7.41: Changes in wholesale price levels 2005 to 2007



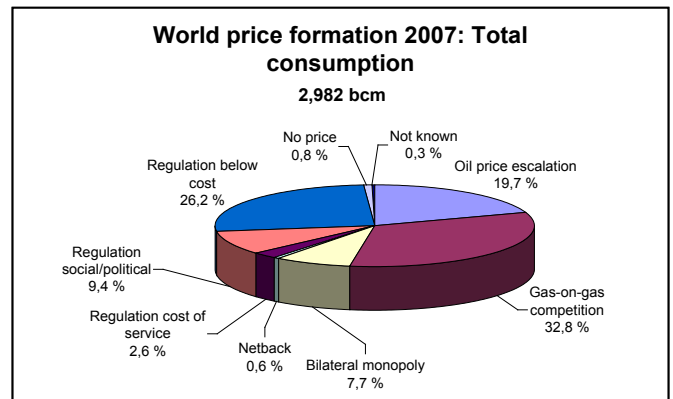
## Conclusions

In 2007 just under 70% of the world’s consumption of gas comprised of domestic production consumed within that country, with no trade across international borders. Some 24% was traded through pipelines and some 7.5% LNG. The wholesale price formation mechanisms are largely very different for internationally traded gas compared to gas which is produced purely for domestic consumption.

Table 7.10: World price formation 2007 – total consumption (BCM)

Region	Total Consumption									
	OPE	GOG	BIM	NET	RCS	RSP	RBC	NP	NK	TOT
North America	0.0	790.3	0.0	0.0	0.0	0.0	0.0	10.7	0.0	801.0
Latin America	26.0	11.0	6.3	15.2	10.7	64.4	0.0	0.0	0.0	133.6
Europe	389.9	118.6	9.7	0.7	2.0	16.0	0.0	3.3	0.0	540.2
Former Soviet Union	0.0	7.2	163.0	0.0	0.0	10.6	491.1	4.0	0.0	675.9
Middle East	0.0	0.0	10.2	0.0	0.0	42.2	238.6	3.8	2.5	297.3
Africa	4.3	0.0	0.0	0.9	25.7	7.8	46.8	0.8	0.0	86.3
Asia	19.7	5.5	18.5	0.0	30.8	83.3	4.8	0.0	0.0	162.6
Asia Pacific	148.6	46.7	21.7	0.0	8.6	55.3	0.0	0.0	5.5	286.5
<b>Total World</b>	<b>588.5</b>	<b>979.4</b>	<b>229.4</b>	<b>16.8</b>	<b>77.8</b>	<b>279.6</b>	<b>781.4</b>	<b>22.6</b>	<b>8.0</b>	<b>2,983.4</b>
	<b>20%</b>	<b>33%</b>	<b>8%</b>	<b>1%</b>	<b>3%</b>	<b>9%</b>	<b>26%</b>	<b>1%</b>	<b>0%</b>	<b>100%</b>

Chart 7.42: World price formation 2007 – total consumption

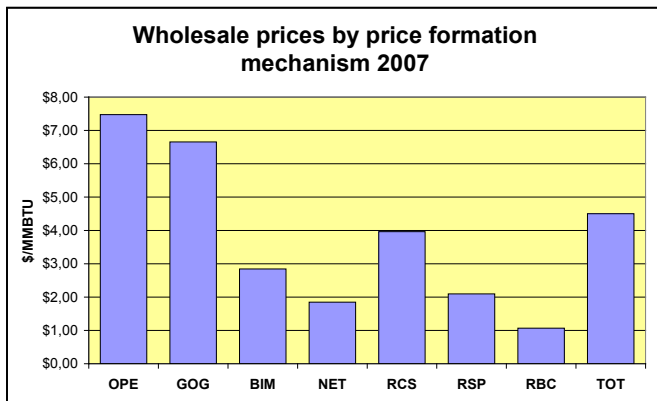


The chart above illustrates the overall results at the world level, while the table looks at the breakdown by region.

- The largest price formation category is GOG at 33%, but this is due to the impact of the North American market, which is predominantly domestic gas production, plus smaller quantities in the UK and, in Asia Pacific, Australia and spot LNG cargoes;
- The OPE category at 20%, is generally only found in internationally traded gas, which is mainly pipeline and LNG in Europe and LNG in Asia Pacific;
- Together the GOG and OPE categories, which could be said to reflect an “economic” or “market” value of gas, account for over 50% of total world consumption;
- Wholesale price “regulation”, which covers 3 categories – RCS, RSP and RBC, accounts for 38% of total world consumption, but is only found in domestic gas production and not internationally traded gas. The RBC category in 2007 was the largest, as a consequence of the low levels of prices in the Former Soviet Union, mainly Russia, and the Middle East. While wholesale prices in Russia have remained regulated there have been recent price increases, which would mean that most of the market may be moving from the RBC category, probably to the RSP category;
- The RSP category, at 9%, is found across all regions, apart from North America;
- The BIM category, at 8%, is mainly traded gas between the Former Soviet Union countries, principally Russian exports, plus, in Asia Pacific, imported gas into India and Thailand and partly domestically produced gas in Indonesia.

In respect of wholesale price levels in 2007, the chart below shows that price levels were generally higher in the OPE markets of Asia Pacific and Europe, followed by GOG, predominantly in the USA and UK. At the bottom end, as might be expected, wholesale prices determined by RBC are less than RSP which, in turn, are less than RCS. The result for BIM is largely impacted by the lower levels of wholesale prices in intra-Former Soviet Union trade.

**Chart 7.43: Wholesale prices by price formation mechanism 2007**



There have been some changes in the relative importance of the different price formation mechanisms between 2005 and 2007, but much of it was due to changing consumption patterns with the main switching between categories occurring with moves away from OPE to GOG as spot LNG trade increased and trading hubs developed in Europe.

Parts of the world are in transit between gas pricing mechanisms. Others are trying to fix problems with their existing mechanisms without plunging into the unknowns of all-out system reform. Yet others do not envisage significant changes, either because there are no perceptions of tensions calling for release measures, or because there are no perceptions of better models, or because the risks of reform are considered too high.

Sellers', buyers' and regulators' preferences with respect to retaining, adjusting or replacing pricing mechanisms are influenced by a number of factors:

- Relative efficiency in resource allocation terms of alternative mechanisms
- Price outlook under alternative mechanisms
- Long term gas supply and demand consequences of alternative mechanisms
- Price volatility under alternative mechanisms
- Price risk mitigation opportunities in alternative mechanisms
- Budgetary and macroeconomic consequences of alternative mechanisms
- Political risks of moving away from existing mechanisms
- Other transition costs

## 8. Trends in the extensiveness of individual pricing mechanisms

Efficiency arguments are typically heard from proponents of gas-on-gas competition based pricing. Only when gas prices are allowed to reflect gas supply and demand will the socially optimal amount of resources flow to the gas sector relative to other worthy causes.

The outlook for gas prices is on everybody's mind, and different pricing models may deliver different prices. However, the importance of this factor will vary, and while one model may be the most (least) attractive from a seller's (buyer's) point of view under one set of circumstances, it may score differently under another set of circumstances.

In 2008 Continental European and Asian oil linked prices outpaced North American gas-to-gas competition based prices. Again this may be seen as proof of the gas industry advantages, and consumer disadvantages, of oil linked gas pricing. But there have been periods in this decade when the relationship has been the opposite.

Another observation is that at least over long periods of time oil linked and gas-on-gas competition based prices tend to move pretty much in parallel due to links provided by interfuel competition and international gas trade.

The only firm – but also rather trivial – conclusion that can be made on the relationship between gas pricing model and gas price level, is that a shift from subsidised to unsubsidised prices will push prices up.

The long term impact of alternative pricing mechanisms on gas supply and demand has been a hot topic in particular in Europe. Observers, and the gas industry itself, in 2008 noted the incongruence between the need for gas to remain the preferred fuel to the power sector if we were to see further growth in overall demand, and the disincentives that oil linked gas prices at USD 100-150/b oil represented to the dispatching of existing and the building of new gas power plants.

On the other hand, demand destruction first became a big issue in the US following the gas price spike in 2005, and the supply boosting impact of the post 2000 price gas price environment is nowhere more obvious than in the US. So again it is not so that one pricing model necessarily represents a bigger threat to future gas demand, and a bigger encouragement to future gas supply, than another.

Gas price volatility is generally seen to be a problem mainly for actors in liberalised markets with gas-on-gas competition based pricing. And indeed, Europe's and Asia's oil linked prices are

less volatile, reflecting the way the indices are defined. With gas prices set to reflect the average of oil prices over a period of time many months prior to delivery, short term peaks and troughs are automatically smoothed out.

However, apart from the fact that price volatility to many actors represents opportunities rather than problems, it might not be very difficult to shape the price clause in a contract based on gas indexation so as to obtain the same smoothing effect.

To decision makers in countries with heavily regulated gas markets where prices are adjusted as rarely as possible, the volatility aspect may nevertheless seem a strong deterrent to convert directly to gas-to-gas competition based pricing.

Price risk mitigation opportunities become indispensable as price volatility increases. When demand for such tools arises, banks and similar institutions normally rush in to provide them. However, a limited availability of risk mitigation opportunities in the early phases of market liberalisation may contribute to the resistance that proposals to shift from one pricing model to another typically encounter.

The budgetary and macroeconomic consequences of leaving gas pricing mechanisms as they are, or embarking on reform, and the inevitable political risks of reform, need to be considered in those countries that practice below cost regulation. Fuel subsidies are weighing heavily on many emerging economies' budgets. The IEA estimated for its World Energy Outlook 2008 that gas subsidies in 2007 cost the Russian state close to USD 30 billion and the Iranian state more than USD 15 billion. Even the oil exporting countries that recently benefitted from record high prices feel the pinch. On the other hand, raising domestic fuel prices too quickly might boost inflation and trigger political and social unrest.

Finally there may be other transition costs related to the dismantling of old institutions and the establishment of new ones, the teaching of new rules of the game to market actors and regulators and possible dislocations in the transition period from the old systems stops functioning properly to the new one starts working.

Clearly the drivers for switching to other pricing models, and thus the likelihood that changes will take place, differ strongly from region to region:

## **North America and the UK**

In the US, Canada and the UK that have adopted gas-on-gas competition as the pricing mechanism there are virtually no calls for shifts to other mechanisms. There is concern about the level of price volatility, and a debate involving market actors, regulators, politicians and observers about how to deal with the harmful effects of price spikes and troughs. But there is little talk about a return to more regulation or for a shift to some variation on the market value pricing theme. As such, gas price determination through multiple sellers competing for multiple

buyers with minimal regulatory interference (apart from tariff control of the natural monopoly elements in the supply chain, aka the transmission link) seems to be widely perceived as an end state without more efficient alternatives.

## **Continental Europe**

With respect to Continental Europe, the EU commission's electricity and gas liberalisation agendas reflect the view that the incumbents dominating electricity and gas supply and cross-border trade in Europe have exploited their monopolist or oligopolist positions to secure unreasonable margins for themselves instead of delivering maximum benefits to the consumers. In any event, it is argued, the incumbents need to be exposed to competition to stay efficient.

Specifically, the commission's initiatives have aimed at securing access at equitable terms to Europe's electricity and gas grids for new players, loosening the grip of long term take or pay contracts, and pave the way for gas-to-gas competition based pricing as an alternative to oil indexed pricing.

The Commission's priorities are being shared to varying degrees by the EU member states' governments and commercial actors. Individual member state positions differ because their incumbent gas companies differ in interests and influence, and because views on the optimal extent of regulation of economic life, and the proper influence of Brussels on national policy making, still vary a lot.

Moreover, positions are changing in response to changes in the context and to the surfacing of new issues. During the 1990s signs of global warming triggered a debate on the sustainability of policies to bring down fuel prices by providing for more competition in the fuel sectors, given the environmental downsides of continued fuel consumption growth. In recent years gas supply security concerns have triggered a debate on the compatibility of open access to gas infrastructure, a shortening of contracts and prices set through gas to gas competition with the required fast growth in investments in increasingly remote upstream options and expensive midstream solutions.

As for the commercial actors, with oil prices at record levels and with a series of new gas import facilities under construction or at the drawing board, as of 2008 Europe's gas suppliers seemed to believe that oil linked prices will hold up better than gas-on-gas competition based prices.

Another factor is the remaining lack of trust in Europe's gas hubs as sources of reliable price information. Apart from the UK's National Balancing Point (which though significant is dwarfed by the US' Henry Hub), European hubs remain small and thinly traded. Illiquidity spells unpredictability and entails a risk of market manipulation. In contrast, the markets for the crude oils and refined products are vast, liquid and well understood by everybody involved.

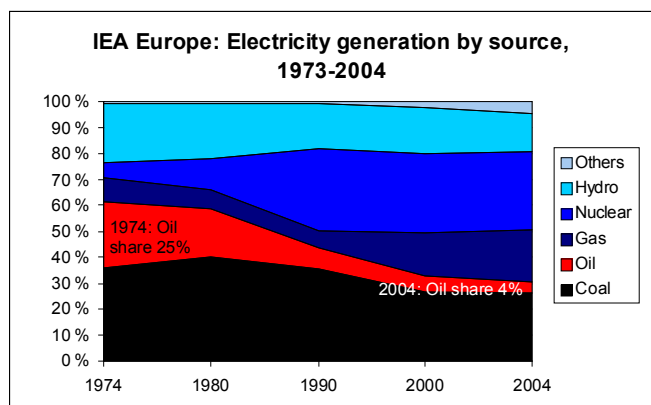
Thus, while there has been considerable movement on the grid

access issue, there is for the moment strong interest in retaining oil linked pricing. European gas market players have also put up a strong fight on the principle of long term contracts.

Testifying to the continued sympathy for oil linked pricing, Gazprom in 2006-07 renewed a string of major gas sales agreements with Western European buyers on oil terms.

Sellers' and buyers' perceptions of the pros and cons of alternative contract forms and pricing models are not set in stone. Gas-on-gas competition based pricing will likely gain ground as more hubs mature. Additionally coal indexation could come to be seen as an alternative. The fact remains that the gas industry needs to look to a sector where oil is no longer an interesting alternative for further growth opportunities (Chart 8.1). Gas prices mirroring record high oil prices could as noted stop that growth in its tracks.

**Chart 8.1: Electricity generation by source in IEA Europe**



Source: IEA

This being said, the transformation of the Continental European gas market will neither be fast nor proceed at the same pace across countries. Gas market based pricing, oil linked pricing and formulae involving links to inflation, to coal or to electricity (the “spark spread”) will likely continue to coexist for many years.

## Asia Pacific

The established Asian LNG importers are sticking to crude oil indexation as the dominant imported gas pricing mechanism. Gas-on-gas competition based pricing is not a target. Gas market based pricing is for the time being not an option other than for spot cargos anyway since the OECD Pacific gas markets are characterised by limited competition and have no gas hubs.

