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There are a number of fundamental issues that characterise the international petroleum industry. Their relative importance varies according to the interests of the different parties that constitute the industry. A private oil company will hold different views than a national oil corporation on what really matters; producers and consumers, or exporters and importers stand in different places on issues of interest. In this *Forum* a number of international authorities address some of these topics, sometimes shedding light on an obscure aspect but always assessing their import.

Two important oil problems – (a) the relationship between host countries and the foreign oil companies seeking investment access to upstream oil (or gas) reserves in their territories *and* (b) the peculiarities of the international oil price regime – have retained our attention.

The relationship between host and foreign oil (gas) investor is governed by contracts sometimes drafted within the framework of a petroleum law. There are instances when these agreements were entered upon at a time when the host country was politically or economically weak, or was badly advised, the consequence being a contract that put the host country at a clear disadvantage. Later the country, usually under a new political regime, realises the problem and seeks renegotiations. But some companies (if not all) reject the idea of renegotiation, or complain loudly about its unfairness. They refer to the principle of *pacta sunt servanda.*

George Kahale, an eminent American lawyer, argues in this *Forum* that reference to the *pacta* principle does not provide complete justification for rejecting renegotiations. There are features of the oil industry that make contract renegotiations either inevitable or desirable. In brief, these are the long-term nature of oil upstream licences or agreements, the sharp volatility of oil prices, and the vital importance of oil revenues for the exporting countries. And circumstances can change radically at least once if not several times over contractual periods that usually extend over 20 or 25 years, if not longer. The sharp volatility of prices is an important change of *economic* circumstances for the simple reason that conditions agreed upon when oil prices were at a certain level become

CONTENTS

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unacceptable when prices move to a significantly different level.

Interestingly, the attitudes of many oil countries seeking an improvement in the financial terms of their contracts are reflected in a statement of Mr Salazar, the US Secretary of the Interior, addressing an oil industry corporate audience: 'Just as your shareholders expect you to get a fair return on your investments…the American people are asking the same of us as we manage their resources.' What is good for the USA must also be good for other countries, a point concealed by the preferential treatment given to the superpower in many discourses.

The Kahale article, importantly, includes three case studies.

The oil price topic is treated in an article by Bassam Fattouh. He indicates that the recent price swings and high volatility have raised the question of a possible 'financialisation' of the oil price regime. The discussions of this topic 'have partly been subsumed within analyses of the relation between finance and commodity markets indexes which include crude oil.' One important aspect is the increasing role that expectations play in the pricing of financial instruments and therefore crude oil.

This analysis is worth reading carefully, for it leads to the conclusion that despite misgivings about the merits of the current international price regime none of the major players has an interest in changing the status quo. Rather ironically, Fattouh notes that 'market participants are interested in what happens to prices rather than in the system that generates these prices in the first place.' But how can one dissociate an outcome from the forces and the system that bring it about?

This issue also includes two contributions on natural gas. Gas production and consumption have significantly increased over the years. Technological advances have allowed LNG to develop and gain an increasing share in gas international trade.

The article by Axel Wietfield is about LNG supplies in Europe. The picture has changed radically over the past two or three years. Until mid-2008, the picture was euphoric: energy prices were rising and the globalisation of gas markets was perceived as being within reach. The structure of gas international trade was expected to involve a shift of Middle East LNG from the Pacific to the Atlantic basin.

This did not happen partly because of a recession-induced decrease in gas demand and partly because of the emergence of sources of 'unconventional' gas in the USA. There are challenges for the European gas industry. Wietfield argues that the industry is well prepared to weather them: Europe has sufficient long-term gas supplies until 2015 but will increasingly depend on LNG imports.

Wietfield believes that spot prices and long-term contract gas prices will 're-couple' in the future with long-term contract prices remaining the backbone of gas sourcing for most European importers.

Hakim Darbouche looks at the implications of the expanded use of gas in power generation for gas exports from North Africa. As in many other countries there is a soaring domestic demand for gas stimulated by price subsidies. In Egypt the fiscal burden caused by subsidies is crushing but their removal risks the emergence of social unrest, which governments cannot afford to contemplate. Some North African countries, particularly Morocco, are planning the development of alternative sources of power to compensate for any limitation of gas supplies.

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The Uproar Surrounding Petroleum Contract Renegotiations

George Kahale, III

In recent years, complaints of unfairness on the part of host states in the renegotiation of international petroleum contracts have become commonplace at conferences and seminars in both the United States and Europe. Not so often discussed are the legal issues underlying the particular cases – simply repeating the mantra of *pacta sunt servanda* is not a discussion. Even less attention is paid to the facts, a point which is the focus of this article. Without an understanding of the facts underlying a renegotiation, one can easily jump to the wrong conclusions, and that is precisely what seems to have been happening with alarming frequency on the conference/seminar circuit, where conclusions are too often drawn from incomplete information derived from press releases or press reports.

Background

This recent period is not the first time that the petroleum industry has provided the setting for political, economic and legal struggle. The same was true in the 1970s, when the principle of Permanent Sovereignty Over Natural Resources[1] was trumpeted as loudly as *pacta sunt servanda.* A wave of nationalisations gave rise to a series of arbitral decisions that would be cited throughout the coming decades, even to this day.[2] When circumstances changed radically, the industry again became the incubator for what has been dubbed a new wave of 'resource nationalism'.

What is it about the petroleum industry that seems to always place it in the eye of the storm? Here are some contributing factors.

First, upstream licences or agreements tend to be long-term in nature. It was not uncommon for concessions granted in the 1950s to have a term of 50 years or longer.[3] Production sharing agreements, the next generation of upstream contracts that became popular in many oil-producing countries when concessions fell into disrepute, were anywhere from 25 to 40 years in length.[4] Agreements of such duration tend to undergo fundamental changes at least once in the course of their life.

Second is the volatility of the price of the resource. In the 1970s, the oil shock sparked by the Arab oil embargo was followed by another extraordinary price rise at the end of the decade. The 1980s saw the market flooded with oil as Saudi Arabia increased production and market share with netback pricing. The price of oil plummeted to less than $10 a barrel, and stayed relatively low throughout the 1990s, averaging around $18 per barrel for the entire decade. In March 1999, the cover story of *The Economist* argued that the price could hover around $5 for some time.

Starting in 2004, the price environment again changed dramatically, averaging around $40 per barrel that year. The seemingly endless upward spiral continued in the succeeding four years, with the price shooting right through the $100 per barrel barrier and reaching a peak of almost $150 per barrel in July 2008. Given this kind of structural change in the petroleum markets, it is not unusual to see adjustments in contractual terms or fiscal regimes to take account of the changed circumstances.

Third, the economic importance of the petroleum industry to host countries cannot be overstated. With the stakes that high, a mistake in petroleum policy can have devastating consequences for the host state concerned. That is why matters relating to the petroleum industry tend to be considered matters of public policy in those countries.

Fourth, the best-known renegotiations and industry restructurings of the last five years have involved upstream contracts entered into in the 1990s, when the price of oil was a fraction of what it was to become and when privatisation was in vogue. The Soviet Union had just collapsed and the prevailing attitude was that everyone would flourish from private ownership and exploitation of natural resources. In that environment, many long-term agreements that were very unfavourable from the host country's standpoint were concluded, agreements that invariably led to trouble as circumstances changed and the anticipated benefits of privatisation did not materialise.

> "In recent years, complaints of unfairness on the part of host states in the renegotiation of international petroleum contracts have become commonplace"

Finally, many of those contracts were not only economically indefensible, but they also purported to cede control over petroleum operations to private parties, often in a manner that raised serious legal issues going to the heart of the contracts. Ownership of petroleum in the subsurface typically is conferred upon the state by constitutional mandate in host countries, and in some cases the political sensitivity of control over the hydrocarbon sector is at least as important as the legal issues raised by such constitutional provisions. This explains the propensity to create new forms of contracts that pass constitutional muster and can withstand the political heat that often accompanies long-term contracts involving foreign, or any private, participation in the oil industry. The proliferation of 'service' contracts, in which the service contractor never acquires title to the oil produced, is attributable mainly to the perceived need to reconcile the desire to attract private investment with the legal and political constraints standing in the way of achieving that objective.

All this has led to contract renegotiations, and in some cases complete national industry restructurings, in the last few years. In many countries, this has involved fundamental issues of structure and governance; all cases involved adjustments in government take.

