



NATURAL GAS PRICING AND ITS FUTURE

EUROPE AS THE BATTLEGROUND



ANTHONY J. MELLING

CARNEGIE ENDOWMENT

FOR INTERNATIONAL PEACE

WASHINGTON DC • MOSCOW • BEIJING • BEIRUT • BRUSSELS

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SUMMARY

Consumption of natural gas has grown rapidly over the last three decades and today accounts for nearly a quarter of the world's energy supply. Driven primarily by the industrialization of Asia, the Middle East, and Latin America, demand for gas has been growing faster than oil and the use of gas is set to increase even further in the coming years.

While clearly a contributor to global greenhouse gas emissions, natural gas is relatively clean compared to crude oil and coal. It can also underpin a rising reliance on renewable energy, as it provides a flexible back-up to intermittent energy supplies from solar and wind power generators. Yet whether—and how rapidly—natural gas assumes a greater role in meeting global energy demand depends on its price.

Unlike other internationally traded commodity markets, natural gas has disparate regional benchmark prices. The dominant mechanism for the international gas trade, however, remains oil indexation, which originated in Europe in the 1960s and spread to Asia. A contrasting mechanism based on hub pricing and traded markets developed in the United States and has spread to continental Europe via the UK. Today, Europe is witnessing an unprecedented collision between these two pricing mechanisms and gas industry cultures. According to the International Energy Agency, one of the most essential questions related to global energy supplies and security is whether the traditional link between oil and gas prices will survive.

While Europe is currently the battleground, the implications stretch beyond Europe's borders because once-isolated regional gas markets are now interconnected through the rising trade in liquefied natural gas. If the spot market model

gains the upper hand in Europe, Asia will be the last remaining stronghold of oil-indexed pricing, possibly making it unsustainable. Alternatively, if oil indexation re-exerts its predominance, there is the prospect that spot prices in North America will be influenced by this model.

Though the outcomes are far from certain, the stakes are high. Any modifications to existing contractual arrangements will directly impact exporters that depend on gas revenue—including Russia, Algeria, Indonesia, and Malaysia. And these changes will enhance or exacerbate energy security and dictate the sustainability of future supply. Gas pricing will impact the competitiveness of industry and the potential to achieve environmental targets around the world.

INTRODUCTION

Europe's gas industry is facing major challenges with profound implications for how gas will be priced and traded internationally in the future. The international gas trade is dominated by a reference pricing mechanism—oil indexation—that originated in Europe in the 1960s but is under growing pressure there, bringing into question how natural gas may be priced in the future, not only in Europe, but in Asia and beyond.

Historically, international trade in gas was quite limited, as gas was produced and consumed locally or regionally. Pricing mechanisms ranged from regulated prices set by governments, prices indexed to competing fuels, or spot¹ market pricing in competitive markets. Contracting structures in each of the major market areas evolved independently of the others and there was little reason for the pricing structures to be linked because gas was not a fungible international commodity like oil.

The practice of indexing gas prices to competing fuels—specifically oil products—gained favor early on in Europe and thereafter in Asia. The very growth of these markets rested on increasing international trade in natural gas that was contractually based on linking gas prices to oil product prices for both pipeline gas and its liquefied natural gas (LNG) counterpart. The United States, by contrast, pioneered commodity markets based on hub trading.

1 Throughout the report, “spot markets” and “spot prices” are used in their broadest sense to cover the wide range of gas commodity markets and dynamic pricing systems that include: formal and informal quotes, spot and futures trades, virtual and physical trades, and over the counter and bilateral contracts. Specific markets will be referred to individually where necessary.

The landscape began to change in Europe in the 1990s. The United Kingdom decided to introduce a liberalized market in natural gas and the industry began developing traded markets based loosely on the U.S. model. And in 1998, the UK gas network was linked to Belgium, causing commodity markets to spread into continental Europe. The European gas market split, with oil indexation dominating the continent while competitive hub pricing—centered in the UK—made inroads into northwestern Europe.

Enhanced interconnectivity was not restricted to Europe in the following decade. Isolated regional markets became increasingly interconnected both physically and commercially by LNG, which today comprises 28 percent of the international gas trade, and is nearing 10 percent of world gas supply. As a result, supply surpluses or shortfalls precipitate rapid shifts in LNG flows from one region to another—in pursuit of a higher price.

At first, wholesalers skillfully exploited differences in long-term contract and spot prices, diverted LNG cargoes as needed, and effectively managed the market balance in Europe, using flexibility embedded in their oil-indexed contracts. Starting in late 2008, however, a number of forces converged, undermining this balance.

Gas demand fell sharply due to recession just as gas supply availability increased, sharply intensifying competition between the two pricing systems. While spot market prices in Europe have traditionally hovered above oil-indexed prices, spot prices dropped well below oil-indexed prices and have remained there. Exploiting liberalized regulations governing the transportation of gas, market-priced gas surged onto the continent, stealing market share from wholesalers supplied with oil-indexed gas.

With European demand down an estimated 7 percent in 2009, LNG sales nevertheless increased dramatically at the expense of pipeline gas supplies under traditional oil-indexed contracts. Wholesalers under contract to purchase gas from producers at oil-indexed prices had too much overpriced gas, and competitors with access to market-priced supplies cherry-picked their customers. While major utilities faced billions of dollars in penalties for failure to take agreed amounts of gas, producers' revenues fell sharply below expectations. Suddenly, gas exporters were pressured to reduce the oil-indexed prices in their long-term contracts with European wholesalers.

This dramatic collision of two industry cultures with competing pricing structures has persisted. In 2010, the downward spiral has been slowed with a moderate economic recovery, cold winter, and contract concessions by several gas exporters.

But the prospect of continued nervous markets and relentless new gas supply has raised the prospect of radical change, including calls from traditionally conservative pro-oil indexation quarters for the “modernization” of existing contracts or decoupling of gas prices from oil.

The clash of the two pricing paradigms in Europe has created obvious winners and losers. Broadly speaking, there are three sets of players: incumbent wholesalers, second-tier buyers, and gas producers. Incumbent wholesalers, despite their enormous power to renegotiate prices, are the obvious losers as they are squeezed by lower demand, oversupply, and greater competition. Second-tier players, with a variety of supply options, and unencumbered by long-term oil-indexed contracts, are the principal beneficiaries as they can take advantage of differences in prices. And gas producers may benefit in the long term as they ultimately control the supply of gas.

What happens in Europe and which pricing system prevails will have broad repercussions for the gas industry in Europe and beyond, with more questions than answers clearly visible on the horizon. Will oil indexation attempt to reassert its primacy in Europe and reinforce its role in the international gas trade, or will this mechanism give way, slowly or suddenly, and when? Can oil indexation and hub pricing co-exist in Europe and the world? If oil indexation is eclipsed in Europe, how will long-term contractual obligations valued at hundreds of billions of dollars between suppliers and wholesalers be sorted out? Is an international gas price benchmark decoupled from oil on the horizon and, if so, what are the alternatives and how will it work? Under those circumstances, how will oil-indexed Asia fit into the future international gas trade? With the gas pricing mechanism uncertain and future revenues clouded, will necessary investments to ensure supply and transit security be made? How will the power sector, which likely drives gas demand growth worldwide, respond to the opportunities and challenges of gas pricing uncertainty?

The price of gas in Europe—and the mechanism used to determine it—will not only impact European companies and customers, but also have profound implications for energy markets around the world. Energy security, geopolitics, and the shift to greener forms of fuel that will be critical for combating climate change will also depend on how gas pricing evolves.

— Adnan Vatansever
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CHAPTER 1

**THE DEVELOPMENT
OF EUROPEAN GAS
CONTRACTING**

THE WIDER CONTEXT

Natural gas prices generally fall into three categories depending on the degree of regulation, the competitiveness of the market, and market liquidity:

- Government-regulated prices, usually based on cost of service
- Price indexation to competing fuels (commonly known as oil-indexed pricing)¹
- Spot market pricing in competitive gas markets

At the retail level in Europe there remain a number of countries where end-user gas prices are capped, restricted, or regulated under close scrutiny of the national regulator. However, at the producer/wholesaler interface, there remain no significant areas within the EU where gas prices are subject to direct government intervention to cap prices. In other words, new gas supplies in Europe may be sold to the highest bidder.

Price terms of wholesale Gas Sale & Purchase Agreements (GSAs) are often dependent on the prevailing price structure of gas in the market into which the gas is sold. In countries where gas prices are already linked to an alternative fuel, the most common price indexation is to crude oil or petroleum products. This methodology is known as oil-indexed pricing. Such price provisions are common in continental European, North African, and Asian GSAs.

Under oil-indexed gas pricing—the main focus of this study—the underlying principle is one of price competition with alternative fuels “at the burner tip.”² For example, gas used for the home heating market is often priced relative to gasoil (known as light fuel oil in Germany or heating oil in the United States) and gas used for industrial and power generation purposes is usually priced relative to one or more types of heavy fuel oil, with low sulfur heavy fuel oil (1 percent) being the most common.³

1 See Appendix for detail of terms.

2 The final point at which natural gas is used for consumption by residential, industrial, or commercial customers.

3 As most large gas producers are also oil companies, they tend to favor the use of crude oil and oil products as price indices. Inflation, electricity, and coal prices have sometimes made inroads into the price formulae, but generally in a “buyer’s market,” or at the expense of a higher starting price. When these deviations cause price divergence from the market norms, they often result in pricing disputes and subsequent renegotiations.

The United States and northwestern Europe provide the best examples of natural gas spot and futures markets and the development of short-, medium-, and long-term GSAs indexed to market gas prices. These price provisions within contracts are common in both the pipeline gas and liquefied natural gas (LNG) businesses, and through the growing international gas trade are increasingly impacting gas pricing terms worldwide.

NETBACK PRICING— THE EARLY DUTCH CONTRACTS

European natural gas development accelerated in the late 1950s with the development of the super-giant Slochteren (Groningen) field in the Netherlands, and the subsequent discovery of natural gas in the North Sea as a byproduct of the search for oil.

Before 1960 there was very little international trade in natural gas in Europe, but in the early 1960s the Dutch began to negotiate with Germany, Belgium, and France for the export of substantial volumes of natural gas by pipeline. This was followed soon afterward by plans for the export of LNG from Algeria, and pipeline gas from Russia to Eastern Europe, and in the following decade by supplies from Norway to northwestern Europe.

As end-user gas prices across much of Europe were state controlled, and free markets did not exist, how to price the gas emerged as an immediate question.⁴ The new Dutch concept of gas pricing was established in 1962 in the famous note of Minister of Economic Affairs Jan Willem de Pous, which became known as the “Nota de Pous.” In order to generate maximum revenue for the state, the “market-value” or netback value principle was introduced as the basis for natural gas marketing, as opposed to the prevailing principle of cost-plus for town gas. The distinction between these two approaches is that the cost-plus methodology is additive, but the netback value approach is subtractive. Cost-plus pricing starts with the production cost, and adds transportation services, overheads, and profit margin, to arrive at the sales price. Netback pricing begins with the “market value”

4 Which market to target was another question that developers of the Groningen gas field needed to address. Following a proposal from Exxon, one of the stakeholders, the developers decided to make gas available to domestic users on a very large scale, and to promote gas usage by residential consumers in a variety of areas previously reserved for coal or oil.

of natural gas in inter-fuel competition (in each market sector) and deducts the costs of transport services and overheads and profit margin to arrive at the “net-back value” at the point of sale. Germany, a key target customer for Groningen gas, was a major consumer of coal gas and also one of the few places where gas companies were partly privately owned. If natural gas were to capture market share from other fuels, then companies would need to incentivize customers to invest in natural gas equipment through competitive pricing.

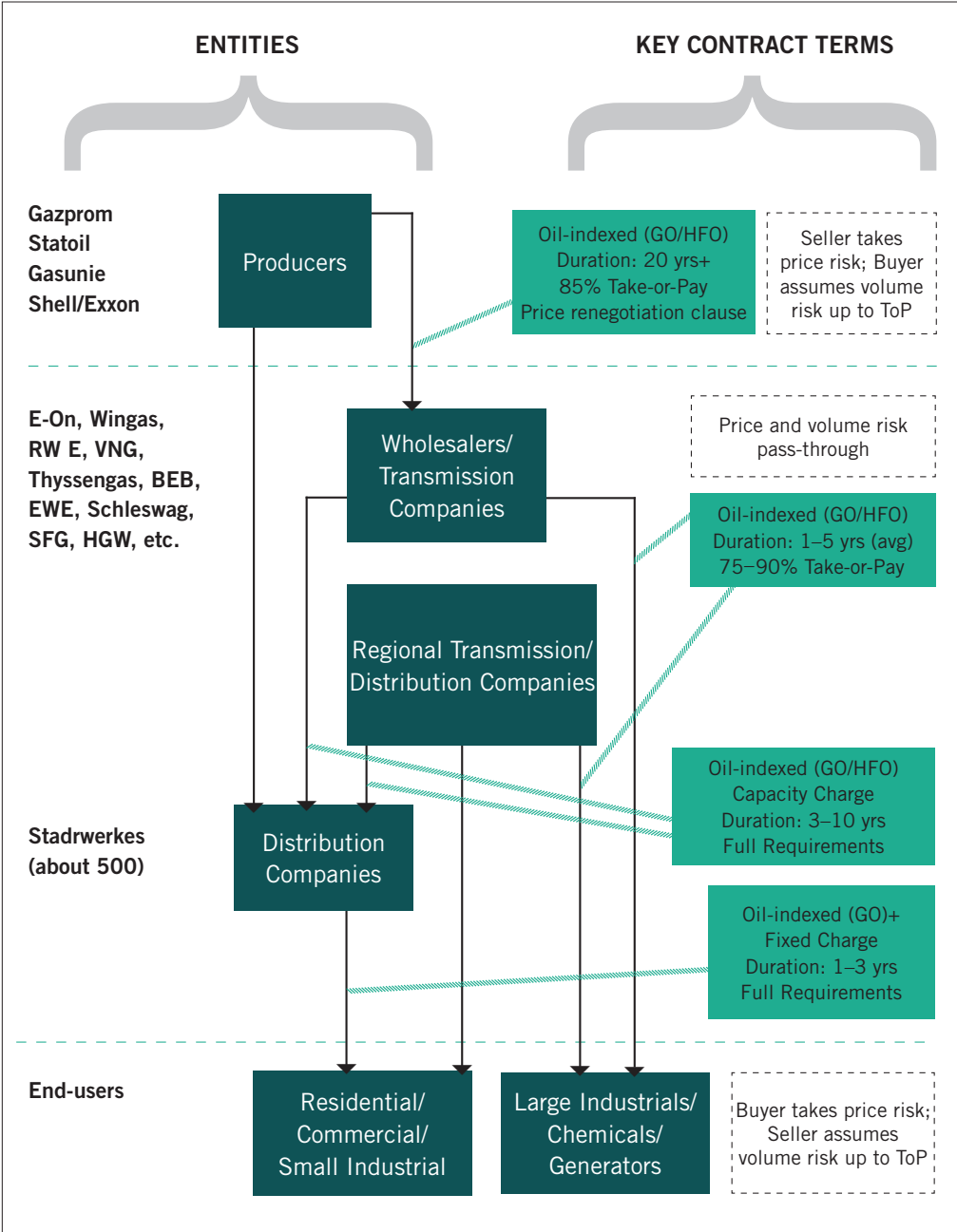
The principal competing fuel in the domestic sector was agreed to be gasoil, as many consumers had already switched from coal, and this was the heating fuel of choice in new homes. Commercial consumers also used much gasoil, but larger consumers frequently used the much cheaper heavy fuel oil (HFO) as the primary source of heat for both industrial processes and space heating. By this time, coal, although still a major fuel, was increasingly out of fashion and targeted toward bulk usage in specific industries, such as power generation and metals.

Based partly on the existing principles for gas pricing in Germany, and allowing for the displacement of competing fuels, the German and Dutch negotiators developed the principles of *Anlegbarkeit* or netback value to calculate the price of natural gas delivered at the German border. The chart on the next page shows the traditional German gas market structure.⁵

As the Dutch expanded their presence in foreign gas markets, this led to several additional innovations for gas pricing. First, the Dutch sellers were negotiating in parallel with potential purchasers in Belgium and France, and had to be seen to be dealing equally with all customers. As the export prices for gas were based on the market value of the individual customer country netted back to the Dutch border (by subtracting the costs to bring the gas to the customer), the Dutch border price would differ depending on the destination country. “Destination clauses” were therefore imperative to ensure that gas with a low price at the Dutch border destined for more distant markets could not be used to undercut

5 In simple terms, the end-user netbacks are compiled and regional averages calculated for each consumer sector. Once the seller and buyer agree upon a market area and the consumption by sector (based on the buyer’s customer portfolio), the end-user value of gas can be calculated. By deducting transportation charges, load management costs, and a reasonable profit at each stage in the gas chain, netbacks could then be calculated for any point within the German system. Using this methodology, the value of gas at the border could be calculated. As most of the producer/wholesaler gas imports used the German border as the transfer of ownership point, the German Border Price became a useful reference point. Even where sales did not take place at the border, the principles of *Anlegbarkeit* could be applied to sales points either within Germany or to points outside Germany.

FIGURE 1 Traditional German Gas Market/Contracting Structure (Simplified)



Source: Author

higher-priced gas in markets closer to the source. Gas-to-gas competition was essentially excluded.

Another important innovation, arising from the replacement value principle, was the introduction of price review (or re-opener) clauses into the export contracts.⁶ Seller and purchaser alike accepted that the netback value would change over time, not only with the price of competing fuels but with technology and the market shares of the alternative fuels. To cover these changes, price review clauses allowed for periodic reviews of the price to reflect those changes. To avoid frequent renegotiations, dates were specified (generally once every three years) at which either party had the right to request negotiations. An additional “Joker” renegotiation, available only once at any time during the entire term of the contract, was an option written into some later contracts.⁷

Finally, the Dutch introduced the “capacity charge,” which was payable regardless of the gas consumed. At the time, this additional charge affecting gas pricing was introduced due to the lack of local storage for the low calorific value (lo-cal) gas from the Groningen field. A decision was made that peak load capacity would need to be provided all the way from the wellhead to the end-customer. The Dutch sellers would provide the load modulation and capacity up to the Dutch border, with the buyer responsible for onward transmission and distribution capacity to meet the maximum hourly needs of the end-user. This was economically feasible because of the relatively low unit costs of onshore field development and relatively short transportation distances. The “full requirements” flexibility was compensated in gas sales contracts by the inclusion of an additional charge—“capacity charge”—proportional to the customer’s maximum hourly delivery rate.

Today the flexibility of the Groningen gas system has been maintained by the development of lo-cal gas storage facilities, but the capacity charges remain a feature of most traditional Dutch GSAs. Therefore the traditional Dutch contracts remain structured with a slightly lower commodity charge than other supplies, but a higher average price at the border than supplies with lower flexibility. For this reason, and in accordance with the policy of husbanding resources, the Dutch are generally less concerned than other producers with the amount of gas taken. This is also reflected in contracts by lower minimum bill requirements than other producers have.

6 See Appendix for further details.

7 Although formal price renegotiations were a key feature of Dutch and German contracts and the surrounding markets, they were not universally applied beyond the German sphere of influence, and were never written into UK contracts.

FOLLOWING IN THE FOOTSTEPS OF THE DUTCH CONTRACTS

The key feature of the sale of Groningen gas that other export contracts did not replicate was the provision of daily and annual supply flexibility sufficient to cover seasonal and other market fluctuations. This was economically feasible for short-haul Dutch gas, but became cost prohibitive at longer distances. The potential supplies from Russia, Algeria, and Norway needed to be transported hundreds or thousands of kilometers, and at these distances the swing could more economically be provided by storage located proximate to the end-user markets. Hence the longer distance contracts included much less upward volume flexibility around the Annual Contract Quantity than the Dutch sales.

These long-distance gas sales also required dedicated pipeline systems, with enormous capital costs, and sellers demanded that purchasers provide a higher annual minimum bill commitment, reflecting the need to repay the heavy investments. Accordingly, the principle became that purchasers would commit to pay for a minimum annual quantity (negotiable), typically 80 to 90 percent of the agreed Annual Contract Quantity. The clauses became known as “Minimum Bill” or “Take-or-Pay” terms.⁸ Upward volume flexibility was also negotiable and the bulk of long-distance contracts were settled at 110 percent or 115 percent of annual contract quantity.

Using the concepts developed by the Dutch, but without the capacity charge payments, GSAs were signed with more distant producers, including the following benchmark contracts:

- Algerian LNG to France (1964) and Belgium (1987)
- The first exports from the USSR to Italy (1973)
- The Norwegian Ekofisk (1977) and Statpipe (1985) exports
- Algerian exports to Italy via the Transmed pipeline (1983)
- Russian exports to former COMECON countries (1988 onward)⁹

8 The Appendix provides a detailed explanation for the key concepts used in long-term oil-indexed Take-or-Pay contracts. It also sheds light on how different players in the gas market are likely to interpret them.

9 With the COMECON countries of Eastern Europe, gas was exchanged not only for hard currency but also for commodities, manufactured goods, and construction contracts. This changed when they became independent and joined the EU, and oil-indexed prices were applied.

- Norwegian Troll deliveries to Germany, the Netherlands, Belgium, France, Austria, and Spain (1996)
- Algerian pipeline exports to Spain and Portugal via the Maghreb pipeline (1996)
- UK exports to the continent (1998)
- Trinidad LNG supply contracts (1999)
- Nigeria (1999) LNG supply contracts
- Russian exports to FSU countries Belarus, Ukraine, and Moldova (2005)

Oil-indexed contracts were frequently, but not always, indexed entirely to oil prices. In general the producers were more comfortable with oil indexation than other indices. The producers, often national or international oil companies, took the view that their shareholders both understood and accepted oil price risk without resistance. End-users, on the other hand, sometimes felt that electricity, coal, orimulsion, or even used vehicle tires were viable alternatives. These customers often argued for indices relating to their own businesses (metals prices, chemicals, electricity, inflation, and so on) and this became more difficult to resist in a buyer's market. Hence various indices were added to oil indexation formulae from time to time.¹⁰

Until the development of spot markets, LNG contract pricing terms in continental Europe were also based on oil-indexed formulae, with some key differences:

- Contracts often included an additional "transportation" element reflecting shipping costs
- Volume flexibility range (95 to 100 percent) was lower than for pipeline gas deliveries

LNG contract terms were similar to pipeline supplies: typically around twenty years. The growth of world LNG trade coincided with the growth of European spot markets, and in recent years an increasing proportion of Europe's LNG supplies have been on short- to medium-term bases with potential for diversion to other markets.

From the 1960s onward, oil-indexed gas contracts underwent a process of constant development, occasionally with serious disputes over price levels and the

¹⁰ See Appendix for further detail.

relationships with other fuels. For the most part, disputes were resolved by mutual agreement. As time progressed, price formula weightings were adjusted to reflect the increasing importance of gasoil and declining importance of heavy fuel oil, and changes to fuel specifications. Different weightings were applied to different users, reflecting their customer mix. Perhaps typical is a weighting of 70 percent gasoil, 30 percent heavy fuel oil. High sulfur fuel oil is one example of an index that has been virtually eliminated, as its use has disappeared from most areas in Europe.

Even until the current decade there was little, if any, provision for the event that the buyers under long-term oil-indexed contracts would suffer a serious decline in markets or market share. The assumption appears to have been that the markets would continue to grow, and that the incumbents would retain a sizeable market share (although this wasn't the case in the UK).

THE UK EXPERIENCE

UK gas development began in the 1960s, following the successful development of the oil reserves in the North Sea. Its contracting methodology developed quite differently from the Dutch model. Four key differences between the UK and Dutch gas experiences shaped the respective commercial development of the two industries:

- The UK fields were offshore, which made them more expensive to develop and required relatively high load factors, or higher prices
- UK fields were developed (until the late 1990s) purely for the domestic market
- The UK fields were much smaller than the Groningen field and not of sufficient size to sign long-term supply contracts of the same order as the Dutch contracts. (West Sole, the first UK gas field development, had reserves equivalent to 2 percent of the size of Groningen)
- The lack of obvious low-cost means to provide seasonal and daily swing on natural gas in the UK

Whereas the Dutch sellers were faced with an abundance of reserves, the UK industry was grappling with the dilemma that UK reserves might not be sufficient to meet UK demand and that imports would be required in parallel to UK supplies.

From October 1964, LNG was imported into the UK from Algeria through the LNG terminal on Canvey Island. The contract provided for the delivery of 700,000 tons of LNG a year, or about 10 percent of UK gas consumption. The Algerian sellers had negotiated a fixed price deal, in common with the initial LNG sales to the United States. Hence the UK incumbent, British Gas, already had a benchmark price for natural gas when negotiating for pipeline gas from the southern North Sea.

UK oil producers wanted oil indexation in their sales contracts in line with developments on the continent, but British Gas was a *de facto* monopoly buyer and wanted inflation as the main element of the price formula. The outcome of negotiations with North Sea producers was a multiplicative formula with an element of inflation (Producer Price Index or PPI) and the inclusion of gasoil and HFO end-user prices in the indexation basket. Some later contracts also included coal and electricity end-user prices, but the PPI/gasoil/HFO remained the core basket for most contracts.

The pricing principles developed for North Sea gas sale and purchase agreements at that time are still present in a number of contracts in use today. Although spot markets have developed since 1995, and are now almost exclusively the preferred price benchmark, there is a significant but rapidly declining percentage of the UK market—about 10 percent—that remains contracted under oil-indexed GSAs.

THE SPREAD OF SPOT GAS MARKETS

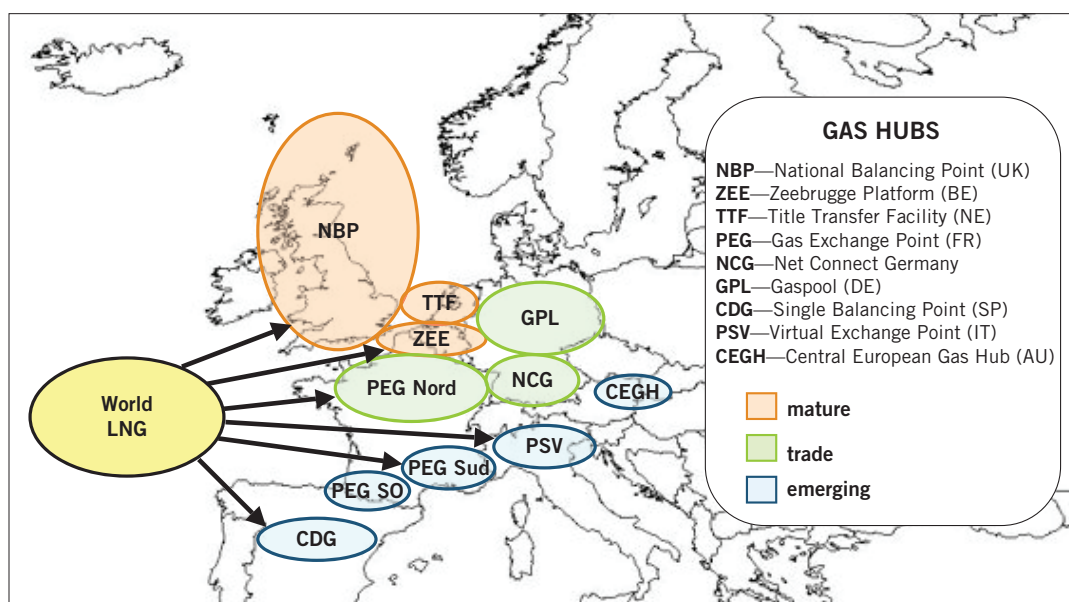
Traded wholesale markets began in the mid-1990s in the UK with the development of the National Balancing Point (NBP),¹¹ still the only European marketplace considered mature by the gas industry. Thanks to its liquidity and to the construction of two gas lines connecting the British market to continental Europe (Interconnector and Balgzand Bacton Line), the NBP strongly influences the continental hubs. Zeebrugge (Belgium) and the Title Transfer Facility (Netherlands) are the two dominant marketplaces on the continent. Other hubs are emerging,

11 A price reference point accounting for nearly all of the UK's traded gas markets.

but their development is hindered, sometimes by lack of supply liquidity, and sometimes by obstacles to infrastructure liquidity at key transit points, such as border crossings within the EU.