The Japanese gas and power utilities, Kogas and Taiwan’s CPC have traditionally paid more than European and North American buyers for their LNG imports. This is mainly because of their traditional preoccupation with supply security and ability to pass the costs of added security on to their customers. Japanese end user prices, to take them as an example, have been regulated by the Ministry of Economy, Trade and Industry on a cost plus basis. Some of these companies campaigned for lower prices in the early 2000s, in response to India’s and China’s successes in securing

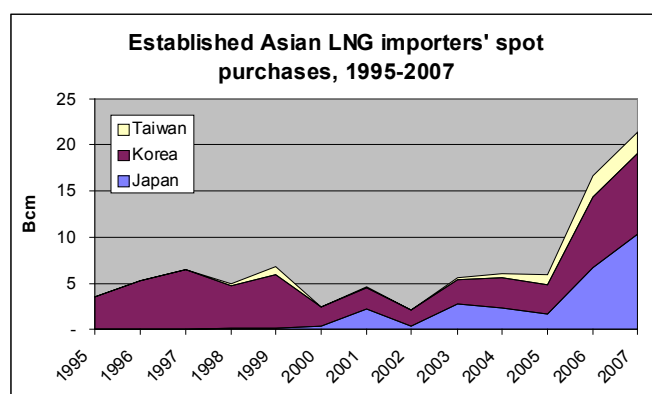
cheap LNG, but since Indonesia’s supply challenges became manifest their main interest has again been to secure volumes.

The Japanese gas market has traditionally been highly fragmented with regional monopolies tolerating no competition within their concession areas and refraining from going for customers in neighbouring regions. This is changing, with the revised Gas Utility Law in Japan providing for third party access to LNG terminals and pipelines. Also, customers using in excess of 100,000 cm of gas a year are now allowed to negotiate their own prices with suppliers. But regulatory reform is only the first step towards a level playing field and real competition.

The changes that are occurring in Asian LNG import and gas end user pricing are changes within the paradigm of oil linked prices. As the Asian LNG market tightened, the gas price–oil price curve steepened towards full parity in energy equivalence terms between LNG and crude oil import prices. Also the S shape of the curve that Japanese buyers prefer – i.e., the ceiling offering protection to the buyer if oil prices should increase above a preset level and the floor offering protection to the seller if oil prices should become too low – came under pressure. The financial crisis and the current outlook for slower growth in LNG demand in a period when much new LNG will come on the market, have reversed these trends but not affected the oil link.

However, the globalisation of the LNG business, the growth in LNG spot transactions as a share of total LNG sales and purchases (Chart 8.2) and in the future the emergence of LNG transactions across the Pacific will shape Asian buyers’ pricing habits too. Kogas uses the spot market to manage seasonal swing in Korea’s gas demand. As a result of several nuclear incidents, since 2006 also Japanese buyers have been active in the spot market. Japan in 2007 had to compete on price for around 20% its total LNG supply. For the moment (1st quarter 2009) Asian buyers are not very active in the LNG spot market but demand could bounce back once the financial crisis is over. Asian buyers will then need to reckon with Henry Hub and the NBP – i.e., indirectly with supply and demand conditions in North America and Europe – as references that sometimes kick in as floors, other times as ceilings.

**Chart 8.2: Asian LNG importers’ spot purchases**

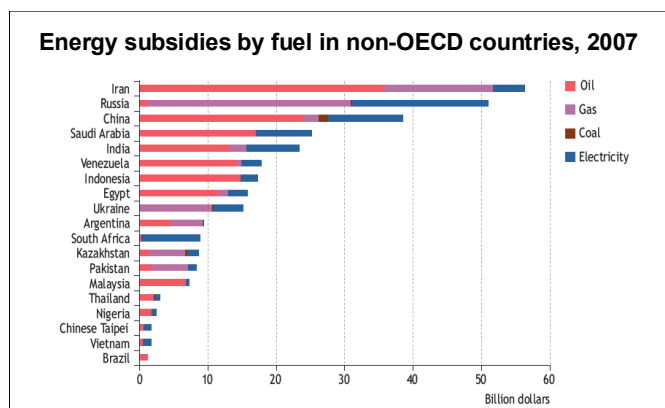


Source: PIRA, defining spot purchases as including contracts up to four years

## Non OECD

In countries where gas end user prices are set below supply costs and where the government is able to ensure that gas demand growth is accommodated by supply growth, gas subsidisation may increase to the point of representing a serious drain on the budget. According to IEA estimates, gas subsidisation is an issue for Iran, Russia, Ukraine, Kazakhstan, Pakistan and Argentina in particular (Chart 8.3).

**Chart 8.3: Energy subsidies by fuel in non-OECD countries, 2007**



Source: IEA: World Energy Outlook 2008

Gas subsidisation takes a particularly heavy toll in periods of extraordinary high international gas prices like 2007 and 2008. Countries that import or need to start importing gas find it increasingly hard in such periods to sustain domestic price freezes or very slow price adjustment schedules.

While domestic pricing options narrowed for a number of gas importing countries, they widened in 2007-08 for some oil and gas producers and exporters. These countries had spending powers then that they did not have in the late 1990s, and may have felt emboldened to continue ignoring recommendations to dismantle subsidy arrangements.

The financial crisis has in a sense reversed the situation. Gas has become more affordable and the subsidisation of gas end user prices has become less burdensome in absolute terms. However, oil and gas exporters need to cope with mounting current account and budget deficits and may be less able to sustain subsidies now than before the crisis broke – and since the crisis has weakened not only oil and gas prices but most commodity prices, all countries on the IEA’s list are probably now facing bigger subsidy burdens relative to their ability to pay.

Governments as a rule respond in two ways: by liberalising prices to select, presumably robust, customers, and by raising remaining regulated prices to the extent politically possible. Typically, households and important industries such as the fertilizer sector continue to enjoy some protection.

Russia – the world’s biggest gas producer and exporter – has embarked on a process of aligning domestic prices with the opportunity costs of selling the gas at home, i.e., with the netback

to the producers if they had exported it instead, and there is every reason to believe that this process will be completed, if not necessarily on schedule.

Other gas producers are proceeding more carefully. They can hold back for a while but not necessarily forever.

China and India face the dilemma that if gas is to become a key fuel to the power sector, and not just a marginal fuel for peak load generation, and if imported gas is to become an important part of the supply picture, coal prices need to be raised to make gas competitive.

While the Middle East’s and North Africa’s needs for gas for power generation and desalination is booming, the two regions’ associated gas production is typically stagnant or declining, forcing governments to add non-associated gas to domestic gas supply to make ends meet. Since non-associated gas developments require upstream investments and carry much higher costs than associated gas, this aggravates the budgetary consequences of continued gas subsidisation.

In the late 1990s when oil prices dipped below USD 10 a barrel and the oil exporters ran up record trade and fiscal deficits, a preparedness to discuss domestic price reform could be detected across a range of gas producing countries. Saudi Arabia, Venezuela and others that took steps to involve IOCs in non-associated gas E&D needed to make the economics of involvement look viable. However, as oil prices have rebounded and the oil exporters are again accumulating trade and fiscal surpluses, the “gas openings” of the late 1990s/early 2000s seem have lost momentum.

## Towards a globalisation of gas pricing?

International gas trade serves to align prices across countries and – possibly – continents. This is, simply speaking, because trade allows gas to flow from the areas with the lowest prices to the areas with the highest prices (adjusted for differences in transportation costs; it is the netback that drives sellers’ prioritisation between markets). In the former areas the gas supply curve shifts to the left, up the demand curve. In the latter areas the supply curve shifts to the right, down the demand curve.

The most interesting countries in this context are those that enter the global marketplace with lower domestic prices than international prices. The importers in this group then come under pressure to raise domestic prices not to be left with unsellable imported gas or increased subsidisation commitments. The exporters come under pressure to raise domestic prices because of the losses incurred by supplying domestic users at below opportunity costs, and/or because unconstrained growth in domestic consumption could choke exports off.

International gas trade is growing. BP estimates that in volume terms, world gas imports and exports increased from 335 Bcm in 1992 to 776 Bcm in 2007 or by an average of 5,8% a year. As a share of world gas consumption – which only increased by

2,5% a year in this period – imports and exports nearly doubled between 1992 and 2008.

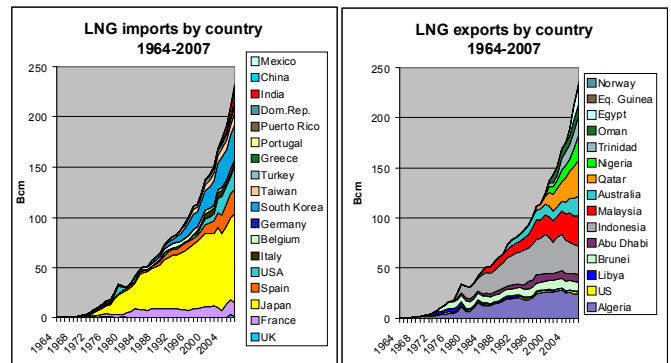
Continental Europe’s interfacing with other market structures has considerably modified its price dynamics. The opening of the Interconnector gas pipeline in October 1998 created a link between the oil-indexed North European gas markets and the liberalised UK market. The UK’s seasonal demand and relatively flat production created arbitrage opportunities for continental buyers who could buy UK spot gas instead of contract gas within their Take or Pay (TOP) – Annual Contract Quantity (ACQ) ranges and use storage to further optimise their positions.

This development looks set to continue. Several new import-export pipelines are under construction or nearing the construction stage. Unsurprisingly, Europe which its large, dynamic, oil linked and increasingly integrated gas markets, and its location in between half a dozen or so of leading gas producers and exporters, is the target of a multitude of pipeline projects. Examples on Europe’s eastern borders include the Russian North and South Stream pipelines, and Nabucco, the IGI project and the TAP project that compete among themselves and with South Stream for supply from the Caspian and Gulf areas. Further to the south, one new Algerian export pipeline – Medgaz to Spain – is close to completion, and another – Galsi to Italy – is going forward, Libya is planning to extend the capacity of its Green Stream pipeline, and Egypt’s Arab Gas Pipeline has reached Syria and could, depending on the availability of gas for pipeline exports, be extended to Lebanon and Turkey. In the more distant future a pipeline could link Nigeria and Europe via Algeria. In China the second West-East pipeline is under construction, and will be extended to pick up Central Asian gas. China is also likely sooner or later to gain access to Russian piped gas.

However it is the international trade in liquefied gas that is seeing the fastest growth and makes observers wonder how soon the characteristics of an integrated global gas market will be in place.

Though LNG makes up only about 30% of world gas trade, and less than 8% of world gas supply, LNG is beginning to dynamically link more than half of global gas consumption. And the list of countries importing LNG and gaining an exposure to global gas prices is steadily growing. In 2008 Brazil and Argentina commissioned regasification terminals, and Canada, Chile, Croatia, Poland, Singapore, the Netherlands, Germany, Indonesia have all taken steps to enter this segment of the global gas market.

Chart 8.4: LNG imports and exports by country



Source: Cedigaz

The growth in US LNG imports in the early 2000s and the reemergence since 2005 of the UK as an LNG importer meant additional opportunities and price influences for Continental European gas buyers:

- Contract LNG diverted to US/UK markets: At times when Henry Hub was higher than European contract prices, France and Spain were able to sell contracted LNG in the US and obtain ‘back-fill’ volumes by increasing offtake under their long-term pipeline gas contracts within the TOP – ACQ band.
- Flexible LNG diverted from US/UK markets: When Continental European oil indexed prices have exceeded Henry Hub or the NBP price, LNG intended for delivery to the US or the UK may instead be imported to continental Europe, with the importers lowering offtake under their long term pipeline gas import contracts correspondingly within the TOP – ACQ band. This has been made easier by the lack of firm long term contracts with market participants in the UK or US.

The UK market is subject to the Interconnector and LNG diversion dynamics described above. A conflict of market models arose in November 2005 when, facing a supply shortage, the UK was expecting Continental European players to send gas bought from the UK the previous summer back to the UK in response to price signals. This did not occur. The continental players were more concerned with ensuring adequate supplies for domestic customers during the first quarter of 2006.

An interesting development in 2007-08 was the rapid growth in Asian imports of Atlantic – i.e., North and West African, Caribbean and even Norwegian – LNG. This trade increased from some 4,8 bcm in 2006 to 9,6 bcm in 2007 and close to 20 bcm in 2008. Offering higher netbacks the Asian importers made Atlantic suppliers divert as many cargos as they could, given their contractual commitments, from their regular markets. US imports in the first 10 months of 2008 plummeted by almost 60% year on year.

The Asian importers’ dips into the pool of LNG supply which otherwise would be delivered to the Atlantic Basin markets had consequences for overall LNG availability and required Europe and North America to rely more on gas in storage. While Asian

LNG contract prices are linked to the oil price, spot purchases were apparently priced on an Atlantic basin netback basis, though they could also reflect substitute fuel prices (usually in Japan and usually distillate prices).

There were particular reasons for the Asian countries' needs for Atlantic LNG in 2007-08 – in the case of Japan TEPCO's temporary loss of big parts of its nuclear capacity, in the case of South Korea a fuzzy regulatory situation that prevented Kogas from signing new long term contracts, and in both cases poor utilisation of storage tanks to manage seasonal demand and Indonesia's problems delivering on its commitments. Some of these drivers will weaken, and the global recession has put an end to the sellers' market conditions that characterised LNG in 2007-08. In 2009 few Atlantic cargos have ended up with Asian buyers. On the contrary, Asia Pacific exporters have needed to place a few cargos with Atlantic buyers. These developments do not constitute evidence that the integration of regional gas markets has stopped in its tracks, but serve as a reminder that the road towards globalised gas pricing may see set-backs and could take longer than expected.

### **Bumps in the road toward globalised gas pricing**

Though the differences between how gas is priced in individual regions may narrow, the driving forces expected to deliver price alignment do not look as powerful as they did some years ago. There may for instance be reasons to revisit the question how effectively LNG will serve to integrate world markets.

It seems a fair assumption that the LNG share of world gas supply needs to reach a certain threshold – whatever that threshold may be – if LNG is to play a key role in delivering market integration and price globalisation. By 2008 the LNG share of world gas trade was about 28%, but regasified LNG still made up only 7,5% of world gas consumption. The conclusion that LNG remains a niche product with limited capacity to drive prices, seems to be still valid. Moreover, most LNG chains are no less rigid than pipeline gas chains, with volumes, sources and destinations laid down in long term contracts. It is only the flexible portion of LNG – the volumes purchased by portfolio players, the volumes available from liquefaction plants after contractual commitments have been fulfilled, etc. – that can be routed at short notice to the highest paying markets.

Clearly, even small supply increments can make a difference in tight markets. Thus under certain circumstances flexible LNG may already have reached 'critical mass' in its role as globalisation purveyor. Under other market circumstances, however, the cargos available for rerouting will probably not matter much to regional price differences.

During the first half of this decade forecasters expected rapid growth in LNG exports and imports. This optimism reflected a bullish outlook for gas in general, an apparent abundance of gas reserves suitable for commercialisation as LNG, favourable gas price / LNG cost developments and other attractions of LNG in comparison to pipeline gas – security of supply advantages

from the point of view of consumers, arbitrage opportunities from the point of view of suppliers.

There is still much enthusiasm, and fairly robust growth projections, for LNG. The reference scenario in the International Energy Agency's 2008 World Energy Outlook had LNG supply and demand growing by 6% a year between 2005 and 2015, and 4,7% a year between 2015 and 2020. These rates were lower than those suggested in previous WEOs but still a lot higher than the Agency's 2008 projections for total gas supply and demand. The IEA last year believed that in a business as usual future the LNG share of total gas would increase from 6,7% in 2005 to 16-17% in 2030.