Host countries that have taken measures in this direction include Algeria, Bolivia, Canada, China, Ecuador, Kazakhstan and Venezuela, all of which imposed new taxes and royalties on production, exports or windfall profits. Bolivia and Venezuela also mandated structural changes for all contracts in their hydrocarbons industries. In Alberta, Canada, the provincial government announced a 20 percent increase in oil and gas royalties. The US Government provided Congress with a report in May 2007 on the question of increasing oil and gas royalties, including a comparison of royalty rates under fiscal regimes around the world, in response to concerns that government take was not keeping pace with record oil company profits. Oil executives were called before Congress to defend windfall profits, and Sarah Palin's Alaska collected billions in additional revenue from a new windfall profits tax. The attitude of many governments is reflected in the following statement of US Secretary of the Interior Salazar to an oil industry audience last year:

> Just as your shareholders expect you to get a fair rate of return on your investments and to be wise stewards of your balance sheets, the American people are asking the same of us as we manage their resources. . . .
>
> That means we are going to take another look at royalty rates. It means that tax breaks that are no longer needed, and which the American people can't afford, will disappear.[5]

Three Case Studies

Three of the best-known renegotiations or industry restructurings of the last few years involved the operating service agreements (*convenios operativos*) in Venezuela, the gas production contracts in Bolivia, and the renegotiation of the world's largest production sharing agreement, the one covering the Kashagan field in Kazakhstan.

In Venezuela, approximately 500,000 barrels per day were being produced under the operating service agreements, which were supposed to be pure service contracts. The 1975 Law Regulating the Industry and Trade of Hydrocarbons did not allow, except in certain cases approved by Congress, any private participation in production. Service contracts were allowed for basic services, such as drilling and seismic survey, but these were supposed to be pure service contracts, not contracts mimicking production sharing agreements that effectively granted the contractors a participation in the business.

The Venezuelan operating service agreements, although structured as service contracts, were in substance anything but pure service contracts. They ceded control over petroleum operations in huge areas for 20 years, and compensation was based on the volume and value of production. Many of the service providers were in effect senior partners in the business, on average taking more than half the value of production. In some cases, the state company actually lost money for each barrel of oil produced, after accounting for the royalty owed to the State. Making matters worse, the contractors, claiming to be only service providers, argued that they were subject to the non-oil income tax rate of 34 percent rather than the rate applicable to oil producers, 50 percent.

In April 2005, the Venezuelan Government intervened to require migration of the operating service agreements to the new structure of mixed company (*empresa mixta*) under the 2001 Organic Hydrocarbons Law, and 30 out of 32 contracts were successfully migrated over a one-year period. The other two resulted in negotiated settlements. The new mixed companies emerging from the migration of the operating service agreements are all subject to combined royalties and special advantages (*ventajas especiales*) of 33 1/3 percent, as well as the 50 percent oil income tax rate. A special assessment for extraordinary prices also applies when the price of crude oil exceeds $70 per barrel. Apart from the fiscal regime, a state company is by law the owner of at least 60 percent of the shares of each of the new mixed companies. Basic minority protections are included in the by-laws, but the legal issue of control has been resolved.

> "terms such as 'resource nationalism' are an oversimplication of what has been happening on the ground"

Turning to Bolivia, we again hear a lot of talk about resource nationalism, but little about the facts of the old agreements. Prior to 2005, contractors were taking 82 percent of production from Bolivia's giant gas fields, paying only an 18 percent royalty. This was after all investment that had long ago been recovered. The contracts had never been approved by Congress, as appeared to have been required by the Constitution.

By 2005, the situation had become untenable. A new Hydrocarbons Law was enacted in May of that year, imposing a 32 percent tax on the gross value of hydrocarbons (*Impuesto Directo a los Hidrocarburos*) in addition to the 18 percent royalty, thereby reducing the private party's share to 50 percent. The Hydrocarbons Law also provided a six-month period for migration of all existing contracts to one of the new legally-sanctioned forms of contract. That six-month period expired with no progress on the migration.

On May 1, 2006, the new administration again nationalised the industry, granting another six-month period for the conversion of the old contracts. While the new operating contracts were being negotiated, the state company was given a provisional 32 percent share, reversing the old 18/82 split to 82/18. Six months later, all of the contractors executed the operating contracts, which are structured as service contracts with the service providers receiving remuneration in cash, not oil.

The third case study is the renegotiation of the PSA covering the world's largest discovery in three decades: Kashagan in Kazakhstan. There the heart of the problem was the concept of cost recovery, under which a large percentage of production, known as 'Cost Oil,' is allocated off the top to the contractors to recover their costs. In the case of

Kashagan, that percentage was 80 percent. After allocation of that 80 percent to the contractor, the remaining production, known as 'Profit Oil,' was allocated initially 90 percent to the contractor and 10 percent to the State, a ratio that was eventually supposed to change in favour of the State based on a set of complicated triggers set forth in the agreement. Until then, the contractor would continue to receive 80 percent of the Cost Oil and 90 percent of the Profit Oil, or 98 percent of total production.

Despite what many feel is a textbook alignment of interests in a contract including such cost recovery provisions, experience shows that this structure is often a recipe for disaster, and that is exactly what happened in Kashagan. Overall costs of the project increased by more than 100 billion dollars, and production, originally scheduled to start in 2005 or 2006, now is scheduled for 2012. The net result was that in the world's largest discovery in recent times, which is expected eventually to produce 1.5 million barrels per day, the state would have received a grand total of only 2 percent of the oil produced for at least the first decade of production, not including the relatively small participation of a subsidiary of the national oil company in the contractor consortium. That was obviously an unacceptable situation, which most people with knowledge of the facts fully recognised. In the renegotiation, the national oil company's subsidiary doubled its stake in the project, a new 'priority share' was allotted to the Government off the top, and new cost and schedule control mechanisms were introduced to help guard against future cost increases and delays.

What lessons can be drawn from these experiences?

First, bad deals spell trouble. The worse the deal, or the more imbalanced the deal, the more likely it is to be renegotiated. That goes for both sides. One might say that the best form of stabilisation is an equitable deal.

Second, don't believe everything you read in the papers. Most of the renegotiations or industry transformations have ended in success, which says something about the reasonableness of the processes. The objective has not been to exclude private participation from the petroleum industry or to make it economically non-viable, but rather to put it on a sound legal and economic footing.

Third, most renegotiations take place without adversarial proceedings, another indication that reason tends to prevail on both sides. There is a school of thought that favours adversarial proceedings, mainly arbitration, as a negotiating tactic, but the wisdom of using that tactic would not appear to be borne out by experience.

Finally, terms such as 'resource nationalism' are an oversimplification of what has been happening on the ground and are no substitute for informed analysis of both the facts and the legal issues underlying the major renegotiations of the last five years.

Notes

1 *Declaration on the Establishment of a New International Economic Order*, G.A. Res. 3201(S-VI) U.N. Doc. A/RES/S-6/3201 (1974); *Charter of Economic Rights and Duties of States*, G.A. Res. 3281 (XXIX), U.N. Doc. A/RES/29/3281.

2 *Libyan American Oil Company (LIAMCO) v. The Government of the Libyan Arab Republic*, Award dated April 12, 1977, 20 International Legal Materials 1 (1981); *B.P. Exploration Company (Libya) Limited v. Government of the Libyan Arab Republic,* Award (Merits) dated August 1, 1974, 53 International Law Reports 331 (1979); *Texaco Overseas Petroleum Co. and California Asiatic Oil Co. v. Government of the Libyan Arab Republic,* Award on the Merits dated January 19, 1977, 17 International Legal Materials 1 (1978); *In the Matter of an Arbitration between the Government of the State of Kuwait and The American Independent Oil Company (Aminoil)*, Award dated March 24, 1982, 21 International Legal Materials 976 (1982).

3 *See, e.g.*, Libyan Petroleum Law of 1955, Article 9(4) ("Concessions shall be granted for the period of time requested by the applicant permitted provided that such period shall not exceed fifty (50) years. A concession may be renewed for any period such that the total of the two periods does not exceed sixty (60) years."). Thomas W. Walde, *Revision of Transnational Investment Agreements: Contractual Flexibility in Natural Resources Development*, 10 Lawyer Of The Americas 265 (1978), pp. 265, 279 ("Traditional petroleum concessions in the Middle East often had a duration of up to 99 years.").

4 Concessions fell into disfavour not merely for economic reasons, but because they appeared fundamentally inconsistent with notions of sovereignty. They granted international oil companies control over petroleum operations, title to production, and control of the marketing of crude oil. Production sharing agreements did not have the stigma associated with concessions because the national oil company was usually a party, receiving a share of production and exercising at least nominal control over operations through approval processes for work programs and budgets. The reality did not always conform to the theory, as became evident from some well-publicized cases.

5 Department of the Interior News Release, March 19, 2009, "Salazar Addresses the American Petroleum Institute's Board of Directors" (http://www.doi.gov/archive/news/09_News_Releases/031909.html).