The chart below illustrates the relative development of the European gas hubs:

FIGURE 2 The Status of European Gas Hub Development



Source: Author

Spot market volumes are still predominantly traded around a physical supply to the UK market, but are beginning to make deeper inroads into the Belgian, Dutch, German, and French markets.

The French- and particularly the German-traded gas markets stand out as the success stories of 2009. From January 1, 2009, the Northern PEG sub-areas were combined into a single PEG Nord area (see Figure 2), connecting the Montoir LNG import terminal with all of the major import pipelines and the bulk of French gas demand under a single trading area. In Germany, the parallel processes of increased liberalization and transparency were given a significant boost by the Gasunie purchase of the former BEB network, and the aggregation of multiple pipeline networks under single trading platforms such as NCG and Gaspool. Liquidity in both France and Germany has significantly improved from 2009 to date.

Further afield, the development of hubs in Austria and Italy is progressing. Gas-release obligations, plus new LNG imports into Italy, may create a surge in spot gas availability there, accelerating the erosion of ENI's market share. While diminished Take-or-Pay obligations to Russia, Norway, the Netherlands, and Algeria remain in place, conditions in Italy may still point toward a potential market revolution.

SUMMARY OF THE DIVERSITY OF PRICE INDICES BY REGION IN EUROPE

Today in continental Europe oil indexation remains the dominant method for long-term contract price adjustment across Europe. Although spot markets have spread across northwestern Europe, there are large areas where spot markets remain at the embryonic stage and conditions are not yet suitable for the early development of traded markets.

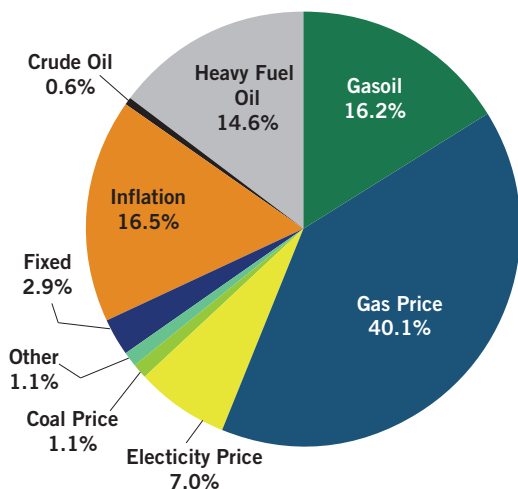
The demise of oil-price indexation has been forecast for much of the last decade, but new oil-indexed contracts and contract extensions are still being negotiated. The pressure for keeping oil-price indexation does not always come from the sellers as some buyers also prefer oil indexation, and many companies are keen to have both oil-indexed and market-based contracts in their portfolios.

There is a considerable variety of price formula variation, both within regions and between regions. The following chart, taken from information collected by the Directorate for Competition of the Commission of the European Communities, reflects the situation in 2006.

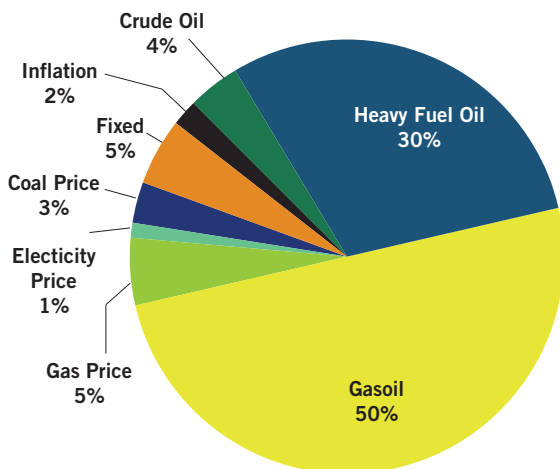
The major change since 2006 has been the increasing proportion of gas price indexation in the UK. Due to declining production from older contracts, contract expiries, and some price renegotiations, spot price indexation now accounts for around 90 percent of sales. Likewise, in Western Europe, the proportion of gas market price indexation has shifted considerably in the last twelve months and is expected to account for around 25 percent of producer sales in 2010, including the Russian and Norwegian revisions of 2009/2010. Gas market pricing has yet to make inroads into Central and Eastern European contracting practices.

FIGURE 3 Price Indexation by Region

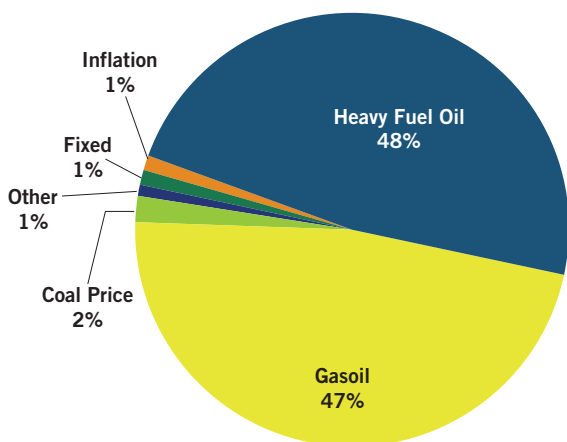
United Kingdom



Western Europe



Central / Eastern Europe



Source: DG COMP. Energy Sector Inquiry 2005/2006

CONCLUSIONS

- The countries of continental northwestern Europe share a common gas contracting evolutionary path, with long-term oil-indexed contracts at the producer/wholesaler interface, and back-to-back price indexation with downstream customers. Volume commitments are not passed downstream to the same extent as pricing terms.
- The Dutch local GSAs generally have greater flexibility, lower minimum volume commitments, and less competition than other oil-indexed contracts, resulting in fewer problems in today's markets.
- Traditional LNG contracts have significantly less volume flexibility than pipeline contracts. Volume flexibility may be possible by diversion to other markets, but this is subject to commercial constraints, including a favorable price differential.
- The UK gas system was isolated from the continent, and contracting practices developed independently until 1998, when the Interconnector was completed.
- Long-term oil-indexed contracts remain the dominant form of GSAs in northwestern Europe.
- At the time of writing, it is apparent that the liberalized, liquid spot markets that previously encompassed the UK, Belgium, and the Netherlands are spreading in all directions. Northern France and Germany are rapidly expanding spot trades, and conditions are becoming more favorable in the Mediterranean markets.

CHAPTER 2

**THE DYNAMICS
BETWEEN
OIL-INDEXED
AND SPOT PRICES**

THE TWO OPPOSING IDEOLOGIES

The two opposing ideologies in European gas contracting are represented by the more traditional oil-indexed contracts and the spot markets used by the new players and converts to traded market structures. Coincidentally, the two largest gas markets in Europe—the UK and Germany—are the ideological bases for the two opposing camps and the locations of the two price reference points that have become universally accepted as the most representative benchmark prices in Europe:

- The German Border Price (GBP)
- The NBP Spot Market Price (NBP)

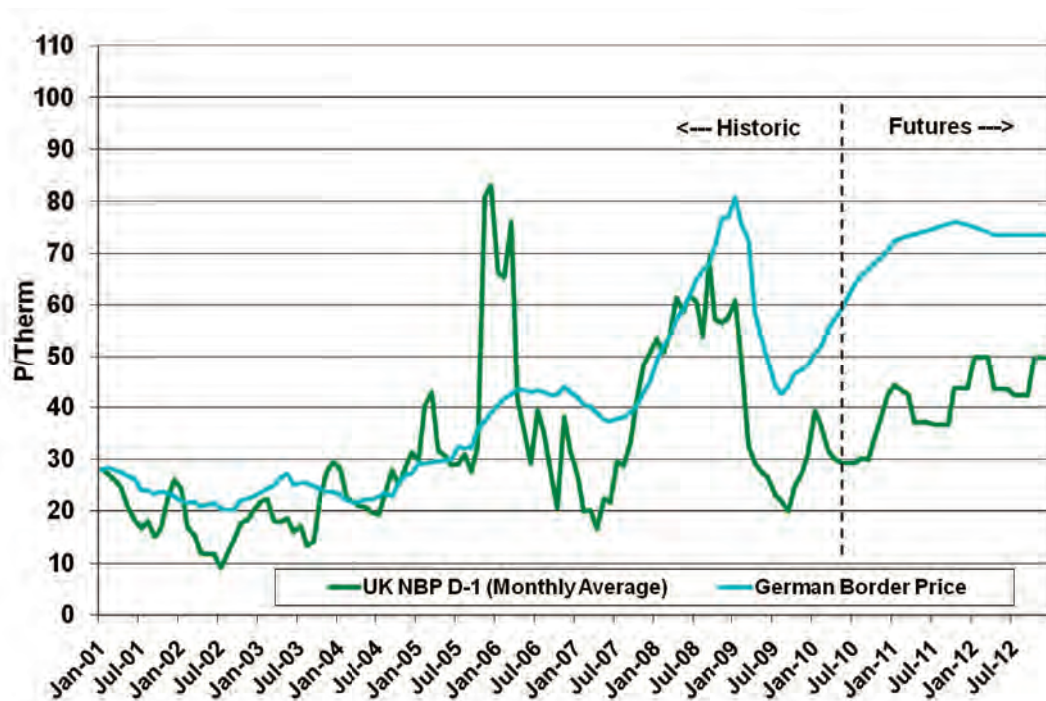
The GBP is published in Germany by Bundesamt für Wirtschaft und Ausfuhrkontrolle (BAFA) each month. BAFA publishes the total value of gas imports into Germany during each month and the total quantity in energy units. By dividing the total value by the quantity, the average gas price can be obtained (this is known as the GBP). The GBP is an average of the oil-indexed contracts that comprised around 90 percent of German gas supplies (2008) and spot supplies that are increasingly available at the Dutch-German border and Norwegian pipeline terminals.

The NBP is the price reference point for virtually all of the UK's traded gas markets, which now comprise around 90 percent of all UK supplies. The NBP became the principal UK hub as soon as the entry-exit transmission pricing model was established by Transco in October 1994. The key to its success was the single hub concept: once the entry fee into the UK transmission system has been paid, the gas is effectively at the NBP; all UK gas within the transmission system has an equal value as there are no distance-related charges to be paid. The single hub concept channeled all of the liquidity into a single trading point.¹

The chart below summarizes the development of the GBP and NBP prices since January 2001, with the current futures spread:

1 The term “NBP price” can be deceptive, as there are a range of contracts traded at the NBP: paper and physical, spot and futures, swaps and options. The most liquid markets are the day-ahead and month-ahead, but traded prices can extend several years into the future, depending on the platform. The Intercontinental Exchange is a major market, but there are a variety of other players including banks, oil majors, multi-utilities, and trading firms. The bulk of trades are bilateral.

CHART 1 GBP vs. UK Gas NBP Day-Ahead (Monthly Averages) Prices



Source: Compiled by author based on Heren and BAFA data

A short look at the price chart above immediately begs the question: “How do the two gas pricing systems coexist?” The simple answer is that there never has been a comfortable coexistence but that, until recently, the stresses have been manageable. Such stresses have increased along with price differentials.

A fundamental assumption for the incumbent wholesalers to maintain a market balance is that the much larger oil-indexed volumes have sufficient volume flexibility to accommodate surpluses of market-priced supplies. By adjusting daily takes, incumbent wholesalers can cause market prices to gravitate toward oil-indexed prices. When spot prices are above oil-indexed prices, there is minimal stress in the oil-indexed markets, other than the threat that producers will call for an upward price revision at the next re-opener opportunity. Temporary oversupplies in spot markets or small discounts in spot markets also present little threat to oil-indexed markets. Heavily discounted spot and futures prices, however, are a signal that traders believe that markets will be oversupplied with market-priced gas for the foreseeable future. This is understandably a serious concern for those players with long oil-indexed positions.

DEFENDING THE STATUS QUO

The major gas producers and wholesalers have always felt that it was in their best interests to defend the status quo of monopolies, demarcation agreements, oil-indexed long-term contracts, and vertically integrated control of the infrastructure. They often argue, quite honestly, that (at least until recently) many of their end-customers across Europe remained in favor of maintaining long-term oil-indexed contracts. The key wholesalers therefore felt justified in their defense of the rights of producers to sell, and buyers to buy, long-term oil-indexed supplies.

The incumbent wholesalers' privileged status gave them several advantages over new entrants, some obvious, others well hidden, including:

- Long-established market intelligence and networks
- Legacy contracts for transmission and storage capacity that effectively allow the incumbent wholesalers access to essential infrastructure at below-market prices
- Contract volume flexibility
- Load factor advantage (arising from a large customer base)
- Preferential access to infrastructure
- Access to confidential system information
- Price discovery through access to multiple contracts
- Guaranteed profits and reliable margins
- A multiplicity of arbitrage opportunities arising from diverse portfolios

During much of the last decade the incumbents became more powerful and profitable, and mergers created super-giant multi-utilities while new market entrants struggled to achieve critical mass. Those that resisted change most effectively appeared to fare better than the new players who sought to take their place.

Some of the incumbents' advantages described above have been whittled away by the EU gas directives, competition law, and the powers of national regulators. But the principal enemy of long-term oil-indexed contracts was not the liberalization efforts of the EU and regulators. Instead, the greatest inroads into the status quo have been made by the emergence of gas oversupply in Europe. This trend has led to a wide and prolonged differential between oil-indexed and market prices. Those inroads made by the EU and regulators represented fissures that were overlooked so long as the market was balanced or tight. In today's oversup-

plied environment, however, those fissures have been exploited by a new breed of competitor to undercut the incumbents in their home markets.

THE THREE MARKET CONDITIONS AND THE IMPORTANCE OF THE MIDDLE GROUND

It is helpful at this point to briefly summarize the three possible market conditions:

- **Scarcity:** Where gas is scarce, spot prices increase above long-term contract prices, as demand outstrips supply. At this point, all of the players, with the exception of spot gas end-purchasers, are comfortable and profitable and there is little desire within the gas industry for radical change. In recent years, real scarcity has only arisen due to system constraints rather than developed reserves shortages.
- **“Middle Ground”:** In Europe there is a large Middle Ground where a supply-demand balance can be maintained by the actions of the large gas wholesalers utilizing the daily and annual flexibility built into their long-term gas purchase agreements, in combination with other load-balancing tools. Most of the time, gas industry players operate comfortably within the range of the Middle Ground. With typical annual volume flexibility of +/- 10 to 15 percent before exceptional measures, for the major wholesalers, there should be relatively little reason to fear losing the Middle Ground.
- **Oversupply:** There comes a point where the oversupply becomes so excessive as to breach the Middle Ground and send spot prices into a downward spiral. This inevitably results in the need for the gas industry incumbents in Europe to take exceptional measures to restore market balance. The possibilities include large financial penalties, negotiated contract restructuring, downward price renegotiations for some, and bankruptcy where price re-openers are weak. For the incumbents, the managed solution will almost certainly be preferable to the market solution.

When spot prices are higher than oil-index, major producers can comfortably sell additional gas into the market without upsetting their core wholesale customers, such as ENI, GDF SUEZ, and Wingas. Indeed this is doubly good news for producers: not only can they sell more gas, but they can activate renegotiations

for higher prices. The potential downside is that customers are less satisfied and long-term demand may suffer.

The resilience of oil-indexed markets against the combined onslaught of the free marketers, regulators, and the EU can best be understood by looking at the magnitude of the Middle Ground, and the relationships between the producers and the incumbent wholesalers. The Middle Ground is a playing field where the incumbent wholesalers have an effective annual bandwidth +/- 10 to 15 percent flexibility on their long-term pipeline purchases, between minimum bill (Take-or-Pay) and maximum annual quantity.² Additional annual flexibility is available through “make-up” and “carry-forward” provisions, though these are more problematic to exercise. The oil-indexed contracts give the buyers, in aggregate, a usable volume flexibility in the order of +/- 60 billion cubic meters/year. That is before the use of “make-up” and “carry-forward” provisions, or the diversion of LNG cargoes away from Europe.

As long as the European market remains comfortably in the Middle Ground, the stresses between the oil-indexed and spot prices are manageable, and over longer time periods, the spot prices have tended to roughly track oil-indexed levels, particularly on the forward market, because sellers are unwilling to sell gas into the spot market at levels much below forecast oil-index price levels.

However, if spot prices are lower than oil-index prices, this is bad news for producers, as wholesale customers will be requesting price renegotiations with a view toward lower prices. The major gas producers have both the ability, through production constraints, and a strong financial incentive to make some of the spot gas volumes disappear from the market if it becomes oversupplied. Because of price renegotiation clauses in many of the major contracts, the major sellers would be extremely unwise to dump volumes of uncontracted gas into oversupplied markets. This would inevitably trigger price re-opener clauses that would undermine their long-term oil-indexed gas sales. In short, the major producers of oil-indexed gas are strongly incentivized to withhold gas from the spot markets.

In the oversupplied market, the major producers may make an exception and sell spot gas to their core customers. Once the customers have exceeded their minimum bill obligations, they are free to purchase spot gas from any supplier, and the long-term supplier will be best placed to fill this need. In effect, the long-

2 See Appendix for definitions of key terms used in long-term oil-indexed Take-or-Pay contracts.

term agreements bind their customers to the major producers and incentivize the seller to grant an informal “preferred customer” status.

THE POWER GENERATION DIMENSION

Gas-fired power generation is a relative late-comer to gas industry development in Europe. Originally, natural gas was regarded as a “premium” fuel, too scarce to be squandered in large-scale power generation usage, which could deprive the distribution systems of long-term supply potential. Also, there were abundant world supplies of coal and uranium that could supply Europe’s needs. However, this perception changed with the increasing gas reserves in the North Sea, North Africa, the Middle East, and Russia. By 1988, the EU was ready to lift the restriction on gas use in power generation. At around the same time, there were significant efficiency improvements brought about by the introduction of Combined Cycle Gas Turbine (CCGT) technology, reducing the capital and operating costs of gas-fired generation. In the UK, these events coincided with both the government’s desire to diminish the coal mining industry and the liberalization of the UK gas industry. This confluence of four distinct drivers, unique to the UK, resulted in the “Dash for Gas” in power generation. For different reasons this acceleration of gas use also took place on differing time scales in Spain, Ireland, Italy, and, to a lesser extent, in most other European countries. By 2008, one quarter of the gas consumed in Europe was used for centralized power generation, from an almost zero base in 1988.

In terms of contracting practices, the power sector, unlike many distribution and industrial customers, was rarely comfortable with traditional oil-indexed contracts. The discomfort, due to the combination of pricing terms and volume commitments, is perfectly understandable. Where power market prices are not linked to oil prices, and with a Take-or-Pay (ToP) commitment of, for example, 85 percent, there is a long-term risk that the purchaser will be forced to buy gas at times when power prices will not cover fuel prices. Whereas this risk might be acceptable to generators with a diverse portfolio of fuels, the risk to an independent project is potentially fatal.

In the UK market, in the early 1990s, generators bought oil-indexed gas volumes under British Gas long-term interruptible (LTI) contracts, or from upstream suppliers. Initially, gas price risk was passed on to electricity customers via “Con-

tracts for Differences” between the generators and the electricity retailers (known as regional electricity companies). In the late 1990s, competition and market liberalization were introduced to the electricity distribution business and regional electricity companies could no longer pass the gas price on to end-customers. As gas prices rose and electricity prices fell, electricity purchasers found themselves paying twice the market price for wholesale electricity. As debts accumulated into the billions of U.S. dollars, purchasers faced insolvency, and the system of Contracts for Differences became unsustainable. In turn, the oil-indexed contracts signed by generators became unsustainable.

The problems that affected UK electricity purchasers (as illustrated by the insolvency of TXU Europe) also fed directly through to some generators. The UK’s first independent CCGT project, Roosecote, went into administrative receivership in 2002 as a result of a fall in wholesale electricity prices, the insolvency of the sole customer, and four years remaining on a partially oil-indexed fifteen-year out-of-the-money GSA. To further illustrate the point, the plant was sold to Centrica, the seller under the GSA.

CONCLUSIONS

- Volume flexibility in long-term oil indexed pipeline GSAs (typically from 85 to 115 percent on an annual basis) gives the large European wholesalers a powerful tool to manage the much smaller spot-market volumes. When the market becomes oversupplied, and incumbent wholesalers lose control of the Middle Ground, the flexibility tool becomes ineffective.
- While the incumbent wholesalers control the Middle Ground, gas-market prices gravitate towards oil-index prices.
- Oil-indexed LNG cargoes continue to flow to Europe under existing long-term commitments with increased obligations in 2009 and the much-reduced potential for economic diversion.
- In 2009, incumbent wholesalers lost control of the Middle Ground due to oversupply, and spot prices fell dramatically. The power to regain the Middle Ground passed into the hands of the producers, who had the ability to relieve the minimum bill obligations of their customers.
- Oil indexation is not a good price mechanism for power generators. The prospect of being locked into gas purchase volume obligations is a deterrent to investment by new players.
- Spot markets give generators more freedom, not necessarily to make a profit, but at least to avoid generation during loss-making periods.

CHAPTER 3

**MARKET
BALANCE
AND OUTLOOK**

WHAT HAPPENED IN 2009?

Market demand in Europe began to decline noticeably around September 2008 and resulted in a downturn in demand of around 7 percent across Europe, yielding an estimated 2009 demand of 520 to 530 billion cubic meters (bcm) (EU 27 + Switzerland + Turkey). The gas balance chart below shows demand in the middle of the range:

TABLE 1 European Gas Balances 2008 and 2009 (bcm estimated)

GAS BALANCE (EU 27, TURKEY, SWITZERLAND)		
	2008	Estimated 2009
Consumption	561.9	522.1
LNG Supply	55.3	68.2
Pipeline Supplies		
Norway	99.2	100.0
Russia	156.6	133.0
Algeria	35.8	32.5
Other	19.7	17.0
Indigenous	196.4	179.2
Total Supply	563.0	529.9

Source: Collated by author from various sources

Observations on the 2009 gas market in Europe are as follows:

- The gas market contracted by about 40 bcm
- LNG supplies increased significantly as the result of weak LNG markets in the United States and Asia Pacific regions, and Europe continuing to provide better netbacks
- Norwegian supplies were stable
- Russian gas exports were significantly below Take-or-Pay levels, with Gazprom appearing to bear a disproportionate share of the European market downturn
- Algerian pipeline volumes in 2009 appeared to decline by around 10 percent year over year

- Indigenous production fell by around 10 percent, reflecting the declining trend of mature production areas (notably the UK continental shelf) and lower nominations (for example, the Netherlands)

European gas consumption could have been even worse in 2009. Demand was supported in 2009 by coal-to-gas switching due to the comparatively high price of coal, especially in northwestern Europe and Spain. Considerations related to the large combustion plant directive, coal stockpiles, and prices could potentially eliminate this support, causing a drop in gas demand on the order of 20 bcm.

Looking a little deeper into the split between oil-indexed and market-based contracts, some additional trends become apparent (see Table 2):

TABLE 2 European Gas Balance by Type of Contract (estimated)

GAS BALANCE (EU 27, TURKEY, SWITZERLAND)		
	2008	Estimated 2009
Consumption	561.9	522.1
LNG Supply		
Oil-indexed	51.7	55.9
Market-priced	3.7	12.3
Pipeline Supplies		
Oil-indexed	390.3	346.9
Market-priced	117.3	114.8
Total Supply	563.0	529.9

Source: Collated by author from various sources

From the above data it can be seen that:

- Oil-indexed LNG supplies increased moderately in 2009 due to contract startup (that is, programmed) or inability to divert to other markets (absence of higher-paying markets)
- Market-priced LNG supplies increased substantially as a result of new supplies (notably from Qatar) and new or expanded terminals (UK, BE)
- Oil-indexed pipeline supplies were down dramatically as a result of reduced nominations from the incumbent wholesalers, who faced reduced demand from their end-customers due to recession and/or sourcing of cheaper spot alternative

- Market-priced pipeline supplies also appear to have declined by a small amount, mostly as a result of the UK production decline and LNG imports causing a reduced demand for pipeline spot supplies
- Year over year, spot gas volumes increased modestly (≈ 5 percent), but this figure must be considered against the backdrop of a demand reduction of 7 percent, and a strong natural decline in UK continental shelf gas supply

Going further, Table 3 provides the estimated supplies by country and contract type. Table 3 shows the following changes in 2009:

- Oil-indexed supplies fell sharply, dropping by 40 bcm/year while spot supplies increased by only 6 bcm/year
 - ☑ Indigenous oil-indexed supplies fell by 17 bcm/year while spot supplies remained flat
 - ☑ External oil-indexed pipeline supplies fell by 26 bcm/year while spot supplies fell by less than 3 bcm
- Oil-indexed LNG supplies rose by 4 bcm/year while spot LNG supplies trebled from a low base
- Of total supplies in 2009, 34 percent were indigenous, 53 percent were pipeline imports, and 13 percent was LNG
 - ☑ Indigenous spot gas supplies were supplied almost entirely from the UK and the Netherlands
 - ☑ Imported pipeline spot gas supplies were supplied almost exclusively by Norway
 - ☑ Spot LNG cargoes were largely from Qatar, supplemented by small volumes from a wide range of sources

In aggregate, the charts show that the rise in spot market supplies at the producer-wholesaler level over the last year was only around 6 bcm. This relatively small volume was highly leveraged by the fact that wholesalers were struggling to meet minimum bill quantities. It is highly likely that the market volumes available were supplemented by oil-indexed purchases having been re-sold on the spot markets by players seeking to avoid penalties. This is supported by the ascendancy of spot markets in 2009 in relation to the traditional oil-indexed trade, highlighted by two notable trends:

TABLE 3

Sources of Gas Supply 2008 & 2009 by Country and Contract Type (estimated)

INDIGENOUS PIPELINE SUPPLY	2008 Bcm		2009 Bcm	
	Oil-indexed	Spot	Oil-indexed	Spot
Netherlands	49.0	24.2	42.0	27.0
UK	18.0	51.9	11.0	50.0
Germany	10.0	3.8	10.0	3.0
Romania	10.7	0.0	10.0	0.0
Denmark	9.0	1.1	7.6	1.0
Italy	9.0	0.1	8.0	0.5
Other	9.2	0.4	8.8	0.3
Subtotal	114.9	81.5	97.4	81.8

EXTERNAL PIPELINE SUPPLY	2008 Bcm		2009 Bcm	
	Oil-indexed	Spot	Oil-indexed	Spot
Russia	150.0	6.6	130.0	3.0
Norway	70.0	29.2	70.0	30.0
Algeria	35.8	0.0	32.5	0.0
Libya	9.9	0.0	7.0	0.0
Iran	5.8	0.0	6.0	0.0
Azerbaijan	4.0	0.0	4.0	0.0
Subtotal	275.4	35.8	249.5	33.0

LNG SUPPLIES	2008 Bcm		2009 Bcm	
	Oil-indexed	Spot	Oil-indexed	Spot
Algeria	19.1	0.4	20.0	1.7
Qatar	5.1	2.8	8.0	7.5
Nigeria	14.6	0.0	10.5	0.0
T & T	4.5	0.5	5.4	2.1
Egypt	6.4	0.0	6.5	0.3
Other	2.0	0.0	5.5	0.7
Subtotal	51.7	3.7	55.9	12.3

TOTALS	2008 Bcm		2009 Bcm	
	Oil-indexed	Market-priced	Oil-indexed	Market-priced
Total Supplies				
Subtotal	442.0	121.0	402.8	127.0
Total	563.0		529.8	

Source: Collated by author from various sources

- Substantial increases in trading activity at Zeebrugge, Title Transfer Facility, and the German hubs
- A reported high level of both buying and selling activity at the hubs by the trading arms of the incumbent wholesalers

Throughout 2008 and 2009, IUK Interconnector flowed predominantly toward continental Europe, despite the UK production decline. In 2009, the IUK Interconnector flows increased and Balgzand Bacton Line (BBL) flows decreased, resulting in a net flow change of an additional 5 bcm of market-priced gas toward the continent.