The globalization trend will get a boost from LNG in the years to 2011-12. During this period some 90 mtpa of new liquefaction capacity will be commissioned. Some 15 new LNG trains, including several very big ones, are under construction with a view to completion before the end of 2011. Nearly all this capacity is tied into long term LNG sales and purchase contracts. However, 35% of the capacity is contracted to the marketing arms of the IOC participants in the projects, and another 24% is contracted to Qatar Petroleum. Thus almost 60% of the capacity to come onstream between now and the end of 2011 may be characterized as flexible – and it cannot be ruled out that the gas and power companies and end users that have contracted for the remainder of the new capacity have plans of their own to engage in arbitrage plays.

However, the pace of LNG supply growth beyond 2012 is for the moment highly uncertain. In 2006-08 only five liquefaction projects took final investment decisions. The 22-23 mtpa of capacity that these projects will add to the global total corresponds to only about half of required incremental capacity over the years when the projects may be expected to come onstream – if, that is, LNG demand grows at around 6% a year. The latter assumption is of course open to question. The credit crunch may well slow LNG demand growth down for a while. Still, the assumption that there will be enough flexible LNG around to support any conceivable growth in arbitrage operations and price alignment across regions and basins also beyond 2012, now seems bold.

The most intriguing aspect of the slowdown in the sanctioning of new liquefaction projects, is that it took place in a period characterized by record high oil and gas prices and extreme tightness in the global LNG market. In 2008 LNG buyers purchased spot cargos and signed short-medium term contracts at prices representing parity with oil at USD 100-150/b. It was widely assumed that parity would become the norm also for longer term contracts. This still did not persuade many LNG project sponsors to proceed from the planning to the implementation phase.

A string of factors have recently thrown spanners in the wheels of LNG supply projects:

- Problems gaining access to gas reserves suitable for LNG due to host country government decisions to prioritise supply for the domestic market and/or for future generations rather than (additional) LNG exports,
- Shortages of input factors, contractor capacity and skilled labour driving costs and undermining the pretax economics of LNG; projects that seemed robust some years ago now look marginal,
- Increasingly tough fiscal terms as host country governments responded to the shift from buyers' to sellers' market conditions by seeking to increase government take,
- Persistently high political risk in key supplier countries,
- Project partner misalignment,
- Technical challenges related to the increasing size of LNG plants, and to the location of plants to more challenging environments.

It remains to be seen how quickly these hurdles will be cleared away or at least made more manageable. Certain cost components, in particular material costs, are on their way down. Others seem quite resilient to the financial crisis.

How quickly the flexible, divertible share of total LNG will increase is just as uncertain. There are projections of this share doubling from 15% to 30% over the next decade as well as expectations of a decline. Unsurprisingly, the Atlantic and Mid East actors that have positioned to become providers of LNG hub services are the most optimistic. At the other end of the scale are certain Asian and European incumbents pointing to the Japanese nuclear problems and other special circumstances that drove the growth in flexible LNG in 2007-08, and claiming that with these problems out of the way it will be in everybody's interest to refocus on long term contracts.

Independently of individual actors' preferences, a tripling of flexible LNG over a decade (a doubling of the flexible share of a total increasing by around 50%) could require more projects to be sanctioned with smaller shares of output under long term contracts, than host governments, company sponsors and the financial community seem to be ready for.

LNG project sponsors may have hesitated to proceed to FID also because of doubts about the sustainability of the 2007-08 LNG market boom. In the first place, there were signs that the prices in 2007 and the first quarters of 2008 would lead to demand destruction. Secondly some players may have suspected that the price explosion in 2008 was part of a bubble that would burst (although very few seemed to have anticipated something like the current price and demand collapse).

Sponsors probably also noticed that US LNG demand was not developing as expected in the early 2000s.

North America was – and is – a key piece of the puzzle expected to give rise to one integrated world gas market and globalised gas pricing. It was the new outlook for US LNG requirements that emerged after the 2000-2001 US gas price spike, and FERC's 2002 "Hackberry decision" to stop requiring so-called

open seasons for new regas terminals, that got the globalization debate started.

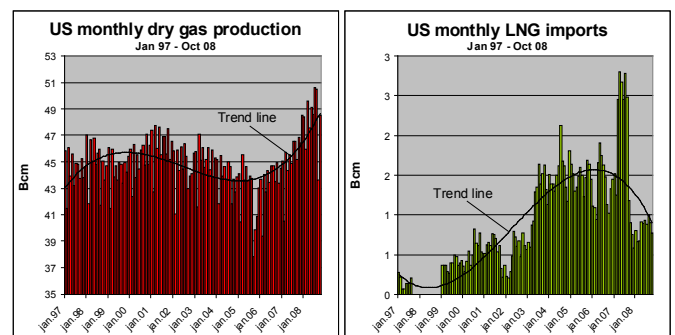
The US market had, it was argued, what no other single national market or cluster of national markets had: The size, the hubs and the storage capacity to provide swing services to everybody else without being destabilized itself in the process. As such US gas prices (adjusted for differences in transportation costs) – principally the Henry Hub spot price – were uniquely positioned to become world benchmarks. Prices elsewhere could not drop much below HH; if they did, flexible LNG would flow to the US and stabilize prices elsewhere. Prices elsewhere could on the other hand not increase much above HH; if they did, LNG destined for the US would be rerouted to the higher priced markets and again align prices across continents.

One thing necessary to make this vision a reality was robust growth in US LNG demand, and that seemed an almost done deal. On the one hand, US gas demand looked set to increase on the back of massive investments in gas fired power generation capacity. On the other, US gas production, and the availability to the US of Canadian pipeline gas, appeared to be in irreversible decline. Mexico also struggled to increase domestic gas production in line with demand. In short, the North American gas supply-demand gap that could only be filled by LNG looked set to widen rapidly.

US LNG imports are by nature volatile since they are not normally underpinned by long term take or pay contracts. Thus the flow of LNG to North America was below expectations in 2006 with European buyers stocking up gas in the aftermath of a cold winter and with the Russian-Ukrainian gas crisis still on people's mind, and above expectations in first half 2007 as a warm winter had left European storage inventories abnormally high. Until then, however, the trend seemed to be pointing squarely upwards.

What many observers missed for a long time was the unconventional gas revolution underway in the US. Tight gas, shale gas and coal bed methane has been supplied in increasing amounts at increasingly competitive costs. US gas productive capacity which had been on a declining curve since 2001 bottomed out in late 2005. LNG largely priced itself out of the US market in 2007 and failed to re-enter in 2008 (Chart 8.5).

**Chart 8.5: US dry gas production and LNG imports**

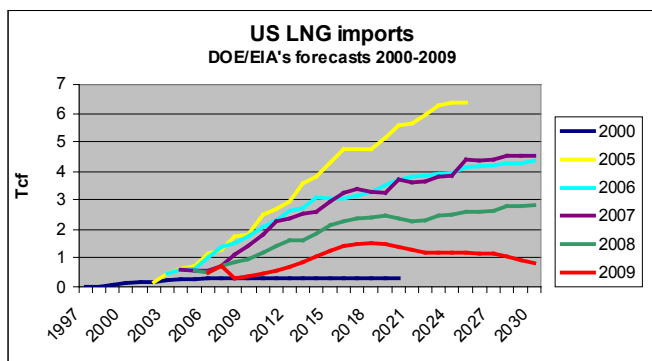


Source: US DOE EIA



Observers/stakeholders like the US DOE have lowered their US LNG import assumptions year by year in response to the signs of demand destruction and the break-through for unconventional gas. The DOE's Energy Information Administration almost comes full circle in its 2009 Annual Energy Outlook. By the turn of the decade the EIA believed that US LNG imports would stagnate at 0,33 tcf (9,3 bcm) a year. In 2005 the EIA put LNG imports by 2025 at 6,37 tcf (180 bcm) a year. In its most recent Outlook the EIA sees LNG imports peaking at 1,51 tcf (43 bcm) a year by 2018 before dropping to 0,84 tcf (24 bcm) a year by 2030 (Chart 8.6).

**Chart 8.6:** US LNG import forecasts



Source: US DOE/EIA: Annual Energy Outlook, various editions

The situation is not that the US may not receive increasing amounts of LNG. As a market of last resort the US will likely receive a significant share of the LNG from the 15 new trains set that will start producing in the years to 2012. But there will at least initially be no bid wars for this LNG. The sellers will have to accept or reject the prevailing US prices depending on relative netbacks. In extreme situations they may have no choice because other destinations are physically unable to receive more LNG. The US will then provide a floor to world gas prices and as such play its part in the price globalisation process.

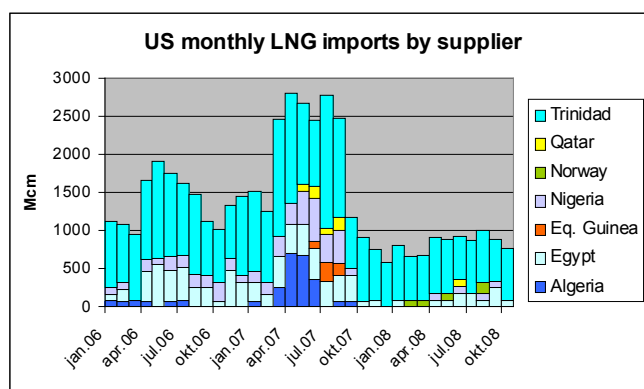
The US gas market is not only large enough and well enough equipped with storage capacity to accommodate such a development, it now also has sufficient regas capacity. By the end of 2008 the US had an estimated total of 62,3 mtpa (8,2 bcf/d) of capacity up and running, and Mexico had an additional 9,5 mtpa (1,2 bcf/d). By the end of 2009 the US total will be almost 100 mtpa (13,1 bcf/d) with Mexico and Canada contributing 19 mtpa (2,5 bcf/d).

Wholesale gas prices in the US will reflect the long term marginal costs of US unconventional gas. These costs are often reported to be in the US\$ 5-7/MMBtu range, though estimates tend to come with warnings about their sensitivity to further improvements in E&D technology, positive or negative surprises in new basins, general oil and gas industry cost developments and a host of other factors. Anyway, if Henry Hub drops below long term marginal costs – which certainly may happen – drilling and eventually supply will decline, pushing prices back into the viability range.

Whether the US also will provide a ceiling to world LNG prices as and when markets recover, and as such continue to serve as market integrator, is a different issue.

If US LNG imports increase in the short term, a recovery in world LNG demand in the medium term could to an extent be supplied from these imports. European and Asian buyers would only need to increase their price offers enough to shift netbacks marginally in their favour. The re-routing potential would however eventually become exhausted just as it was in 2007-08 when little else than Trinidad cargos under long term contracts found their way into the US (Chart 8.7).

**Chart 8.7:** US LNG imports by supplier



Source: US DOE EIA

LNG prices could then decouple from the US price level which – if US gas demand and/or indigenous gas supply is flexible enough to quickly accommodate any loss of flexible LNG to other market regions – might not change at all.

If the US instead develops the dependence on LNG that observers in the early 2000s thought they could see around the corner, but now tend to discard, US buyers would need to compete on price with the rest of the world for LNG supply. Then the LNG price ceiling provided by US indigenous gas supply costs could disintegrate – but we would still in this scenario characterised by intercontinental competitive bidding see gas market integration and price globalisation.

The differences between recent long term US LNG import forecasts testify to the complicated nature of this issue. US gas demand growth will play a key role, implying that economic growth and the current administration's energy and environmental policies will be important drivers. The exact shape of the North American unconventional gas supply curve, today and 5, 10 and 20 years from now considering the resource base and the scope for further technological progress, is another key to the outlook for LNG. Whether incremental LNG supply costs will stay at today's level or fall back towards their 2004 level is yet another key.

To state the obvious: If

- US gas demand picks up on the back of an economic recovery and policies favouring gas over competing fuels for mid- and baseload power generation,
- unconventional gas proves to have its limits, and
- global LNG supply costs decline to the level of ensuring competitiveness in netback terms to the alternatives in the US market,

then LNG may only be temporary down as a component of the US fuel mix, and the growth in LNG supply to the US that many observers took for granted a few years ago could still materialise. If on the other hand US gas demand, unconventional

gas supply and/or LNG costs develop differently, then the anticipated recovery in US LNG imports linked to the need for new Qatari, Russian, Indonesian, Yemeni etc. liquefaction capacity to be accommodated, could be short lived.

The former scenario would underpin a rapid development of a global gas market with unified pricing. The latter would mean that a vital globalisation and unification driver would disappear from the scene with the result that the processes might take much longer.

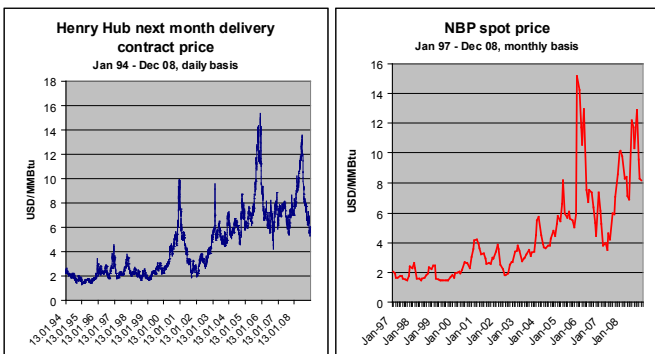
# 9. Price volatility

## General

In general terms, price volatility refers to the frequency and amplitude of price fluctuations. In financial terms volatility refers to the magnitude of stock variations. The concept of volatility is used to quantify yield and price risk. The stronger the volatility, the bigger the potential yield but also the bigger the risk. The concept is typically used to describe short term variations rather than long term oscillations, but may in principle be used to discuss all kinds of fluctuations.

There is a strong popular perception that gas prices fluctuate more often and more strongly now than in the past. A glance at select wholesale gas prices in the markets relying on gas-to-gas competition supports this notion (chart 9.1).

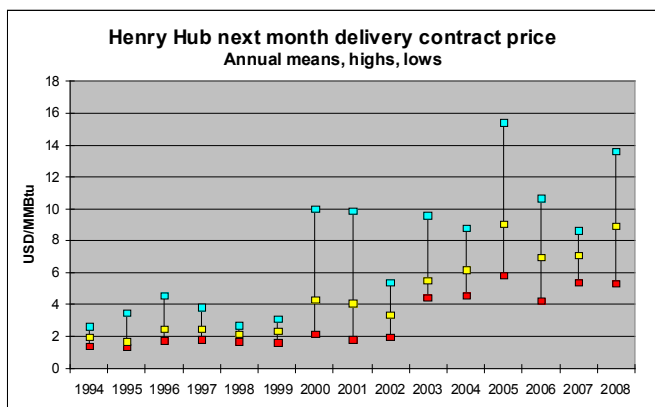
**Chart 9.1: Henry Hub and NBP price fluctuations**



Sources: US DOE EIA, CERA

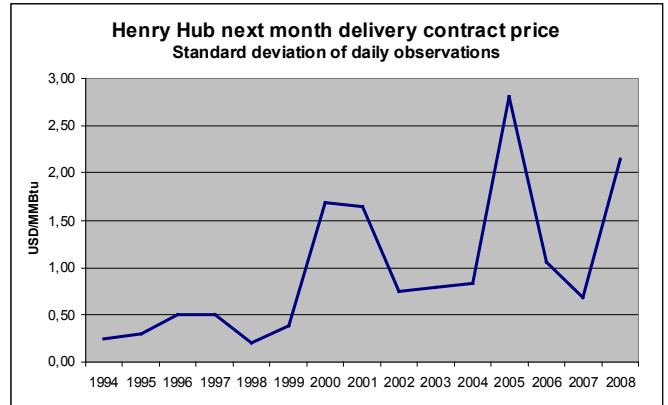
It is however not evident that there has been a continued and consistent increase in volatility through the 2000s. Prices fluctuated less in 2002-04 and again in 2006-07 than in 2000 and 2001. (Charts 9.2 and 9.3).