An Anatomy of the Oil Pricing Regime

Bassam Fattouh

Introduction

The sharp swings in oil prices and the marked increase in volatility during the latest price cycle have focused attention on the possibility that crude oil has acquired the characteristics of other financial assets such as stocks or bonds. The view that the oil market has become 'financialised' and that crude oil price behaviour in recent months has mimicked the behaviour of other financial assets has gained credence among many analysts. However, the nature of such a transformation and its implications are not yet clear. Discussions of 'financialisation' of oil markets have partly been subsumed within analyses of the relation between finance and commodity markets indexes, which include crude oil. The elements that have attracted most attention have been *outcomes*: correlations between levels, returns, and volatility of commodity and financial indexes.

However, a full understanding of the degree of interaction between oil and finance requires, in addition, an analysis of *processes*: the investment and trading strategies of distinct types of financial players; the financing mechanisms and degree and forms of leverage supporting those strategies; the structure of oil derivatives markets and financial instruments; and most importantly the mechanisms that link the financial and physical layers of the oil market.

One important aspect of the 'financialisation' of crude oil often highlighted is the increasing role that expectations play in the pricing of financial instruments. For instance, in the case of equities, pricing is based on expectations of a firm's future earnings. In the oil market, expectations of future market fundamentals have increasingly been playing an important role in its pricing. If there is large uncertainty as to what the long-term oil market fundamentals are, or if perceptions of these fundamentals are highly exaggerated and inflated, then the oil price can diverge away from its true underlying fundamental value causing an oil price bubble.

"The collapse of the OPEC administered pricing system in 1986–1988 ushered a new era in oil pricing in which the power to set oil prices shifted from OPEC to the 'market'"

However, unlike a pure financial asset, the crude oil market has also a 'physical' dimension that should in principle anchor these expectations in oil market fundamentals: crude oil is consumed, stored and widely traded with millions of barrels being bought and sold every day at prices agreed by transacting parties. Thus, in principle, prices in the futures market through the process of arbitrage should eventually converge to the so-called 'spot' prices in the physical markets. These 'spot' prices form the underlying basis of physical supply agreements and should reflect existing supply–demand conditions.

In the oil market, however, the story is more complex. To begin with, the 'current' market fundamentals are never known with certainty. The flow of data about oil market fundamentals is not instantaneous and is often subject to major revisions that make the most recent available data highly unreliable. More importantly for this article, though many oil prices are observed on screens and reported in the media, it is important to understand what these different prices really mean. Thus, although the futures price often converges to a 'spot' price, it is important to understand the process of convergence and what is meant by the 'spot' price in the context of the oil market.

Unfortunately, little attention has been devoted to such issues and the processes of price discovery and price formation in oil markets remain under-researched. It is important to stress that while this topic is strongly inter-linked to the role of speculation versus fundamentals in determining oil prices, it goes beyond the existing debates, which have dominated policy agenda. It offers a fresh and a deeper perspective to the current debate by identifying the various layers relevant for the price formation process and by examining the links between the financial and physical layers in the oil market, which lie at the heart of the current international oil pricing system.

Background to the Oil Pricing System

The collapse of the OPEC administered pricing system in 1986–1988 ushered a new era in oil pricing in which the power to set oil prices shifted from OPEC to the 'market'. First adopted by the Mexican national oil company PEMEX in 1986, the market-related pricing system received wide acceptance among many oil-exporting countries and by 1988 it became and still is the main method for pricing crude oil in international trade. The oil market was ready for such a transition. The end of the concession system and the waves of nationalisations that disrupted oil supplies to multinational oil companies established the basis of arm's-length deals and exchange outside these companies. The emergence of many suppliers outside OPEC and many buyers further enhanced the importance of such arm's-length deals. This led to the development of a complex structure of interlinked oil markets which consist of spot but also physical forward, futures, options and other derivative markets referred to as paper markets. The most complex structures emerged in the North Sea around Brent and in North America around the West Texas Intermediate (WTI).

Physical delivery of crude oil is often organised through long-term contracts. These contracts are negotiated bilaterally between buyers and sellers for the delivery of a series of oil shipments. They specify among other things, the volumes of crude oil to be delivered, the delivery schedule, the actions to be taken in case of default, and above all the method that should be used in calculating the price of an oil shipment. Price agreements are usually concluded on the method of formula pricing which has become the basis of the pricing system.

Formula pricing has two main advantages. Crude oil is not a homogenous commodity. There are various types of internationally traded crude oil with different qualities and characteristics that have a bearing on refining yields. Thus, different crudes fetch different prices. Given the large variety of crude oils, the price of a particular crude oil is usually set at a discount or at a premium to a marker or reference price according to its quality and the relative demand–supply conditions. These reference prices are often referred to as benchmarks or 'open market spot prices'. The formula used in pricing oil in these contracts is straightforward. Specifically, for crude oil of variety x, the formula pricing can be written as $P_x = P_R \pm D$ where P_x is the price of crude x, P_R is the benchmark crude price and D is the value of the price differential. The differentials are adjusted periodically to reflect differences in the quality of crudes as well as the relative demands and supplies of the various types of crudes.

Another advantage of formula pricing is that the price of physical deliveries can be linked to the time of delivery. When there is a lag between the date at which a cargo is bought and the date of arrival at its destination, there is a price risk. Transacting parties usually share this risk through the pricing formula. Agreements are sometimes made for the date of pricing to occur around the delivery date. For instance, in the case of Saudi Arabia's exports to the United States, the date of pricing can vary between 40 to 50 days after the loading date. The price used is the benchmark quotes averaged over ten days around the delivery date. Since the point of sale is closer to the destination than the origin, this is closer to c.i.f. rather than f.o.b. pricing.

"One of the most interesting features of the current oil pricing system is that the least liquid markets (WTI, Brent, and Dubai) set the price for most liquid markets"

At the heart of formulae pricing is the identification of the price of key 'physical' benchmarks, such as West Texas Intermediate (WTI), Dated Brent and Dubai. These benchmark crudes are widely used in contracts and are often inaccurately referred to as 'spot' market prices. Since these constitute the basis of the large majority of physical transactions, some observers claim that derivatives instruments such as futures, forwards, options and swaps derive their value from the price of these physical benchmarks. However, as argued below, this is a gross over-simplification and does not reflect accurately the process of oil price formation in crude oil markets.

Main Features of Benchmarks

It is important to stress three features of crude oil benchmarks that are useful for our analysis later on. First, the prices of these benchmarks are not directly derived from physical markets. Instead, the prices are assessed or indentified by oil pricing reporting agencies such as Platts and Argus Media. Assessments are needed in opaque markets such as oil where transactions concluded between parties cannot be directly observed. Assessments are also needed in illiquid markets where not enough transactions occur. One of the most interesting features of the current oil pricing system is that the least liquid markets (WTI, Brent, and Dubai) set the price for most liquid markets. Oil reporting agencies assess their prices based on information about bids and offers, concluded deals, as well as other private and public information gathered by journalists. Since oil prices are 'assessed' prices and given that the type of information used in these assessments and pricing methodologies differ, these agencies do not always produce the same price for the same benchmark.

Second, the nature of these benchmarks tends to evolve over time. Although the general principle of benchmarking has remained more or less the same over the last twenty-five years, the details of these benchmarks in terms of their liquidity and the type of crudes that are included in the assessment process have changed dramatically over the years. The assessment of the traditional Brent benchmark now includes the North Sea streams Forties, Oseberg and Ekofisk (BFOE) and that of the Dubai price includes Oman and Upper Zakum. These streams are not of identical quality and often fetch different prices. Thus, the assessed price of a benchmark does not always refer to a particular 'physical' crude stream. It rather refers to a constructed 'index', which is derived on the basis of a simple mathematical formula which aggregates the assessed prices of the different crudes.

Third and most importantly, in the last two decades or so, many financial layers (paper markets) have emerged around these benchmarks. These include the forward market (in Brent), swaps, futures, and options. Some of the instruments such as futures and options are traded on regulated exchanges such as ICE and CME Group, while other instruments, such as swaps and forward contracts, are traded bilaterally over-the-counter. Nevertheless, these financial layers are highly interlinked through the process of arbitrage. Over the years, these markets have grown in terms of size, liquidity, and sophistication and have attracted a diverse set of players both physical and financial. These markets have become central for market participants wishing to hedge their risk and to bet (or speculate) on oil price movements. Equally important, these financial layers have become central to the oil price identification process.

The Links between Physical and Financial Layers

At the early stages of the current pricing system linking prices to 'physical' benchmarks in formulae pricing provided producers and consumers with a sense of comfort that the price is grounded in the physical dimension of the market. There are still big suspicions as to whether the oil price derived from paper markets such as the futures markets reflects the physical realities of the market - which, in part, explain the current reluctance of many players to adopt futures prices in the pricing formulae. In recent years, the futures markets have attracted a wide range of financial players including swap dealers, pension funds, hedge funds, index investors, technical traders, and retail investors. There are concerns that these poorly informed financial players and their trading strategies can move the oil price away from the 'true' underlying fundamentals.