In continental Europe, the markets experienced a decline of ≈ 30 bcm/year in 2009, and an influx of new spot gas supplies. The incumbent wholesalers were forced to reduce their nominations by a volume even greater than the continental market decline.

The simple message is that the second-tier players, enabled by improved access to infrastructure and a moderate increase in spot supply at a favorable price, gained market share at the expense of incumbents. The preconditions that facilitated this shakeup are discussed below.

PRECONDITIONS OF THE 2009 CRISIS

The recession of 2008/2009 certainly played a role as a catalyst for the European gas contracting crisis, by causing a rapid downturn in demand. But the gas industry crisis of 2009 was due to a confluence of several forces that had been putting pressure on the contracting structures long before the storm broke:

- Growing liberalization, liquidity, and transparency
- Too much contracted/committed supply
- Uncertainty about demand, particularly in power generation
- Second-tier players as emboldened insurgents

Growing Liberalization, Liquidity, and Transparency

Progress toward creating traded gas markets has, for some, been unbearably slow. The liberalization of gas markets began in 1986 in the UK with the privatization of British Gas and moved steadily toward the opening of end-user markets, third-

party access to infrastructure, the unbundling of the incumbent gas company, and the development of traded gas markets. Also in the late 1980s, the European Community (EC) rediscovered Article 86 of the establishing treaty, which stated clearly that

Undertakings entrusted with the operation of services of general economic interest or having the character of a revenue-producing monopoly shall be subject to the rules contained in this Treaty, in particular to the rules on competition, in so far as the application of such rules does not obstruct the performance, in law or in fact, of the particular tasks assigned to them. The development of trade must not be affected to such an extent as would be contrary to the interests of the Community.

In other words, gas (and electricity) utilities were subject to the same competition rules as private companies in all other sectors. This article was largely ignored by sovereign governments and the incumbents until the late 1980s, when utility monopolies began to be challenged by the EU.

Market opening began with the 1991 Gas Transit Directive, which obliged gas transmission companies to allow third-party access (TPA) to their pipeline networks. In practice, the legislation was weak and ineffective, particularly where incumbent gas companies resisted strongly, and sovereign governments chose to incorporate only the minimum obligations of the legislation. This weakness called for progressively tougher legislation in the First EU Gas Directive (98/30/EC), the Second EU Gas Directive (2003/55/EC), and the Third Energy Package approved in 2009, effective March 2011.

Through the combination of industry pressure for action, national legislation, and the EU framework, there has been enormous progress in the development of competition and liberalization in European gas markets since 1991. Improvements include:

- Elimination of destination clauses
- EU Gas Directives and regulatory pressures for some incumbents to exceed and precede the obligations
- Improved third-party carriage, including transparent, short-term (and comparatively inexpensive) secondary markets for pipeline capacity and short-term storage plays (UK, Belgium, the Netherlands, and northern France)

- EU pressure to reduce unnecessary “contractual congestion” at cross-border points where unused capacity is not released into the market in a timely manner
- Enhanced interconnectivity between regional producers and consumers (Tampen Link, Langeled, BBL, IUK)
- Large-scale regasification capacity expansion and development in liberalized, liquid markets (UK, Belgium). Expansions at Zeebrugge and the Isle of Grain, followed by the belated online entry of Dragon and, most importantly, South Hook in 2009, created a 50 bcm/year LNG supply “bridgehead” for access to continental markets, with new players gaining access
- Unification of disparate balancing zones (France) and/or separate pipeline systems (Germany), making possible immediate title transfer via a single platform, seamlessly navigating not only between hi-cal systems, but across hi-cal and lo-cal systems
- Growth of a new breed of competitor—the second-tier players—previously constrained by the incumbents but increasingly assertive players like Nuon (Vattenfall), Delta, Eneco, Electricite de France (EdF), and EGL. Growth of gas-on-gas competition through geographical expansion. Forced out of home markets, the incumbents expand across borders where they act as insurgents, joining the ranks of the second-tier players
- EU transparency initiatives, such as the publishing of available capacity and flow data on company websites and the Gas Infrastructure Europe transparency platform enable better market knowledge and hence improved access to infrastructure

Despite the vast improvement in recent years, liberalization remains patchy. Particularly notable are the former COMECON (Council for Mutual Economic Assistance) countries of Eastern Europe, where market liberalization has not yet brought new supplies or traded gas markets. Connectivity between the Mediterranean countries and northwestern Europe remains poor. Links between the Iberian Peninsula and France are weak but improving, while Greece remains isolated from northwestern Europe. The successful expansion of traded gas markets in northwestern Europe serves partly to mask the poor liquidity elsewhere, and the EU aims to address the shortcomings, partly through the roles of ACER (Agency for the Cooperation of Energy Regulators) and the Madrid Forum.

In the Third Energy Package, the EC wanted a full ownership separation of transmission infrastructure from gas marketing, but a compromise solution of

legal, management, and accounting separation has been agreed upon. This compromise will require increased monitoring, and inevitably new legislation will be required as the market develops.

The pursuit of the objective of a single European market in gas is still seen very much as a work in progress at the EU level. Following the latest legislation it is widely acknowledged that there remains a substantial amount of work to be done, and it is possible that the completion of the Single Market and the facilitation of international competition will be the most demanding stage of the process to date.

Despite the number of acknowledged remaining flaws and constraints on liquidity, the events of 2009 illustrated a marked improvement in market access by new players. At least for competitors in northwestern Europe, the playing field is open.

Too Much Contracted/Committed Supply

Over-contracting was a major contributor to the perfect storm observed in 2009. Although there is a general consensus on the cause, the numbers have rarely been summarized. Table 4 is an approximation showing the magnitude of the problem. The geographical area covered is the EU27 plus Turkey and Switzerland. In 2009, the approximate volumes of gas committed for supply into Europe were as follows:

Volumes of contracted supplies are based on the annual contract quantity (ACQ) of the long-term oil-indexed contracts. The downward contractual flexibility is around 48 bcm/year from the external producers, using a simple 15 percent downward flexibility, and additional downward flexibility is available under some of the indigenous supply contracts. A realistic total downward flexibility is on the order of 60 to 70 bcm/year.

Based on table 2, the gas demand in 2008 (563 bcm) could easily be accommodated within the downward flexibility, effectively keeping the wholesalers within the Middle Ground. However, the gas demand of 2009 (523 bcm + some storage build) was beyond the reach of contract flexibility.

This situation was further aggravated by the emergence of a new dynamic in the LNG markets. From the last quarter of 2008, accelerating in the second half of 2009, the previously tight global market loosened, due to the global recession and the belated arrival of incremental LNG supplies. While underperformance in key Atlantic producers, like Nigeria and Algeria, masked the supply build, much

TABLE 4 Committed Gas Supplies to Europe

SUPPLY SOURCE	BCM	BCM	NOTES
Indigenous Production		185.0	Excludes Norway
Pipeline Supplies Contracted		321.1	Excludes Indigenous Contracts
Algeria	40.5		ACQ
Azerbaijan	6.6		ACQ
Iran	10.0		ACQ
Libya	8.0		ACQ
Norway	86.0		ACQ
Russia	170.0		ACQ
Other Committed Pipeline Supplies:		25.0	ACQ
Norway to UK	25.0		Vesterled/FUKA/ Langedled/FLA
LNG Supplies (Oil indexed long term)		56.0	Outturn number
LNG Spot Availability		15.0	Outturn number
Total Supply Availability (2009)		602.1	

Source: Compiled by author from multiple sources

of the incremental supply was from Qatar and had been earmarked for the UK. Many observers, including the UK regulator, were unsure how much of these volumes would flow to the UK. The belief was that some of the volumes would be redirected to Asia or the vast “sink” market of the United States. But with Asia largely sated, due to recession and the start-up of new production targeting Asian markets, such as at Sakhalin in Russia and Tangguh in Indonesia, the region did not require much flexible LNG. Furthermore, the United States itself, in the grip of recession, faced falling prices and rising production due to the “shale revolution.” Throughout most of 2009, European markets provided “flexible” LNG marketers with the best spot prices, with the result that imports into liberalized, liquid markets surged to record highs. The influx of LNG into the UK and Belgium, which totaled 17 bcm in 2009, was quadruple the levels seen in 2007 and 2008.

In summary, the supply position for Europe is commensurate with a market size in the range of 580 to 620 bcm/year. Despite the overheated European markets in the second half of the last decade, actual demand peaked at only 563 bcm in 2008.

So how did this misalignment occur?

In the years leading up to the financial crisis of 2008, four factors may have contributed to over-contracting by key players in Europe for the current period:

- Bullish forecasts of gas demand in Europe (see next section)
- The defensive strategy of over-purchasing in order to prove to regulatory authorities that there was no room in the marketplace for competitive supplies
- Optimistic estimates of market shares by individual players, contributing to aggregate purchases in excess of market size
- Alleged corrupt practices by the representatives of national gas companies¹

The result of these various purchasing strategies is that the contract flexibility is much greater on the upside than on the downside. In a shrinking market characterized by increased competition from cheaper spot gas, incumbents will face an uphill task to take their minimum bill quantities. The penalty for failure is having to pay enormous sums of money for “Banked Gas.”² In some cases this gas may not be used for several years, but the worst scenario is when the purchaser realizes that the gas cannot be recovered at all.

Uncertainty About Demand: The Key Role of the Power Generation Sector

The third precondition for the 2009 gas contract crisis was the over-optimism of some gas forecasters. This writer’s rule of thumb is that gas volume forecasts often materialize, but rarely within the time scales envisaged.

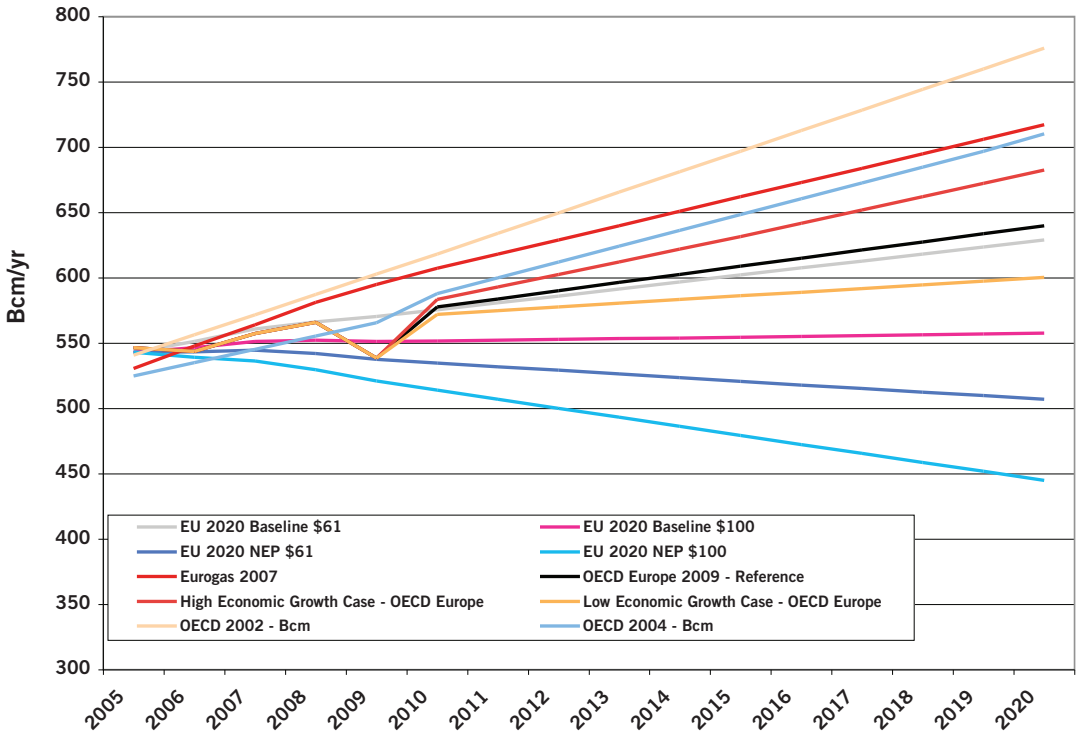
In Europe, demand forecasts have generally receded since the beginning of this decade. This trend can be seen in the periodic forecasts from most of the world and European demand forecasting institutions. Adding further confusion

1 The author has no proof of this, but reports have been published in more than one country alleging that deals were signed against the national interest.

2 Banked gas is the value of inventory held due to “Take-or-Pay” contractual arrangements.

to the picture is the wide range of scenarios often presented around the base/central/most likely scenarios. The following chart illustrates the range of forecasts in recent years:

CHART 1 Gas Demand Forecasting Ranges



Source: Various—see legend

As can be seen, the forecasts range varies from 445 to 775 bcm/year for the year 2020. This is not in any way intended as a criticism of any of the organizations, as all of these scenarios were credible and possible at the time of publication.

When one looks behind the numbers, the key difference between the scenarios is the volume forecast to be consumed in the power generation sector. Nowhere is this better illustrated than in the four scenarios developed by the EU Athens forum and published in November 2008 (shown under the EU 2020 headings in chart above). Studying their underlying numbers, one can see that two significant drivers of the gas demand are the rate of development of renewable energy resources and the inter-fuel competition with coal-fired generation in Europe. Variations in these factors account for much of the 185 bcm/year scenario range by 2020. By contrast, there are relatively small differences between publications in

the forecasts for the domestic, commercial, and industrial sectors.

In practice, one factor that is grossly underestimated is the importance of gas contracting structures in determining the scenario outcomes. In power generation in particular, contracting practices affect consumed volumes for several reasons. First, under oil-indexed contracts, generators have to make substantial volume commitments. The developer can rarely guarantee that electricity prices will be sufficient to cover the cost of gas, and Take-or-Pay commitments can potentially result in the necessity to purchase out-of-the-money gas year after year. In short, oil-indexed contracts are incompatible with traded electricity markets and can provide a significant barrier to investment in CCGTs.

Second, where generators have access to liquid spot and futures markets, there is little reason for them to make long-term commitments to GSAs. This avoids the risk associated with long-term Take-or-Pay commitments, presumably lowers the hurdle rate of return for new projects, and possibly helps explain the development of power generation where market-priced gas is available.

An additional factor reported by power developers is that the interface between gas and electricity market-balancing mechanisms needs to jointly support the operation of CCGTs. Both the gas contract and the gas market mechanisms must support flexible generation nominations.

The above points may help explain the difficulties that power generators face investing in the power markets of Eastern Europe, where spot gas has a very limited penetration, versus the relative willingness of power companies to develop CCGTs in northwestern Europe.

Since 2008, market-priced gas has substantially diverged from its historic linkage to oil, and the liquid gas markets of northwestern Europe are now taking price direction increasingly from electricity markets, and vice versa. At the time of writing, there is a strong argument that gas prices are being driven by coal/carbon generation economics. It remains to be seen how that linkage will develop but with the increasing integration of gas and electricity markets (25 percent of gas in Europe consumed by central generators, additional volumes in industrial Combined Heat and Power units), the interaction between gas and power markets should strengthen.

In short, the spread of liquid gas markets across Europe should be a positive driver for the development of new CCGT plants.

Second-Tier Players—Emboldened Insurgents

The fourth precondition of the gas crisis was the emergence of this new breed of player during the decade. As alluded to above, the principal beneficiaries of the present disconnect between spot and oil-indexed gas have been second-tier players. As these market participants typically attract less attention, especially when viewed from a distance, it is worth considering who they are and how they have played their hand, and are likely to do so in the future.

The second-tier players include not only the regional gas distribution companies, but other utilities, consortia of industrial purchasers, and power generators; they were formerly the customers of large incumbents. In many cases the second-tier players were (and still are) customers of the incumbent wholesalers, often feeling that the wholesalers' margins were inflated. With pressures to reduce market share in their home countries, some incumbent wholesalers have expanded abroad, where they have joined the ranks of the second-tier players. As would be expected, with relatively accessible gas supplies, foreign second-tier players often include the incumbents from neighboring countries.

Examples of second-tier players in the gas markets include:

- **Italy:** Power liberalization and consortia of gas distribution and industrial companies have yielded the majority of second-tier players. Other European utilities have swelled the ranks, often by links with existing players. Key second-tier players: ENEL, Edison, Plurigas, Sorgenia, GdF, and Gas Natural.
- **France:** EdF was a natural competitor in gas markets, together with other utilities from France and neighboring countries. Some upstream players have also taken an interest. Key second-tier players: EdF, Poweo, Soteg, ENI, EOn, BP, Hydro, and Gas Natural.
- **The Netherlands:** Major Dutch utilities became natural second-tier players, together with neighboring utilities and some upstream players. Key second-tier players: Nuon, Statoil (Hydro), RWE/Essent, GdF, and ENI.
- **Germany:** The magnitude of demand in Germany, and its central position in Europe, ensures that international energy players take an interest. Liberalization also re-invigorated some slumbering regional giants. Key second-tier players: Wingas, Exxon–Mobil, Shell, ENI, Gasunie, and VNG.

- **Spain:** The rapid growth of gas-fired power generation and the displacement of LPG meant that power generators and oil companies became natural second-tier players in the gas industry. Key second-tier players: ENI, Iberdrola, Endesa, Cepsa, Naturgas, Shell, GdF, and BP.

The second-tier players have a variety of supply options and hence a wide range of different portfolio structures. In the Netherlands and Germany, the distribution companies have been relieved of their long-term contractual obligations to incumbent wholesalers, and these deals replaced by short/medium contracts, typically one to three years. In other countries the distribution companies were traditionally on annual agreements with the wholesalers, there being no need for longer-term deals as there was no other supplier. Furthermore, the distribution companies are developing supply portfolios where they purchase only a percentage of their gas from their historic producer-suppliers and the remainder through deals with other producers and directly from the traded markets. These portfolios include varying percentages of oil-indexed and market-price supplies.

Prior to liberalization, the incumbent wholesalers added volume flexibility to the gas supply in order to provide a “full-requirements” service in terms of meeting end-user needs. Second-tier players often (rightly or wrongly) felt overcharged for the additional services and were motivated to deal directly with the gas producers at the border but, before market liberalization, were generally unable to do so. In the liberalized markets, flexibility needs are increasingly being fulfilled by arms-length contracts between the second-tier players and the storage companies, at prices controlled by national regulators.

Gas liberalization legislation has also enabled larger end-users to bypass the incumbents and purchase from willing suppliers or purchase spot supplies directly from the traded markets. These power companies and industrials, sometimes in consortia, have also become significant second-tier players in gas markets.

Whereas the incumbent wholesalers (the first-tier players) are purchasing oil-indexed volumes under oil-indexed Take-or-Pay contracts of fifteen to thirty years’ duration, they resell to large end-customers and second-tier players under contracts typically ranging from one to three years’ duration. Therefore, during periods of prolonged oversupply (low spot prices) the contracts between the incumbent wholesalers and their customers can be both curtailed (nominated at minimum) and then terminated on expiry, leaving the incumbent wholesalers with unsold supplies. The large end-customers and second-tier players simply purchase their requirements from the liberalized markets at spot prices.

For over-contracted incumbent wholesalers, the 2009 market dynamics became highly problematic: they were losing their sales of oil-indexed supplies to former customers—second-tier suppliers—who themselves were reaping windfall profits by marketing spot purchases directly to the incumbents' formerly captive large customers. In other words, the large incumbents were being squeezed from all directions: diminished demand, excess supply, and aggressive competition.

HISTORICAL ANALOGY

The current situation is unprecedented in its magnitude and implications. Since the development of gas in the Netherlands and the North Sea in the 1960s, there has only been a single notable case of an incumbent losing its foothold in the Middle Ground. That was in the UK, in the 1990s, where British Gas was over-supplied and was forced to renegotiate contracts and buy its way out of both price and volume obligations.

Centrica was divested from British Gas in 1997. Although the company announced a desire to better focus on specific businesses as the reason for the split, it was widely speculated that the company was trying to force contract renegotiations with gas producers and, further, that this solution was supported by the government and regulator OFGAS. The truth is probably that both focus and the need to put their legacy contract problems behind them were strong drivers of the division. The company was locked into contracts signed in the 1980s and early 1990s, under which British Gas was paying almost double the market rate for gas set by the newly established spot markets. Furthermore, BG's market share was falling as competitors homed in on the profitable customers. BG announced in 1996 that all of these contracts would be allocated to the cash-poor Centrica, effectively forcing renegotiation of these contracts. Financial results for 1996 highlighted the cost of gas contract renegotiation and restructuring, when the company posted a one-off charge of £1.2 billion. In 1997 Centrica posted a further loss of £791 million after one-time charges, but by the end of 1997, Centrica had renegotiated all its major high-priced contracts, gaining lower rates from major gas North Sea producers such as Shell, Exxon, Amoco, Conoco, and Elf Exploration. Importantly, Centrica's gas portfolio was competitive and the company solvent.

The UK situation bears some uncanny similarities to today's continental market:

- Over-purchasing by the incumbent wholesaler

- Regulatory changes forced on the market to promote choice of gas supplier, TPA to infrastructure, liquidity, and competition
- Spot prices lower than oil-indexed prices

However, there was one key difference in that the distress situation in the UK took place against a backdrop of a growing market for natural gas created by the “dash for gas” in power generation. Oversupply was clearly a problem, as competition unleashed an excess of new UK continental shelf gas production. The bigger problem facing Centrica was its average purchase price, and this was exacerbated by the lack of price reopener clauses.

In summary, the conditions exist for a major change in European gas contracting practices. The question is whether there will be a market response or a managed response.

THE BLEAK MARKET OUTLOOK AT Q4 2009

For many years the incumbents felt comfortable as the European balance remained in the Middle Ground, but during 2009 the comfort zone was threatened by prolonged oversupply. The potent combination of market contraction, oversupply, and an influx of new spot gas supplies took the demand balance into new and uncharted territory where, for the first time, management of the situation was beyond the control of the incumbent wholesalers.

In aggregate, the new market dynamics creating the Take-or-Pay crisis of 2009 looked likely to worsen in thermal year 2009/2010. Demand remained anemic, oil-indexed gas prices comparatively high, and second-tier players, with all the tools needed to capture market share, left incumbent wholesalers trying to push their problem upstream onto unwilling producers.

Furthermore, the anemic market in thermal year 2008/2009 has been sustained partly by some regional increases in spot gas consumption in power generation resulting from relatively buoyant world coal prices. Given the magnitude of this sector (around 140 bcm/year of gas-fired power generation demand in Europe), the dynamics of this sector cannot be ignored by any serious gas industry player. Were the economics to shift back in favor of coal-fired power generation, then another significant slice of gas demand would be lost.

In terms of how the market would develop, there was clearly a wide range of possible scenarios. The rate of world economic growth, general energy prices, carbon taxes, and government policy could each play a role in determining where European gas demand would be.

European gas markets are characterized by a relatively low price elasticity of demand in the residential, commercial, and industrial sectors of the gas market. In other words, a large reduction in price will be required to stimulate a small increase in demand, particularly in the short term. It is this feature that drives the producers to avoid an oversupplied market at all costs. Flexibility built into long-term oil-indexed contracts creates a broad Middle Ground and a potent weapon to avoid downward pressure on gas prices.

Accurate calculation of the limits of the Middle Ground are problematic, as the contracts are highly confidential, and even the largest producers and purchasers are a long way from having complete information on the status of all contracts. However, numerous reports for the gas year starting October 2008 eventually confirmed a significant breach of the Middle Ground, as several players ran into Take-or-Pay problems valued in the billions of U.S. dollars. For 2009/2010, with increased commitments and potentially more market-priced supply, the problems appeared potentially more serious.

Toward the end of 2009, the key market characteristics included:

- Low off-takes in 2008/2009 indicated virtually zero carry-forward potential. No contractual gas volumes beyond ACQ were taken by most wholesalers.
- Following 2008/2009 Take-or-Pay difficulties, Gazprom had stated publicly that, with the limited exception of the Ukraine, it was unwilling to accept minimum bill reductions.
- A potent combination of a large increase in spot LNG volumes, and large surplus of regas capacity in Europe were evident, particularly in north-western Europe, which forms a natural bridgehead, using the IUK Interconnector, for penetrating oil-indexed continental markets.
- The full Medgaz pipeline capacity from Algeria to Spain was planned to be available from the first half of 2010. Sonatrach would then have capacity for spot pipeline sales into both Italy and Spain, with marketing organizations and downstream obligations in place, notably in Portugal, and regulatory cover for its activities (limited to 2 bcm in Spain).