**Chart 9.2: Henry Hub means, highs, lows**



Source: US DOE EIA

**Chart 9.3: Henry Hub standard deviation**



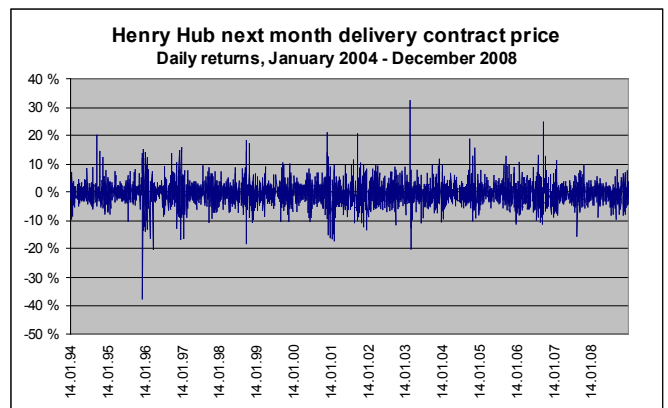
Source: US DOE EIA

The importance of not jumping to conclusions on volatility developments becomes even clearer when we look at price changes rather than absolute prices. Traders and risk managers typically measure volatility in terms of the “return” on an investment in a commodity, with returns calculated on a log-normal basis using the form

$$\text{Return}(t) = \ln(\text{Price}(t)/\text{Price}(t-1)).$$

In this perspective where a USD 2 increase in a USD 10/MMBtu price represents the same level of volatility as a 40 cents increase in a USD 2/MMBtu price, it becomes difficult to see any clear trend in volatility over the 1994-2007 period (Chart 9.4).

**Chart 9.4: Henry Hub daily returns**



Source: US DOE EIA

What effects price volatility has on the affected markets and economies is also a controversial issue.

In the 1980s and 1990s oil price volatility was much debated. Many politicians and market actors recommended producer to consumer cooperation to dampen price fluctuations. While the oil price increases in 1973 and 1979-80 triggered consumer country interest in this concept, the oil price collapse in 1986 persuaded many producer countries to support it too. The 1990 ‘mini-shock’ related to the Iraqi invasion of Kuwait further boosted enthusiasm for some kind of dialogue.

Economists however cautioned against politicising markets in this way. One study<sup>5</sup> examined the allegations that oil price volatility had boosted inflation and dampened economic growth by:

- Boosting oil prices
- Reducing oil industry investments and thereby oil supply,
- Boosting transaction costs – e.g., costs associated with investments in facilities to increase flexibility – for consumers and producers

The study failed to find conclusive proof for any of them. Price volatility as such did not seem to be the reason for any of these three situations.

Price volatility may keep investors that pursue low risk activities with correspondingly low returns, and look for a stable environment, from launching new investments. As such, volatility may be an issue from a gas supply security point of view. However, to other investors price volatility may, by providing arbitrage opportunities, be seen as preferable to price stability in terms of value added. It is important to nuance the perception of volatility as a problem for the industry. It needs to be acknowledged that different types of stakeholders look for different price contexts.

This difference is related to the one between long term oil indexed gas prices and shorter term gas to gas competition based prices on gas exchanges.

## Causes of volatility

Many explanations have been offered for the perceived increase in gas price volatility in the 2000s. Those that are most popular with the media are not necessarily on top in terms of explanatory power.

Blaming fingers are pointed at commodity trading techniques resulting from time to time in waves of speculative gas sales or purchases. The public is also occasionally fired up by reports on downright market manipulation. However neither trading techniques nor criminal activity are credible explanations for a general increase in price volatility.

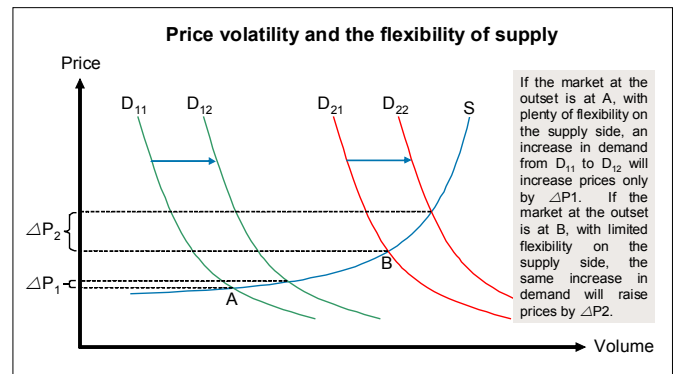
Basic gas supply and demand fundamentals go a long way towards explaining this increase.

Price volatility is the consequence of supply failing to respond immediately, smoothly and precisely to price signals caused by

changes in demand, or demand failing to accommodate price signals due to changes in supply.

How quickly supply is able to respond to a shift in demand depends on the state of the market – i.e., on the shape of the supply curve at the point of intersection with the demand curve – when the shift occurs.

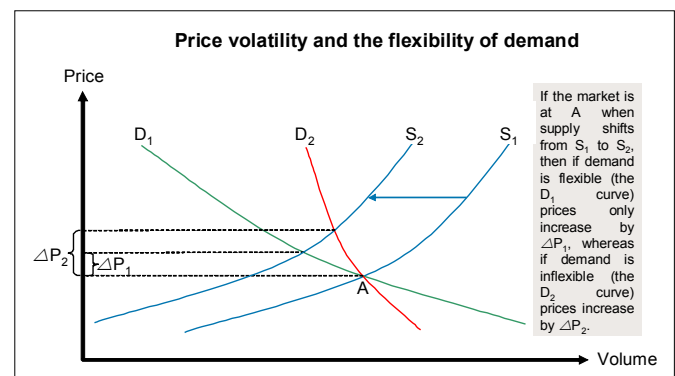
**Chart 9.5: Price volatility and the flexibility of supply**



The less suppliers are able to accommodate an increase in demand by activating spare capacity, the stronger will the price impact be.

How quickly demand is able to respond to a shift in supply depends on the shape of the demand curve at the point of intersection with the supply curve when the shift occurs

**Chart 9.6: Price volatility and the flexibility of demand**



The less consumers are able to accommodate a decline in supply by switching to other fuels or just cutting consumption, the stronger will the price impact be.

On the margin, if supply has become so stretched that the market is on the vertical part of the supply curve, or if demand has become so rigid that the market is on the vertical part of the demand curve, disturbances will need to be accommodated 100% by price adjustments. Since gas markets are ‘disturbed’ all the time by changes in the weather, maintenance of supply facilities, etc., under such conditions there will inevitably be frequent and sometimes violent price fluctuations.

<sup>5</sup> Philip K. Verleger, Jr.: *Adjusting to Volatile Energy Prices*, Washington DC 1993

Gas exchange prices reflect the supply and demand circumstances of the day. Both variables are characterised by frequent deviations from trend, and delayed and imprecise responses are the rule rather than the exceptions. Gas exchange prices are therefore inevitably characterised by fluctuations.

### **Volatility associated with gas price increases**

Gas price increases incentivise producers to increase supply, but liberalised markets as a rule have little spare productive capacity that can quickly be brought on-stream. In the US the gas sector restructuring that was triggered by the passing of the Natural Gas Policy Act in 1978 led to efficiency improvements, cost cuts and a period of low gas prices, but also to a decline in underutilised delivery infrastructure available to dampen volatility.

Gas price increases incentivise buyers to cut their gas purchases within the limits set by their flexibility to switch to alternative fuels. Typically, power sector gas demand declines as generators switch from gas to coal or oil-fired capacity, while industrial gas demand declines as firms relying on gas for process heat switch to oil products and firms using gas as a process feedstock temporarily shut down facilities.

However, only a portion of gas users can easily and quickly switch to alternative fuels, and this portion is shrinking, because of efficiency considerations and also since environmental and land use policies many places have prevented dual fuel power generating units from being constructed.

Prolonged periods of high gas prices trigger more drilling for gas. Traditionally in North America the rig count has responded quickly to price signals, and production has in turn responded quickly to changes in the rig count. The latter relationship seemed not to apply between early 2002 and late 2006 when prices more than tripled and the number of gas rigs increased from fewer than 600 to more than 1400, but production trended downwards. However, growth in unconventional gas production has since early 2006 been strong enough to deliver a recovery in total gas, and demonstrated that the old relationship still holds – at least for now.

The UK industry would be stimulated by prolonged high prices to harvest the remaining gas accumulations – probably through step-outs and extensions of existing fields. Aggregate additional production is not expected to be significant.

As for demand, prolonged periods of high gas prices reduce power sector gas needs by encouraging investment in alternative (typically coal fired) capacity, industrial sector demand by encouraging plant owners to re-locate to countries offering cheaper gas, and residential and commercial sector demand by triggering conservation measures such as improved building insulation, double glazing and more efficient heating boilers.

### **Volatility associated with gas price declines**

Gas price declines incentive producers to curtail drilling. When drilling goes down, lost production from wells in decline is not fully replaced and aggregate production starts going down. But all this takes time, and when production eventually starts to sag in response to lower prices, the response is initially very gentle. This is because it pays to shut in wells only at extremely low price levels.

In the UK some fields which are nearing the end of their lives are typically reducing production in the summer months when prices are soft in the expectation of using the ‘saved’ gas at the end of their field lives and in addition capturing a winter’s price premium.

How supply responds to price changes depends also on how storage inventories are managed. A price increase encourages accelerated withdrawal of gas from storage, and vice versa.

Gas price declines incentivise buyers to increase their gas use, again within the limits set by their flexibility to switch from alternative fuels to gas. Typically, power generators bring unused gas fired capacity on line at the expense of coal fired capacity. Industrial gas demand is unlikely to change.

Prolonged periods of low gas prices would strengthen the case for new investment in gas fired power generation, and slow the relocation of gas intensive industry to other parts of the world, but probably do not affect residential and commercial sector demand noticeably since past conservation measures reflected in, e.g., building standards for new premises would hardly be reversed.

On the supply side, the intensity of gas drilling in the US and Canadian gas drilling would decline from current levels and rapidly depress production, the Alaska and MacKenzie Delta projects would be further deferred, and UK fields would be shut-in and abandoned on earlier timings.

In sum, there are rigidities in both gas supply and gas demand that results in price volatility in competitive markets, and these rigidities appear to have hardened.

An increase in gas demand due perhaps to a cold snap does not trigger any appreciable production response. A decline in gas supply due perhaps to a hurricane damaging critical pieces of infrastructure does not trigger any appreciable demand response. Prices rise to activate whatever fuel-switching capacity exists in the power sector. If this additional cushion is insufficient to restore balance, prices continue to rise to the point where storage withdrawal reach extraordinary levels, or to the point where demand is ‘rationed’ – i.e. industry shuts down plant and all alternative power generation options to gas are exhausted.

## Volatility of oil indexed prices

In Continental Europe and Asia gas prices are as noted indexed to oil prices depend on imported gas to satisfy significant portions of their needs. This gas typically travels significant distances from the well-head to the city-gate.

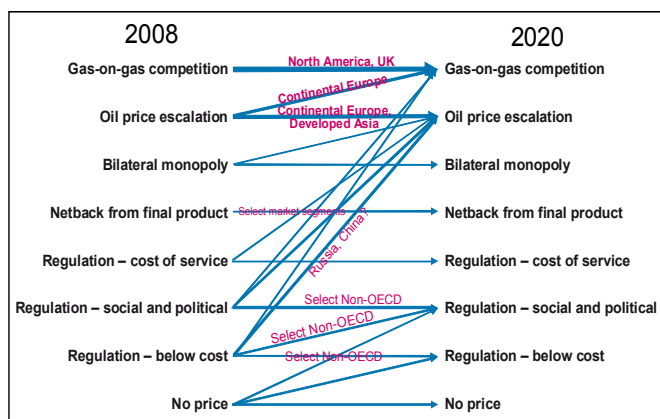
Importantly, the indices are not crude or product spot prices, which are highly volatile, but rolling price averages typically ironing out fluctuations over 6-9 month periods in European pipeline contracts and 3-6 months in LNG contracts. This averaging (and where applicable, upper and lower limits to the oil price range where indexation applies) significantly dampen the impact of the underlying oil commodity price volatility on gas prices. The result is ‘long wavelength’ oil price driven volatility

From the perspective of price volatility, the long-term oil indexed contract market structure gives rise to the following dynamics:

Supply and demand in these markets are managed through contract volume nominations and storage operations. The gas price does not automatically respond to gas demand. The buyer is implicitly paying the seller to maintain a surplus supply capacity in excess of the base capacity the buyer under normal circumstances will need. City gate prices reflect contract border prices and in addition in-country transmission and storage costs. The latter are spread across the year – hence there is no seasonal shape to city gate gas prices.

Chart 9.7 confirms that ‘short wavelength’ price volatility does not really feature in ‘pure form’ oil-indexed markets. From the perspective of, say, a large Continental European gas and power utility company, price uncertainty under the loose heading of ‘volatility’ would largely be confined to the existence of contract re-openers. Whether triggered by the buyer or the seller, re-openers can result in significant re-basing of the underlying contract price.

**Chart 9.7:** Standard deviations of monthly observations of sample of gas prices



Source of price data: PIRA

## Volatility and LNG

LNG under traditional long term take-or-pay contracts is no different from pipeline gas under similar contracts in its capacity to aggravate or dampen price volatility. Thus a shift in gas supply from long term pipeline gas to long term LNG will not in itself matter to price volatility. However, a material shift inside the LNG portion of gas supply from long term contracted to flexible LNG would imply further commoditization of gas and different volatility patterns across countries.

Flexible LNG is diverted according to price signals. Thus some countries may be deprived of LNG they had counted on, with the result that local or even national prices escalate. On the other hand the recipient countries may receive LNG they had not counted on with the result that the price increases that triggered the diversions in the first place are arrested.

To an extent this happened in 2008 when Asia – prompted by strong economic and energy demand growth, Japan’s problems with its Kashiwazaki-Kariwa nuclear power complex and a severe drop in Indonesian LNG supply – played the price card to attract numerous flexible cargos from the Atlantic basin. If these diversions had not been possible, Asian prices would have gone even higher while US prices would have been even lower than they were.

If Atlantic markets in general, and the US market in particular, had been tighter than they were in 2008, the only buffering mechanisms would have been North American producers’ flexibility to boost supply, European buyers’ possibilities to vary their nominations of long term pipeline gas in Europe, and storage inventories above annual norms.

By making local supply curves less rigid the advent of flexible LNG will likely dampen average price volatility. On the other hand, the commoditization of gas that is taking place is also attracting the interest of financial investors, and does as such imply a risk of speculative booms and busts.

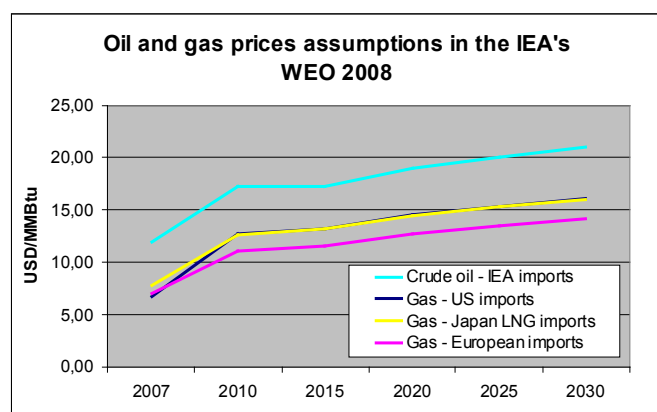
## 10. Towards further changes in the extensiveness of individual pricing mechanisms?