However, these suspicions implicitly assume that the process of identifying the price of benchmarks can be isolated from the 'contamination' of financial layers. This is far from reality. Oil markets are highly interconnected to form a complex web of links, all of which are needed for the price discovery process. In fact, one could argue that without these financial layers it would not be possible to 'discover' or 'identify' oil prices in the current oil pricing system.

In the case of WTI, the main benchmark used to price oil shipments to the USA, the use of the futures price in the pricing formulae would make little difference. The NYMEX contract is a physical one and the price of the futures contract converges to the spot price at the expiration of the contract. Given the high liquidity and diversity of players in the futures market surrounding WTI, it remains unclear (at least to the author) why exporters who use WTI in their pricing formulae continue to rely on assessed prices.

In the case of Brent, the issue is more complex. The Brent futures contract is not a physical one and at expiration the futures price converges to the ICE Futures Brent Index. This in turn is based on the 21 day BFOE market (the informal forward Brent market). This peculiar feature of the Brent market has led to the creation of a series of market layers for the purposes of risk management such as Exchange for Physicals (EFPs) and contract for differences (CFDs). Trades in the levels of the oil price rarely take place in these layers. Instead, these markets trade price differentials that fluctuate based on hedging pressures and expectations of traders. The participants in these markets are mainly 'physical' and include refineries, producers, downstream consumers, and market makers. Financial players such as pension funds, index and retail investor have limited presence in these markets.

This feature poses a legitimate question: how can markets that trade price differentials set the price level? The answer is that the information derived from financial layers plays an important role in identifying the price of the benchmark. In the Brent market, the oil price in the forward market is sometimes priced as a differential to the price of the futures contract on ICE using the Exchange for Physicals (EFP). The price of Dated Brent or North Sea Dated (the closest one can get to the spot market in Brent and the most widely used reference price in contracts) in turn is priced as a differential to the forward market through the market of Contract for Differences (CFDs), which is a swaps market. This is also evident in other benchmarks such as Dubai. Given the limited number of physical transactions and hence the limited amount of deals that can be observed by oil reporting agencies, the price of Dubai, the main benchmark used for pricing crude oil exports to East Asia, is priced as a differential to the very liquid OTC Dubai/Brent swaps market. The OTC Dubai/Brent swap market is in turn linked to Dated Brent, which in turn is linked to the Brent futures market through CFDs and EFPs.

Thus, one could argue that the level of the oil price is set in the futures markets; the financial layers such as swaps and forwards set the price differentials. These differentials are then used by oil reporting agencies to identify the price level of a physical benchmark. If the price in the futures market becomes detached from the underlying benchmark, the differentials should in principle adjust to correct for this divergence through a web of highly interlinked and efficient markets.

The above discussion has some important implications. First, the idea that one can isolate the physical layers from the financial layers in the current oil pricing regime is a myth. The oil price is jointly or co-determined in both layers. In a way, the issue of whether the paper market drives the physical or the other way around is difficult to construct theoretically and test empirically. The identification of the oil price is like filling an excel spreadsheet; the information needed to fill the spreadsheet is obtained from the various markets.

Second, the idea that the current oil pricing system can generate a spot price that reflects the true current fundamentals of the oil market is also difficult to achieve. In reality, changes in the benchmark price reflect the hedging and speculative pressures and the arbitrage between very efficient markets. These are in turn influenced by expectations of these players, most of which are physical and how the flow of information affects their expectations. The pricing system is a reflection of how the oil market functions: if market participants attach more weight to future rather than current fundamentals, these will be reflected in the different layers and will ultimately be reflected in the assessed price.

Third, the current regulatory reforms in the USA and elsewhere aimed at derivatives instruments will affect the pricing of 'spot' crude oil by affecting the structure of different layers in the oil market and the players' incentives to hedge and speculate. However, their impact remains unclear at this stage.

Finally, the above analysis shows that the most important prices in oil markets are not levels – the most relevant for consumers, producers and their governments. Instead, the identification of price differentials in the various markets underlies the basis of the current oil pricing system. Unfortunately, this fact has received little attention and the issue of whether price differentials between different markets showed strong signs of adjustment in the 2008–2009 price cycle remains an open question and has not yet received its due attention in the empirical literature.

Conclusions

The current oil pricing system has now survived for almost a quarter of a century, longer than the OPEC administered system did. While some of the details have changed, such as Saudi Arabia's decision to replace Brent futures price with dated Brent in pricing its exports to Europe and the more recent move to replace WTI with Argus Sour Crude Index (ASCI) in pricing its exports to the USA, these changes are rather cosmetic. The fundamentals of the current regime have remained the same since the mid 1980s (i.e. the price of oil is set by the 'market' and not by an administrator). In the light of the 2008–2009 price swings, the current oil pricing system has received criticisms with some observers calling for a radical overhaul of this system such as bringing back the administered pricing system or calling for producers to assume a greater responsibility in the method of price formation by removing destination restrictions on their exports, or allowing their crudes to be auctioned. These calls have so far received limited attention. However, they are a constant reminder of the unease that some observers feel about the current system. Although alternative pricing systems can be devised (at least theoretical ones), the reality remains that none of the key players has an interest in rocking the boat. The simple fact is that market participants are interested in what happens to prices rather than in the system that generates these prices in the first place.

The Balance between Long- and Short-term LNG Supplies in the European Gas Industry

Axel M Wietfeld

The European Gas Industry in Turbulent Times

The gas industry has been on a rollercoaster ride in recent years. From 2007 until mid-2008, we saw rising energy prices and euphoric markets with a seemingly bright future. The globalisation of gas markets was within reach. The vision two years ago encompassed huge LNG demand growth in the Atlantic Basin and a shift of Middle East LNG from the Pacific to the Atlantic Basin.

However, the financial crisis and the subsequent worldwide recession have removed huge volumes of demand from the market, causing an oversupply situation that was even augmented by the US unconventionals. As a result, the global gas industry and hence the European gas industries find themselves in turbulent times which are characterised by a shift from long-term to short-term supplies.

Economic Growth and Gas Consumption

Economic growth in Europe has suffered disproportionately from the financial and economic crisis. 2009 saw the largest decline in consumption in the history of the European gas industry, with the majority of this decline occurring in the industrial and gas-to-power sectors. The expectations for 2010 and beyond are a little better. Many experts in Europe predict a stabilisation and a slow recovery over the medium term and, for the long term, a full recovery of demand.

Despite the substantial decrease in current demand, the European region will maintain its global importance (see Figure 1).

Notwithstanding the low Compound Annual Growth Rate of 0.8 percent in Europe, consumption – at 651 bcm in 2030 – will still be in a similar order of magnitude as in China, India and Other Asia combined. The main reason is that – at 25 percent – Europe's natural gas share in primary energy consumption is much higher than in Asia. China, for example, is dominated by coal. Natural gas only accounts for 3 percent of primary energy demand, and even in Japan its share is only 16 percent.

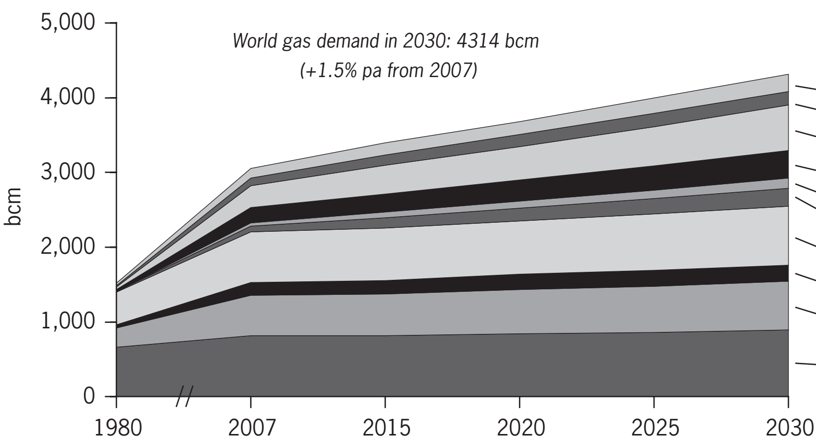
The strongest growth in gas consumption is clearly outside the OECD, particularly in India and China where consumption will quadruple from 2007 to 2030, though from a rather modest level. Both in Europe and Asia the majority of the incremental natural gas demand will come from the power sector.

Natural Gas Supplies and Europe's Main Players

Figure 2 shows contracted volumes including contract extensions with Norway, Russia and Algeria – the main gas exporters into the EU. It is a well diversified supply portfolio based on the current long-term contracts (LTCs), and there are sufficient supplies to meet demand until 2015.