- Market liquidity and TPA improvements in Europe were enabling a wider range of players, notably the second-tier players, to access the increasingly available spot supplies and to supply a wider range of end-customers.
- Industrial gas demand had fallen dramatically across Europe, typically between 15 and 25 percent. Economic indicators are uncertain, but European gas demand could remain stagnant during much of 2009/2010.
- Gas demand for power generation in Europe is heavily exposed to the gas and coal spark spreads, which could easily turn back in favor of coal.
- There was a perceived abundance of potential new spot supplies, from Norway via the UK, LNG via the UK or Zeebrugge, gas release programs (Italy, Turkey), and/or contractual volumes resold on the spot market at a loss, to penetrate other markets or “dispose” of unwanted excesses.
- A warm winter in Q1 2010 (as then predicted by the UK Met Office) would further reduce gas consumption, particularly in the residential/commercial sector.³

In isolation, the recession-induced demand reduction was around 40 bcm/year in 2009, with a potential slow recovery in 2010. However, this could rise or fall by a further +/- 20 bcm/year in response to the competitive position of coal versus gas in the power generation sector. Abundant rainfall could further reduce the gas demand in the same sector.

Given that the Middle Ground has a downward flexibility of around 60 bcm/year around the contract ACQs, and likely much less as the buyers' ACQs in aggregate exceeded market estimates, there was clearly a strong possibility of a significant breach of the Middle Ground again in 2009/2010. This was all the more likely given the dynamics between wholesalers and their former customers, second-tier players, as earlier described.

At the other end of the spectrum of possibilities, the highly optimistic scenario for 2009/2010 included:

- Economic recovery with resumption of recent historic levels of industrial gas demand
- Continuation of gas-fired power generation advantage over coal
- Cold winter/poor rainfall/nuclear outages

3 Many of the large contracts allow for a minimum bill Take-or-Pay reduction based on heating degree days, so this would bring partial relief to this particular downside.

- Diversion of significant LNG volumes to resurgent Asian markets

In summary, the range of possible outcomes for 2009/2010 appeared to extend from the lower end of the Middle Ground to well into the oversupply region. The outlook for incumbent wholesalers looked bleak.

Yet not all purchasers were in the same situation. Most purchasers were already facing the possibility of gas surpluses, others were within the Middle Ground, and many were facing the uncertainty of not knowing their year-end outcome.

Q1 2010—OUTLOOK CHANGES AND GAZPROM PLAYS A TRUMP CARD

Looking back on 2009, the situation probably looked worst around the third quarter, as news of anemic gas demand became confirmed by data from around Europe. Initial optimism for a quick recovery would have been overtaken by the gradual realization through 2009 that the situation was a medium-term problem, at best disappearing by winter 2012/2013, but possibly lasting until 2015 to 2020. Going into the winter of 2009/2010, there was little good news to encourage the gas industry players, although some economies were beginning to show the first signs of recovery.

However, by the end of the first quarter of 2010, despite some lingering doubts about the future, the outlook had brightened for the traditional gas industry players. Two factors were responsible for this: the weather and contract renegotiations.

The Cold Winters of 2008/2009 and 2009/2010

With the possible exception of vodka, nothing warms a gas man's heart—and fills the coffers—quicker than cold weather.

Winter 2009/2010 started with above-normal temperatures, and the forecast overall was for a “mild” winter in northwestern Europe—until the second half of December, as temperatures fell dramatically shortly before Christmas, and the prolonged cold spell lasted until late February, resulting in some record cold months across a number of countries. Counterintuitively, the European gas-demand weighted average temperature across the winter period starting October 1

has been almost identical to the winter of 2008/2009.⁴

Overall, in terms of the average European temperatures, the last two winters have been significantly colder than most of the previous years. It is estimated that the effect of the cold weather during each of the last two winters was to increase gas demand by 15 bcm per year, compared to the milder winter of 2007/2008.

However, this masks a second and important point: the cold weather has been markedly concentrated on the spot-market areas of northwestern Europe. The increased demand across the UK, northern France, Belgium, the Netherlands, and Germany is slightly greater than the total 15 bcm/year increase in both years. Other areas in aggregate have shown a consistent average temperature over the last three years.

The charts below shows a crude weighted average of Heating Degree Days (HDDs) across Europe. Overall, the weather has been extremely kind to oil indexation. The extra 30 bcm of demand, had it been available to spot markets, could potentially have tipped the balance against oil indexation. It would certainly have added an extra dimension to the contract price renegotiations of 2009 and 2010, discussed in the following sections.

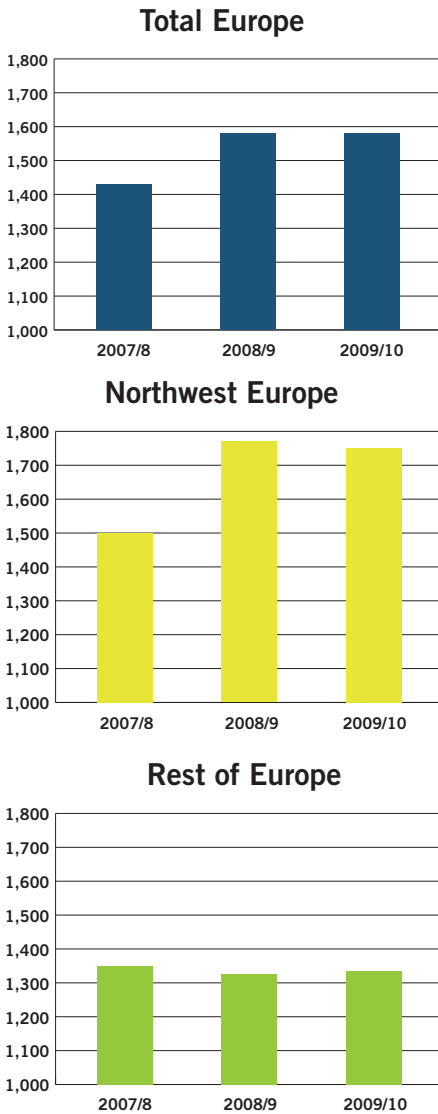
Strategy Formation

The major sellers would have been aware of the likely need for defensive measures in support of oil indexation from early 2009, with the extent of the required action becoming clear during winter 2009/2010.

The major sellers would equally have understood the need to act in parallel if the status quo of oil indexation was to be effectively defended. To minimize the short- to medium-term financial damage, they would certainly be motivated to act in parallel on both price and volume reductions. Statements by Gazprom and Algeria have supported the strategy of coordinated action in order to protect oil-indexed contracting structures; by contrast, the Norwegians and Qataris have preferred to remain silent on this issue. However, all of the key producers would have known by this time that if the oversupply situation could not be controlled by negotiated reductions in minimum bill offtake obligations, the result will almost certainly

4 In winter 2008/2009, temperatures in northwestern Europe fell below seasonal normal levels early in the heating season and remained cold until a warm period around Christmas break. The second half of the winter was variable, with some fairly deep cold spells, notably around the time of the Russia-Ukraine supply disruptions.

CHART 2 Winter HDDs From October 1 to March 10, Last 3 Winters



Source: Compiled by author

to the point where spot market prices rise to equivalent levels to oil-indexed prices

Under the Rigid Contract scenario, through their formal price renegotiation clauses, the continental wholesalers are at least partially protected from economic distress and more able to pass the economic pain to the upstream producers. And through back-to-back pricing, the wholesalers may recover at least some of the Take-or-Pay downside.

be economic distress for the wholesalers, followed by step changes to gas contracting practices across Europe. It would also have become apparent that recovery of the Middle Ground would require some exceptional price and/or volume flexibility on the part of the producers.

Hence, the meetings between the gas producers and incumbent wholesalers, which would have begun as early as the first quarter of 2009, assumed a greater importance as the year progressed. Where possible, negotiations would have been performed in parallel in order that a uniform and coordinated response could be developed across a range of purchasers.

What Would the Producers' Strategy Be?

It is logical to assume that the producers' strategy would be one of revenue maximization, but how could this be best achieved? The two options most likely under consideration would have been:

- **The Rigid Contract scenario:** where customers were held rigidly to the terms and conditions of the contract
- **The Volume Flexibility scenario:** where contract volumes are revised downward

However, very importantly, the price renegotiation clauses do not relieve the purchasers of their volume obligations under the long-term contracts. This has proven especially problematic under prevailing market conditions, in which the overall market is diminished, and competitors are engaging in predatory practices, leaving wholesalers oversupplied, even at lower prices. Arguably the Rigid Contract scenario is doomed once the Middle Ground has been seriously breached, as the end result will be the destruction of the customer's businesses, with the likely demise of oil indexation.

Ultimately, of course, this is not just a problem for the purchaser, as the enforced sale of undiminished volumes will result in further downward pressure on prices—which can then be passed upstream to the producer.

Under the Volume Flexibility scenario, the seller accepts the downside in the expectation that it will yield the best outcome in the prevailing situation. As discussed previously, the Middle Ground can be recovered either by volume or price reduction, but due to the price elasticity of demand, volume reduction is by far the producers' most effective tool for revenue maximization.

The principal problem is that the tool does not work to maximize revenues if it has to be applied by one of several producers; it becomes more effective when the volume reduction is spread across all producers. In other words, it takes a brave supplier to be the “first mover” in the absence of agreement by competing producers to make equivalent concessions.

A further important question that undoubtedly arose was whether any contract revisions would be temporary relief (during the current period of recession), or whether permanent changes had to be made.

During the negotiations of 2009 and early 2010, the parties considered the options available and negotiated under a virtual media blackout before announcements were made by Gazprom in late February and by Statoil in early March 2010.

Contract Revisions Unveiled in Q1 2010

In February 2010, Gazprom announced that a percentage of its gas supplies would be indexed to spot market prices. Although its statement surprised many observers (because it reversed a previously rigid policy), it was a fairly logical strategic move under the circumstances.

According to Alexander Medvedev, Gazprom's deputy chief executive, it had renegotiated some contracts with European customers for a three-year “crisis pe-

riod.” The key elements of the deals were that:

- up to 15 percent of volumes are linked to spot market gas prices, and
- certain volume obligations had been reallocated from the crisis period to a future period, but they were not losing volumes overall.

Medvedev added that contracts had been renegotiated with key purchasers E.On, ENI, and GDF SUEZ. He was keen to stress that the basis of the company’s business in long-term oil-linked contracts remains the same, that the renegotiation was purely for a period of three years, and that contracts would be unaffected in the medium to long term.

E.On confirmed that certain volumes would no longer be pegged to the oil price but to the gas price on spot markets, giving E.On Ruhrgas the flexibility to adapt its offers for customers.

Following the Gazprom announcements, Statoil, in a separate statement⁵ in March 2010, confirmed earlier reports that during 2009 it had renegotiated its long-term gas sales contracts with some buyers to include new terms, including spot-market elements. Spot market indexation had already been used by Norwegian sellers for sales into the UK, and this was rumored to have been extended to partial and even the total indexation of contracts for sales into the spot market areas of northwestern Europe. The March 2010 statement is therefore taken as a sign that the spot indexation was extended and/or increased. Statoil statements have also said that the spot market volumes have been written into a separate contract in order that the legacy contracts remain largely unchanged. This appears to indicate a parallel long-term contract for volumes permanently subtracted from the oil-indexed contracts, which may be a key difference from the Gazprom solution.

Bjorn Jacobsen, the senior vice president for natural gas marketing at Statoil, said that the revisions were carried out within terms agreed to in the original contracts, demonstrating the continuing validity of the original long-term deals. He added that the deals were handled by the terms within the contracts and he gave no indication that the Statoil deals were temporary in nature.

At the time of writing, Sonatrach has not yet confirmed that it has made any concessions on price, but reports have consistently stated that Minimum Bill commitments have been relaxed.

5 Statement made at the Flame gas conference at the beginning of March 2010.

Analysis of the Contract Revisions

At the risk of stating the obvious, the alacrity of response increases with proximity to the spot markets of northwestern Europe. It appears that Statoil was much quicker to respond to the market changes than Gazprom, which, in turn, appears to have responded faster than the Algerians. This is likely to have been a contributing factor to resilient sales of Norwegian gas in 2009.

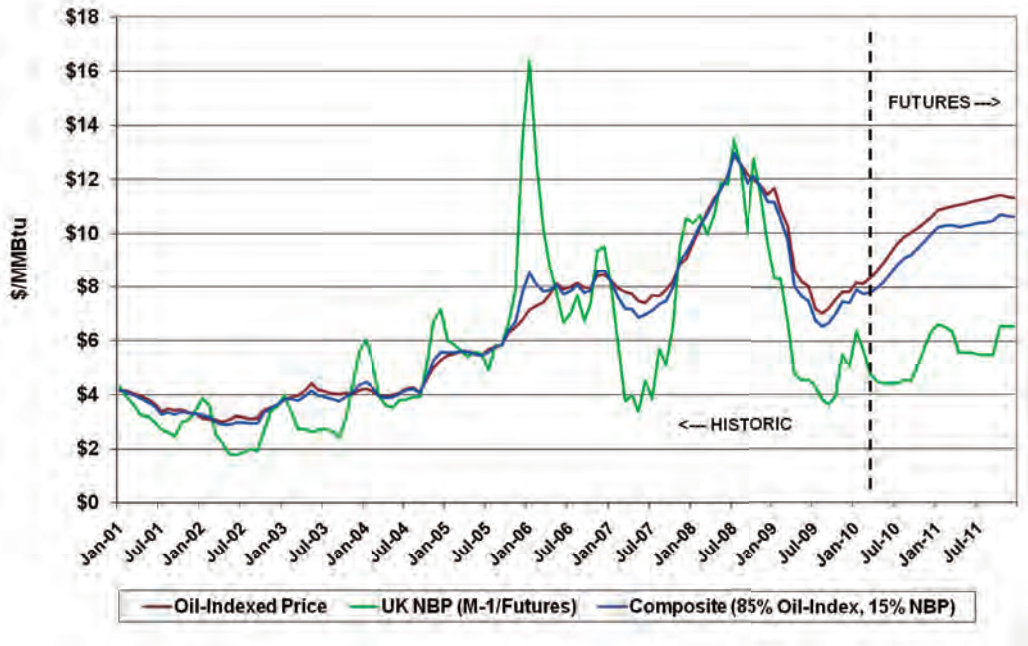
The contract revisions bear all the hallmarks of the Volume Flexibility scenario discussed above, but in a classic “defensive strategy” by Gazprom and Statoil in support of long-term oil-indexed gas contracts, the changes give the purchasers additional limited relief on the pricing front. However, the response by the Norwegian and Russian sellers is considerably more sophisticated than a simple volume flexibility response.

IMPACT OF THE PRICE REVISION

By introducing a tranche of spot market-priced gas, the incumbent wholesaler has the ability to compete with the second-tier marketers. It also helps to enhance flexibility and effectively extend the Middle Ground, providing a buffer zone within which the purchasers will be financially motivated to nominate Russian/Norwegian supplies in preference to competing supplies. The producers thereby achieve their objectives of protecting the oil indexation, and maintaining the Minimum Bill Volume. On the negative side for the producers, a percentage of the Minimum Bill Volume is sold at spot market prices. However this concession is relatively small compared to the benefits, as shown in the chart on page 65.

The chart uses German Border Price (GBP) as a proxy for an oil-indexed price, projected forward using an oil-index formula derived from line-of-best-fit methodology. This is compared against the UK NBP month-ahead price, and composite price reflecting a combination of the two. This analysis shows that on a look-back basis, over the period 2005 to 2010 inclusive, the composite index generated prices 2.5 percent below the oil-indexed price. Looking forward, using market forward prices from early March 2010, spot prices in the period ending in 2012 average 34 percent below the oil index, but the composite average is only 5 percent below the pure oil-indexed formula. When seasonality of prices and volumes is taken into account, the differential is reduced because of higher spot market futures prices in the winter. Therefore, in allowing 15 percent of volumes to be taken at spot market prices, the Russians and Norwegians are effectively giving

CHART 3 Analysis of the Impact of 15% Spot Price Indexation



Source: Compiled by author from various sources

a price discount of 5 percent in the short to medium term, and likely declining, or even reversing as the oversupply disappears.

For the producers, the rationale for this move is that the 5 percent price reduction is the least-worst of all the alternatives. In the short term, this concession probably achieves the objective of revenue maximization. For the incumbent wholesalers, it allows them to offer spot-priced deals to their most vulnerable customers, thereby mitigating further sales volume losses.

THE IMPACT OF THE VOLUME CONCESSIONS

It is not yet clear how much the minimum bill obligations have been reduced, but a figure of 10 percent would appear to be of the right order of magnitude required to contain the oversupply. The Gazprom statements imply that these reductions will be added to minimum bill obligations in later years, post-2012.

The gamble for traditional producers is that the Middle Ground is now large enough to absorb the temporary glut of LNG, and that the oversupply will have

TABLE 5 Indicative European Gas Supply Scenario for 2010

INDIGENOUS PIPELINE SUPPLIES		
2010 Bcm	Oil-indexed	Spot
Netherlands	40.0	35.0
UK	7.0	49.0
Germany	9.0	3.0
Romania	9.0	0.0
Denmark	7.0	1.0
Italy	7.5	0.5
Other	8.0	0.5
Subtotal	87.5	89.0

EXTERNAL PIPELINE SUPPLIES		
2010 Bcm	Oil-indexed	Spot
Russia	120.0	14.0
Norway	64.0	41.0
Algeria	35.0	1.0
Libya	9.0	0.0
Iran	6.0	0.0
Azerbaijan	5.0	0.0
Subtotal	239.0	56.0

LNG SUPPLIES		
2010 Bcm	Oil-indexed	Spot
Algeria	20.0	4.0
Qatar	9.0	15.0
Nigeria	10.0	0.0
T & T	8.0	4.0
Egypt	7.0	0.5
Other	7.0	4.0
Subtotal	61.0	27.5

TOTAL SUPPLIES		
2010 Bcm	Oil-indexed	Market-priced
Subtotal	387.5	172.5
Total	560.0	

Source: Collated by author from various sources

disappeared by October 2012. At this point, the volumes available to spot markets will have declined, and the gas market volumes will have recovered to their pre-recession levels. Also, at this point, the incumbent wholesalers must take additional volumes to compensate for the temporary reductions during the three-year period from October 2009 to October 2012.

A potential problem with this strategy is that it could open the door to new volumes flowing into Europe. 2010/2011 remains potentially a period of significant oversupply and if LNG imports maintain their recent ability to access willing customers then the limits of the Middle Ground may once again be tested. However, on the other side of the equation is a recovery in demand in 2010, with prospects of continuation into 2011. Indications are that industrial demand is significantly stronger in 2010 than in 2009, and this is on top of a strong heating gas demand in the first quarter of 2010 that also created the need to top up storage facilities during the summer. The stronger industrial demand in 2010 is also a positive indicator that power generation gas demand will remain healthy. Although it is early to estimate 2010 outturn gas demand, it seems cer-

tain that the decline of 2009 has been reversed and that consumption will recover by somewhere in the range of 25 to 35 bcm over 2009 levels.

Table 5 gives indicative numbers for supplies in 2010, using the upper end of the demand range. The assumption is made that indigenous gas supplies decline further, based on long-term decline rates in the mature producing regions, mitigated by some uplift for improving economic conditions. LNG supplies are significantly higher than in 2009, based on increased global availability of LNG, with some increases in supplies to Asian markets.

The indicative numbers show that, because of the decline in indigenous production and the market size increase in 2010, there is some headroom for Russian and Norwegian supply volumes to expand from 2009 levels. The key conflict in battleground 2010 is clearly between spot LNG supplies and incumbent pipeline producers. This year, the defenders have reluctantly armed themselves with the same powerful weapon as the insurgent—market-priced gas.

HAS THE PRESSURE BEEN RELIEVED—OR SHIFTED?

Although the Take-or-Pay pressures on the incumbent wholesalers appear to have been relieved in 2010, this does not lead to the conclusion that the next two years will be comfortable for traditional oil-indexed gas contracting structures. The stresses between oil-indexed and spot markets are multi-dimensional, and the recent contractual changes can create problems elsewhere. The resurgent problem in 2010 is the demand of dissatisfied consumers. Emerging from the recession, end-consumers across Europe have become increasingly aware of the wide differential between oil-indexed and spot markets. At some point the wholesalers, in protecting their market share, need to decide which customers to protect from spot price insurgency by competitors. In offering some customers lower prices, stresses are created with customers paying higher prices. In 2010, the availability of spot gas supplies will have been increased by between 20 and 30 bcm, bringing many new customers into market-based pricing structures. The problem is that there is not enough market-priced gas to go around for the industrial customers and power generators, let alone the increasingly dissatisfied distribution customers. In other words, the stress point in the first half of 2010 was temporarily shifted from the producer/wholesaler interface onto the wholesaler/end-customer interface. Drawing on the UK experience once again, customer dissatisfaction became a major

driver of change. At the time of writing it is looking increasingly likely that this will be the same in continental Europe, as end-customers vote by placing their accounts with market-priced suppliers. With market-based pricing mechanisms still on the ascendancy, it remains to be seen if the stresses on oil-indexed mechanisms will prove to be manageable.

WINNERS AND LOSERS

The most obvious losers from liberalization to date are the wholesalers. The first casualties in the battle between incumbents and regulators were the cozy relationships whereby the wholesalers passed costs through to consumers, taking a steady margin for very little risk. Some government budgets were also affected. In Germany, Italy, the Netherlands, Belgium, France, and elsewhere, the utilities were partly or fully owned by national and local governments, contributing to government coffers and in some cases paying for libraries, swimming pools, and other local amenities.

In the last decade, loss of monopoly status and market liberalization reduced the market power of the incumbents, and, in many cases, this was followed by unbundling, sometimes legally, other times by ownership separation. To make matters worse, the decade ended with them paying substantial amounts to producers for gas they could not sell. The massive powers of the renegotiation clauses should not be forgotten, but these do not protect against volume over-commitments. Although the economic pain has been relieved by recent negotiations, the threat to their livelihood has not disappeared. They continue to suffer from loss of market share, albeit at a reduced rate, and a competitive disadvantage to second-tier players. In the face of further potential problems, some incumbent wholesalers may face impaired credit status and declining share value. Most large incumbent wholesalers remain within vertically integrated companies with diversified cash flows, and this can be used to support the gas business. The downside is that it can make it difficult to argue for concessions on long-term contracts.

The failure of some wholesalers could, in turn, leave more room for others to expand. Some of the multi-utilities may yet become more powerful. At the entrepreneurial end of the spectrum, some of the faster-evolving companies have managed to keep up with and even get ahead of the game, expanding beyond the traditional demarcated areas and layers, and increasing their sales and trading businesses. The recent market conditions have helped to accelerate this trend.

The clearest beneficiaries of the collision between spot and oil-indexed gas on the continent are second-tier buyers, local distribution companies and industrials, and new market entrants that source gas under shorter-term contracts, and who have seized the moment, capitalizing on liberalized infrastructure access to source and move cheaper gas and grow their market share.

Most upstream producers, after many years of working with oil indexation together with the incumbent wholesalers, are strongly supportive of oil indexation. In the short term, for as long as there is oversupply, it can be universally agreed that the oil-indexed prices will yield higher prices and that upstream players selling into spot markets will be losers in terms of annual gas revenues. Gazprom, with its pressing need for both investment funds and contributions to state coffers, can justifiably be forgiven for supporting the status quo in relation to oil indexation. Its short-term outlook is likely shared by Sonatrach in Algeria. However, selling out-of-the-money gas into oversupplied markets is not a sustainable strategy, as spot market sellers will progressively gain volume at the expense of oil-indexed sales. Ultimately, in the face of continued oversupply, the oil-indexed sellers have little choice but to reduce prices or volumes. In other words, if the recent measures do not work, further concessions by the producers are inevitable.

In the context of access to European markets, the LNG sellers and European terminal operators must be considered winners in 2009 and 2010, as LNG sales have reached record highs. Without the opportunities provided by European terminals, the next best option for sellers would have been the oversupplied U.S. marketplace, where netbacks would have been lower.

Having said that some major gas producers support oil indexation, some upstream players feel that the destruction of the powerful incumbent wholesalers would put the producers back in the driving seat. Their arguments are many, but most powerful perhaps is that put forward by Gazprom itself that spot markets will ultimately yield higher netbacks for producers than oil-indexed deals. With the production in the hands of a few large producers, Europe risks exposure to oligopoly behavior (which some argue would be almost certain to emerge), enabling the producers to control prices through the gas valves on the key pipelines. Ironically, the loss of the battle to defend oil indexation could result in a power shift away from the incumbent wholesalers toward the producers. The belief of some observers that all of their upstream producers support their oil indexation mantra may in part be a forgivable self-delusion. The truth is that there are wide variations between the opinions of individuals within both the producers and wholesalers.

The upstream producers could find that their special relationships with major incumbent wholesalers are less important than previously. In the event that incumbent wholesalers continue to lose market share, the producers will increasingly bypass the wholesalers by selling to traders, second-tier players, and increasing numbers of end-users. This change will give the upstream players a broader vision of European market dynamics, which will inevitably lead to increased market penetration. Together with an increasingly scarce resource (beyond the current oversupply), this has the potential to increase the power of the upstream players. The counter to this power is likely to be increased interaction with the EU and national regulatory authorities.

Among the producers, the principal beneficiary, due to its location and established policies favoring the husbanding of the national resource, and special buyer/seller role of GasTerra, would appear to be the Netherlands.

Current dynamics certainly point to a shift of industry power in favor of EU and national regulatory authorities. Based on the negotiated agreement of the Third EU Gas Directive, 2009 saw the establishment of two new European regulatory institutions: ACER (Agency for the Cooperation of Energy Regulators) and ENTSOG (European Network of Transmission System Operators for Gas). Participation in pan-European institutions, and the necessity of becoming well-versed in EU legislation and policy, elevates national regulators into a coordinating role that becomes indispensable in the formation of national energy policy. This is well illustrated by the recent issue of gas demand forecast scenarios by the UK regulator for comment within the national energy industry. The issue of the EU Second Strategic Energy Review scenarios in November 2008 threw many of the gas and electricity industry infrastructure and investment plans into a state of suspended animation. In the meantime, while the EU struggles to fill the gaps between meeting its environmental targets and finding a practical solution to its energy needs, the UK energy regulator was the only available candidate to bridge the constantly shifting disparity between a nebulous European energy policy and an unsettled UK energy policy. While the task itself is logically impossible, it does illustrate the point that regulators across Europe have the potential to be drawn into a similar coordinating role.

With respect to the winners and losers in the European gas market, one may agree with Charles Darwin's statement: "It is not the strongest of the species that survives, nor the most intelligent that survives; it is the one that is the most adaptable to change."

WILL OIL INDEXATION SURVIVE IN THE LONGER RUN?

During the last decade, there was a noticeable acceleration of change, both in the physical and information systems infrastructures and the attitudes of the participants, and a growth of market liquidity. On top of the underlying change, there is the recent oversupply crisis for many players resulting from reduced demand. Will this result in further gradual evolution or an outright revolution in contracting structures?

While acknowledging the accelerated evolution, with the prospect of further step change or revolution it would be extremely unwise to underestimate the resilience of the existing long-term contracting structures. Volume flexibilities around the ACQ and price renegotiation—including modification of the base formulae and indices—are powerful tools that have been successfully deployed repeatedly in the past, albeit to navigate shoals less threatening than those presently facing the European gas industry.