Neither the IEA nor the DOE/EIA anticipates much change in gas pricing mechanisms – at least not in their respective reference scenarios.

The EIA derives its US price assumptions mainly from its supply cost assumptions. The IEA expects that gas prices will remain linked to oil prices through contracts or substitution.

The IEA further assumes that gas will continue to be priced at a discount to oil. The imported gas/imported crude oil ratio was by 2008 assumed to stabilise around 75% for the US and Japan, and around two thirds for Europe (Chart 10.1)

*Chart 10.1: Oil and gas price assumptions in WEO 2008*



Source: IEA: World Energy Outlook 2008

The split of gas transactions by price formation mechanism could however change significantly between now and 2020.

As noted there is little to indicate that the countries that have adopted gas-to-gas competition based pricing – mainly North America and the UK – will turn away from this mechanism. On the contrary, the still fairly significant share of oil linked contracts in the UK market will likely diminish with buyers insisting on competitive pricing as opportunities to do so arise.

In Continental Europe and in big parts of Asia, various pricing mechanisms co-exist with oil indexation playing a dominant role. Opinions on the sustainability of this situation differ.

The original rationale for oil indexation has weakened. Gas still competes with oil in industry but faces mostly other fuels in the battles for residential, commercial and power sector market share.

The possibility of oil linked gas falling out of favour with the key power sector is particularly worrisome. Here gas needs to be perceived as competitive with coal and in the future increasingly with biomass, wind, solar, etc. The competition from coal is blunted by differences in capital costs, lead times, taxation and regulatory provisions. The competition from renewables other than hydro is blunted by the still high costs of these options. Extended oil driven gas price rallies could still erode gas' position as the preferred fuel.

Industrial buyers benefit from oil indexation when oil prices are sufficiently low for sufficiently long to make oil linked gas cheaper than spot gas. Sellers of course benefit from the opposite situation. Oil market cycles in combination with price renegotiation clauses in long term contracts may deliver a balanced distribution of costs and benefits over time. Oil driven gas price rallies like the one in 2007-08 that led to significant industrial demand destruction are nevertheless bad for gas' image as a reliable and affordable fuel across cycles.

More gas-on-gas competition and more use of gas exchange prices would to an extent decouple gas prices from oil prices. It would however increase short term price volatility, and whether it would eliminate the risk of longer term price rallies is an open question. Basically that would depend on Continental Europe's and Developed Asia's future gas supply-demand balances.

For the moment there is ample spare capacity in Europe's pipeline gas supply chains as well as in the world's LNG supply system. The financial crisis, the recession and the consequent drop in gas demand nearly everywhere have forced gas suppliers to significantly lower capacity utilisation. Sharp declines in sales revenues and doubts about the timing and shape of the anticipated recovery are however delaying vital up- and midstream investments. The IEA and others are concerned that the current global gas market downturn will only pave the way for another rally.

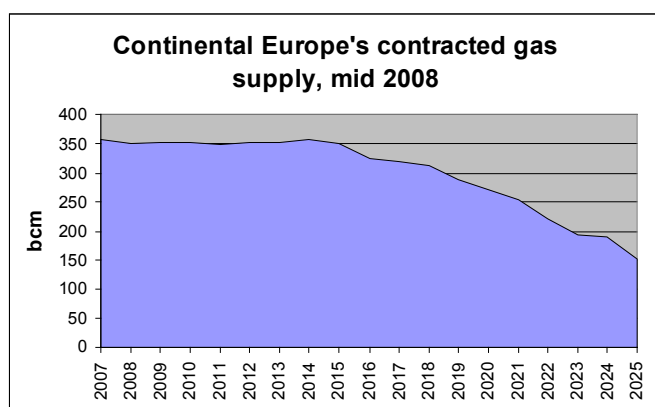
Evidence from North America underlines the question mark at the long term consequences for gas prices of switching from oil escalation to gas-on-gas competition. Although gas prices are not in any way linked to oil prices in US contracts, gas has over the years – across frequent, sometimes violent short-medium term disturbances – tended to track oil in a fairly stable long term relationship. This is probably because gas and oil prices besides being linked by interfuel competition in the industrial sector are influenced in the same manner and to the same extent by the oil and gas industry's cost cycles, and with deviations also being arrested, eventually, by changes in oil and gas industry investment priorities.

Oil indexation will in any event not disappear any time soon, for several reasons.

Continental European buyers have signed medium-long term contracts <sup>6</sup> for an estimated 350-350 bcm of gas a year, and a very high share of these contracts are of the standard oil linked type. Annual commitments start declining only from around 2015.

By 2008 existing medium-long term contracts corresponded to more than 80% of Continental European gas consumption (with the rest being short term purchases). Going forward, this share will of course decline (Chart 10.2). If gas demand increases by 2,4% a year, in line with average annual growth between 1987 and 2007, already contracted supply will meet around two thirds of Continental European gas demand by 2015 and less than a quarter of demand by 2025. Moreover, the take or pay provisions in most contracts give customers the option to offtake somewhat less than 100% of annual contracted volumes.

**Chart 10.2:** Continental Europe's contracted gas supply, mid 2008



Source: Wood Mackenzie

Still, the existing body of oil linked contracts considerably reduces the maximum pace at which a shift towards, e.g., gas indexation could proceed.

This is not to say that there is a desire among gas sellers and buyers to get rid of the oil link overnight even if they could. As noted, the incumbents on both sides of the table seem for the moment to be broadly in favour of retaining oil indexation.

The EU Commission will likely continue to push for gas-on-gas competition based pricing, but it cannot push very hard in the absence of trading places offering reliable price information and the full range of trading facilities and services. Continental Europe's gas hubs will take on these characteristics and functions but that will take time.

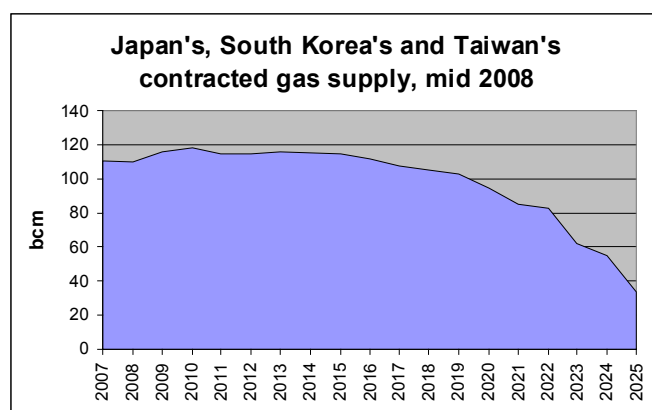
Japanese, South Korean and Taiwanese gas importers have on balance been even more hesitant than their Continental European counterparts to switch from oil indexed import prices and cost plus based domestic prices to more competitive arrangements.

Gaining acceptance for alternative pricing models will likely take longer in Asia than in Europe.

Legislation to make these countries' domestic gas markets somewhat more competitive have been passed, and their recurrent needs to purchase spot LNG will constantly bring them into contact with the Henry Hub or NBP price levels. However, there seemed by mid 2009 to be few champions in the region for dramatic reforms.

Moreover, Japan, South Korea and Taiwan have just as Continental Europe entered into a large number of oil linked medium-long term gas import contracts that constitute a limit to the possible pace of introducing alternative pricing principles (Chart 10.3). The ratio of contracted supply to total demand was in 2007 – when spot purchases reached unprecedented highs – around 80%. If gas demand increases by 6% a year the share will fall to around 50% by 2015 and less than 10% by 2025. A 6% annual growth would be in line with the average for 1987-2007 but no one expects these comparatively mature markets to continue to expand this fast. A perhaps more realistic 3% a year demand growth assumption gives ratios of already contracted supply to future demand much in line with those of Continental Europe.

**Chart 10.3:** Japan's, South Korea's and Taiwan's contracted gas supply



Source: Wood Mackenzie

China and India are in the midst of painful adjustments to 'world level' gas prices. These adjustments are driven by a need for imported gas that is unlikely to peak any time soon, in spite of gas discoveries that will allow significant growth in indigenous production in both countries. They proceed, broadly speaking, by introducing competitive pricing for the customers able to cope with steep gas cost increases while retaining price regulation for everybody else, but in a differentiated manner, and with the aim of gradually increasing prices across the board. In other words, they are on their way from domestic pricing systems dominated by below cost regulation, to alternatives characterised by a mixture of below cost regulation, some sort of cost based regulation and gas-to-gas competition based pricing, with the split of sales gradually shifting from the first to the second and third pricing principle.

<sup>6</sup> Including deals at HoA or MoU level as well as firm sales and purchase contracts



More countries than China and India – possibly the majority of countries in Asia and Latin America, apart from the richest ones, and the gas importing FSU republics – are struggling to accomplish similar transitions. The timelines for getting there vary across countries and as rulers come and go. As noted, price reform is risky business. Factors such as the pace of economic growth, inflation and the popularity and leeway of the incumbent government need to be constantly considered.

Russia appears to be on a broadly parallel course although from a different starting point as the world’s biggest gas producer and exporter. Russia’s traditionally uneconomic domestic gas prices that have over-stimulated domestic gas use and limited Gazprom’s and other companies’ ability to invest in new fields and supply infrastructure, are as noted to be partly replaced by opportunity cost based prices over a period of 4-5 years.

To the extent European border prices – the starting point for netback calculations – remain oil linked, Russian wholesale prices will come to reflect oil prices too. This could transfer the problems of oil linked pricing into a Russian market poorly prepared to deal with them, possibly leading to delays, exemptions and special arrangements that would reduce the transparency of the process.

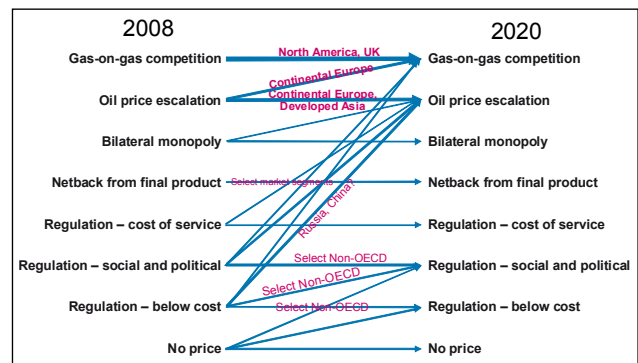
A fair number of Non-OECD countries – in particular those in the Middle East and North Africa that benefit from high oil prices – will likely seek to continue subsidising domestic gas prices. Cheap electricity, gas and motor fuels are widely seen as obligatory government deliverables in these parts of the world, and also indispensable to the global competitiveness of the regions’ petrochemical industry. In periods with high oil export revenues there has historically been limited interest in

challenging these perceptions. Now, with oil export revenues considerably down on their 2007-08 levels, concerns about the budgetary consequences of subsidisation are likely resurfacing.

At the same time, with many North African and Middle Eastern countries beginning to feel the pinch of stagnant indigenous gas supply, intraregional gas exports and imports look set to increase, and this trade will not be at subsidised prices. Qatar aims for the same netback from its LNG sales to Kuwait and Dubai as from its other LNG sales, and if Doha decides to contract additional pipeline gas to the UAE or Oman it will be at international market prices. This will increase subsidisation burdens in the importing countries and could eventually pave the way for domestic price adjustments.

Chart 10.4 is an attempt to summarise these hypotheses.

**Chart 10.4:** Hypotheses on future changes in the extensiveness of individual pricing mechanisms in individual regions



# Appendix 1

## – Price Formation Mechanisms 2005 Survey

### Format of Results

In looking at price formation mechanisms, the results have generally been analysed from the perspective of the consuming country. Within each country gas consumption can come from one of three sources, ignoring withdrawals from (and injections into) storage – domestic production, imported by pipeline and imported by LNG. In many instances, as will be shown below, domestic production, which is not exported, is priced differently from gas available for export and also from imported gas whether by pipeline or LNG. Information was collected for these 3 categories separately for each country and, in addition, pipeline and LNG imports were aggregated to give total imports and adding total imports to domestic production gives total consumption. For each country, therefore, price formation could be considered in 5 different categories:

- Domestic Production (consumed within the country, i.e. not exported)
- Pipeline Imports
- LNG Imports
- Total Imports (Pipeline plus LNG)
- Total Consumption (Domestic Production plus Total Imports)

Each country was then considered to be part of one of the IGU regions, as described in the Introduction, and the 5 categories reviewed for each region. Finally the IGU regions were aggregated to give the results for the World as a whole for 2005.

In terms of the presentation of results, the World results will be considered first, followed by the Regional results for the separate regions – North America, Latin America, Europe, Former Soviet Union, Middle East, Africa, Asia and Asia Pacific.

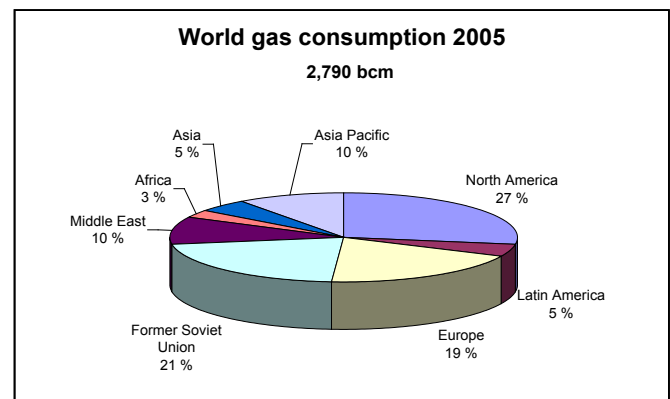
As well as collecting information on price formation mechanisms by country, information was also collected on wholesale price levels in each country in 2005. These results on a country and regional basis are also presented together with an analysis of price trends.

### World Results

#### World Consumption and Production

Before considering the results on price formation mechanisms for 2005, it is useful to consider the regional pattern of consumption and production. In 2005 total world consumption and production was of the order of 2,800 bcm. Chart A?? below shows the distribution of world consumption.

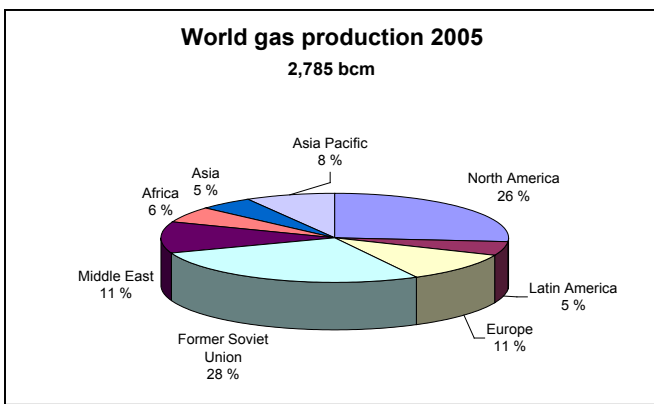
*Chart A1: World gas consumption 2005*



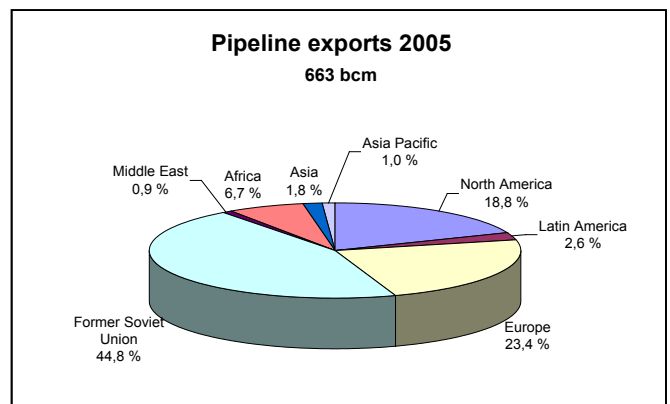
North America and the Former Soviet Union, followed by Europe are the main consuming regions, and it is these regions, therefore, which will have the greatest influence on the results on price formation mechanisms at the World level. The Middle East and Asia Pacific will also have an important, but smaller, influence.