Countries in the European Union only have a small domestic production and will depend on imports even more in the future. Demand growth – by nature – encompasses a certain degree of uncertainty since especially the long-term effects of the economic crisis and the gas volumes used in the power sector are difficult to predict. In any case, after 2015, a supply gap will emerge, which will have to be filled by new supply sources. While part of this gas will be pipeline supplies, the share of LNG will rise significantly in Europe

Figure 1: Natural Gas Demand by Regions

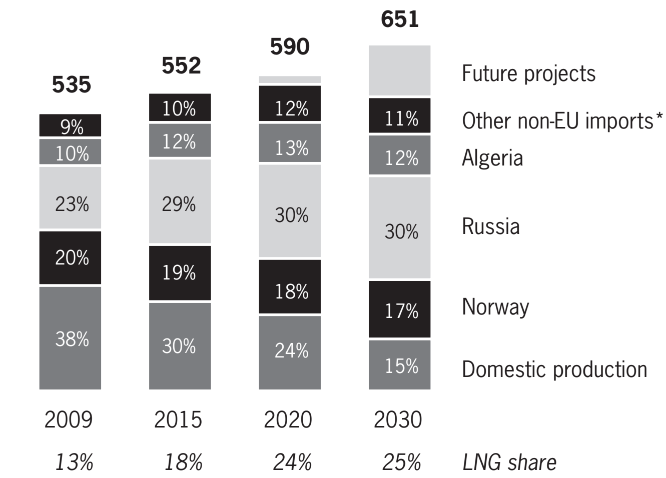


		2007	2030	Annual average % growth
Non-OECD	Latin America	127	229	2.6
	Africa	101	187	2.7
	Middle East	294	602	3.2
	Other Asia	207	374	2.6
	India	39	132	5.4
	China	73	242	5.3
	Eastern Europe/Eurasia	682	787	0.6
OECD	Pacific	170	218	1.1
	Europe	544	651	0.8
	North America	813	892	0.4

Source: IEA World Energy Outlook – Reference Scenario

Note: In this article, gas volumes are referred to in bcm/a (billion m^3 per annum) of natural gas or mtpa (million tons per annum) of liquefied natural gas. 1 mtpa corresponds to 1.3 bcm/a.

Figure 2: Natural Gas Supplies in Europe, bcm



Basis for imports: contracted volumes and prolongations
Demand forecast according to IEA World Energy Outlook 2009
* of which: Qatar 4%, Egypt 1%, Trinidad 1%, Nigeria 2% (2009)

from today's 13 percent to 24 percent in 2020.

The main importers and market leaders in Europe are German E.ON, the French-Belgian GdF Suez Group and ENI of Italy, all of which sell comparable quantities of gas, i.e. between 100 and 120 bcm/a. What is more interesting than the overall volumes is the distribution of supplies. Most European gas companies base their portfolio on various sources and on LTCs – the backbone of the European gas business. LTCs support long-term investments in the supply chain on the buyers' and the sellers' side and hence typically have a duration of between 25 and 30 years. Consequently, companies have a limited number of LTCs. E.ON, for example, Europe's largest gas supplier, sources its gas on the basis of approximately 35 LTCs which provide more than 90 percent of its gas portfolio.

There are two complementary compelling forces for European gas companies to build a material LNG business in addition to their pipeline imports:

- First, to strengthen their gas supply position. While in Northern Europe the replacement of declining indigenous production is the main issue, Southern Europe is mainly trying to limit the exposure to incumbent gas suppliers. All of the European importers are looking to use LNG as a means to actively manage their portfolios.
- Second, to enter a new growth segment with global opportunities. LNG provides more options than the rather inflexible pipeline business. Consequently, European gas companies try to leverage their traditional business by making use of the flexibility LNG offers. Furthermore, they are desperate for the opportunities a global unregulated business provides.

New Global LNG Market Environment

There are plenty of reasons why LNG challenges traditional supply patterns in North West Europe and why LNG connects global markets.

Global liquefaction capacity has increased by more than 30 percent over the last two years and a large number of additional projects are still under construction, creating an oversupply situation with favourable conditions for buyers. LNG cargoes, even if bought under LTC conditions, provide new flexibilities for the producers on the one hand and the importers on the other.

So, the question remains: 'Where will these flexible LNG volumes be heading?'

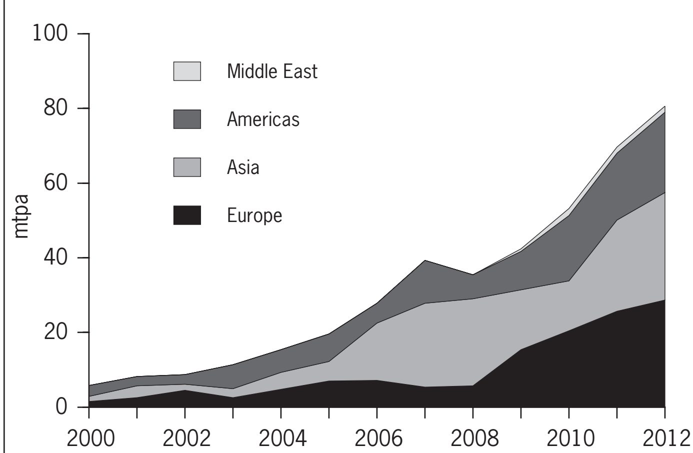
- The United States has sufficient import capacities to take large LNG quantities, but the shale gas revolution, which has resulted in high indigenous production and low import requirements in the country, has changed the parameters at least for a decade. Qatar, the world's largest LNG exporter, for instance, may end up exporting just 6 mtpa of LNG to the USA after diverting as much as 20 mtpa away from there to other countries. Consequently, regasification projects are delayed and even liquefaction projects are under consideration in North America. Those would offer attractive export opportunities and an additional outlet for US natural gas production.
- Asia and Southern Europe will slowly recover from the economic crisis.
- Northern Europe, however, could be an outlet with premium price conditions. If the current suppliers can overcome the temptation to pump too much gas into the markets, the price level will remain favourable for the producers – due to the oil linkage.

Even in an oversupply situation, LNG is able to connect spot markets around the world. More and more LNG will flow into European markets forcing Norwegian and Russian gas suppliers to compete with LNG producers.

Short-term LNG Supplies

LTCs will remain the backbone of the European gas industry, but short-term LNG supplies will steadily increase their share – in global terms and also in Europe (see Figure 3).

Figure 3: Destinations of Short-term LNG Supplies



Source: IHS, CERA

Short-term LNG volumes include three types:

- Spot LNG, which is produced outside contractual volumes and is normally offered by the supplier to the highest bidder,
- Flexible LNG, which is procured under LTCs by aggregators with the ability to deliver to various destinations, and
- Diverted LNG, which is purchased by end users who have the right to divert that cargo to alternative markets.

As destination restrictions are being relaxed, short-term volumes are going to increase significantly. Europe in particular will grow its share for several reasons:

1. Huge regasification portfolio in Europe to absorb LNG volumes
2. Increasing liquidity in European downstream markets
3. Sellers' preference for short-term deals, so as to not lock-in prices well below oil price parity, which they would currently have to do due to the oversupply situation
4. Buyers' preference for short-term deals to phase out long-term take-or-pay obligations (pipeline and LNG)

In the following, we will investigate these four reasons in detail and, by doing so will come to understand the European LNG market a lot better.

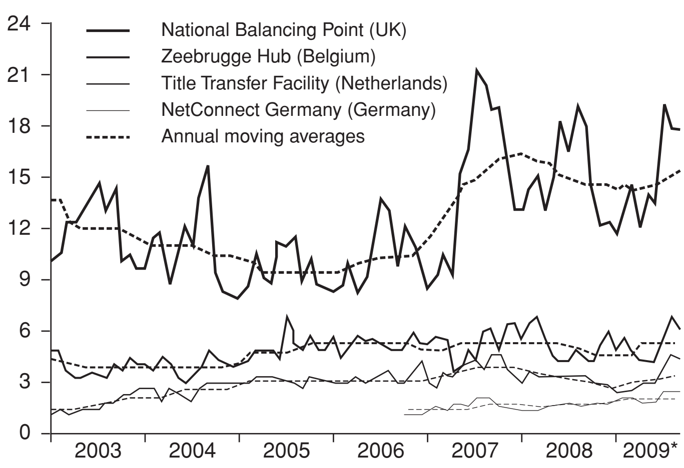
First, Europe's large regasification portfolio is able to absorb additional supplies mainly from Africa and the Middle East because it significantly increased its regasification capacity by 50 mtpa (~ 60 percent) between 2008 and 2010; another 30 mtpa of regasification capacity are currently under construction. In addition, the countries are fairly well connected via pipeline, including the UK and the Continent – hence the term 'single European gas market', in which importers can receive LNG through a UK regasification terminal and transport it via pipeline to the European continent, and vice versa. An optimal European regasification portfolio, combined with lower import requirements in the USA and larger global liquefaction capacities, results in LNG cargoes being re-routed to Europe. The largest volumes have traditionally been shipped to the Mediterranean countries, such as Spain and France, but now the UK is gradually receiving more and more LNG cargoes.