Traded markets are clearly ascendant, and oil-indexed markets currently in decline. This does not mean that there will be an overnight step-change, however. It does mean that we must consider the future rate of change. Oil indexation is likely to remain in continental Europe alongside traded markets for a number of years into the future, as it still exists today in the UK, many years after the spot-market “takeover.”

The more demanding question is whether traded markets for gas will become the universal Europe-wide price-driver, and under what conditions? The movement toward traded markets will depend on gas demand (itself dependent on the rate of economic recovery), the availability of market-priced gas (particularly LNG), and the outcome of the recent round of price renegotiations, to mention just a few key drivers. Will the actions taken to relieve the stress of oversupply create greater tensions elsewhere that become the drivers of change?

While short-term dynamics clearly indicate a growth in traded markets, in the longer term, the requirement for gas in power generation is likely to tip the balance in favor of traded markets. As mentioned previously, long-term oil-indexed contracts do not sit comfortably with the dynamics of power markets. Of particular interest in this respect is the recent 20-year sales agreement signed by Statoil and Poweo, for power generation in France, reportedly using a combination of gas, electricity, and carbon market prices, under a profit and risk-sharing mecha-

nism. With other gas markets in Europe generally on a decline, the power market assumes a growing importance in future gas contracting. It may be this dynamic more than any other that will shape the future of European gas contracting.

Another major factor in the discussion is the range of practical problem of switching from oil-indexed to market-pricing mechanisms. To give a few examples:

- **Revise or Discard:** Would the existing contracts be revised with market price indexation, or discarded?
- **Compensation:** Major gas producers have signed oil-indexed contracts in the order of 430 bcm per year, and a total volume in the order of 7,000 bcm. Valuing these contracts at \$300 per thousand cubic meters gives an annual value of around \$130 billion, and a total value of \$2.1 trillion. Given that gas market prices are considerably below oil-indexed prices, the potential case for compensation of producers can clearly be seen. Who should pay the bill?
- **Volume Commitments:** In liquid commodity markets, where gas can be bought or sold through a variety of counter-parties at market prices, volume supply commitments and purchase obligations become unnecessary, or assume a different meaning. There is an argument that sizeable purchase commitments to suppliers reduce the volumes of gas traded in the liquid markets, creating a higher volatility than if all the gas were traded.
- **Geographic Area:** Where liquid gas commodity markets exist in north-west Europe there are, as yet, no reliable benchmark prices across the remainder of Europe.
- **Monopoly Supply Areas:** A number of EU, Balkan, and central European countries currently rely very heavily on a single supply source for natural gas. Even in the event of a gas-market price becoming available, the supply competition necessary to underpin liquidity may not be available for a number of years.

Although the writer has no doubt that there are many experts willing and able to provide practical solutions for all of the above problems, he also has no doubt that consensus between the multiplicity of solutions will be difficult and time-consuming to achieve.

CONCLUSIONS

- For most of this decade, gas demand forecasts were over-optimistic, resulting in an aggregate over-contracting of gas in Europe.
- The European gas market supply portfolio is commensurate with a market size of around 600 bcm/year, and in 2008 it was contractually oversupplied by about 40 bcm/year.
- European gas consumption was supported in 2009 (and into 2010) by coal-to-gas switching due to the comparatively high price of coal, especially in northwestern Europe. Considerations related to the large combustion plant directive, coal stockpiles, and price could potentially have reduced this support, causing a further drop in gas demand on the order of 20 bcm.
- The combination of new market-based (mostly LNG) supplies and recession-induced demand contraction (in 2009, European gas demand slumped by 7 percent) have rapidly diminished the available market for gas supplies at oil-indexed prices.
- In 2009, the incumbent wholesalers could no longer manage the oversupply within their contract flexibility clauses. As a result, a number of the incumbent European wholesalers, such as E.On, ENI, and Botas, were exposed to Take-or-Pay payments in the fourth quarter of 2009.
- Oil-indexed LNG cargoes continue to flow to Europe under existing long-term commitments, with increased obligations through 2009 and 2010, and limited contractual potential for diversion.
- Spot LNG suppliers, led by Qatar, have benefited from the ability to access the European infrastructure and markets that currently yield the highest netbacks for their surplus supplies (once Asian demand is saturated).
- The task of recovering the Middle Ground fell into the hands of the major producers in 2009. Voluntary “Minimum Bill Quantity” reductions on a temporary basis are the primary tool of choice for producers attempting to regain the Middle Ground. This was supplemented by pricing around 15 percent of supplies against market-based gas prices.
- The outcome of negotiations will likely relieve the pressure on the producer/wholesaler interface, but as wholesalers decide who gets the spot-priced gas, this could lead to new tensions at the wholesaler/end-customer interface, leading to new pressures for change. *(continued on next page)*

CONCLUSIONS *(continued)*

- In the event of a prolonged oversupply supported by rising spot gas availability, the oil-indexed producers can maintain the Middle Ground for a number of years by progressive Minimum Bill revisions and price renegotiations.
- At the other end of the spectrum of possibilities, gas markets have the potential to recover quite quickly from the oversupply position. As the Asian economies of China and India expand, attracting increased LNG supplies, and European indigenous production declines, there is potential for a switch from oversupply to undersupply. At this point there is a potential for spot price volatility and relatively high prices.
- Counterintuitively, some producers may be content to see the old regime modified, as in the long run it represents the only path out of the current cul-de-sac, in which gas is priced at a discount to oil. (Currently, German Border Price [GBP] \approx 70 percent of Brent.) It warrants noting that Algeria and Russia, and more recently in the LNG context, Qatar, have each at different times sought to move gas prices to oil price parity.
- The traditional market power of the incumbent wholesalers will be further diminished through competition, unbundling, and market fragmentation, while the actual supply will remain in the hands of only a handful of sovereign actors.
- The gas producers are likely to come out of the process with more power. However, the power lost by the incumbent wholesalers may have to be shared with the increasingly powerful EU and regulatory bodies.
- Future rounds of the gas industry power struggle may play out increasingly between the EU and the producers' respective sovereign governments.
- The prospect of a revolution in gas contracting practices has effectively been deferred by recent contractual changes. Whether or not the current dynamic precipitates a revolution or the more widely preferred managed evolution in contracting and trading of gas in Europe remains an open question. The outcome will heavily hinge upon macroeconomic developments from 2010 and the disappearance of the gas surplus.
- In the event of an accelerated geographical spread of market-based pricing mechanisms, there are a number of practical problems that will be difficult and time consuming to resolve.

CHAPTER 4

**REVIEW OF THE
CONTRACTING
PRACTICES OF KEY
GAS INDUSTRY
PLAYERS**

REVIEW OF THE PRINCIPAL GAS PRODUCERS

This chapter examines in detail the key players in the European gas market. After providing the background for how these players have operated in the recent past, it provides insights on their reactions to the developments in this gas market in the past two years. A main distinction is drawn between strategies adopted by suppliers and Europe's principal gas purchasers.

RUSSIAN GAS EXPORTS

After much lobbying by independent Russian, Commonwealth of Independent States (CIS), and international oil and gas companies, Gazprom retains its absolute control of Russian gas exports. The Russian government knows that the Gazprom monopoly is a massive bargaining chip and is unlikely to relinquish Gazprom control, unless it can extract a concession of similar magnitude.

Gazprom is divided into numerous companies and factions, so it is difficult to gauge its opinion on some key issues. However, there were a number of fundamental principles of the Russian policy on gas exports:

- Sale of gas on the basis of long-term export contracts by the “Take-or-Pay” principle
- One channel of export of gas to European countries (Gazprom OJSC and its 100 percent subsidiary, Gazprom Export LLC)
- Access to end-users with a simultaneous increase in the share of delivery to internal markets of European countries
- Setting gas prices (with a lag of six to nine months) dependent on the market value of petroleum products, using the appropriate formula
- Attainment of monopoly of purchase of gas from Central Asian countries
- Investment in the development of new deposits dependent on obligations under long-term export contracts. (Chairman of the Board of Gazprom OJSC, A. Miller, put this principle as follows: “Gas will not be extracted until it is sold”)

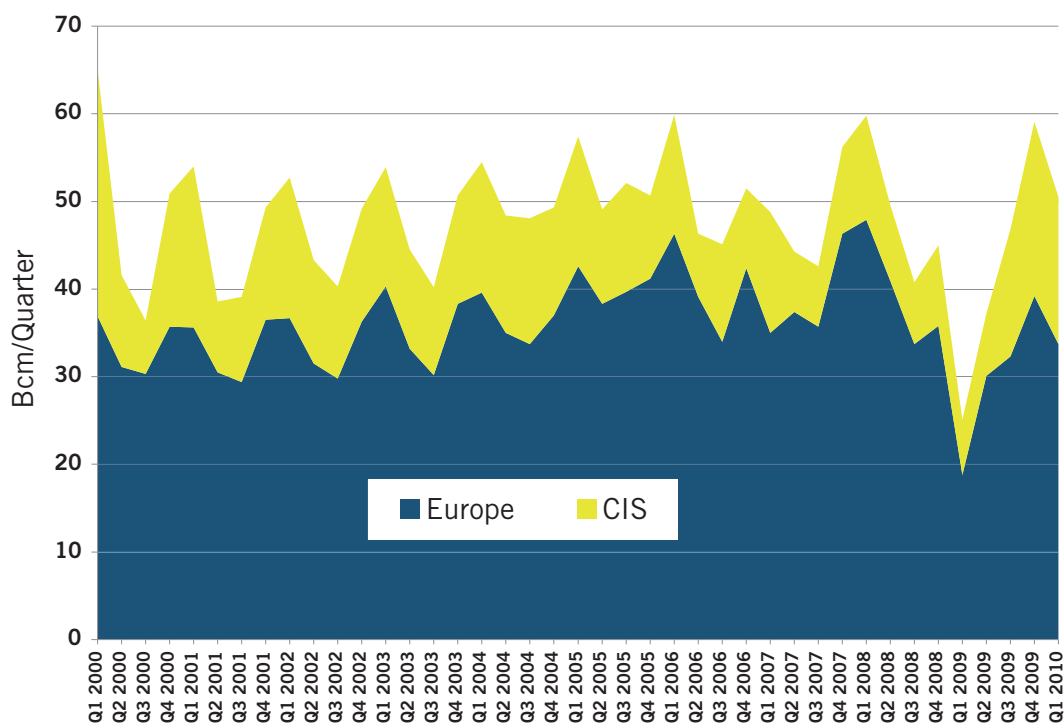
- Diversification of transportation routes to reduce transit dependence on neighboring countries. Gas pipeline projects include Nord Stream, South Stream, and Altai (West Siberia–China).

Gazprom Export, a relatively small business unit, is responsible for gas deliveries to European countries. Sales to former CIS countries remain under Gazprom’s more politically driven centralized organization.

Although these principles have been breached in several respects, they remain indicative of Russian government and Gazprom aims.

The chart below shows historical Russian exports to Western Europe (non-CIS) and CIS countries:

CHART 1 Russian Gas Supplies to Europe and CIS—Quarterly Sales 2000 to 2010



Source: Bank of Russia

Spot sales into continental markets are possible through subsidiary companies, but Gazprom is always cautious of upsetting key customers and potentially triggering price re-opener negotiations. Sales into the UK market meet less internal

resistance as there are no long-term contracts for sale in the UK. Gazprom Export can act as supplier only to Gazprom Marketing and Trading in the UK market.

The bulk of Russian gas to Western Europe is contracted under long-term agreements indexed primarily to gasoil and secondarily to heavy fuel oil. The ratio of oil products is intended to reflect the end-customer markets. High sulfur HFO has been phased out of EU energy markets by progressive legislation and taxation and a similar squeeze is now being applied to low sulfur HFO. As a result, high sulfur HFO has largely been removed from gas price indexation, and the percentage of low sulfur HFO in long-term contracts has been progressively reduced. In former CIS and Southern European countries the percentage of HFO in the primary energy mix tends to be higher, and this is reflected in the price formulae where 50 percent HFO indexation can still be found.

Following the breakup of the Soviet Union, the “favored nation” gas supply relationships with former Iron Curtain and CIS countries were broken, but inadequate attention was given to the restructuring of gas industry relationships with the newly independent states. Despite their independence, some states over-optimistically assumed that they would continue to purchase gas at Russian domestic prices. The Russians made short-term contracts with a number of states with the intention of incrementally increasing prices to “world gas market” rates as the contracts were renewed. Upon German reunification in 1990, the Eastern German supply contracts were almost immediately renegotiated at Western prices, and several other East European gas supply contracts were brought up to European price levels over the next few years after the Russians moved out. Once prices reached Western levels, longer-term contracts were signed by countries such as the Czech Republic, Poland, the Slovak Republic, and Hungary. In less economically developed economies, such as Romania and Bulgaria, it took longer to reach Western price levels. Most EU countries now pay prices similar to the German border price, with the exception of the Baltic States.

In Lithuania, the import price of natural gas was indexed only to heavy fuel oil on the international market until the end of 2007. Following amendments to the gas sales and purchase agreement effective January 1, 2008, the natural gas import price formula included a percentage of gasoil for the first time, but remained lower than the prices for other EU member states. This reflects a market dominated by relatively inefficient gas-fired power generation and fertilizer production. In 2008, only 8 percent of the gas was supplied into the residential sector. Estonia pays a similar price as Lithuania. Latvia pays a lower price than other Baltic States, reflecting the fact that it imports gas only during the summer months (a counter-

seasonal gas import profile). All three countries are in the process of transition to full EU legislation compliance and living standards, and this is reflected in their “transitional” gas contract status.

The former CIS countries of Ukraine, Belarus, and Moldova, and some of the Balkan countries, notably Serbia, continued to receive preferential rates as their economies struggled to make the transition into self-sustaining or market economies. The price for continuation of “preferred nation” status in gas pricing was the relinquishment of equity in their gas infrastructure to Gazprom. The Ukraine notably refused to accept Gazprom terms for equity participation in their transmission system, with the inevitable result of demands for market-based gas prices. The Gazprom-Ukraine gas relationship remains unresolved, and once again the issue of Gazprom equity in the Ukrainian system appears to be under discussion.

Various additional anomalies exist in some of the Russian gas sale and purchase agreements to Europe, including:

- **Capping and Inflation:** Some of the contracts for the sale of gas into Germany have a percentage of HFO “capped” at quite low levels. The intention was to reflect the portion of gas intended to be used in gas-fired power generation in competition with coal. The absence of a widely acceptable coal price index in Europe was a problem for many years and, as a result, various indexation mechanisms were used as a substitute, the most common being either an inflation index or a capped HFO element. Inflation was used in some countries such as the Netherlands, but this was legally unacceptable in Germany so the “capped” element was preferred. In some cases it is reported that 30 to 50 percent of the HFO element is capped. A substantial capped element has also been reported in the first Russian gas sales contract to Turkey.
- **Spot Price Indexation in Long-Term Oil-Indexed Sales Agreements:** This was announced by Gazprom in the first quarter of 2010.
- **Spot Sales into Continental Europe:** As mentioned previously, this can be problematic in relation to contract price renegotiation clauses. When spot prices are higher than oil-indexed prices, customers with long-term oil-indexed agreements will generally be nominating daily volumes at or near the upper limit. At such times, Gazprom will have no internal disputes over releasing additional volumes into the European spot markets. When spot prices are below oil-indexed prices, it will be difficult for Gazprom to release volumes directly into continental spot markets, both bypassing and undercutting long-term customers. However, it will be possible to release spot volumes to existing customers, provided they honor their

minimum quantities under the long-term Take-or-Pay contracts. In fact, it may be in the best interests of Gazprom to supply the volumes—if they don't, the gap will quickly be filled by a competitor.

- **GSA Concluded with Gasunie of the Netherlands as a “Sellers Nomination”:** In return for giving the seller the right to nominate daily volumes, Gasunie received a discounted price.
- **Spot Sales into the UK:** It might be thought that Gazprom could simply sell unlimited volumes of spot gas into the UK without upsetting its continental customers. However, the unrestricted sale of spot gas into the UK would have the effect of supplying competitors with gas for resale to undercut Gazprom customers in Europe by re-export via the Interconnectors. Where spot markets are at a premium to oil-indexed prices, again there is much less of a problem. Similarly, UK spot sales to existing continental customers are less problematic than sales to their competitors. It should therefore be assumed that Gazprom spot sales, even into the liquid markets of the UK, are constrained by company internal stresses.
- **Sales by Intermediaries:** For reasons not immediately obvious to the independent observer, a number of Russian gas sales have been made in Eastern and Central Europe via a variety of entities structured in a non-transparent manner, by means of complex chains of intermediary companies and trusts. These companies were created around the purchase of gas from former CIS countries, particularly Turkmenistan, and serve as vehicles for the resale of gas to the West. Deals were done with national gas companies, including in the Ukraine and Poland, and some of these companies (such as Itera in Hungary) established gas sales organization to sell gas directly to large end-consumers. Following sustained political pressure from sovereign governments and the EU, and contract disputes with Turkmenistan, several of these companies have now ceased to operate.
- **Distance Discounts:** Perversely, there is less competition in gas supply east of the German border. Consumers become more distant from Dutch, Norwegian, UK, and Algerian pipeline gas and all of Europe's accessible LNG terminals. This enables Gazprom to charge slightly higher prices to consumers in Eastern Europe when adjustments for transportation costs have been made.

Russian sellers maintain that in the future long-term oil-indexed contracts will withstand the onslaught from market-based pricing mechanisms, and that long-term contracts are necessary to underpin their future investments. Their goal is to bring all contracts up to comparable price levels, phasing out “favored na-

tion” clauses and anomalies. Parity with Brent crude is generally in the range of 65 to 80 percent, depending on location and performance of oil products and foreign exchange (FX) rates against the Brent price. Gazprom aims to increase this percentage over time to reflect the low-carbon properties of natural gas versus other fossil fuels.

Gazprom’s recent goals include the following:

- To expand Russian gas production
- To expand European gas sales to 180 to 220 bcm/year by 2020
- To continue acquiring assets in gas distribution companies and pipeline companies across Europe, enhancing its access to European gas markets
- To form alliances and partnerships in key transit states in order to secure deliveries
- To expand spot market deliveries through its London-based subsidiary Gazprom Marketing & Trading, which trades spot volumes in the UK and Belgian markets
- To invest in the LNG business in order to diversify into new markets, such as the United States and China
- To expand its presence in European and Russian gas-fired power generation
- To raise Russian domestic gas prices to the same level as European sales netbacks by 2012

Following the onset of recession in 2008, with associated reduction in gas demand, and the rapid development of shale gas in North America, Gazprom has recently been forced to revise a number of these goals. European and U.S. gas sales targets have been delayed (together with some production projects), and the company aims to avoid undermining contract sales with indiscriminate sales into European spot markets. However, the broader goal of expansion of export sales remains, with Asian markets becoming increasingly important targets.

In October 2003, the EC’s competition services reached a settlement with Gazprom and ENI regarding destination clauses and other restrictive practices in their contracts. Under the settlement, ENI is no longer prevented from reselling, outside Italy, the gas it buys from Gazprom. Gazprom is free to sell to other customers in Italy without having to seek ENI’s consent. ENI was also the first of the European importers to have reached a settlement with Gazprom. The companies agreed to the following key points:

- To delete the territorial sales restrictions from all of their existing gas supply contracts. The amended contracts provide for two delivery points for Russian gas, as opposed to only one in the past. ENI is free to take the gas to any destination of its choice from these two delivery points.
- To refrain from introducing the contested clauses in new gas supply agreements. To this extent, ENI committed not to accept such clauses or any provision with similar effects (e.g., use restrictions and profit-splitting mechanisms) in all of its future purchase agreements, be they for pipeline gas or LNG. Gazprom had already agreed last year not to introduce the clauses in future contracts with European importers.
- To delete a provision that obliges Gazprom to obtain ENI's consent when selling gas to other customers in Italy, even if ENI claims that it never relied on this provision. The companies already implemented the amendment allowing Gazprom to sell to ENI's competitors in Italy.

In addition to these contractual issues, ENI agreed to offer significant gas volumes to customers located outside Italy over a period of five years.

The settlement is significant because of the large volumes of gas (around 20 bcm/year), and the major players involved. The agreement effectively marked the end of destination clauses within the EU.

The gas year 2008/2009 will undoubtedly go down as one of the worst in Gazprom's history, as the company witnessed a massive drop in its production volumes. From a revenue perspective, however, despite being hit badly by falling prices and volumes, it had the second best year ever.¹ The disappointments are that expectations were set much higher and that results could have been much better if five to six bcm of sales had not been lost in January 2009 (worth an estimated \$1.5 to \$2 billion). Further bad news is that market projections for the medium term have been revised downward, spot market prices look set to remain depressed, and existing contracting structures are likely to remain under severe pressure from European market liberalization.

Predictably, Gazprom has reacted by maintaining its support for oil indexation and long-term contracting structures (in order to underpin the economics of large infrastructure projects already underway). On the other hand, Gazprom has responded thoughtfully to its leading customers, and negotiations have resulted in contract modifications to reduce the market pressures resulting from the

1 Its export revenues dropped from the record-high \$66 billion in 2008 to \$42 billion in 2009.

European gas oversupply. Benchmark deals were struck with pivotal customers including E.On and ENI who jointly purchase around 40 percent of Gazprom's exports to Europe. These deals served as models for later deals, some already completed and others either in progress or awaiting the scheduled dates for price renegotiation discussions. Over the course of 2010 and 2011, it is likely that the impact of these deals will become clear, and we will see whether the predicted revolution in contracting practices materializes.

For the future, it will also become increasingly difficult for Gazprom to maintain its dominant position in the former COMECON countries of Eastern Europe. EU initiatives on transmission system liquidity will make backhaul (sales against the prevailing physical flow of gas) a reality, and security of supply concerns will also result in an increasing physical reverse flow capacity from West to East, in the event of emergency situations. These measures in combination will likely result in increased gas supplies to Eastern Europe from the West.

NORWEGIAN GAS EXPORTS— STATOIL–HYDRO

Norway is not an EU member but a contracting party to the European Economic Area (EEA) agreement and therefore contracted to comply with specific EU legislation. The non-EU members have agreed to enact legislation similar to that passed in the EU in the areas of social policy, consumer protection, the environment, company law, and statistics, including legislation relating to the development of the “Single Market” in gas.

Like the Russians, the Norwegians need to develop upstream gas production in parallel with extensive pipeline infrastructures and feel that this process is best underpinned by long-term gas sales agreements.

Early gas sales were to the UK (Frigg contracts) and continental Europe (Ekofisk) under field depletion contracts (annual volumes profiled to match field production profiles). These contracts accepted the traditional price indexation formulae of their respective markets, UK end-user prices to industry and German gasoil and heavy fuel oil prices, delivered to customers in the Rheinschiene area. After the early Frigg requirements, the UK became self-sufficient in gas until after 2000, so no large new UK contracts were signed during this period. On the other hand, sales to the continent increased dramatically after the discovery of the super-giant Troll field. The gas volumes from Troll were so large that the

Norwegian government intervened to prevent sellers from flooding the market in competition with each other and driving prices down. A state gas sales organization was established (the GFU) and the Troll gas (together with other fields) was sold under long-term supply contracts, with most customers paying a similar price to each other. As a result, the Troll contracts, though highly confidential, became a leading European benchmark gas price, still used today. The Troll contracts were large volume, long-term, oil-indexed contracts, typically with 60 percent gasoil, and 40 percent HFO price indexation, using the German Rhein-schiene oil product prices as the reference source. Take-or-Pay was typically 85 to 90 percent and maximum take 110 to 115 percent. Some of the contracts had a top-stop on a percentage of the HFO indexation, though the top-stop could be increased in line with inflation.

Statoil is the major player in Norway by virtue of the Statoil merger with Norsk Hydro and the marketing of Petoro (Norwegian State share) production by Statoil. Total Statoil sales amount to over 70 percent of Norwegian gas exports.

Its strategy is fairly simple. The bulk of gas production is sold under long-term Take-or-Pay contracts and the contractual obligations are the first priority. Maintenance obligations are also substantial, and the scheduled shut down of facilities in the North Sea is arranged during the summer and customers notified months in advance. Whatever gas is left over is potentially available for spot market sales into the UK and continental Europe. These are clearly a lower priority.

Various additional anomalies exist in some of the Norwegian gas sale and purchase agreements to Europe, including:

- **Top-Stops:** Some of the contracts had a top-stop on a percentage of the HFO indexation, though the top-stop could be increased in line with inflation.
- **Power Generation End-Use:** The Troll contract to SEP (the Dutch association purchasing gas on behalf of a consortium of regional power generators) signed a contract with the GFU under which the gas price had a bottom stop of around €2.5/gigajoule (\$3.70/MMBtu at current FX rates), but a more gradual price increase slope than typical oil-indexed contracts. The price was “out of the market” (way above other gas prices) for most of the first ten years of supply. The contract was eventually renegotiated and disaggregated early this decade, following the dissolution of SEP.
- **Distant Customers:** The Troll contract to Spain requires transportation across the entire French gas transmission system from north to south at

considerable cost to the Norwegian sellers who pay a tariff to GRTgaz. As in other similar cases, there is an unwritten rule that the parties divide the costs, not necessarily equally but in some measure.

- **Spot Sales to the Continent:** Buyers have successfully argued that their end-user alternative fuel is spot market gas. As a result, the sellers have made concessions whereby a percentage of the contract volumes are sold at market prices. Spot percentages were further increased during recent price renegotiation—as announced by Statoil in the first quarter of 2010.
- **The Statoil–Poweo GSA of June 2010:** According to the Statoil press release, the 20-year agreement, starting in 2012, “builds on the liberalizing gas, power and emissions markets and the available market price indices to enable risk and profit sharing between parties.”