The Chart on the next page shows World Production by region. The largest consuming region – North America – was largely self-sufficient in 2005. The Former Soviet Union was a net exporter, principally to Europe, which was a net importer. Asia Pacific was a net importer, principally from the Middle East, while Africa was a net exporter, mainly to Europe. Asia and Latin America were largely self-sufficient.

**Chart A2: World gas production 2005**

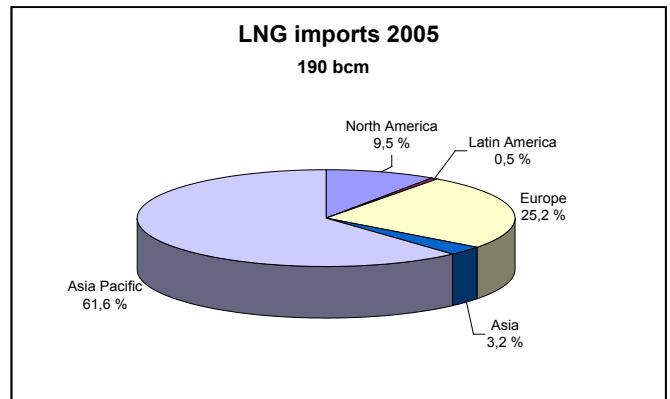


**Chart A4: Pipeline exports 2005**

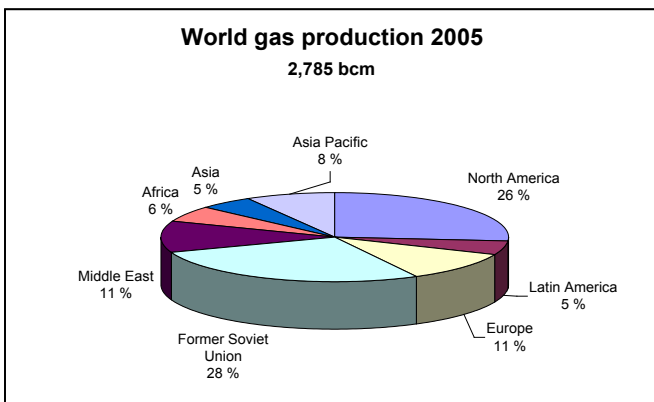


With respect to imports by pipeline (both intra- and inter-regional), Europe accounts for more than half of the world total. Both European intra-regional gas imports (Norway to various countries) and Europe's imports of gas from outside Europe (Russia and Algeria) are very significant. In the other regions, pipeline imports are all intra-regional.

**Chart A5: LNG imports 2005**



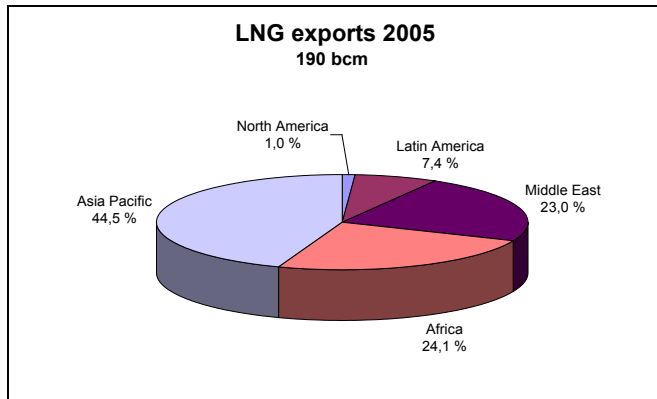
**Chart A3: Pipeline imports 2005**



With respect to gas exports via pipeline, the Former Soviet Union in 2005 accounted for some 44% of the world total. Africa, meaning in this case Algeria, is also a significant exporter to Europe, while any trade in the Asian and American regions is intra-regional.

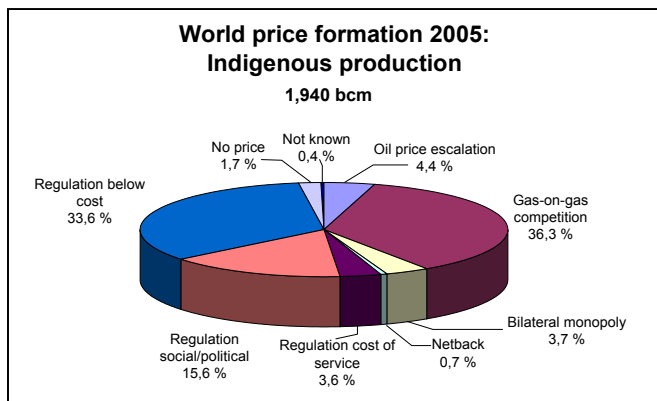
LNG imports are dominated by Asia Pacific – principally Japan, Korea, and Taiwan, with Europe being the second largest importing region. When compared with the LNG Exports chart, much of the Asia Pacific trade is intra-regional, but the region also imports significant quantities from the Middle East, while Africa and Latin America (Trinidad) are key exporters to Europe and North America.

**Chart A6: LNG exports 2005**



**Price Formation: Domestic Production**

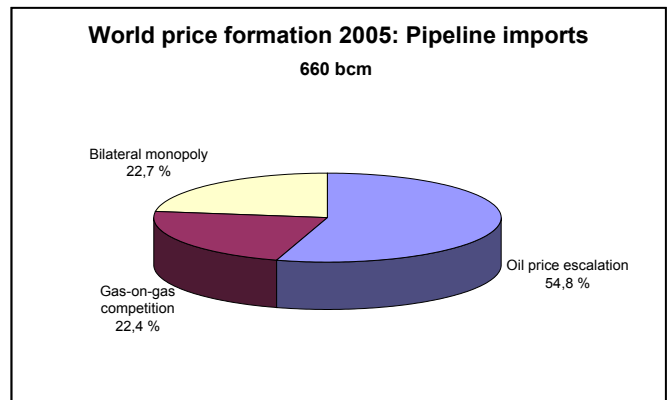
**Chart A7: World price formation 2005 – indigenous production**



Domestic production, consumed in own country, accounted for just under 2,000 bcm in 2005, around 70% of total world consumption. The two largest price formation categories were GOG – accounting for some 35% mainly in North America, UK in Europe and Australia in Asia Pacific – and RBC – accounting for 34%, largely the Former Soviet Union and Middle East with some in Africa. RSP at 16% is spread through all regions apart from North America. RCS, at 4%, is principally in Africa and Asia, while BIM, at 5%, is mainly the Former Soviet Union and Asia Pacific. There is a small amount of OPE in Europe and Asia.

**Price Formation: Pipeline Imports**

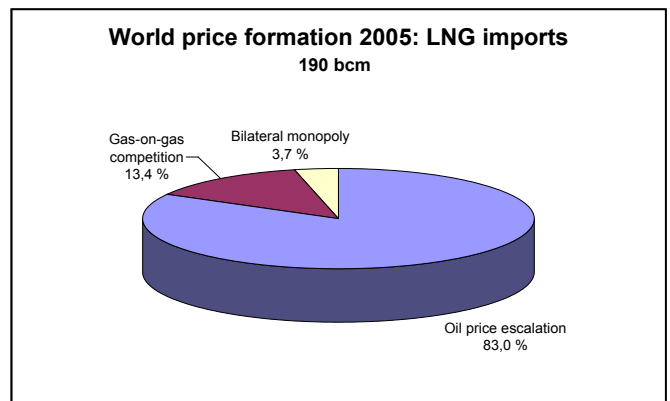
**Chart A8: World price formation 2005 – pipeline imports**



Pipeline imports at 660 bcm account for some 22% of total world consumption. Three categories account for internationally-traded pipeline gas – OPE almost all in Europe; GOG in North America with small amount in Europe into UK and BIM almost all intra-Former Soviet Union trade.

**Price Formation: LNG Imports**

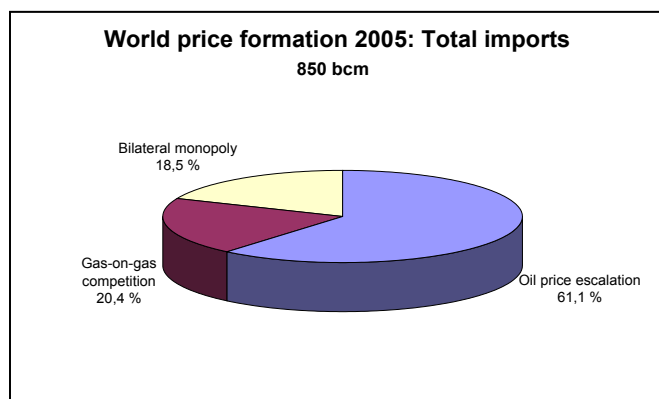
**Chart A9: World price formation 2005 – LNG imports**



LNG imports at 190 bcm account for some 6% of total world consumption. Internationally-traded LNG is largely dominated by OPE into Europe and Asia Pacific. GOG is mainly North America with some spot LNG cargoes into Asia Pacific, while BIM is in Asia reflecting the LNG cargoes to India.

## Price Formation: Total Imports

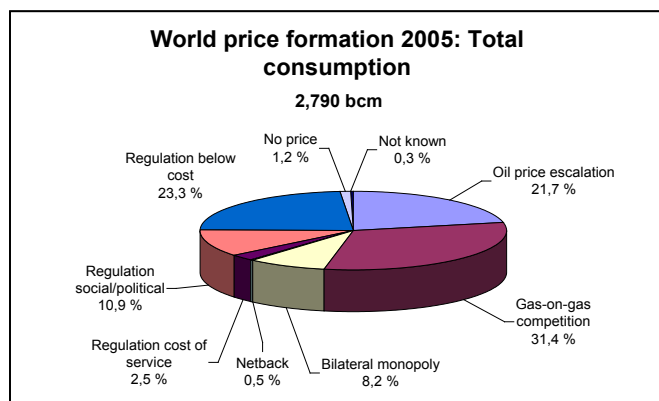
Chart A10: World price formation 2005 – total imports



Total imports at 850 bcm account for some 30% of total world consumption. 60% is OPE with Europe (pipeline mainly) and Asia Pacific (LNG) dominating. GOG is both pipeline and LNG imports, with BIM largely intra-Former Soviet Union pipeline trade.

## Price Formation: Total Consumption

Chart A11: World price formation 2005 – total consumption



The respective shares of total world consumption for each price formation mechanism reflect largely the dominance of domestic production consumed in own country. OPE becomes more important because of its dominance in gas traded across borders.

Just over 50% of total consumption is either OPE or GOG, while over 1/3rd is subject to some form of regulatory control including RBC, where it could be said gas is effectively subsidised. Regulation of wholesale prices occurs in all regions apart from North America.

The small amount of NET pricing is in Latin America (Trinidad to methanol plants) while NP (gas effectively given away) is principally in the Former Soviet Union (Turkmenistan) and North America (in Mexico, where Pemex refineries and petrochemical plants use gas as a “free” feedstock).

## Regional Results

In presenting the World results all 5 identified categories – Domestic Production, Pipeline Imports, LNG Imports, Total Imports and Total Consumption – were reviewed and analysed. At the regional level not all the categories will be relevant, for example, there may be little or no LNG imports into a region. The data and charts presented for each region, therefore, will differ depending on the relevance of each consumption category.

### North America

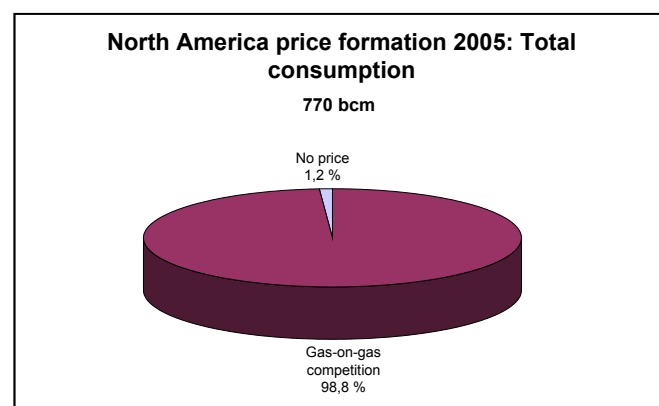
In terms of an IGU region, North America consists of only 3 countries – Canada, USA and Mexico – but it is the largest consuming region.

Table A1: North America consumption and production 2005 (BCM)

Country	Consumption	Production	Imports		Exports	
			Pipeline	LNG	Pipeline	LNG
USA	629.8	511.8	104.2	17.9	20.3	1.8
Canada	91.4	185.9	10.1	10.1	104.2	0.0
Mexico	47.6	39.2	10.1	0.0	0.0	0.0
<b>Total North America</b>	<b>768.8</b>	<b>736.9</b>	<b>124.5</b>	<b>17.9</b>	<b>124.5</b>	<b>1.8</b>

Consumption is dominated by the USA, which is also by far the region’s largest producer. All pipeline trade is intra-regional with the USA importing from Canada, but also exports to both Canada and Mexico. USA LNG exports are from Alaska to Japan, while LNG imports are principally from Trinidad but also small amounts from the Middle East and Africa.

Chart A12: North America price formation 2005 – total consumption



The gas market in the USA is completely deregulated and all prices are effectively set by gas-on-gas competition. Imports, whether by pipeline or LNG are effectively price-takers. The market in Canada is linked to the USA markets and the price formation mechanism is the same. Mexico imports gas from the US at US prices. For domestically produced gas, a reference price is set, which is based on the US price at the US-Mexico border, plus the cost of transportation to the Los Ramones “hub”. From the Los Ramones “hub” further south the reference price gets reduced based on transportation costs. However, some 10 bcm of gas is estimated to be used by Pemex for its own internal

consumption, related to feedstock for petrochemical plants, fuel for equipment in refineries and plants and for secondary oil recovery. This gas is not priced and has been allocated to the No Price category.