Second, growth in European downstream spot markets supports short-term deals (LNG and pipeline). Access to gas for new entrants and transparent pricing mechanisms are seen as critical elements in the development of liberalised gas markets. Consequently, many hubs, trading points and exchanges have emerged. Among these pricing points, the National Balancing Point (NBP) in the UK remains the dominant one in Europe. Over the past years there have been a number of initiatives – particularly by the European Commission and regulators – to drive liquidity in European spot gas markets. Zone mergers and simplified balancing rules have made it easier for market players to buy, sell and transport gas around the Continent. Considerable progress has also been made in reducing the number of hubs, particularly in Germany. Given the continuing increase in traded volumes and its growing market area, NCG (NetConnect Germany) may become the dominant pricing point for gas in Northwest Europe and may establish itself as a distinct European price benchmark as opposed to trading as a spread off the NBP. However, the creation of a true European benchmark will require the formation of a regional hub spanning more than one national market because simplifying the transit of gas over large regions and zone mergers should inherently support the growth of liquidity in a market by bringing together a larger number of active players.

After establishing hubs and exchanges, European markets became increasingly liquid. The development of the NBP far exceeds the pace of change at any hub in Continental Europe, so it is likely to retain its dominant position. The key measure of liquidity in a market is churn, the ratio of traded volumes to physical volumes (see Figure 4). Churn at the NBP has exceeded 5 since 1998 and currently averages 14 (in other words, each unit is traded 14 times prior to delivery) compared with 5 at Zeebrugge in Belgium, 3 at TTF (Title Transfer Facility) in the Netherlands, and 2.5 at NCG in Germany. We have seen positive developments at established hubs, such as Zeebrugge and TTF, but churn at both hubs appears to have stabilised at current levels. There has been no material growth in churn in either market since the beginning of 2005. Growth at NCG – on the contrary – is now nearing the levels of TTF activity and is expected to continue, driven by further zone mergers that increase its geographic scope and attract new players. The German cabinet approved a plan to further reduce the number of market areas from the current six to a maximum of two by 2013 in order to boost access and transparency across the country's gas market.

Third, the sellers' behaviour is changing. The price chart (Figure 5) illustrates the disruption in the gas market. The NBP and 'Henry Hub' prices represent liquid trading points and are, by nature, more volatile than oil-indexed prices such as the 'Average German Import Price' or the 'Japan Average'. The 'Average German Import Price' has traditionally been linked to oil products and hence has a high correlation with crude oil. Until the end of 2008, the correlation between prices at liquid trading points (such as NBP and Henry Hub)

Figure 4: Churn Ratio at Major European Hubs



Source: IHS, CERA

and oil-indexed contracts had always been quite high. This changed with the economic crisis, lower import requirements in the USA and more LNG liquefaction trains coming on stream. Spot and oil-indexed prices decoupled. This market disequilibrium, which usually corrects itself very quickly in most commodities such as oil, can continue for years in the LNG industry. Due to this decoupling and oversupply situation, sellers are hesitant to positively sanction new projects in times of oversupply and low prices on the downstream markets. Buyers of long-term gas supplies from producing countries such as Russia, Norway and Qatar can expect lower oil indexation levels in the next five years. Consequently, sellers are shying away from concluding LTCs now because they would have to lock in prices well below oil price parity. The main question is whether the gas-oil spread shown in the graph is sustainable. Many experts predict that spot gas and LTC prices will re-couple in the medium/long run.

“More and more LNG will flow into European markets forcing Norwegian and Russian gas suppliers to compete with LNG producers”

Fourth, the buyers have also faced challenging times with downstream prices far below their purchase prices. As already mentioned, the prevailing global gas glut has heaped pressure on oil-indexed gas contracts because the recession has significantly reduced demand, forcing buyers to sell unused long-term contracted gas supplies for roughly half the price. That has swelled European spot markets and further undercut prices. In addition, the demand dive resulted in take-or-pay problems for most of the European gas importers. The likes of E.ON, GdF Suez, ENI, Econgas and BOTAS have renegotiated their LTCs with the major exporters to Europe, e.g. Russia’s Gazprom, Norway’s Statoil and Dutch GasTerra using standard price review clauses. Consequently, some level of indexation to cheaper spot gas prices was introduced into mainly oil-indexed LTCs. Furthermore various technical adjustments were made to reduce the price level of oil-indexed gas. Importers also succeeded to increase the volume flexibility in their contracts, i.e. a reduction of take-or-pay and daily minimum levels. All in all, the LTCs demonstrate that they are a highly suitable instrument for coping with the current, in some cases very difficult, developments in the gas market. They have enough levers for adaptation to the present situation. This underscores, firstly, the flexibility of LTCs and, secondly, their contribution to reliability and security of supply. However, short-term deals and spot indexation will become more relevant in the European market. Currently, European importers prefer term and spot deals, and are hesitant to take additional volumes on board because they prefer to phase out existing take-or-pay obligations first.

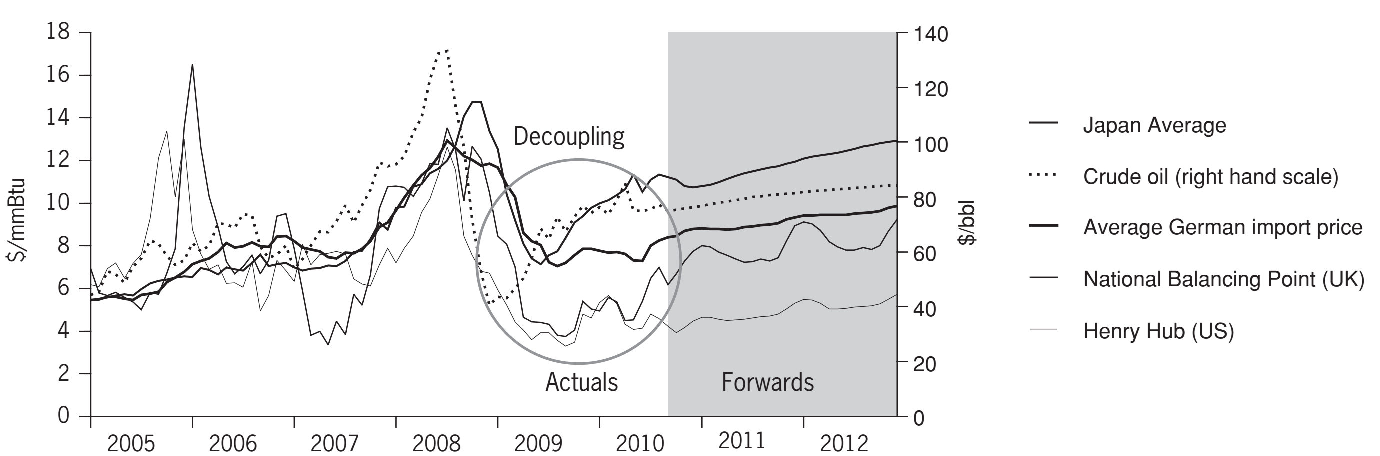
Summary and Conclusion

The European gas industry is well prepared to find its way through challenging times. European gas demand suffered from the financial and economic crisis. Europe has sufficient long-term gas supplies until 2015, but it will increasingly depend on imports (LNG).

Short-term LNG supplies will steadily increase their share with growing European influence. This trend is buoyed by the unconventionals in the USA, large regasification capacities in Europe, strong growth and liquidity in European spot markets, as well as some hesitation on the part of buyers and sellers to conclude LTCs.

European gas players have re-negotiated their pipeline LTCs to reduce their oil exposure via pricing and volume measures, but spot gas and LTC prices are still expected to re-couple. The following outlook seems reasonable: LTCs will remain the backbone of gas sourcing for most European importers, with the right mixture of various contract durations and price indexations being key. Consequently, the major players will optimise their portfolio (short/long-term) and hence mitigate future risks.

Figure 5: Spot Prices versus LTC Price Indicators



Gas-to-power in North Africa: Implications for gas exports and supply

Hakim Darbouche

The power sector in North African gas exporters Algeria, Egypt and Libya, as well as in transit countries Tunisia and Morocco, has been the main driver of growth in gas consumption since the introduction of the fuel in the respective energy balances of these countries. With demand for electricity expected to show no signs of abating in the medium term, the exporting countries are facing added pressure on their gas export expansion plans, while Morocco and to a lesser extent Tunisia are having to make tough decisions with regard to future gas supply options. Issues of artificially low domestic prices, endemic to the gas-and-power sector across the region, lie at the heart of these challenges.