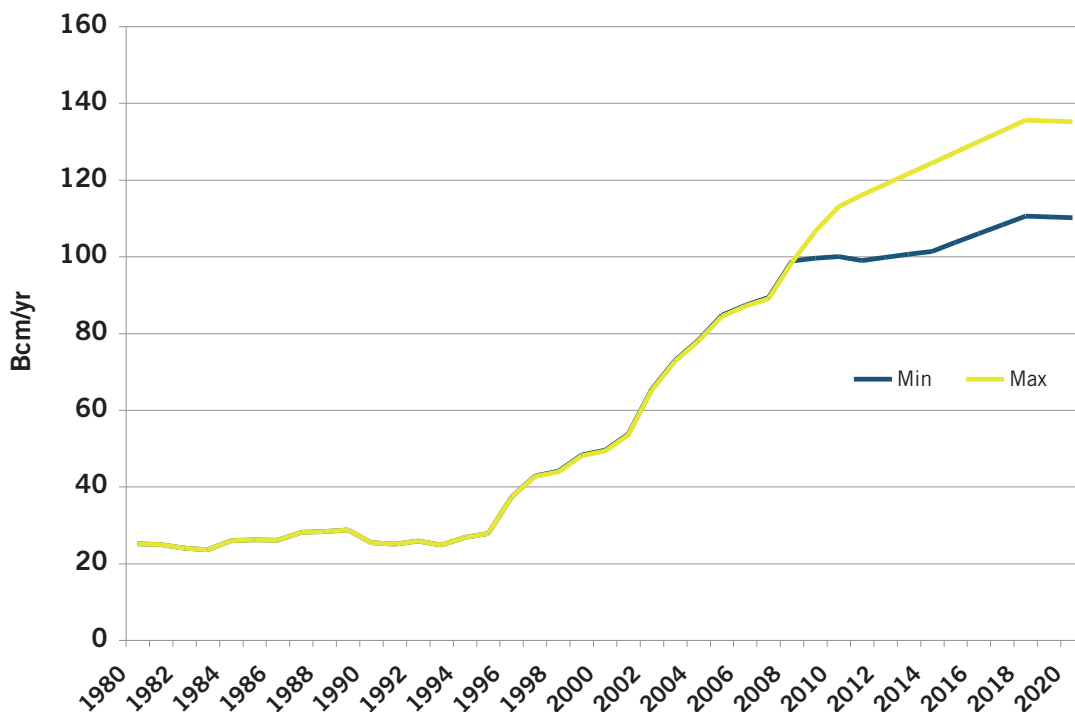
For the future, Statoil-Hydro plans to:

- Protect long-term contracts with its European customers
- Actively seek new customers
- Expand its short-term trading activities
- Diversify into upstream projects across the world, particularly in Arctic Russia, where its cold weather expertise can be best exploited

The chart that follows uses numbers provided by the Norwegian Petroleum Directorate to illustrate the historic exports and forecast range of Norwegian gas exports to 2020.

In 2008 and again in 2009, Norwegian exports to the UK were around 25 bcm/year; 2009 volumes were expected to be higher in the expectation that UK exports and planned European contract increases would both contribute to export growth. Outturn figures showed a small increase as market declines eroded the potential growth. It looks increasingly likely that Norwegian sales will remain toward the lower end of expectations in the near term, before rising with market recovery.

2009 saw a decline in revenues from gas sales, in consequence of lower oil-indexed prices and lower spot prices in the UK. The market conditions in 2010 and beyond are a concern to the government and the key players, but not nearly such a concern as in Russia or Algeria, where there is much greater economic dependence on revenues from hydrocarbons. In Norway, a surplus is banked every year for the future post-oil industry years.

CHART 2 Norwegian Gas Exports: Historic and Forecast

Source: Collated by author based on “Facts—The Norwegian Petroleum Sector” (2009), published by Ministry of Petroleum & Energy, Norway

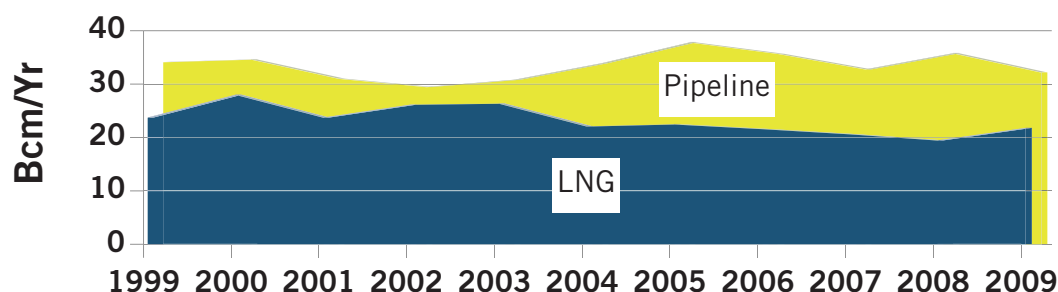
The response of the Norwegian gas players will be to continue business much as usual, servicing the long-term commitments as a priority. The Norwegians are long-term planners and, after many years of oil sales, are used to the idea that markets do not perform to expectations every year. The giant Troll field, which supports the bulk of Norway’s gas production, was developed in a \$20/bbl oil price world and has been extremely profitable during most years of production.

For the future, it is likely that as UK production declines this will result in spare capacity in pipelines such as FUKA, CATS, and SEAL that could potentially be connected to the Norwegian sector. Increased export capacity to the continent and onshore Scandinavia has also been discussed but would require additional new-build infrastructure. The next export route was expected to be a new pipeline to southern Norway and Sweden, but this was shelved in 2009, due to adverse economic conditions.

SONATRACH

Alongside Russia and Norway, Algeria ranks in the top three external gas producers supplying the EU. Whereas Russia and Norway predominantly supply by pipeline, about 40 percent of Algeria's gas exports to Europe are supplied as LNG. Exports for the last ten years are shown below:

CHART 3 The Status of European Gas Hub Development



Source: BP Statistical Review of World Energy

As in Norway and the Netherlands, gas exports are centered around a supergiant gas field, Hassi R'Mel.

Algeria's biggest customer, Italy, is supplied almost exclusively through the Enrico Mattei Pipeline system, commissioned in 1983, and effectively controlled by ENI, the developer and principal customer. Sonatrach strategy options in the direction of Italy are limited by the sale of gas to Italian buyers at the Algeria-Tunisia border. Third-party access needs the approval of ENI, Sonatrach, and STEG (the Tunisian state gas company). Shippers pay a tariff to STEG in the form of a percentage of the Tunisian transit volume, in the order of 5.5 to 7.5 percent, and a tariff to the Trans Mediterranean Pipeline Company (TMPC) for the subsea leg of the journey. Once the gas arrives in Sicily, an onshore pipeline tariff is payable to the Italian gas transmission company (Snam Rete Gas S.p.A).

The infrastructure ownership of the Algerian gas sales to ENI make the supplies difficult to displace from the Italian marketplace. The gas is sold at a relatively low price, but ENI bears the transportation costs for the subsea leg of the journey as a sunk cost. Therefore, the marginal cost of Algerian pipeline supplies delivered to ENI will often be lower than the marginal costs of ENI's competitors' supplies.

In the 1990s, the incumbent Italian electricity generator ENEL emerged as a second major customer. The dynamics of the ENEL deal are reported to include a price slightly higher than the ENI price and similar indexation formulae, with pipeline tariffs payable to STEG, TMPC, and SRGI as a third-party customer. The tariff terms are believed to be significantly more expensive than ENI's own transportation costs as an equity holder. As a result, ENEL has been unable to undermine ENI's cost base in the Italian gas industry. ENEL uses a significant proportion of its imported gas in its own gas-fired power plants in Italy.

During 2002/2003, ENI decided once more to increase the transport capacity of the Algerian gas pipeline. ENI received multiple requests from potential gas shippers for third-party access to the new capacity. It therefore established a procedure for the pro rata allocation of the additional capacity between the interested parties and entered into ship-or-pay transport agreements with a number of shippers on the basis they would share the investment in new capacity and to start importing gas into Italy as of 2007 to 2008, subject to a number of conditions.

Four shippers were reported to have fully met the conditions. According to the evidence later given to an inquiry by Autorita Garante della Concorrenza e del Mercato (AGCM), ENI subsequently sent a letter to the shippers who had entered into the ship-or-pay transport agreements, informing them that it could not implement the proposed allocation of the new capacity because of changed conditions in the Italian gas market from 2007.

ENI claimed that the revised forecasts on the medium-term gas supply and demand in Italy showed that, if the four new shippers were to import gas as of 2007 to 2008, the Italian gas market would be oversupplied, threatening ENI's ability to meet the Take-or-Pay obligations in its own gas supply agreements. According to AGCM, ENI's refusal to approve the import capacity expansion could only be interpreted as a commercial measure to prevent the entry into the Italian market of four new suppliers. The AGCM therefore decided to investigate whether this amounted to exclusionary abuse of ENI's dominant position under article 82 of the EC Treaty, with the effect of hampering and/or preventing the entry of independent operators into the Italian wholesale market for the supply of natural gas. Following the inquiry, several smaller players were awarded capacity in the pipeline, and from 2008 onward, Sonatrach has acquired 2 bcm/year of the incremental capacity expansion in the Transmed pipeline for its own marketing efforts.

The other key Algerian export pipeline, the Pedro Duran Farrel system to Morocco and Spain, is a single pipeline with about one-third of the capacity of the five parallel pipes to Italy. Once again, opportunities for equity sales by Sonatrach are constrained by the long-term supply commitments to Spain and Portugal, and the unwillingness of buyers to compete with Sonatrach. Sonatrach owns the pipeline and pays a transit fee to Morocco in the form of a percentage of the gas transported, thought to be around 6 percent of transit volumes. Currently, Sonatrach is unwilling to expand the capacity beyond the current limits following transit disputes with the Moroccan government. Further constraints on Sonatrach are the Spanish government's limits on the supply percentage by any single country and limits on the direct sale of equity gas by Sonatrach into the Spanish market.

Like Statoil and Gazprom, Sonatrach must give first priority to honoring long-term contract obligations. In summary, the Algerian pipeline export strategy has largely been limited by the long-term supply commitments and Sonatrach has been restricted to the supply of wholesale gas to the incumbent gas companies in Italy and the Iberian Peninsula. Furthermore, for diversity of supply reasons, the Spanish government historically restricted the volumes from Algeria to around 60 percent of the Spanish market, though some additional flexibility has been reported during the recession.

In the LNG sector also, most of the sales are under long-term contracts to European buyers. Destination flexibility has been improved in recent years, giving more opportunity for increased profits through profit-sharing and the option to divert cargoes to the American and Asian markets. Volumes in excess of contract quantities can be sold spot, but opportunities were limited by reduced output following the Skikda explosion in April 2004.

Prospects for downstream sales of gas will improve when the Medgaz pipeline to Southern Spain begins to flow. Commissioning was originally scheduled for the first half of 2009, but a consortium spokesman was reported in November 2009 as saying that tests on the pipeline will start in March 2010, and the pipeline will be fully operational around June 2010. The delays are thought to be due to the partners' concerns about oversupply on the Spanish market, and the limited pipeline export routes from Spain into continental Europe.

Sonatrach has a 36 percent equity in the pipeline and intends to use some of this capacity for sales into Spain and beyond. This has the potential to make Sonatrach a major player in the Iberian-traded gas markets and, pending improvements in the France-Spain pipeline linkages, possibly also a player in the hubs of

southern France. Similarly, equity in the GALSI line to Italy could give Sonatrach a valuable physical position in the Italian market, but likely post-2012.

Another key dynamic of Algerian gas sales is the indexation to the “Basket of Eight” crude oils. Early contracts merely used the average price of the basket, but in the 1990s a complex netback formula was developed under which the average netbacks from northwestern European refineries of the eight crudes was calculated. Fortunately, the results are published as a single series by Platts Oilgram. In the long run, the series is unlikely to deviate significantly from its current relationship to Brent or other crude oils, the main difference being refinery margins and the secondary influence being the product yields versus other crude oils. However, the formula does give a slightly different price dynamic that can sometimes make a key difference in the merit order decision between gas from Algeria and gas from other sources.

There are some anomalies in Algerian gas pricing. For instance, under a number of the Algerian contracts, there is a discontinuity in the price formula at a price level of \$25 to \$30 per barrel, yielding a small reduction in the gas price.

Sonatrach’s future plans can be summarized as follows:

- To exploit its proximity to the European market and its competitive edge with respect to transport costs
- To exploit potential arbitrage opportunities by maintaining capacity and/or sales in UK and U.S. LNG import terminals
- To increase exports to Europe possibly to around 100 bcm/year by 2020, which in turn requires increased pipeline capacity to countries beyond Italy and Spain
- To expand pipeline capacities to Europe in partnership with customers
- To acquire a percentage of the capacity in pipelines for equity gas sales to end-customers

EU challenges to the legality of “destination clauses” have been an obstacle to contract negotiations, as Algeria was unwilling to relinquish such clauses. In January 2005, Algeria reached an agreement with the EU under which the destination clauses would be deleted from contracts. Under the agreement, Algeria would be allowed to enter into profit-sharing agreements under (delivered ex-ship) (DES) LNG contracts, where the cargo was diverted to a third-party customer. This would be unacceptable in the case of pipeline contracts or free-on-board (FOB) LNG contracts.

The current decade is characterized by constant rescheduling of Algeria's exploitation of its indigenous reserves. Exploration licensing rounds have attracted less interest than the hydrocarbons potential would suggest, and LNG partnerships have disintegrated over disagreements around the commercial structures and the sharing of profits. According to the Algerian Hydrocarbons Agency, the seventh licensing round, held in 2008, was "disappointingly undersubscribed" and "failed to attract the expected number of bids." The common theme, and participants are reported to have stated this privately though not publicly, is that the fiscal terms are insufficiently competitive with other Exploration and Production (E&P) areas.

Sonatrach's development plan provides for increasing gas exports to 85 bcm/year by 2012 after commissioning of new pipelines and LNG plants. However, with domestic gas demand also scheduled to increase, some doubt the ability of Sonatrach to provide the gas unless foreign companies can be attracted to the exploration acreage. It might also be unwise to rely on early supplies from the planned gas pipeline from Nigeria, which remains in the commercial development planning phase and which in the current climate might struggle meet financing requirements.

In 2009, Algeria's pipeline gas exports were badly hit by the recession, with a reduction of about 10 percent. With most exports being to Italy and Spain, and Algeria's two key customers being ENI and Gas Natural, pipeline exports are likely to remain depressed. Algeria has expressed its negotiating position that it expects long-term contracts to be honored, in terms of Take-or-Pay, pricing and future volumes. However, both ENI and Gas Natural were reported to have serious Take-or-Pay problems in 2008/2009, likely to be worsened in 2009/2010 by the commissioning of new LNG terminal capacity in their home markets, and the commissioning of new pipeline capacity to both countries. Gas contract negotiations have taken place and Sonatrach is reported to have made concessions on volume. Although details are not known, it is expected that a mutually acceptable compromise was reached along similar lines to the Gazprom and Statoil volume adjustments. The need for price adjustments in Italy and Spain would be reduced because of the relative absence of liquid spot markets.

In response to the drop in global demand for natural gas and the problems of negotiating long-term oil-indexed contracts in the current environment, Sonatrach has recently stated its intention to offer customers short-term gas contracts.

DUTCH DOMESTIC SALES AND GAS EXPORTS

The Dutch domestic market was historically supplied almost exclusively by Gasunie, which supplied large industrials directly from the high-pressure gas transmission system and smaller customers indirectly through wholesale supply contracts with the gas distribution companies (predominantly owned by the regional government authorities). The market remains divided by two separate gas systems:

- **Hi-cal gas**, which is supplied mostly to large customers with relatively high load factors and is broadly compatible with the bulk of the European grid
- **Lo-cal gas**, which is supplied mostly to distribution companies for the high swing residential and commercial markets (the Rotterdam area is an exception to this general rule as the lo-cal gas coverage in this area is limited)

This derives from Dutch gas production of two different qualities. As a general rule, the lo-cal gas production is onshore and the hi-cal gas is mostly offshore. The lo-cal gas fields are predominantly located in the northeast Netherlands and across the border in northwest Germany.

In 2008, Gasunie acquired BEB, including the lo-cal network developed by BEB (Shell and ExxonMobil) in northwest Germany. This highly strategic move expands Gasunie's control over the lo-cal network and covers almost the entire lo-cal gas production area.

Large customers were historically on oil-indexed contracts of one to three years' duration, with exceptional cases of customers on ten- to fifteen-year contracts. Suppliers have been offering the option of TTF-linked contracts for the last two to three years, but the uptake has been mixed due to price uncertainty—nobody wanted to risk paying more than his competitors. However, with spot prices lower today than oil-indexed prices, those with the opportunity of renewals are increasingly choosing the spot price option.

During and after the process of market liberalization, distribution companies were given the opportunity to terminate or renegotiate their historic ten-year evergreen contracts with Gasunie. Distribution companies now generally have a portfolio of purchase with varying percentages of spot purchases supporting renegotiated Gasterra contracts.

Although Gasterra's competitors do not have direct access to significant quantities of lo-cal gas, Gas Transport Services B.V. (GTS) is obliged to offer a gas

quality conversion service (under a regulated tariff), whereby hi-cal gas will be exchanged for an equal quantity of lo-cal gas (in energy terms). Using this service, competition can take place across the lo-cal gas network, which stretches from the Paris suburbs in the West to the Gasunie Deutschland network (formerly the BEB lo-cal network) in the East.

Dutch gas exports are managed almost exclusively by Gasterra, the largest of the incumbent Dutch gas marketing companies. Some volumes are exported by independent producers from the Dutch offshore sector directly to Germany via the NGT pipeline but such deals are the exception to the rule.

Gasterra's strategic advantages over competitors include:

- Almost total control over the European lo-cal gas network covering the Netherlands, Belgium, Luxembourg, northwest Germany, and northwest France
- A central location at the epicenter of gas consumption in Europe
- An abundance of lo-cal gas supply for the next ten to twenty years from the super-giant Groningen field

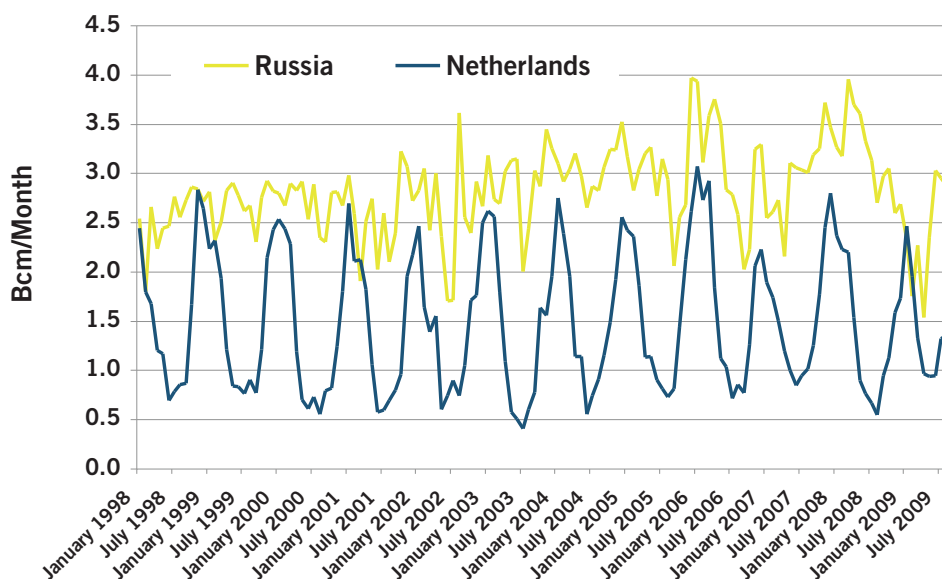
Gasterra's exports are predominantly lo-cal gas, the exceptions being supplies to the UK and Italy (which are 100 percent hi-cal gas), about 40 percent of the German export volumes, and small H-Gas volumes to France and Belgium.

From the very early days of Dutch gas production it has been the objective of the Dutch government to manage its finite gas resource in a strategic rather than purely commercial manner. As a result, the developers receive a management fee rather than a share of the profits in order that they not be incentivized to deplete the field too quickly. There is an additional safeguard in the form of a production cap on the Groningen resource. This means that the demand on the lo-cal gas system will not increase beyond a long-term sustainable level. The intention is to draw back the extremities of the lo-cal gas system if no alternative supply source can be found.

Most of the Dutch export contracts are high swing. Dutch lo-cal gas sales are generally "full-requirements" in terms of load balancing, as there are no lo-cal gas storage fields outside of the northeastern Netherlands/northwest Germany production areas. The super-giant Groningen field has been developed together with smaller gas storage fields to provide the seasonal and much of the daily load balancing for sales across France, Belgium, and Germany.

To illustrate the point, the chart below shows the difference between the load factors of Dutch sales to Germany (predominantly lo-cal gas) and Russian sales to Germany:

CHART 4 German Imports From the Netherlands and Russia



Source: BAFA, Germany

In order to compensate for the additional in-built production and transmission capacity in the lo-cal gas network, Gasunie export contracts comprise a capacity fee and a commodity fee. The capacity fee is indexed to Dutch inflation and the commodity fee is a typical oil-indexed additive formula. Older export contracts were based on Wiesbaden price statistics, and some of these still exist, but most have been rewritten to use Rotterdam gasoil and heavy fuel oil prices.

ANOMALIES

The ten-year contract signed between Centrica and Gasunie for deliveries via the BBL pipeline broke the mold by being the first long-term Dutch sales contract agreed to be linked to spot market (NBP) prices.

A second unusual feature of the Centrica contract is that it provides for two-thirds of the volumes to be delivered during the winter months starting October 1

each year, and one-third during the summer months. This is achieved by the seller reserving less BBL pipeline capacity during the summer.

For the future, Gastera intends to:

- Continue to satisfy long-term customers in Europe
- Maintain sales in the lo-cal gas network, acquiring new volumes as they become available, or by converting hi-cal gas in the long term
- Develop trading activities across the Netherlands with the aim of making the TTF a major hub

The Netherlands is uniquely well positioned geographically, and the Dutch are motivated to withhold production, in order to conserve supplies for the longer term. In the early years of gas liberalization, the Dutch industry clearly took the side of the incumbents. However, this changed early this decade when the Dutch resurrected their historic trading mentality and devised the strategy to develop the Dutch system into a major European hub (Hub Holland), supported by the presence of substantial reserves.

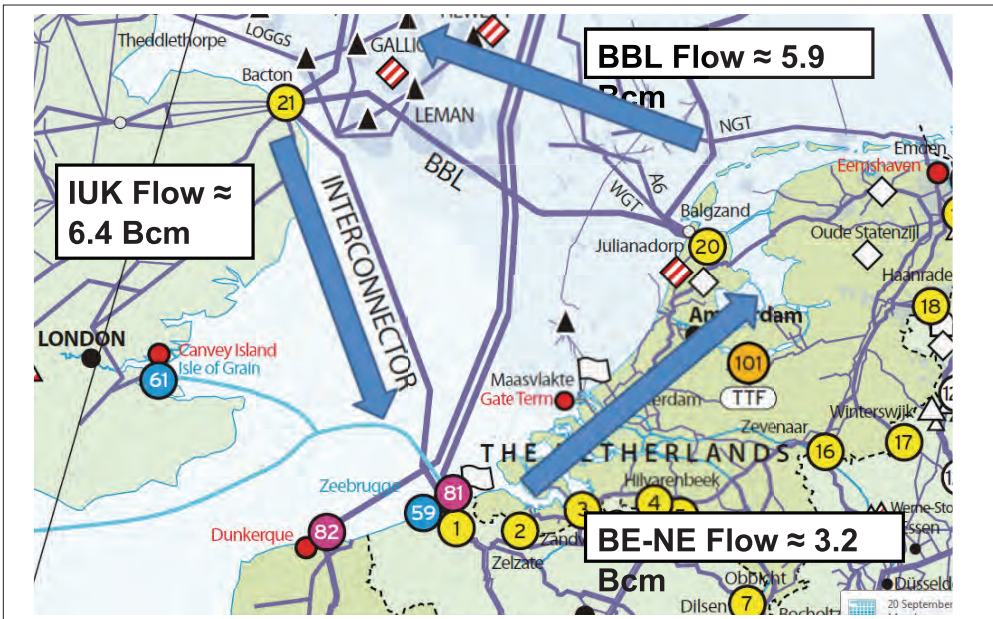
The gas industry regrets having missed out on the opportunity to host the first interconnector and for Rotterdam to become an LNG import terminal many years ago. The political will to become a major gas trading hub was a major driver behind the seemingly indecent haste to build the BBL pipeline. With the IUK interconnector backhaul capacity available there seemed to be little reason for a second pipeline.

However, the Russian plans for a Nordstream route from Russia to the UK and Centrica's need for additional supplies in the UK gave Gasunie the strategic reason to construct BBL. The medium-term economics could be underpinned by the Centrica contract, and the pipeline would be in place for Russian gas in the later years, bringing large Russian volumes through the Dutch system, for the superfluity of the BBL pipeline is amply illustrated by the figure on the next page.

In 2009, Dutch production was generally below the previous year, except during the Ukrainian gas crisis when additional volumes were supplied. The Dutch producers are not expected to be unduly worried about this turn of events, although reduced prices are of more concern, particularly as more gas was sold into the TTF markets.

Due to the structuring of the Dutch lo-cal gas GSAs, the wholesale customers are unlikely to suffer any Take-or-Pay problems for two reasons:

FIGURE 1 The Bacton Triangle: Gas Flows in 2009



Source: GIE data and estimates by author

- Lo-cal sales are heavily weighted toward residential customers whose demand has been least affected by the recession
- Dutch lo-cal sales contracts are the most flexible in terms of volumes

Dutch gas export sales in 2009 (≈ 47 bcm) will be down about 10 percent from 2008 levels, but still around the same level as 2006 and 2007. Domestic sales and imports in 2009 are both down, but only slightly, meaning that domestic production cutbacks have been used to modulate the exports change. In other words, the Dutch have taken the export downturn as an opportunity to conserve domestic reserves.

UK GAS DOMESTIC SALES AND EXPORTS

About 99 percent of UK gas production is from the offshore continental shelf, mostly from the North Sea, but with significant volumes from the Irish Sea (Morecambe Bay area) and potential volumes from the Atlantic (west of Shetlands). Gas is piped to shore via gas-gathering systems where the bulk of volumes

are processed before entering the National Grid transmission system.

Older contracts were predominantly oil-indexed, but distinctly different from continental oil-indexed contracts. Ownership transfer generally takes place at the flange between the upstream processing plant and the National Grid reception (mixing, measurement, compression) facility, located at the beach. Today, once gas passes this flange and enters the National Grid system, it is commercially defined as being at the National Balancing Point (NBP). Because there is no distance-related transportation charge (entry, exit, and commodity charges apply), all gas at the NBP has an equal value.

Today, there are hundreds of participants in the continental shelf gas production industry and therefore hundreds of sellers. Sellers used to group together and sell gas under multi-seller contracts, but this practice is no longer acceptable under EU legislation, so the contracts were disaggregated. Today, the smaller sellers usually market their equity volumes under short-term deals at the NBP. Larger portfolios are often used to support existing long-term bulk sales contracts, with the remainder being marketed under a portfolio strategy using spot and futures markets to spread risk.

UK gas development began in the 1960s, and the oil-indexed pricing principles developed for North Sea gas sale and purchase agreements at that time are still present in a number of the contracts in use today. Although spot markets have developed since 1995 and are now almost exclusively the preferred price benchmark, there is a residual percentage of the market that remains oil-indexed. UK oil indexation differs from that on the continent in several important respects:

- The benchmark oil indices are UK market end-user prices for industrial consumers.
- The indexation basket often includes a sizeable element of inflation (based on a UK Producer Price Index). The PPI indexation element frequently exceeds the oil indexation element.
- The indexation basket often includes elements of electricity and coal indexation, published by the same source, on the same page as the UK gasoil and HFO end-user prices.
- Prices tended to vary significantly according to prevailing market conditions when the contract was signed. (The range of differences was reduced in the 1990s, when Centrica was forced to renegotiate some of the higher priced contracts in return for cash payments.)