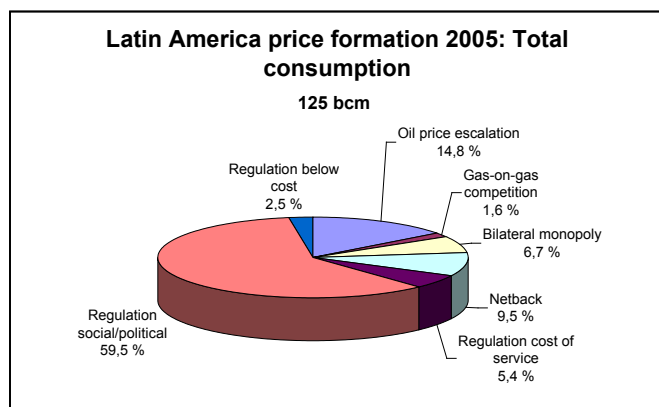
### Latin America

**Table A2: Latin America consumption and production 2005 (BCM)**

Country	Consumption	Production	Imports		Exports	
			Pipeline	LNG	Pipeline	LNG
Argentina	40.4	45.6	1.7		6.8	
Bolivia	2.1	12.4			10.4	
Brazil	19.9	11.4	8.8			
Chile	8.5	2.0	6.5			
Colombia	6.8	6.8				
Dominican Republic	0.3			0.3		
Ecuador	0.3	0.3				
Peru	1.5	1.6				
Puerto Rico	0.7			0.7		
Trinidad	16.3	30.3				14.0
Uruguay	0.1		0.1			
Venezuela	28.9	28.9				
<b>Total Latin America</b>	<b>125.7</b>	<b>139.2</b>	<b>17.2</b>	<b>0.9</b>	<b>17.2</b>	<b>14.0</b>

Latin American gas is largely produced and consumed within each individual country with Venezuela, Colombia and Peru being completely domestic markets. All pipeline trade is intra-regional with Argentina importing from Bolivia but also exporting to Chile. Bolivia also exports gas to Brazil. Even then almost all of Argentina's consumption is domestically produced and over half of Brazil's.

**Chart A13: Latin America price formation 2005 – total consumption**



Latin America consumption at 125 bcm accounts for less than 5% of total world consumption. The traded pipeline gas to Brazil and Chile mainly account for most of the OPE. Wholesale prices in the 2 largest consuming countries, Argentina and Venezuela, are largely determined by regulatory and/or government control (RSP). Some large customers in Argentina are free to negotiate directly with suppliers (BIM), as are power generators in Trinidad. NET is in Trinidad where gas is provided to Methanol plants. There is a small amount of GOG in Chile.

### Europe

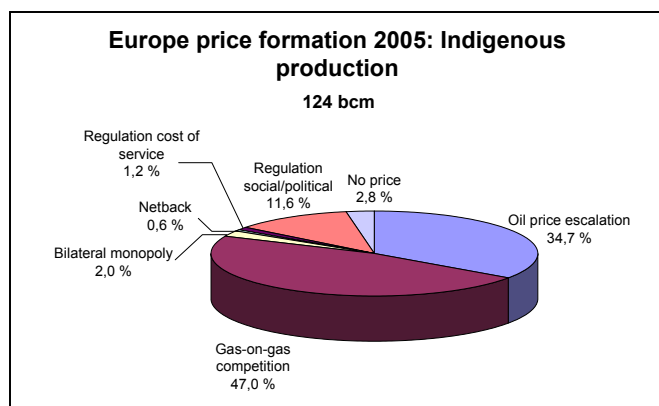
**Table A3: Europe consumption and production 2005 (BCM)**

Country	Consumption	Production	Imports		Exports	
			Pipeline	LNG	Pipeline	LNG
Austria	10.0	1.6		8.7		
Belgium & Luxembourg	16.6			18.0	3.0	4.4
Bosnia-Herzegovina	0.4			0.4		
Bulgaria	3.0			2.9		
Croatia	2.7	1.5		1.2		
Czech Republic	8.5	0.2		9.5		
Denmark	5.0	10.4				5.3
Estonia	1.5			0.7		
Finland	4.0			4.2		
France	45.8	1.2		36.2	12.8	
Germany	86.2	15.8		90.7		9.8
Greece	2.8			2.3	0.5	
Hungary	13.2	3.0		10.8		
Ireland	3.9	0.6		3.1		
Italy	78.7	12.1		71.0	2.5	
Latvia	1.8			1.2		
Lithuania	3.3			2.9		
Netherlands	39.5	62.9		23.0		46.8
Norway	4.5	85.0				79.5
Poland	13.6	4.3		10.2		
Portugal	4.2			2.6	1.6	
Romania	17.3	12.1		6.3		
Serbia & Montenegro	2.2	0.3		1.9		
Slovakia	6.6	0.2		6.4		
Slovenia	1.1			1.1		
Spain	32.4	0.2		11.6	21.9	
Sweden	0.8			1.0		
Switzerland	3.1			2.8		
Turkey	26.9	0.9		22.2	4.9	
United Kingdom	95.1	87.5		14.7	0.5	9.7
<b>Total Europe</b>	<b>534.6</b>	<b>299.7</b>	<b>367.4</b>	<b>47.6</b>	<b>155.4</b>	<b>0.0</b>

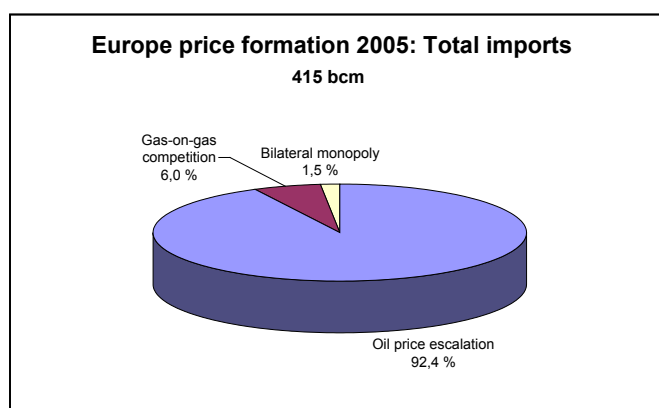
Europe is highly dependent on imported gas both by pipeline and LNG. Of the largest consumers, only the UK produced almost all of its gas requirements, and this situation is rapidly changing. Norway and the Netherlands provided a significant proportion of the rest of Europe's pipeline supplies, but Europe remained heavily dependent on Russian and Algerian pipeline supplies. The major importers of LNG were Spain and France with Algeria being the principal supplier, but significant quantities of LNG were also sourced from West Africa and the Middle East.

Out of the total European consumption in 2005 of 535 bcm, only 124 bcm (23%) was produced and consumed within the country and 2/3rds of this was in the UK market. The chart below shows the price formation mechanisms for this domestic production with GOG at 46% and OPE at 36% dominating. This was largely the UK, where some of the older contracts still retain key elements of competing fuel indexation, but also domestic production in the Netherlands and Italy is largely on an OPE basis. Wholesale prices for domestic production remained regulated on a RSP basis in Poland and Romania. There were small elements of NET in Norway and BIM in Denmark.

**Chart A14: Europe price formation 2005 – indigenous production**

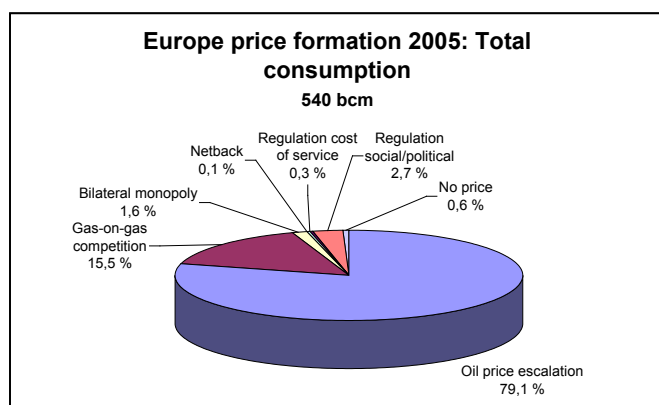


**Chart A15: Europe price formation 2005 – total imports**



The situation for total imports (both pipeline and LNG, comprising 415 bcm or 78% of total consumption) is markedly different, with OPE dominating at 92%. The small amount of GOG (6%) is predominantly the UK, plus Ireland and a small amount in the Netherlands. The BIM category (2%) is accounted for by imports into the Baltic States (Estonia, Latvia and Lithuania) from Russia.

**Chart A16: Europe price formation 2005 – total consumption**



In total, at 540 bcm, Europe accounts for around 20% of world consumption. The dependence in imports, most of which are priced on an OPE basis, is illustrated in the chart above, with OPE at 79%. GOG is largely the UK market.

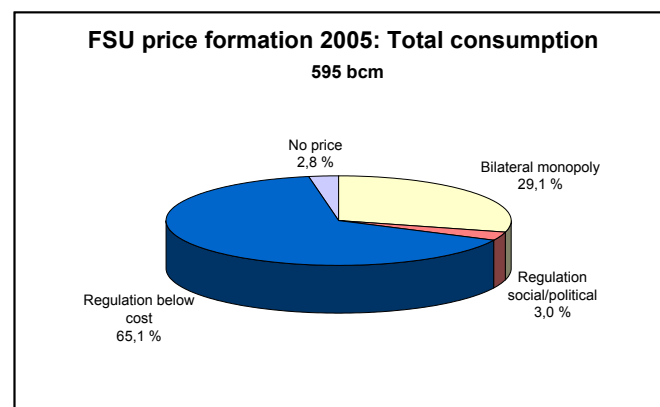
### Former Soviet Union

**Table A4: FSU consumption and production 2005 (BCM)**

Country	Consumption	Production	Imports		Exports	
			Pipeline	LNG	Pipeline	LNG
Armenia	1.7		1.7			
Azerbaijan	8.9	5.3	4.5			
Belarus	18.9	0.3	20.1			
Georgia	1.5	0.2	1.5			
Kazakhstan	19.6	23.3	11.6			7.6
Kyrgyzstan	0.7	0.0	0.7			
Moldova	2.5	0.1	2.5			
Russian Federation	405.1	598.0	25.6			229.0
Tajikistan	1.4	0.0	1.4			
Turkmenistan	16.6	58.8	0.0			45.2
Ukraine	72.9	19.4	55.3			2.5
Uzbekistan	44.0	55.0	0.0			12.4
<b>Total FSU</b>	<b>593.8</b>	<b>760.5</b>	<b>124.8</b>	<b>0.0</b>	<b>296.7</b>	<b>0.0</b>

The Former Soviet Union region is dominated by Russia, both as the largest consumer and producer of gas. All the imported gas within the region is intra-FSU trade i.e. no imports come from outside the region. Russia exports gas to almost all its neighbouring countries but Kazakhstan, Turkmenistan and Uzbekistan are also exporters, including to Russia. Ukraine is the major importer of gas.

**Chart A17: FSU price formation 2005 – total consumption**



At 595 bcm the Former Soviet Union accounts for just over 20% of world consumption. All imported gas is priced on a BIM basis, together with some Russia domestic production sold to large users. The dominant price formation mechanism, however, is RBC in Russia, Uzbekistan and Kazakhstan. Since 2005, however, this situation in Russia, at least, is likely to have changed with increased prices to domestic consumers raising levels above the average cost of production and transportation. Domestic production in Ukraine is the RSP category and NP in Turkmenistan.

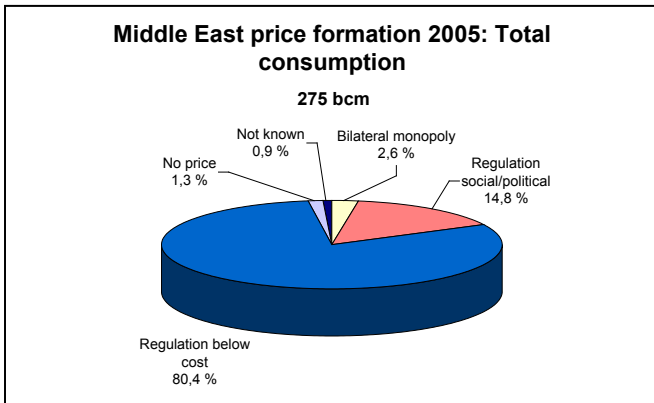
**Middle East**

**Table A5: Middle East consumption and production 2005 (BCM)**

Country	Consumption	Production	Imports		Exports	
			Pipeline	LNG	Pipeline	LNG
Bahrain	10.7	10.7				
Iran	102.4	100.9	5.8		4.3	
Iraq	2.5	2.5				
Israel	0.7	0.7				
Jordan	1.6	0.3	1.3			
Kuwait	12.3	12.3				
Oman	9.2	19.8			1.4	9.2
Qatar	18.7	45.8				27.1
Saudi Arabia	71.2	71.2				
Syria	6.1	5.4				
United Arab Emirates	41.3	47.0	1.4			7.1
<b>Total Middle East</b>	<b>276.6</b>	<b>316.6</b>	<b>8.5</b>	<b>0.0</b>	<b>5.7</b>	<b>43.5</b>

The Middle East region is largely an insulated market in terms of gas consumption with very little gas being traded (excluding exports) across borders. Small quantities of gas are imported by Iran from Turkmenistan and Jordan from Egypt.

**Chart A18: Middle East price formation 2005 – total consumption**



Middle East consumption at 275 bcm accounts for almost 10% of total world consumption. The dominant price formation mechanism in the region is RBC in largely Iran, Saudi Arabia, Kuwait and Qatar. The RSP category is accounted for by the UAE, where price is regulated by each emirate. The BIM category relates to Iranian imports from Turkmenistan and the trade from Oman to the UAE.

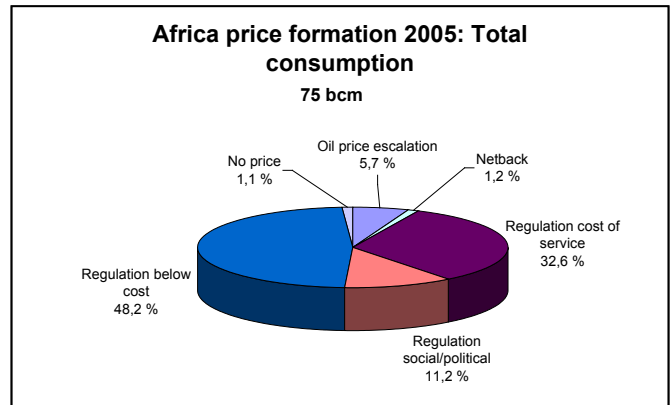
**Africa**

**Table A6: Africa consumption and production 2005 (BCM)**

Country	Consumption	Production	Imports		Exports	
			Pipeline	LNG	Pipeline	LNG
Algeria	23.2	88.2			39.1	25.7
Angola	0.8	0.8				
Egypt	25.8	34.6			1.1	6.9
Equatorial Guinea	1.3	1.3				
Ivory Coast	1.3	1.3				
Libya	5.8	11.3			4.5	0.9
Nigeria	10.4	22.4				12.0
South Africa	2.2	2.2				
Tunisia	4.3	2.5	1.8			
<b>Total Africa</b>	<b>75.1</b>	<b>164.6</b>	<b>1.8</b>	<b>0.0</b>	<b>44.7</b>	<b>45.5</b>

Excluding its export trade, Africa has virtually not traded gas, with only Tunisia importing some gas from Algeria via the pipeline to Italy.

**Chart A19: Africa price formation 2005 – total consumption**



In terms of consumption, Africa is the smallest region at 75 bcm, or 2.5% of total world consumption. Wholesale prices are highly regulated, with RBC accounting for just under half, in Egypt and Nigeria. RCS is predominantly Algeria and RSP in Libya and South Africa. The OPE category reflects the only traded gas with Tunisia importing from Algeria.