Growing Importance of Gas

The use of natural gas and the extent of its penetration of North African energy markets reflect the availability of this resource in countries of the region as well as relevant government policies.

In Algeria, the region's biggest reserve-holder, gas consumption has been actively encouraged by government policy from the early 1970s, both as feedstock for a growing industrial base and the 'fuel of choice' for power generation. In the case of the latter energy-transformation industry, the aim behind this policy was to release higher value oil products for exports by using a fuel that had hitherto been flared. As a result, the power sector has become almost entirely dependent on natural gas, which represents 97 percent of its fuel input.

"Over the last decade, power demand in the region has surged at an average annual rate of 6–8 percent, with Egypt, Morocco and Algeria experiencing the highest levels of growth"

Similarly, with the expansion of Egypt's gas reserve base from the early 1990s, demand for gas was boosted by the government's policy of substituting gas for oil in the power generation sector and the consolidation of the petrochemical industry's capacity around gas-prone areas. In 2009, over 80 percent of Egypt's electricity output was generated from gas-fired power plants, compared to around 30 percent in 1989.

In Libya, gas consumption has remained flat at around 5–6 Bcm/yr over the last decade, despite the government's plan to expand the use of gas domestically, capitalising on the country's relatively large reserves and its growing output since 2005. The return of foreign investors to the country following the lifting of UN and US sanctions in 2003–4 has allowed the government to convert a reasonable number of power plants from heavy fuel to natural gas, pushing up to 45 percent the share of gas in power generation. However, a real 'dash for gas' is expected to take place in the course of this decade with the coming online of a string of new power, desalination and petrochemical projects.

Tunisia has made full use of its status as transit country for Algerian gas to Italy through the Trans-Med pipeline. It chose early on to take its transit fees in kind and to contract additional imports from Algeria to supplement its own modest production. This means that the country's power sector has benefited from the availability of relatively cheap gas supplies, upon which it now depends for about 83 percent of its fuel input.

By contrast, Morocco – a country with negligible hydrocarbon reserves – only introduced gas in its energy mix in 2005, using part of its transit allowance to fuel the country's first CCGT power plant at Tahaddart, in the northwest of the country. For almost ten years following the entry into operation of the GME pipeline in 1996, the Moroccan government remained politically averse to developing any dependence on Algerian gas supplies, in spite of the country's growing energy needs and the increasingly burdensome fiscal weight of other fossil fuel imports. This apparent change of attitude paved the way to further domestic use of natural gas, with the country's second gas-fired power plant in Aïn Beni Mathar using since May 2010 the remainder of transit royalties, leading to an increase of the fuel's share in power generation to about 14 percent.

Soaring Demand and Domestic Price Subsidies

Over the last decade, power demand in the region has surged at an average annual rate of 6–8 percent, with Egypt, Morocco and Algeria experiencing the highest levels of growth. This upward trend was unaffected by the recent global downturn, which had a relatively limited impact on the North African economies. Local demand for energy is fuelled by economic and population growth, but it is also a reflection of distorted consumption patterns stimulated by subsidised prices of gas and power.

Artificially low prices of gas feedstock are a structural feature of energy markets in the region. Prices of gas sold to industrial end-users are thought to be generally lower than delivery costs, causing heavy fiscal burdens for government budgets across the board and resulting in a higher opportunity cost for gas exporters in particular, not to mention the implications for upstream development in producing countries. In 2008, energy subsidies in Egypt and Morocco amounted to 8 percent and 4 percent of GDP, respectively.

As far as natural gas is concerned, these pricing practices originate in the fact that, as a by-product of oil, as a payment for NOCs' share under PSAs or for transit fees for pipeline shipments, the fuel was considered a 'free good'. However, with time these subsidies have become an integral part of the 'social pacts' that underpin the often-problematic state-social relations in the region and that the increasingly unpopular governments have found daunting to revise.

Prices of gas feedstock in North Africa range from $0.2/MMBtu in Libya and $0.6/MMBtu in Algeria to around $1.25–3/MMBtu in Egypt, depending on users. By far the most populated country in the region, Egypt has shown the most urgency in recent years to come to terms with the issue of subsidies, though not without difficulty.

In 2004, the government decided for the first time in twelve years to hike electricity tariffs and to ensure that they remain cost-reflective for large users by increasing at an annual nominal rate of 7.5 percent. The bulk of electricity consumption is in the residential and commercial sector.

And in June 2008, the government fixed the price of natural gas for energy-intensive industries at $3/MMBtu, and decided to gradually increase it for other industrial users from $1.25 to $2.65/MMBtu by July 2010. The move followed an earlier decision to revise upwards the price paid by Egyptian NOCs EGAS and EGPC for the gas purchased from their foreign upstream partners to sell on the domestic market – normally two-thirds of IOC reserves. Prior to 2008, this price was capped at $2.65/MMBtu – the top of a sliding scale capped at a Brent price of $22/bbl – but the new cap ranges from $3.7–4.7/MMBtu depending on the concession and the position of the acreage.

"By far the most populated country in the region, Egypt has shown the most urgency in recent years to come to terms with the issue of subsidies, though not without difficulty"

More recently, Egyptian government and BP/RWE Dea agreed to amend the terms of the existing PSA for gas produced from their joint North Alexandria and West Mediterranean Deep Water concessions, stipulating that the contractors will assume all investment costs, which are estimated at $9 billion, while Egyptian NOCs will have the right to buy all gas produced – instead of a limited share – at a price of $3/MMBtu at a floor of $50/bbl Brent, rising to a ceiling of $4.10/MMBtu at an oil price of $120/bbl. The deal was hailed as a groundbreaker in Egypt's struggle to come to terms with booming domestic demand, as it is expected to send a positive signal to investors and encourage more contractual flexibility within the PSA regime, which is likely to lead to more exploration in the Mediterranean. However, even with the 2008 price arrangement, selling volumes onto the domestic market at a heavily subsidised price – well below the price paid to IOCs, as discussed below – meant that Egyptian NOCs have on many occasions struggled to pay their dues to contractors on time, leading to further frustration amongst foreign investors and to decision delays for key upstream projects.

However, Egyptian government efforts to grapple with pricing issues were soon met with resistance from industrial lobbies, which can exert pressure on the government through representative tycoons with prominent influence on national politics. As a result, in January 2009 the price of gas for energy-intensive users was reduced to $1.7/MMBtu, while the incremental increase for other industries has yet to be implemented. The government used the pretext of deteriorating global economic conditions to effectively reverse its decision to adjust domestic prices, but many remain sceptical about the political will shown so far by decision-makers to deal with this longstanding issue. Yet, in the first half of 2010, the government seemed to have resumed the implementation of its subsidy-reduction plan, but promised to eliminate all energy subsidies by the end of 2011. This revised schedule is reflected in the 2010–11 spending budget, which provides for almost a $12 billion energy subsidy bill and confirms observers' prediction that the issue is too sensitive for the Egyptian government to tackle effectively before the presidential election of September 2011.

Across the region, governments are likely to continue ducking opportunities to grapple with the domestic pricing issue, which will remain a political hot potato at least in the short term. Questions of succession are not only the focus of current political debates in North Africa, but are also fuelling rising tension between supporters of incumbent leaders and opposition movements. In the absence of outside pressure and/or incentives to redress existing pricing policies, tackling the issues will not take precedence over pressing socio-political concerns.

Power Projects and Gas Supply

Across North Africa, the power sector accounts for the biggest chunk of domestic gas consumption: 45 percent in Algeria, 56 percent in Egypt, 65 percent in Libya, 74 percent in Tunisia, and over 95 percent in Morocco. As regional demand for power is expected to continue growing at a minimum rate of 6 percent per year to 2015, pressure on gas supply will be ratcheted up in view of the competing requirements of the industrial and export segments. This will especially be the result of the overwhelming reliance of the planned new generation capacity on gas-fired combined and steam cycle technologies.

Through its 6th five-year (2007–2011) investment programme, Egypt plans to add to the existing 23,500MW over 7,700MW of new generation capacity, expecting power demand to grow at an average annual rate of 6.4 percent. Another expansion plan for 2012–2017 has recently been sanctioned by the state-owned Egyptian Electricity Holding Company (EEHC), with the aim of installing over 11,000MW of new, mostly thermal capacity. Most of the new investment will be done through EEHC with the help of donor finance from IFIs, but the government has recently signalled that private investment will be resorted to in future. To this effect, new electricity legislation about to be ratified is expected to introduce greater liberalisation to the power sector and encourage IPP participation, following a hiatus since 2003 as a result of a local currency crisis.