- The applicable price was often a “lesser of” two indexation formulae, which was typically a method of partial indexation capping.

Traditional UK oil-indexed contracts are generally linked to UK large-industrial end-user prices collated by the UK Department of Energy and Climate Change. Data is published in “National Statistics Publication – Quarterly Energy Prices – Table 3.1.1 – Prices of fuels purchased by manufacturing industry in Great Britain – Category Large or Extra Large.” Prices include Oil Duty but exclude VAT and Climate Change Levy.

The indexation basket often includes an inflation index from the National Statistics Office – Business Monitor MM22 – PLLV PPI: 7209299000: Products of manufacturing industries excluding food, beverages, petroleum, and tobacco – Output prices (not seasonally adjusted). These prices are rarely, if ever, used in GSAs outside the UK.

Because of the range of price differences there has never been a long-term benchmark price in the oil-indexed markets, though large contracts have often served as a temporary reference point, and a watchful eye was kept on continental prices, particularly on important Norwegian deals such as Statfjord, Sleipner, and Troll sales. Russian contracts were regarded as too distant; Dutch sales as the wrong type of gas. Both of these countries were inaccessible anyway (until 1998), whereas Norway had strong interconnections via the Frigg pipelines with combined potential capacity of around 25 bcm/year from 1977.

Production from the UK sector of the North Sea had already been underway for twenty years before the idea materialized that the UK might become a net exporter of natural gas. Initial exports were small fields close to the Dutch sector that could not justify a UK connection, but were close to developed Dutch fields. Up until 1990, the development process was constrained by the needs of British Gas, the sole purchaser. From the 1980s, the inventory of undeveloped fields was growing and oil companies were looking for new ways to monetize their assets. Market liberalization and the break-up of British Gas in the 1990s brought new opportunities to continental Europe. A project company was established from gas industry players willing to commit to equity in the pipeline, and a contract awarded for the construction of the IUK Interconnector linking the UK to continental Europe at Zeebrugge. It was commissioned in 1998, and the UK shippers began exporting via Belgium.

In parallel with the pipeline construction, equity holders negotiated GSAs, and several export contracts were concluded with customers in Germany and the

Netherlands. Prices were mostly indexed to oil products using price indexation typical of the end-user markets, at competitive prices. Because of unused capacity, spot sales were theoretically possible. The capacity holders with gas trading capabilities quickly found this to be a profitable asset when combined with market positions at each end of the line, and it became established as an essential foundation component of a successful trading business. The combination of the ability to access UK supplies and to arbitrage between the three different market dynamics (UK oil-indexed, spot markets, and continental oil-indexed) remains a highly lucrative position. The ability of the non-incumbents to enter the game took several years to develop as access to infrastructure only gradually became more liquid. When the Interconnector was commissioned in 1998, the Zeebrugge hub was non-existent and gas could only be transported to the German and Dutch borders. Much of the capacity was held by incumbents initially hesitant to release liquidity.

Today, the liquidity of the UK spot market is beginning to be rivaled by the liquidity of the Dutch TTF markets, and Zeebrugge has become a thriving hub with connections first to the Belgian Fluxys system and then to the Zeepipe and LNG terminals. The oil-indexed UK export contracts have mostly expired, and today the new export deals are struck at market prices.

Norwegian capacity to the UK has been expanded significantly with additional connections to the Frigg system, the FLAGS system, and the recent Ormen Lange pipeline, and it has become evident from the increasing forward flow volumes that the UK is now being used both directly and indirectly as a bridge for Norwegian exports to the continent.

Traditional UK contracts use end-user energy prices for large consumers in the UK, often with a sizeable proportion of a UK producer price inflation index. However, the indexation formulae based on the common theme varied widely in the indices, percentage weightings, and initial prices, giving rise to a significant range of prices at any given time.

These indices were widely used within the UK and reflect the UK's former status as a "gas island." Once the Interconnector was built, very few new contracts used the traditional indexation methodology. Most new contracts used spot pricing or, if the gas was for export, the end-market pricing methodology.

ITALIAN DOMESTIC GAS

Indigenous production mostly takes place around the Po Valley region, but over time the epicenter of production has shifted eastward into the offshore waters around the mouth of the Po River. The Italian gas industry began development of consumption in the towns around the Po Valley and then spread further across Italy with imports from abroad. Italy does not export significant volumes of gas.

Historically, the prime production acreage was granted under a national monopoly structure to ENI, and the bulk of it remains in their hands. The indigenous production (currently around 10 percent of total market size) provides a sizeable contribution to the ENI supply portfolio. Transfer prices are not in the public domain but are reported to be oil-indexed. Today, small quantities of gas are being produced by independents with recent deals being done at “Gas Release Program” prices, equivalent to the average price paid by ENI (as calculated by ENI and challenged by others).

Imported Italian gas supplies are delivered at a range of supply points at various distances from Italy. The gas is then transported to the Italian border in pipeline networks partly owned by ENI and partly owned by shareholders based in the transit countries. As a result, there is no widely accepted benchmark price for gas delivered to the Italian border.

Gas prices under long-term supply contracts to wholesalers (and contracts to large end-users) are predominantly oil-indexed. Some contracts are linked to crude oil prices, and others are linked to oil-product prices at Genoa/Lavera or Rotterdam. The combination of gasoil, fuel oil 1 percent, and “Basket of Eight” crudes (or Brent) is a feature of a number of the key import contracts. The price of gas delivered to Italy varies considerably between contracts, according to the price indexation terms and the transportation costs. On average, the Italian gas supply prices have been slightly more expensive than the average for northwestern Europe.

There is limited real gas-to-gas competition in Italy at the producer-wholesaler level. Because of the distant “transfer of ownership” points for imported gas and the ENI monopoly of indigenous supplies, there has been little availability of spot gas within Italy itself. As a result, the Italian spot market (PSV) has struggled to gain momentum and remains in an embryonic stage; with limited liquidity, it does not provide an adequate reference price. However, Italian wholesalers can purchase gas at the NBP, Zeehub, or TTF for delivery to Italy via the TENP and

Transitgas systems across Germany and Switzerland, respectively. What little data there is suggests that the index of TTF plus transportation to Italy is an approximate benchmark for the Italian market.

With improved liquidity in European transmission systems, the second-tier wholesalers in Italy (independent distribution companies, consortia of industrial buyers, and foreign wholesalers and suppliers) are now able to bring gas more freely into Italy. With low spot prices, this enables them to undercut ENI and ENEL, which are losing market share at what must be for them an alarming rate. The longer there remains a large price differential between the oil-indexed and market prices, the greater the urgency for ENI and ENEL to call for a renegotiation of the oil-indexed prices.

In early October 2009, Eurogas president and ENI's head of gas and power, Domenico Dispenza, publicly stated that the divergence between oil-indexed and traded gas prices, together with Europe's oversupply of contracted gas, could lead to a "massive shift" in pricing as well as a string of price renegotiations. This statement was particularly notable for being delivered by the chief executive of a major European gas incumbent in a public forum.

REVIEW OF KEY EUROPEAN PURCHASERS

E.ON, GDF SUEZ, and ENI have been selected as representative examples of key European purchasers:

E.ON of Germany

E.ON, by virtue of its takeover of Ruhrgas in 2003, became one of the major gas purchasers in Europe, buying a volume of around 62 bcm in 2008. The company is also a major European power generator and owns gas and electricity transmission networks and gas storage businesses across Europe. The deeply entrenched gas sale and purchase positions made Ruhrgas a leading defender of the status quo in Europe, often organizing the opposition to gas market reforms across Europe, and notably to the EU Gas Directives. However, this defense of the status quo did not preclude using their wide range of assets to reap massive rewards from the arbitrage opportunities they brought. Ruhrgas obstructed all liberalization initiatives that threatened to dilute profit margins.

Following the takeover by E.ON, the Ruhrgas organization initially pursued a “business as usual” policy. However, within the E.ON corridors, the contradictory messages of the dynamic liberalized electricity business and the intransigent gas business must have comingled uncomfortably within the minds of senior management and created internal stresses in the generation of consistent messages to shareholders. At the same time as the takeover, the second EU Gas Directive was passed, and the appointment of a regulator in Germany was beginning to be discussed seriously. Furthermore, the tide of opinion in Germany was beginning to shift in favor of gas market liberalization.

By 2006, there was a noticeable shift in E.ON’s corporate message toward gas market liberalization. It certainly wasn’t a sudden shift but a gradual relaxation of opposition to reform, and the beginning of a more constructive approach to the new systems required to accommodate market liquidity. Since that time, there have been significant developments in TPA to gas industry infrastructure and the entry-exit transmission pricing structures. From E.ON’s perspective, the direction may have changed, but the company retains the desire to be a market leader.

Gas portfolio management priorities are much the same as any other continental incumbent wholesaler. The first objective is to manage their long-term purchase commitments in order to avoid all unnecessary penalties. The balance-of-gas requirements will be met by optimizing purchases under the full range of oil-indexed and market-priced contracts in order to minimize overall costs.

Within the purchasing priorities, storage facilities need to be refilled to meet daily and seasonal operational requirements. Any surplus storage capacity will be used to support the trading businesses. Continental European storage capacity holders are often very conservative in their willingness to release gas to assist other companies or countries in times of shortage. They will often use the argument that they cannot be expected to compromise the security of their own customers, even if there is a much greater need elsewhere in Europe. Indeed, they have no such contractual or legal obligation to do so. However, during the Ukrainian crisis of 2009, flows of gas from Germany to E.ON group businesses in Eastern Europe were reported. It seems that where external sales were unacceptable, intra-group sales were deemed by management to be acceptable.

In July 2009, the EC imposed a fine of €553 million on E.ON, and the same amount on GDF SUEZ, in connection with alleged anti-competitive practices. According to the EC, there was a deal relating to the construction of the MEGAL pipeline across Germany, which is used by GDF SUEZ to transport Russian gas from the point of sale at Waidhaus to the French border. The EC claims that under

the terms of a deal done in 1975, GdF and Ruhrgas agreed not to sell into each other's home markets. The EC argues that the agreement was maintained long after it became clear that such arrangements breached European competition rules.

E.ON has publicly stated that it will appeal the decision. It maintains the agreement did not contravene EU law and that the companies began to compete in each other's markets from 2000, as soon as it became possible. E.ON maintains that the occurrence of market collusion is an assumption by the EC, and not a fact; collusion never took place between the companies.

2009 was undoubtedly a difficult year for E.ON, and there is little doubt that they have had serious Take-or-Pay problems. E.ON is facing the predatory practices of second-tier players in a range of markets across Europe and, like other incumbents, indulging in them in foreign markets. In 2008, E.ON found it profitable to sell gas supplies to the UK, supplying around 6.4 bcm out of its portfolio of non-UK supplies. It also signed contracts to supply Swissgas and the Italian Industrial Association, and began marketing to end-customers in France. In 2009, conditions turned against E.ON, and it was forced to open discussions with major producers. E.ON was partially successful at renegotiating volumes downwards, but it maintains a high percentage of oil indexation in its gas purchase portfolio.

Recent indications are that 2010 will not be as financially bad for E.ON as 2009. However, market liberalization has progressed significantly in Germany with the development of the Gaspool and NetConnect hub areas, making it much simpler for the second-tier players to access end-customers on a level playing field. The pressure relieved by contract negotiations in 2009 and 2010 will require constant attention and management.

Germany has no LNG terminals, and its favorable geographical location (next to the Netherlands, Norway, and Denmark, and close enough to Russia) gave it a low priority as an LNG destination. However, declining gas reserves across the North Sea, Russian supply problems, and the Snohvit and proposed Stockman LNG project have caused a rethink among the German gas market players. Concurrent with this national rethink, E.ON has expanded across Europe and into markets where LNG plays a much larger role, or where it can use LNG as a market penetration tool, and/or to support its power sector plans, such as in south-east Europe. This is an important strategic dimension behind the maneuvering not only of E.ON, but other European players in the LNG space who see regas capacity, particularly into high-priced illiquid markets like Italy, as the means to catapult themselves into heretofore closed markets.

As a result, there has been an increased drive by E.ON to take a position in the European LNG markets. Currently, the company has operational capacity at the terminals in Barcelona and Huelva in Spain (0.8 bcm/year each). It has terminal capacity under construction at Isle of Grain (phase 3), Gate in the Netherlands (3 bcm/year), and Livorno, Italy. The total capacity in operation and under construction is reported by E.ON to be 7.8 bcm/year.

E.ON is also involved in the planning of other new LNG receiving terminals, including at Wilhelmshaven on the German coast and the Northern Adriatic. These are currently in the feasibility study phase and face significant planning and/or commercial problems. Wilhelmshaven, in particular, has been effectively shelved for the time being.

In 2007, E.ON Ruhrgas also signed a memorandum of understanding with the Algerian company Sonatrach on cooperation in LNG projects, and a deal is currently under negotiation. In November 2009, E.ON's office in the Middle East announced talks with Qatar for the purchase of 1 to 3 million tons per year of LNG for destinations in Europe. E.ON Ruhrgas has stated its aim to source 10 to 15 bcm/year of LNG supply for its customers by 2015, and sooner if possible.

E.ON has been expanding in the Middle East and North and West Africa and is aiming to become a vertically integrated LNG producer and marketer. However, it does not currently have ambitions to expand into the LNG shipping sector at this point, as it sees the market as oversupplied.

The LNG strategy looks ambitious in today's market, and one has to question the possibility that the company will be adding to its Take-or-Pay problems if it procures additional supplies before addressing its current difficulties. However, E.ON has a culture of planning carefully for the future and making bold decisions when required. At the present time, E.ON can probably be characterized as a company in transition from conservative incumbent European utility to major international energy company. It still retains elements of the former, but its future is certainly the latter.

GDF SUEZ

GDF SUEZ is the major player in the French gas market, importing 75 to 80 percent of all French gas supplies (49.3 bcm in 2008), and owning the bulk of transmission, distribution, and storage infrastructure. There is very little gas production in France (less than 1 bcm/year) and this is owned by Total, the second

incumbent in the French market. Gaz de France merged with Suez of Belgium in 2008, becoming GDF SUEZ.

With the merger, GDF SUEZ made the strategic choice to become a major player across the gas and power sectors, with a highly diversified energy supply portfolio. The merger creates:

- A major buyer and seller of gas in Europe
- A major importer of LNG in Europe with a leading position on the Atlantic basin
- A leading LNG terminal operator in Europe
- A leading European power producer with strong positions in the United States, Brazil, and the Middle East

Despite strategic forays into the upstream sector, GDF SUEZ remains predominantly a gas wholesaler and trader, rather than producer. The merger has brought Gaz de France a larger position in LNG liquefaction, wholesale, and regasification, elevating its status as a leading player in the business. The company intends to use its new status to accelerate its development of the upstream business.

Gaz de France's European strategy was always to stand united with E.ON and others in opposition to excessive liberalization, but the desire to merge with Suez gave the EU and regulators a key opportunity to accelerate the liberalization process and force a partial unbundling of both Gaz de France and Distrigaz. Distrigaz, the Belgian marketing arm of Suez, has subsequently been purchased by ENI.

The combined wholesale businesses of Gaz de France and Suez give both a diverse supply portfolio and valuable trading positions across Europe. The group has steadily built a sizeable trading business based in Paris. Gas supplies remain largely purchased under long-term Take-or-Pay agreements, but market-based purchases can be made in both the pipeline and LNG markets. Arbitrage opportunities extend beyond Europe to LNG regas terminal capacity in North America and LNG supply from the Middle East and Africa.

Long-term gas destined for France is purchased from the Netherlands, Norway, and Russia at prices similar to or slightly above the German border price. The group also purchases volumes of gas from the UK, the Netherlands, Norway, and the Zeebrugge LNG terminal at market prices. This gives the group a strong position to arbitrage between oil-indexed and market prices. GDF SUEZ is also a long-term player in the NBP–Zeebrugge arbitrage via its role as shipper and primary capacity holder in the pipeline.

The combined group has a larger percentage of LNG purchases in its portfolio than most other European buyers. Some of this LNG volume, such as the purchases from Qatar, is priced against spot markets, but the bulk will be oil-indexed. This gives the group some flexibility to divert cargoes to other destinations but leaves them exposed to price risk if the oil-indexed cargoes have to be diverted to lower netback destinations.

Since the beginning of cooperation in the gas supply sector back in 1975, Gazprom has provided Gaz de France with over 300 bcm of gas, including around 10 to 11 bcm/year in recent years.

On December 19, 2006, Gazprom and Gaz de France signed an agreement to extend the existing contracts for 12 bcm/year of Russian gas supply to France until 2030. The agreement also increased the annual volumes by 2.5 bcm/year, with the additional volumes sold at Griefswald in Germany via the Nord Stream gas pipeline. Gazprom also negotiated the opportunity to directly deliver gas to final consumers in France, up to nearly 1.5 bcm per year.

Having negotiated what they thought was a partnership with Gaz de France, Gazprom will now be disappointed that volumes taken in France have since fallen from over 9 bcm/year to around 6 bcm/year (2009). To add to their disappointment:

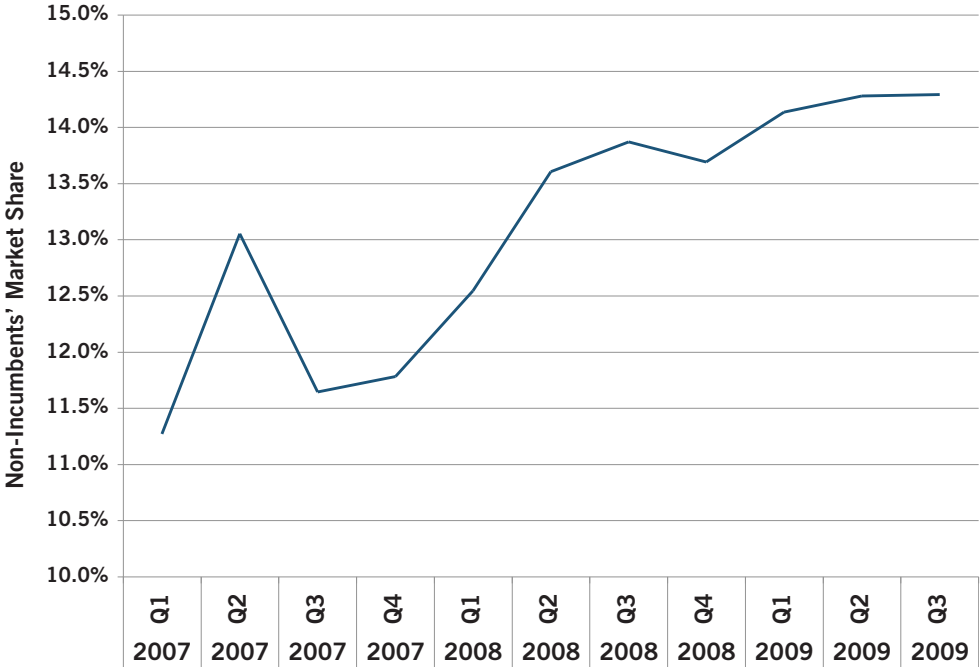
- GDF SUEZ, over the same period, has increased supplies from Norway and maintained steady volumes from other directions
- GDF SUEZ has been supplying Russian gas into its subsidiary gas marketing operations in the Gazprom heartlands of Germany, Poland, the Czech Republic, and Italy using the delivery points negotiated many years ago in the days before destination clauses were abolished

It is probably true that, had gas demand increased as forecast, this would not be such a great problem. However, the gas demand decline in France (about 6 percent or 3.5 bcm year over year) appears to have been borne almost entirely by Gazprom at the expense of its “core” markets to the east.

The motivations for GDF SUEZ to “export” its oversupply problems are relatively simple. The chart that follows shows the progress made by second-tier players over the last few years.

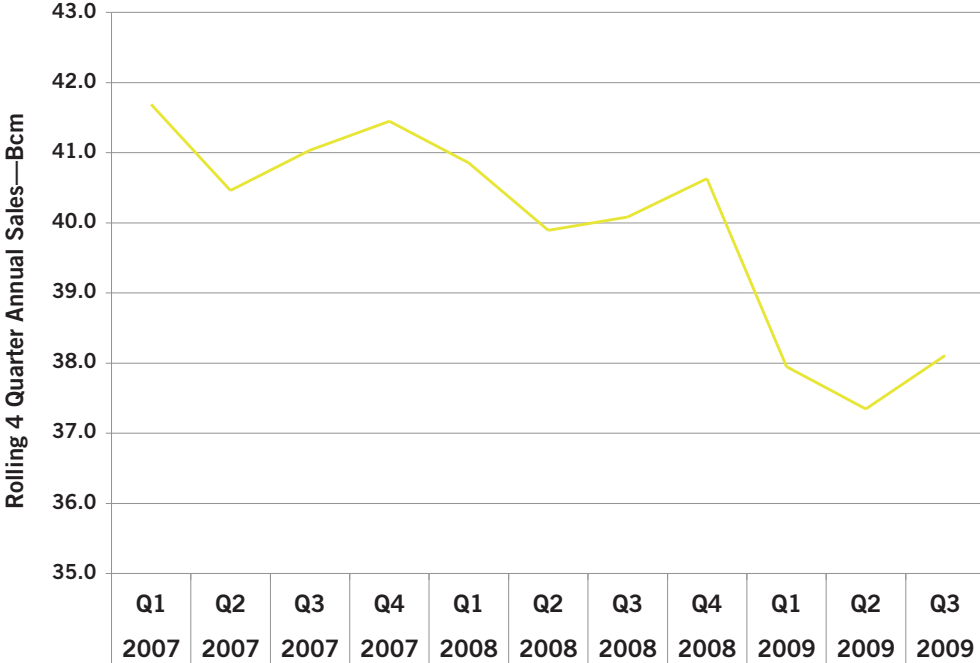
At first sight, the growth of the second-tier suppliers does not appear dramatic, except for one factor: it is the customers of the second-tier suppliers that have been hit the hardest by the recession. Most of the non-incumbent suppliers are focused on the larger consumers in the market, the medium and large

CHART 5 The Growth of Market Share by Second-Tier Suppliers



Source: Compiled by author from CRE Data

CHART 6 The Growth of Market Share by Second-Tier Suppliers



Source: Compiled by author from CRE Data

industrial consumers, the group hit the hardest across Europe. It is therefore an exceptional performance for the second-tier suppliers to have gained ground. This performance will almost certainly improve as the industrial contracts expire at the end of October and December. Data from CRE (the French Energy Regulatory Commission) shows that 47 percent of new non-residential contracts were signed with non-incumbents.

Over the twelve months to mid-2009, for GDF SUEZ the market contraction was actually a bigger downside than the inroads made by the competition. The chart on the previous page shows the combined effect of competition and recession on incumbent gas sales.

Once again, the data available almost certainly understate the impact on GDF SUEZ sales in 2009. The reason is quite simple: French energy company Total SA is also regarded as an incumbent, but the inroads made into the GDF SUEZ market areas has been much greater than inroads into the Total market areas.

Although French gas consumption has fared better than the European average, the second-tier suppliers have progressively made inroads in the past two years. This is partly due to market liberalization, low market prices, and the integration of PEG (Points d'échange de gaz) zones on January 1, 2009 (making it much easier for second-tier players to supply customers in northwest France). For GDF SUEZ, the French market problem appears to be getting worse. New players continue to take more customers, contracted volumes are too high, and there is little sign of relief on the horizon. Unable to “export” the problem commercially by means of LNG diversion in 2009, their remaining option was to “export” the problem to other parts of Europe, the simplest option being to unload volumes at the delivery points in Central Europe—hence the reported falling-out with the Russians; 2010 may bring the prospect of having to sit down and negotiate reduced volumes, and/or push more LNG away from France. This latter option has limitations, however, as LNG is required on the periphery of the system on the Mediterranean at Fos, and the Atlantic at Montoir.

ENI

ENI has been a long-term incumbent in Italy, dominating total imports of 75 bcm (2008), and a staunch defender of the status quo, but appears to be among the European wholesalers facing the gravest problems with Take-or-Pay obligations.

Although competitors have always been present in the Italian market, ENI used its control of infrastructure very effectively to constrain their growth. Tra-

ditionally, ENI held strong monopolies in gas import infrastructure, gas import contracting, the Italian transmission system, gas storage, and the ownership/purchase of domestic production. Through its Italgas subsidiary, it also held various stakes in a wide range of local gas/multi utilities. As the regulator increasingly strengthened its position, based on the EU Gas Directives, it is from the previously constrained potential players that much of the competition has arisen. The key competitors include:

- **ENEL:** An incumbent power generator that has always held a strong position as a major gas user and developer of much-needed modern CCGT's in Italy. ENEL imports gas through the ENI network, and in addition to own-power generation use it acts as wholesaler and also has a significant retail gas business.
- **Edison:** Developed a gas transmission system based around equity gas production and distribution companies in central Italy. It has gas supply from various sources, including Qatar, into the recently commissioned Adriatic LNG terminal. In 2005, EdF took effective control of Edison, but discussions are ongoing with partner shareholder A2A, which made efforts to gain greater control in 2010.
- **Plurigas:** Municipality-owned wholesale trading group.
- **A2A Trading** (formerly AEM Trading): Subsidiary of A2A S.p.A (Milan Municipal distribution company formerly AEM Milano), partner in Edison, and major purchaser of Plurigas volumes. A2A also has a stake in Premium Gas, a gas marketing joint venture with Gazprom.
- **GDF SUEZ:** Wholesales 2 to 3 bcm/year of gas purchased mostly from Libya via Greenstream contract. Also purchased two distribution companies.
- **Gas Natural Vendita:** Has purchased smaller Italian marketers to establish a position as a wholesaler and marketer.
- **Gazprom and Sonatrach:** Both have pipeline capacity and uncontracted supply potential into the Italian market.
- **Dalmine Energie:** Established as an independent trader of gas and electricity in 2000, bought by E.ON Trading in late 2006.
- **Sorgenia:** Merger of Italian subsidiary of German Verbund and established Italian market player, Energia.
- **Hera Comm:** Large distributor with companies across several regions and has 10 percent stake in GALSI pipeline project.
- **Blumet, Blugas, etc.:** Consortia of independent Italian players.

Today, ENI finds its monopolies under pressure from all sides, and its defenses eroded by EU legislation. The defensive tactic of overcontracting has partly been negotiated away by allowing Gazprom rights to market gas within Italy. In other words, some of the volume risk has been passed back to the producer. However, with the 8 bcm/year Rovigo LNG terminal accepting its first cargo on August 10, 2009, and gas demand well below expectations, Italy could find itself oversupplied for a prolonged period. Faced with this possibility, there are two possible courses of action: to renegotiate contracts or to export the problem.

The statement (October 2009) by Domenico Dispenza, Eurogas president and ENI's head of Gas and Power, that "oil and gas traded price divergence and the Europe's oversupply of contracted gas could lead to a massive shift in pricing as well as a string of price renegotiations" was interpreted as an admission of serious Take-or-Pay problems among Europe's incumbent wholesalers. It is particularly unusual for the chief executive of a major European player to state the case so definitively in a public forum.