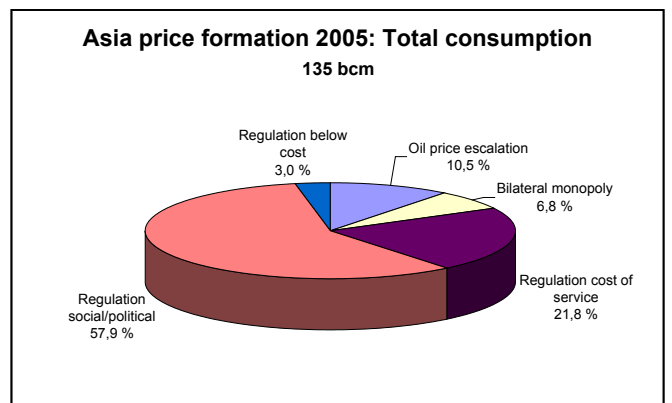
**Asia**

**Table A7: Asia consumption and production 2005 (BCM)**

Country	Consumption	Production	Imports		Exports	
			Pipeline	LNG	Pipeline	LNG
Afghanistan	0.2	0.2				
Bangladesh	14.2	14.2				
China	45.7	50.0				3.1
China Hong Kong	3.1		3.1			
India	38.1	32.1		6.0		
Myanmar	4.1	13.0				8.9
Pakistan	29.3	29.3				
<b>Total Asia</b>	<b>134.7</b>	<b>138.8</b>	<b>3.1</b>	<b>6.0</b>	<b>12.0</b>	<b>0.0</b>

Again there is not a large amount of traded gas within this region – China Hong Kong imports from China, while India imports LNG, principally from Qatar. China, India and Pakistan are the largest consumers. China and India are expected to increase gas consumption significantly from both indigenous resources and imports.

**Chart A20: Asia price formation 2005 – total consumption**





Asia accounts for less than 5% of world consumption at 135 bcm. Regulation of wholesale prices is widespread. RSP at 57% is predominantly China and India, RCS in Pakistan and RBC in Myanmar. OPE at 11% is all in Bangladesh. The BIM category is Indian LNG imports and Hong Kong imports from China.

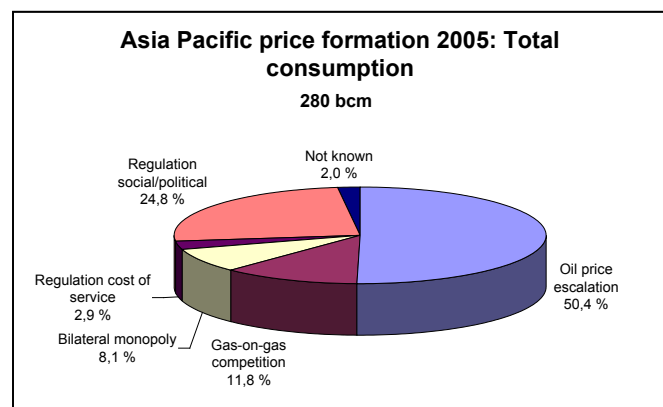
### Asia Pacific

**Table A8: Asia Pacific consumption and production 2005 (BCM)**

Country	Consumption	Production	Imports		Exports	
			Pipeline	LNG	Pipeline	LNG
Australia	26.8	40.3				14.9
Brunei	2.4	11.5				9.2
Indonesia	37.5	73.8			4.8	31.5
Japan	79.0	5.1		76.3		
Malaysia	39.3	59.9			1.8	28.5
New Zealand	3.5	3.8				
Philippines	3.0	2.9				
Singapore	6.6		6.6			
South Korea	33.7	0.5		30.5		
Taiwan	10.7	0.8		9.6		
Thailand	29.9	23.7	8.9			
Vietnam	6.9	6.9				
<b>Total Asia Pacific</b>	<b>279.3</b>	<b>229.2</b>	<b>15.5</b>	<b>116.4</b>	<b>6.6</b>	<b>84.0</b>

After Europe, Asia Pacific is the region most heavily dependent on internationally traded gas, principally LNG into Japan, Korea and Taiwan, although much of the LNG comes from within the region together with imports from the Middle East. A distinguishing feature of Japan, Korea and Taiwan is that they are virtually totally dependent on LNG imports for all their gas consumption, leading to what some might argue are the premium prices paid for the gas. The pipeline imports are into Singapore from Indonesia and Malaysia and Thailand from Myanmar.

**Chart A21: Asia Pacific price formation 2005 – total consumption**

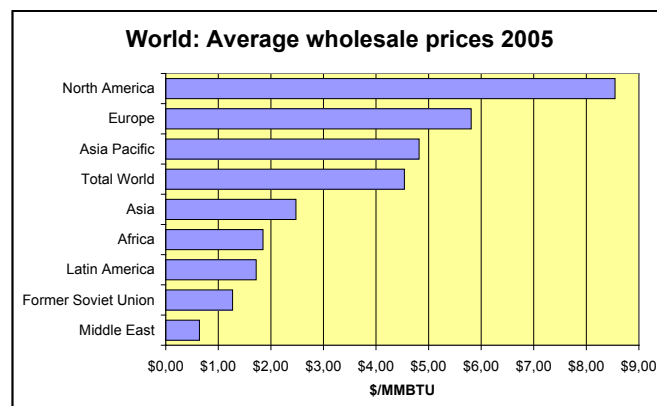


At 280 bcm, Asia Pacific accounts for 10% of total world consumption. Some 50% of gas is imported by countries. OPE at 50% is the largest category and comprises LNG imports into Japan, Korea and Taiwan, pipeline into Singapore and domestically produced gas in Thailand. GOG is Australia and spot LNG trade. BIM is mainly imports into Thailand and some domestic production in Indonesia and New Zealand. RSP is the majority of wholesale gas in Indonesia and Malaysia. RCS is Vietnam.

### Wholesale Prices

As well as collecting data on price formation mechanisms the IGU study also collected information on wholesale price levels in 2005. As noted elsewhere, the results here should be treated as broad orders of magnitude, since the definition of wholesale prices is quite wide. It is typically a hub price or a border price in the case of internationally traded gas, but could also easily be a wellhead or city-gate price.

**Chart A22: Wholesale prices by region 2005**



The chart above shows a snapshot of price levels for 2005. Wholesale prices have changed since 2005, as discussed elsewhere. Generally the highest wholesale prices are in regions where, it could be said that, there is more “economic” pricing – GOG and OPE – in North America, Europe and Asia Pacific. The lowest wholesale prices are generally where regulation dominates in the Middle East and Former Soviet Union, particularly RBC.

These conclusions are illustrated more clearly in the chart below which considers wholesale prices at the individual country level, at least for those countries with more than 10 bcm annual consumption. Only Bahrain, UAE and Turkmenistan are missing with over 10 bcm consumption. The highest wholesale prices in 2005 were found in North America (USA, Canada and Mexico). The LNG dependent countries of Japan, Korea and Taiwan also had relatively high wholesale prices. These were followed by a whole host of European countries headed by UK and France. At the bottom of the chart were generally countries where wholesale prices were subject to some form of regulation, typically RBC – Iran, Nigeria, Saudi Arabia, Russia and Egypt.

Chart A23: Wholesale prices by country 2005

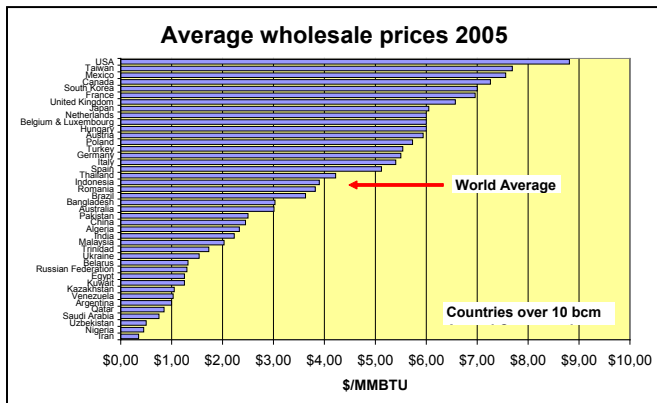


Chart A25: World price formation 2005 – total consumption

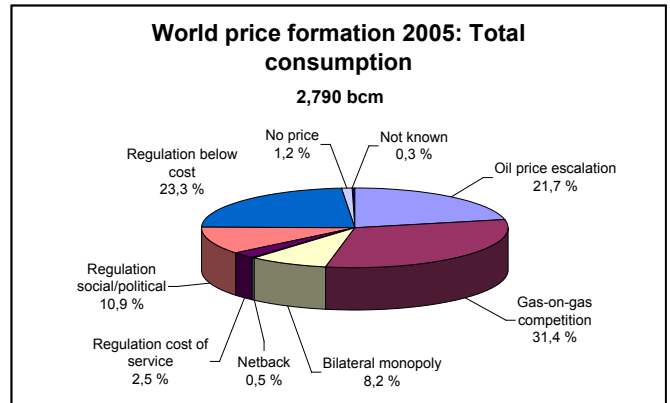


Chart A24: Wholesale prices by price formation mechanism 2005

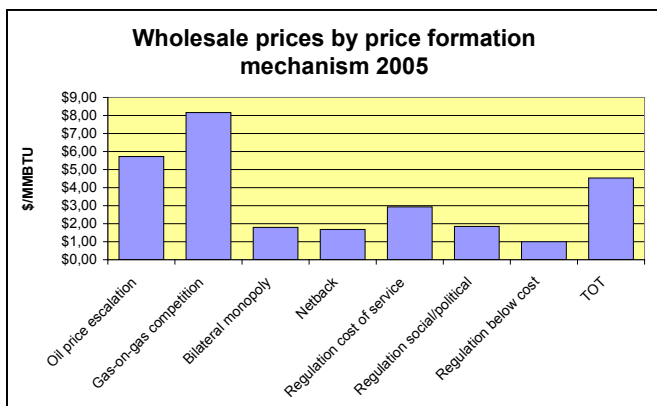


Table A9: World price formation 2005 – total consumption (BCM)

Region	Total Consumption									
	OPE	GOG	BIM	NET	RCS	RSP	RBC	NP	NK	TOT
North America	0.0	759.4	0.0	0.0	0.0	0.0	9.4	0.0	0.0	768.8
Latin America	18.7	2.0	8.4	11.9	6.8	74.8	3.1	0.0	0.0	125.7
Europe	426.6	83.4	8.7	0.7	1.7	14.4	0.0	3.5	0.0	539.1
Former Soviet Union	0.0	0.0	172.9	0.0	0.0	17.6	386.6	16.6	0.0	593.7
Middle East	0.0	0.0	7.2	0.0	0.0	40.6	221.5	3.6	2.5	275.3
Africa	4.3	0.0	0.0	0.9	24.5	8.4	36.2	0.8	0.0	75.1
Asia	14.2	0.0	9.1	0.0	29.3	78.0	4.1	0.0	0.0	134.7
Asia Pacific	140.8	33.0	22.6	0.0	8.0	69.3	0.0	0.0	5.6	279.3
<b>Total World</b>	<b>604.6</b>	<b>877.9</b>	<b>228.9</b>	<b>13.5</b>	<b>70.3</b>	<b>303.2</b>	<b>651.4</b>	<b>33.8</b>	<b>8.1</b>	<b>2,791.7</b>
	<b>22%</b>	<b>31%</b>	<b>8%</b>	<b>0%</b>	<b>3%</b>	<b>11%</b>	<b>23%</b>	<b>1%</b>	<b>0%</b>	<b>100%</b>

An alternative way of analysing the data is to categorise by price formation mechanism. The highest wholesale prices are GOG followed by OPE. At the bottom end, as might be expected, wholesale prices determined by RBC are less than RSP which, in turn, are less than RCS. The low level of wholesale prices for NET are presumably affected by low commodity prices for the final products – almost all Trinidad and some in Norway. The result for BIM is largely impacted by the low levels of wholesale prices in intra-Former Soviet Union trade.

**Conclusions**

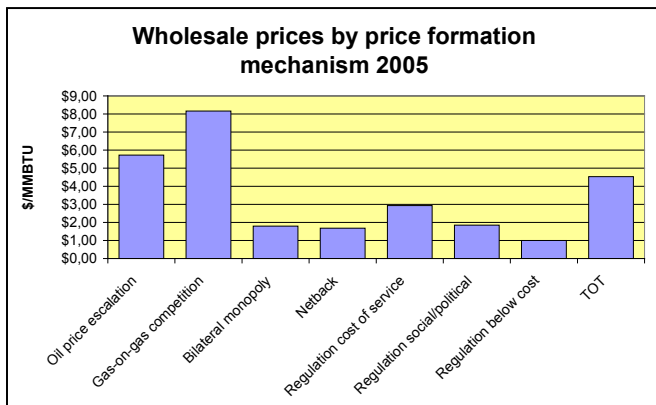
In 2005 just over 70% of the world’s consumption of gas comprised of domestic production consumed within that country, with no trade across international borders. Some 22% was traded through pipelines and some 6% LNG. The wholesale price formation mechanisms are largely very different for internationally traded gas compared to gas which is produced purely for domestic consumption.

The chart above illustrates the overall results at the world level, while the table looks at the breakdown by region.

- The largest price formation category is GOG at 31%, but this is due to the impact of the North American market, which is predominantly domestic gas production, plus smaller quantities in the UK and, in Asia Pacific, Australia and spot LNG cargoes;
- The OPE category at 22%, is generally only found in internationally traded gas, which is mainly pipeline and LNG in Europe and LNG in Asia Pacific;
- Together the GOG and OPE categories, which could be said to reflect an “economic” or “market” value of gas, account for just over 50% of total world consumption;
- Wholesale price “regulation”, which covers 3 categories – RCS, RSP and RBC, accounts for 37% of total world consumption, but is only found in domestic gas production and not internationally traded gas. The RBC category in 2005 was the largest, as a consequence of the low levels of prices in the Former Soviet Union, mainly Russia, and the Middle East. While wholesale prices in Russia have remained regulated there have been price increases, which would mean that, by 2007, most of the market would not be in the RBC category, probably moving to the RSP category;
- The RSP category, at 11%, is found across all regions, apart from North America;
- The BIM category, at 8%, is mainly traded gas between the Former Soviet Union countries, principally Russian exports, plus, in Asia Pacific, imported gas in India and Thailand and partly domestically produced gas in Indonesia.

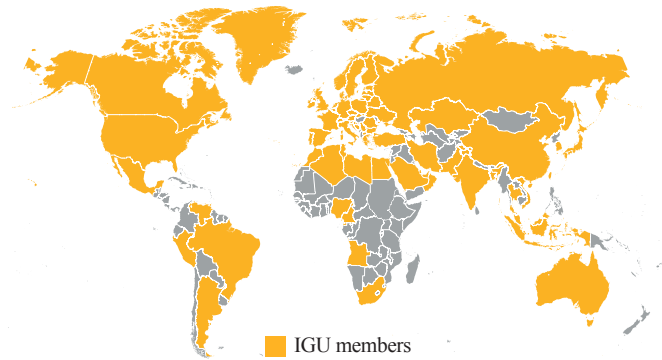
In respect of wholesale price levels in 2005, the chart below shows that price levels were generally higher in the GOG markets of the US and the UK, as prices peaked at high levels during the year, followed by OPE. At the bottom end, as might be expected, wholesale prices determined by RBC are less than RSP which, in turn, are less than RCS. The result for BIM is largely impacted by the low levels of wholesale prices in intra-Former Soviet Union trade. In 2006/7, however, GOG prices have declined to below comparable OPE prices.

Chart A26: Wholesale prices by price formation 2005



## IGU

The International Gas Union is a worldwide non-profit organisation aimed at promoting the technical and economic progress of the gas industry. The Union has more than 100 members worldwide on all continents. The members of IGU are national associations and corporations of the gas industry. IGU's working organisation covers all aspects of the gas industry, including exploration and production, storage, LNG, distribution and natural gas utilisation in all market segments. IGU promotes technical and economic progress of the gas industry emphasising environmental performance worldwide. For more information, please visit [www.igu.org](http://www.igu.org)



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