Algeria, Libya and Tunisia are also pursuing ambitious capacity expansion plans, almost all of which are based on gas-fired technology. Algeria aims to more than double its existing generation capacity by adding another 10,000MW between 2008 and 2017, in addition to a 2.3 million m^3 of water desalination programme by 2012. Libya for its part is constructing 4,500MW on top of the existing 6,000MW of generation capacity and the 400,000 m^3/day of desalination capacity. Finally, Tunisia plans to bring online one major combined cycle plant per year until 2015, increasing total installed capacity by an estimated 2,400MW.

Having over the last five years brought online two CCGT power stations with a combined capacity of 856MW, Morocco is now directing its attention towards expanding its Jorf Lasfar coal-fired power plant by installing two new 350MW units by 2012. Meanwhile, plans to convert to gas around 900MW of existing oil-fuelled capacity are still on hold, pending new gas supply.

> "Unlike gas resource-holders in the Gulf, North African exporters are not facing a situation of gas shortage"

In all countries, power sector strategies have been devised on the basis that foreign investment should form an important part of expansion plans. So far, foreign interest in the power sector has largely been positive, and the share of IPP projects is likely to become more important as governments increasingly resort to outside investment to meet their growing requirements. Further reform of the power sector in North African countries as well as their access to project finance will be the main determinants of foreign investor interest in future. In Libya and Egypt, a lot more will hinge on the introduction of more attractive legal frameworks, which in the case of the former is still inexistent.

Despite holding ample natural gas reserves, North African countries – with the exception of Morocco – have seen the unrelenting demand for feedstock from the power sector exacerbate a constrained supply situation that is the result of a number of well-chronicled upstream impediments. This has cast uncertainty on the region's gas export expansion plans and is forcing gas-short countries to reconsider external supply options.

What Next for Gas Exports?

Unlike gas resource-holders in the Gulf, North African exporters are *not* facing a situation of gas shortage. These countries are tied by a string of long-term, gas pipeline and LNG export commitments, and all three have expressed plans to expand exports in the short to medium terms, going as far as building the necessary infrastructure in the case of Algeria. However, booming domestic requirements, driven largely by the power sector but also petrochemical industries, are forcing a re-think of these policies.

It has by now become evident that Algeria is unlikely to reach its 85 Bcm/yr export target, and if it did it would be after 2015. Gas consumption is expected to exceed 50 Bcm/yr by 2020, putting a heavy break on the possibility of monetising new gas supplies on export markets. This will have implications for planned export infrastructure such as the Galsi direct gasline to Italy, which will most likely be scrapped.

Egypt is doubling its efforts to boost gas supply from offshore reserves, but that will just be enough to maintain gas exports at their current level (18–19 Bcm/yr) to 2020. Domestic demand is projected to reach just under 80 Bcm/yr by 2020 and output to grow by an average annual rate of 4 percent. However, this hinges on the willingness of IOCs to continue investing in the upstream in the absence of further export prospects, and on the ability of the government to pay a higher price for gas to be sold on the domestic market. Constraints on gas feedstock experienced by power generators in summer 2010 suggest that the moratorium on new gas export projects is likely to be renewed at the end of the year.

Libya's gas potential remains elusive for now, but if and when new gas reserves are discovered the expansion of exports will be constrained by domestic demand – though a lot will depend on the size of eventual discoveries, the rate of utilisation and the commercial terms offered for foreign investors.

Transit countries Tunisia and Morocco could benefit a great deal from increased regional gas trade, but political tensions, in particular between Algeria and Morocco, continue to militate against further progress in this regard. There are questions about the ability of the Moroccan government to sustain its current policy of using oil and coal imports to supply its growing power sector, given the costs involved, but imports of Algerian gas beyond the transit royalties remains an unpalatable option. Instead, a 3.8 mtpa LNG receiving terminal and the introduction of reverse-flow technology to the GME to purchase gas from Spain are being considered by the Moroccan government as alternative, even if more costly, supply options.

Plans to develop alternative sources of power are being drawn up across the region, more tangibly in Morocco, Tunisia and Egypt. These consist of ambitious renewable (solar and wind) power projects, as well as nuclear technology, which some countries are hoping would account for at least 20 percent of their energy needs by 2020. However, in view of the funding and policy challenges these options present, as well as the long lead times they involve, action on the more immediate issues of pricing, upstream development and regional cooperation carries a better chance of addressing the region's power needs.

Asinus Muses

Best Price

Asinus has previously remarked on oil price outliers, including BP's $2-per-barrel deal in Iraq last year, surpassed only by the $1.50 per barrel received by Somali pirates as a ransom for a hijacked oil tanker. But BP is unlikely to be outdone on their new upside record: $32 billion, or $6,500 per barrel, for 4.9 million barrels of unconventionally-extracted (and distributed) oil.

Bonus, Please

In the land of opportunity it is not only the banks who get government-sponsored pay-offs for sowing destruction. The US government is living up to its traditional role as welfare state for giant corporations by covering approximately $10 billion of BP's costs through tax write-offs. Now we know why Congress didn't want to extend unemployment benefits: they needed to save their scarce resources for the truly deserving.

Bruised Posteriors

Apparently on a different page from the tax authorities, President Barack Obama's reaction to the record-breaking spill at Deepwater Horizon was to consult 'experts' to advise him on 'whose ass to kick'. Asinus, as readers will anticipate, is against kicking anyone's ass, on the basis that it is surely the owner of the ass, not the poor animal itself, who deserves the boot. Be that as it may, the ass selected was soon-to-be-ex-BP CEO Tony Hayward – though, out of respect, Asinus prefers to refer to him with the less prejudicial term 'donkey'.

Rand Paul, Republican Senate candidate for Kentucky, did not approve of Obama's belligerent approach, remarking, 'I think that sounds really un-American in his criticism of business.' But then Mr Paul wants to repeal parts of the Civil Rights Act that outlaw race discrimination by businesses, so his own ass may be in Obama's sights.

Bad Performance

Unfortunate though he has been, Hayward's selection for the ass-kicking was based on more than his being in the wrong place at the wrong time. Obama and the world were particularly dubious about Hayward's claim that 'There's no one who wants this over more than I do. I would like my life back.' Asinus, who believes in charitable interpretation, supposes that Mr Hayward was simply pointing out that his incentives were aligned with those of the victims of the spill. But could he really not think of anyone else who wanted it over more than he did? One local fisherman whose desire for closure was plausibly greater than that of the BP CEO was quoted as saying 'Our way of life is over.' Unlike Hayward he did not mean that he had got only one day of yacht racing in two months.

Asinus's sympathy for the fisherman was somewhat attenuated, however, when he likened the events to 'the apocalypse'. Everyone, it seems, wants to blame the equine genus.

Blame a-Plenty

Few doubt that those responsible for the spill should be held to account. But fewer still seem to realise that the need for ass-kicking spreads far beyond US waters. An international report by the World Wildlife Fund UK and others found that between 9 and 13 million barrels of oil had been spilled in the Niger delta over the last 50 years. On some estimates this is as much as an Exxon Valdez every year. Speaking of whom, an ExxonMobil pipeline in the region ruptured in May, pumping more than a million gallons of oil into the delta before the company sealed off the pipe. Hot on their heels, Shell just closed off a pipe that had been spewing oil into the mangroves for two months. Readers may also recall Asinus's review of the documentary *Crude*, on ChevronTexaco's alleged dumping of oil and related substances on indigenous people's land in Ecuador. Asinus wonders when Congress and the US president will start kicking executive *derrières* at ExxonMobil, Shell and Chevron.

Beyond Parody

Locals near Selby, North Yorkshire have been complaining about the 'eyesore' of a dozen new wind turbines. 'You wouldn't want those on your doorstep,' one local was reported as saying. What is interesting about this case is that, rather than standard NIMBYism, it is an example of the lesser-known NIMCPSBYism: not in my coal-fired power station's backyard-ism. For, as some readers will know, Selby is the local town to Drax, Britain's largest coal-fired power station, and next to which the aesthetically-unacceptable wind turbines have been placed. The Press Association has a charming photograph of the turbines standing in front of hulking cooling towers. Why the opposition? The same local reasoned: 'The power station has been there for years. But the wind turbines are new.'

Also in the news, Matt Simmons, author of the controversial *Twilight in the Dessert*, was recently found dead in his Texan hot tub. Simmons' claims about declining Saudi production had irritated and exasperated the more technically-literate observers of the Kingdom's oil production. But his most original claims came in the last few months of his life and concerned the Deepwater Horizon spill. After first claiming that the 'real' leak was some seven miles away from where BP claimed, he then declared that 'the only way' to seal the hole was to use 'a small diameter nuclear bomb.' Asinus fears that between the people of Yorkshire and the people of Texas, parodists will be out of a job.

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