Amid the contracting crisis, ENI put the company's 2009 to 2012 strategic plan to the financial community. ENI confirmed its objective of increasing its gas sales outside Italy in order to grow total European gas sales to 100 bcm by 2012, an objective already partly fulfilled by the purchase of Distrigaz. At the same time, the company plans to become a major player in the LNG industry, where it already has significant assets.

The ENI purchase of Belgian distributor Distrigaz, completed in May 2009, will not have helped ENI significantly reduce its Take-or-Pay problems, as 90 percent of Distrigaz requirements were met by long-term contracts from Norway, the Netherlands, and Qatar (LNG).

ENI plans to expand significantly in all sectors of the LNG business, from the supply of gas to the regas terminals. The company plans to expand its world LNG regasification capacity, but the impact on Europe is likely to be small, with the bulk of the increase being in the United States (Cameron and Pascagoula). Current capacity held directly by ENI is only around 0.7 bcm/year at the Panigaglia terminal in Italy, but additional capacity held by Distrigaz (2.8 bcm/year at Zeebrugge), and by equity holdings in Union Fenosa and GALP Energia, bringing ENI's European capacity to 12 bcm/year.

LNG supplies are currently sourced from three liquefaction terminals in the Atlantic-Mediterranean basin (Trinidad, Damietta, and NLNG), one in the Middle East (Qalhat), and one in the Pacific basin (Darwin). Current equity LNG liquefaction capacity is just under 10 bcm/year, and some of this gas is contracted

to third parties. However, additional purchases from Algeria, Qatar (Distrigaz), Qalhat (Union Fenosa), and other contracts bring ENI's LNG supply to over 12 bcm/year. Increases in supply are expected from new projects in Angola and Nigeria (Brass LNG) and from expansions at Damietta and NLNG. By 2015, ENI expects to have doubled its LNG terminal capacity and sales, but the bulk of this increase will be outside Europe.

The concurrent gas crisis in Italy, but ambitious expansion of ENI across most sectors, can be explained by the fact that ENI's upstream business now generates healthy profits. With the downsizing of ENI's gas business in Italy, the company needs to expand abroad to maintain its current status. The upstream profits provide cash to fund the international expansion program. The dilemma is that these riches may also become a target in price/volume renegotiations with major producers. To secure a bright future, ENI needs to move forward from the current crisis, but the solution may be costly. It will certainly involve some tough bargaining in 2010.

INTERNATIONAL E&P MAJORS

The E&P majors have often expanded both horizontally and vertically into a broad range of energy-industry activities and in many cases beyond. In recent years, however, the leading companies have increasingly understood the advantages of focus and specialization on their core activities. As a result, many of the international E&P majors have liquidated many of their non-core business activities, and even their E&P assets in non-core business areas. In Europe, there has been a realization that regulated assets require a different style of management, and several of the E&P majors have chosen to shed their regulated business areas to companies that specialize in regulated markets. Recent examples include the sale of the BEB gas transmission network to Gasterra and the ENI sale of its storage business to Rete Gas Italia.

Two examples of an international E&P major based in Europe are French-based Total SA and UK-based BG Plc:

Total

Total of France has become one of the world's largest oil companies, having absorbed Fina of Belgium and Elf in recent years.

Like Shell, ExxonMobil, BP, and Chevron, Total sees itself primarily as an upstream specialist and does not have strategic ambitions to develop the gas busi-

ness in preference to any other sector. Total is in the midstream/downstream gas business as a consequence of its investment strategy rather than as an objective of its business strategy. Total is highly focused on return on capital employed, and 75 percent of its investments are in the upstream sector. In Europe, Total's significant gas assets include:

- A presence in France as the second incumbent gas company following the purchase of Elf Aquitaine in the 1990s, including the gas production, storage, and transmission business in southwest France
- A significant position in the Norwegian upstream, including stakes in Ekofisk and as both seller and purchaser under Troll gas sales contracts
- A position as a leading upstream operator and stakeholder in the UK North Sea
- Dutch gas production
- Gas trading and marketing operations in the UK, France, and Spain (JV with CEPSA)
- Approximately a 10 percent stake in the Medgaz pipeline from Algeria to Spain (through its equity in CEPSA)
- 30.3 percent equity in Fos Cavaou LNG terminal

Total also has stakes in LNG plants within economic range of Europe, including Abu Dhabi, Oman, Snohvit (Norway), Qatargas, Yemen LNG, Angola LNG, Nigeria LNG, Brass LNG, Shtokman, and Pars LNG in Iran. Pipeline gas within striking distance of Europe includes Shah Deniz in Azerbaijan.

In terms of gas pricing strategy in Europe, the international E&P majors are drawn in several different directions. The following drivers impact their thinking:

- Oil companies often enjoy working with oil-indexed gas sales contracts, as they feel that their shareholders understand and accept oil price risk. However, the acceptance of oil commodity markets also makes it difficult to argue against the sale of gas into commodity markets. As a general rule, the oil majors will readily accept the sale of gas into commodity markets where they feel there is sufficient liquidity.
- Some sovereign governments strongly support oil indexation (Russia, Algeria) and others (the UK, the United States) oppose it quite strongly. This makes it difficult for the oil majors to voice their support or opposition to gas commodity markets. E&P majors depend heavily on the

goodwill of sovereign governments for continued presence in their most prospective acreage, so they will rarely oppose proposed market changes too vociferously.

- Oil companies depend heavily on integrity of long-term agreements and strongly promote adherence to contracts until there is compelling argument for change.
- European customers, including wholesalers, distribution companies, and end-customers, of the E&P majors often support oil indexation in preference to spot markets.

The E&P majors believe that hydrocarbons will become increasingly scarce in the medium to long term and that prices will rise. This will be the case in both oil and gas commodity markets, and most oil majors therefore have little economic preference for either market structure.

In view of the various forces, and the limited preference for either system, the E&P majors often prefer to keep out of the debate.

BG Plc

BG Plc arose out of the unbundling of the UK gas industry in the 1990s. Following the divestment or sale of the gas marketing, transmission, and storage businesses, together with some of the UK E&P assets, BG Plc was left with a portfolio of UK and International E&P assets and much of the international business outside Europe, including the LNG assets (excluding the UK peak-shaving LNG plants that remained with the storage business).

BG's UK production remains substantial and was used to support the early international expansion from the 1990s that was necessary to expand the business after the unbundling of the former incumbent monopoly, British Gas. BG's UK production now accounts for only 27 percent of global production, with liquids having risen to half the total. UK gas production now stands at ≈ 3 bcm/year, or about 5 percent of the UK's indigenous supply. In 2008/2009, BG completed an E&P asset exchange with BP. BG Group acquired BP's equity in core area fields located in the UK central North Sea. In return, BG Group transferred its equity interests and operatorship in fields in the southern North Sea to BP. This transaction consolidates BG's position in the central North Sea and gives the Group control of key infrastructure hubs.

BG's international strategy, formed in the 1990s, resulted in a focus on "core areas," as opposed to the scattergun approach that characterized the company's

first forays into the international energy business. These core areas allowed the business units to concentrate on integrated plays where this created synergies, but the focus was primarily on the exploration and production business. Successful exploration and production in areas such as Trinidad and Egypt were unable to be exploited commercially without the export of gas, in the form of LNG; hence the LNG business became an expanding component of the BG Plc business.

BG had a small shipping business dating back to the purchase of LNG from Algeria in the 1960s, and this was expanded first as a speculative venture when vessels became available at low cost, and again as BG became an LNG producer. BG has a core fleet of ships and it contracts additional shipping as required on a short-, medium-, and long-term basis in order to capture business opportunities and maintain a balanced shipping position. In 2008, BG Group ordered two new ships, taking the total number of ships expected to be delivered during 2010 to four.

BG Group has equity stakes in liquefaction plants in Egypt and Trinidad and sources gas from both of these countries, as well as Nigeria and Equatorial Guinea, providing the company with roughly 12 million tons per year of destination-flexible LNG. BG has been among the most active in reselling its term supplies on a spot (China, India, Japan, Korea, and elsewhere) and long-term (Chile, Singapore) basis. BG is actively pursuing new LNG supply projects in Equatorial Guinea, Egypt, Australia, and Nigeria, aiming to increase its long-term contracted supply to 20 million tons per year by 2015, including an anticipated 7.4 million tons per year from the QCLNG project in Australia (from 2014).

BG's LNG strategy differs from the traditional LNG business models built around long-term point-to-point contracts. BG's model is based on destination flexibility, ensuring that a portion of its LNG portfolio can be marketed globally in pursuit of margin opportunities. BG believes that its deep understanding of global gas markets, combined with risk management expertise and destination flexibility, provides a solid foundation for the LNG business.

Liquefaction capacity is central to the strategy. In 2001, BG decided to take 100 percent of the capacity rights at the Lake Charles regas terminal in the United States, gaining access to the largest and most liquid gas market in the world. BG also booked capacity rights at Elba Island on the East Coast of the United States and the recently commissioned Dragon terminal in the UK where BG Group has capacity rights of 2.2 million tons per year for twenty years. BG is currently developing new terminals in Chile and Italy. Unfortunately, construction was halted at the 6.0 million tons per year Brindisi LNG regasification project in southern Italy

in February 2007 after criminal charges were brought against certain current and former employees of BG Group, and against BG Italia S.p.A., in connection with allegations of improper conduct related to the authorization process. The Brindisi site remains seized by the Italian authorities, and it is unclear when work can recommence.

In anticipation of a global LNG oversupply, BG Group took preemptive action by contracting a proportion of the Group's flexible LNG volumes into premium markets to protect short-term margins. At the end of January 2009, the Group had contracted around 80 percent of its LNG supply in 2009 and around 75 percent in 2010, with margins locked in on a significant portion of those contracts. More than half of LNG volumes have been contracted to customers over the period 2011 to 2013.

For the future, BG is planning LNG business expansion around the middle of the next decade, when LNG markets will comfortably tighten once again. Strategy remains focused on a truly international business and, with the exception of Italy, continental Europe is not among the "core areas." BG has access to northwestern Europe and needs access to the Mediterranean coast of Europe. If an alternative to the Brindisi terminal becomes available, then BG could move to acquire capacity for the next train of LNG from Egypt or another supply alternative.

In 2009, the European gas production continued with "business as usual" despite the downturn in prices. Much of the UK gas production, like that in Norway, is associated gas and will flow almost regardless of the price of gas. BG's asset swap with BP results in a greater proportion of liquids and associated gas than ever before. Since the commissioning of the Dragon terminal, BG is reported to be marketing third-party access and will attempt to maximize utilization of the 3 bcm/year of capacity it has available.

CONCLUSIONS

The European natural gas industry grew rapidly in the 1960s. Major producers sold their gas at international borders to a relatively small number of national (or sometimes regional) wholesalers under long-term GSAs. Producers wanted contracts that would underpin the financing of major infrastructure investments, and wholesalers wanted prices that would capture market share from other fuels. Typical contract terms included a twenty-year term, the buyers' commitment to pay for a minimum annual volume (whether taken or not), and quarterly pricing adjustment based on published prices of competing fuels (generally agreed to be oil products). Many of the contracts allow for prices to be "re-opened" in the event of a shift in the market value of gas. Until the period 1995 to 2000, virtually all of the gas sold in Europe was sold under these long-term oil-indexed contracts.

So what changed? The UK gas system was isolated from the continent, and contracting practices developed independently. Gas was sold at the beach terminals under oil-indexed contracts, often incorporating additional inflation, coal, and electricity indices. Prior to market liberalization, incumbent monopoly British Gas had carefully "harvested" the market, buying gas from the E&P companies (as sole purchaser) under long-term contracts, and reselling to customers—on a cost-plus basis to smaller customers and on a pass-through basis to larger end-users—even using the same oil-indexed terms as in the beach contracts with producers. This was not only highly profitable, but low risk—until market liberalization. Starting in the 1980s, the market had been opened to competitive supply with relatively little effect, but, when the market was liberalized in the 1990s, the E&P companies had simply bypassed the incumbent gas company and sold directly to large customers, making huge profits. Competition ensued and gas began to be traded under commodity-market conditions, small amounts at first, but increasing with UK gas oversupply.

British Gas had tried to mop-up the available supplies, but this simply generated more supply and made the problem worse. The company was left with over-priced long-term contracts for volumes in excess of their rapidly declining customer base. Worse still, British Gas, under the Take-or-Pay terms, was committed to minimum annual payments for the gas it could not sell. It was forced to renegotiate price and volume terms, at great cost, in return for assets or cash payments.

Events in the UK had no effect on continental Europe—until 1998 when the Bacton–Zeebrugge Interconnector opened for business and gas became available at the borders of Belgium and Germany.

The continental incumbents feared what they had seen in the UK. Continental gas companies were highly expert at “harvesting” the markets, which were demarcated vertically and geographically by legislation or, in the case of Germany, by industry agreements. Fearing the damage that market prices could do to the existing contracting structures, European incumbents acted, often together with producers, to manage the impact of the “English Disease.” At first, containing the contagion was relatively easy, as the incumbents had control of the markets and the gas infrastructure, and had the portfolio volume flexibility to eliminate the surpluses when market prices were low. Requests for access to continental pipelines were initially met with responses such as “there isn’t any capacity available,” “the gas is the wrong specification,” and “we’ll have to build a new pipeline and the tariff will be expensive.”

To their surprise, the continental gas companies found it to be a highly profitable arbitrage opportunity. By utilizing the downward flexibility in their contracts, they purchased less volume at oil-indexed prices and purchased spot gas via the Interconnector, which was then resold to customers at oil-indexed prices. When UK spot prices were low, the profits were huge. The consensus was that the UK oversupply was a temporary phenomenon that would disappear by 2005, leaving continental Europe to pursue business as usual.

So how did this relatively comfortable situation turn against the incumbents in such a relatively short space of time? Did the credit crisis and subsequent recession cause the problem, or was it the catalyst that accelerated the process?

By way of background, in 2009 European gas purchasers in aggregate had a contractual gas supply commensurate with a market of 600 bcm/year, but market demand had peaked in 2008 at just over 560 bcm/year. This meant that some continental wholesalers had little choice but to nominate minimum volumes for much of the year. In other words, there was limited flexibility that could be used to maintain the Middle Ground as the oversupply worsened in 2009.

Beyond a doubt, the recession played a critical role, but against a backdrop of other major changes in European gas markets, notably:

- Market liberalization bringing increased transparency and liquidity to gas and supply infrastructure markets, and emergent new marketers
- The maturation and spread of market-based pricing mechanisms
- Commissioning of new import (piped and LNG) and transportation infrastructure

- Ever-declining expectations of gas demand growth, especially from the power sector
- A 40 bcm/year decline in gas demand in the wake of the credit crisis
- A growth of LNG supplies into Europe's LNG terminals due to rising world LNG supply at the same time as
 - ☑ demand in major Asian LNG markets was contracting due to recession, and
 - ☑ U.S. LNG appetite and prices fell due to both recession and rising shale gas production

The credit crunch acted as a catalyst, unifying disparate forces that may have combined only later, if ever at all. On the demand side, the sudden downward step-change in 2008 left the markets overcontracted. On the supply side, Europe's traded gas markets received LNG volumes above expectations.¹ Several of the above conditions coincided, allowing LNG and spot Norwegian gas sold into the UK to flow to other parts of northwestern Europe via the Interconnector, without resistance. As market-based supplies grew, in 2008 spot and futures prices began to fall, creating a widening gap between the oil-indexed and market prices. By virtue of the liberalized market infrastructure and abundance of cheap gas supplies, the unconstrained second-tier players grabbed market share from the incumbents.² Sales to large end-users simply bypassed the incumbent wholesalers. This left the incumbents not only oversupplied, but unable to claw back market share by discounting.

The dilemma facing some major continental gas utilities in 2009 bore an uncanny resemblance to the situation faced by British Gas/Centrica in 1996/1997. Faced with an oversupply of uncompetitively priced gas, the incumbent wholesaler was forced to renegotiate contracts, paying billions of pounds in compensation to producers in return for lower volumes and prices.³ However, the UK market exhibited one important difference that facilitated change: producers did not support the status quo. Some wanted change, and others recognized that the battle had been lost.

1 Many observers had expected a proportion of Europe's contracted supplies to be redirected to other markets, but in 2009 this didn't happen.

2 See chapter 4, chart 5—The Growth of Market Share by Second-Tier Suppliers and accompanying text for an example from the French gas market.

3 See chapter 1 for further details.

For the contract year ending in 2009, the financial losses by the continental incumbents were arguably bearable, but the prospect of continued adverse trading conditions was a matter of grave concern. At prevailing gas prices, Italy's long-term oil-indexed commitments have a value of around \$400 billion, and Germany's around \$600 billion. In the event of oil-indexed contracts remaining out of the money, European utilities potentially faced billions of euros in losses. Take-or-Pay commitments were the immediate problem. At prevailing gas prices, the shortfall in Russian gas nominations by E.ON in 2008/2009 was valued in the order of \$600 million owing to Gazprom in the fourth quarter 2009, which was partially mitigated by a counterclaim by E.ON for a separate, unrelated contractual dispute.

Markets spent twelve months watching the situation unfold, and only toward the end of 2009 did the full extent of the crisis come clearly into focus. Companies needed to develop response strategies, but major players faced a range of dilemmas:

- Should producers cut production to raise prices, risking that others would simply fill the gap?
- Should producers offer relief on minimum volumes during the crisis, or risk worsening the situation by claiming their full minimum bill payments?
- Should buyers argue in favor of market-based prices, or renegotiate oil-indexed prices downward?

The first response of some buyers was to activate scheduled and optional contract price renegotiations. In other cases the parties met to negotiate by mutual consent. Gazprom negotiations took place against the backdrop of a constant monitoring of the 2009/2010 winter gas demand, which likely influenced the outcome. No doubt to the relief of both sellers and purchasers, the weather in the spot market areas of northwestern Europe produced some record cold months. Without this event, it is possible that negotiations could have been much more prolonged.

Throughout the crisis, it became clear that growing LNG supplies were not a short-term phenomenon. LNG imports into Europe in 2009 set new records in terms of both volume (≈ 68 bcm) and market share (13 percent). Given global LNG supply growth, avowed commitments to continue supplying the UK irrespective of price (from Qatar), and new supply commitments starting up in Italy,

European LNG imports look certain to increase again in 2010. Pipeline supplies could also increase due to scheduled contract increases and new infrastructure, such as the Medgaz pipeline from Algeria to Spain.

Demand in 2010 appears to be recovering from the lows of 2009. It is early in the year and the cold weather in the first quarter distorted the true picture, but reports indicate that industrial demand has recovered from 2009 levels for the same period.

Overall, the potential supply increase in 2010 looks similar in magnitude to the likely increase in demand.

Therefore, without some economic pain, there was very little that the incumbents could do to stem this flow or balance the market. For the markets to regain their balance, allowing spot prices to once again gravitate toward oil-indexed prices, demand would need to surge, indigenous declines to take their toll on supply, and/or world LNG market dynamics to shift. The incumbents could not afford to wait for a strong price signal in Asia or the Americas that would draw discretionary LNG away from Europe's liquid markets, demand to recover, or indigenous declines to play out. To prevent a revolution in gas contracting practices, action was required without further delay. How could the traditional order be preserved?

A "managed volume" solution was the tool chosen by the producers, with some concessions on price at the margins. The potential downside of this option is the danger that it leaves more room for LNG in Europe, at higher prices. However, the managed solution is certainly preferable to an uncontrolled price war, where the lower netbacks to LNG producers would create more diversions to other markets and a moderate increase in European demand, at a high cost to the incumbent producers' revenues.

At the present time, the largest external producers (Gazprom and Statoil) have completed negotiations with their largest customers and have agreed to reductions in both volume and price. Minimum Bill commitments have been temporarily relaxed, probably by around 10 to 15 percent. This effectively extends the Middle Ground downward, relieving the Take-or-Pay pressure on the incumbent wholesalers. The price reductions effectively allow the wholesalers to offer market-based prices to a percentage of their customers, with the intention of creating a buffer zone to protect them against the predatory advances of second-tier competitors.

Coming out of the heating season, the predicted "revolution" appeared to have been temporarily averted. Moving into warmer weather, oil-indexed contracts faced their next challenge in the oversupplied summer market. The outstanding problem was that the price differential between market-based and oil-

indexed prices remained, and the price war would continue. Could the incumbents contain the oversupply?

In the current round, the incumbent wholesalers have an increased supply of the same potent weapon as the second-tier insurgents: market-priced supplies. As customers lower down the chain discern they will not be receiving market-priced supplies, the pressures relieved at the producer/wholesaler interface could reemerge as consumer dissatisfaction at the wholesaler/end-customer interface, becoming the next agent for change.

Key players continue to support the status quo, but will they prevail? Revolution remains a possibility, but the Gazprom gamble is that the European oversupply will disappear before the oil-indexed contracting structures crumble under the weight of the price differential.

Were the calmer markets of the first half of 2010 a sign of the storm passing, or were they really just the eye of the storm?

APPENDIX

**KEY TERMS OF
LONG-TERM
OIL-INDEXED
TAKE-OR-PAY
CONTRACTS**

KEY TERMS OF LONG-TERM OIL-INDEXED TAKE-OR-PAY CONTRACTS

The following section provides a summary of key terms developed for use in long-term oil-indexed gas contracts. It also explains how specific provisions may be exploited by, or constrain the behavior of, signatories in present-day market conditions.

Take-or-Pay Contract Definition

A long-term contract under which the producer guarantees to supply gas to a purchaser, and this purchaser guarantees to pay, whether or not it takes delivery of the gas.

Annual Contract Quantity (ACQ) and Daily Contract Quantity (DCQ)

ACQ is the primary reference point for long-term gas contracts in Europe. In most cases the DCQ is simply the ACQ divided by 365.

In practice it is often the case that the ACQ changes over the life of the contract, per the following:

- Build-up periods, where the ACQ volumes increase periodically over initial years, often apply
- Contracts often include options to increase (or even decrease) volumes at predetermined dates or trigger points
- Depletion contracts anticipate production declines beyond the plateau period and allow for the producer to notify the customer(s) of the ACQ reductions over a predetermined period in advance of the decline

In most cases, the ACQ is not itself a limit of any kind but the reference point around which the limits are set. The minimum and maximum quantities are often a percentage of the ACQ and, in depletion contracts, or during a volume build-up phase of a supply contract, vary pro-rata to changes in the ACQ.

Minimum Bill (Take-or-Pay) Clauses

Take-or-Pay clauses tend to be fairly uniform across European pipeline contracts. The purpose of the Take-or-Pay clause is to set the boundaries for downward volume flexibility in any single contract year. If the buyer is unable (or unwilling) to take the Minimum Bill Quantity specified in the contract, the buyer remains contracted to pay for the specified Take-or-Pay volume.

Take-or-Pay volumes are typically 85 percent or 90 percent of the ACQ, with adjustments for exceptional items such as sellers' shortfall, force majeure, off-spec gas, etc.

High-swing contracts, such as the Dutch local Groningen sales contracts, are an exception, tending to have much lower Take-or-Pay commitments in return for a substantial capacity charge payable regardless of the gas consumed. UK high-swing contracts from the fields developed for seasonal supply (South Morecambe and Sean) also had much lower Take-or-Pay commitments.

Long-term LNG contracts for supply into Europe have more stringent Take-or-Pay commitments than pipeline contracts. However, the volume risk can be reduced by negotiated redirection of cargoes.

In the oversupplied markets of Europe in 2009, a number of purchasers were unable to meet the minimum Take-or-Pay obligations, resulting in substantial liabilities for the minimum bill payments. Normal procedure is for an end-of-year reconciliation payment to be prepared by the seller and issued to the buyer at the end of contract year. This statement shows the quantity and the amount due for the gas not taken, after allowances have been made for any volumes deductible from the minimum bill.

The terms for recovery of gas "paid for but not taken" are variable, but the recovery period is often limited to five years. The gas can only be recovered once the minimum bill quantity for the prevailing contract year has been taken. Therefore, where the buyer is experiencing prolonged adverse market conditions, recovery of the volumes may be viewed as impractical. In such circumstances, the Take-or-Pay obligation is effectively a very severe penalty. The loss of 1 bcm of gas under these terms will cost around \$300 million at today's oil-indexed prices, and, without changes, a number of companies face the prospect of losing billions of dollars worth of gas for many years into the future. It is these clauses that are forcing the incumbent wholesalers to the negotiating table with the suppliers.

From the perspective of producers, the Minimum Bill clause allows them to mitigate exploration, production, and oil price risks. However, in exceptional market conditions, suppliers have an interest in accepting downward revisions in order to alleviate oversupply, as was the case in 2009 to 2010 (see Chapter 3).

For wholesalers, historically, volume and price risks were often wholly or partially passed downstream to distribution companies, power generators, and industrial customers. This was achieved through various measures, such as back-to-back contracts and market demarcation. But, in increasingly liberalized markets, the problem for wholesalers is that long-term volume and price risk cannot easily be passed on to end-customers. Most end-customers are on short- to medium-term contracts, which are simply terminated on expiry when second-tier marketers offer lower-priced gas.

Another significant problem faced by wholesalers is the ability of their long-term end-customers to finance Take-or-Pay terms. There have been reports that substantial end-customers have been unable to fund Take-or-Pay payments under short- to medium-term contracts as a result of their own product market problems. It is almost inevitable that some European manufacturing plants nearing end-of-life will be prematurely retired due to negative cash flows, and that this will affect wholesaler volumes.

Make-Up Quantities (aka Annual Deficiencies)

In traditional UK GSAs, the quantities paid for but not taken under the Take-or-Pay clauses are referred to either as “Make-Up volumes” or “Annual Deficiencies.” The sum of Annual Deficiencies is commonly referred to as the “Take-or-Pay Bank” or “Make-Up Bank,” as if it were the equivalent of money in the bank.

In some contracts, 100 percent of the Annual Deficiency (below the Take-or-Pay volume) must be paid for at the prevailing contract price. Other contracts may demand that the gas is paid for at a percentage (typically 75 or 85 percent) of the prevailing contract price and the remaining percentage paid in a subsequent year when the gas is taken.

The Take-or-Pay Bank must be managed carefully as the banked gas can only be accessed once the buyer has already taken the Minimum Bill Quantity (or other specified volume) in a subsequent year. The purchaser must notify the seller in advance that the volumes taken will be from the accumulated Annual Deficiencies. Volumes of Make-Up gas taken in any contract year will normally

be limited to a percentage of the ACQ, typically 15 percent. In most cases, Annual Deficiencies can only be kept in the Take-or-Pay Bank for a limited period, usually a negotiated maximum of typically three or five years, to avoid excessive buildup.

For wholesalers it takes skill and effort to maintain a portfolio of GSAs in a market where there is a multiplicity of different price levels and a range of obligations and pitfalls embedded in the contracts. A current dilemma may be whether to take gas from the cut-price spot market, at the risk of increasing the Take-or-Pay Bank. It is difficult to assess how full the Take-or-Pay banks may be, but given the background of an overheated economy in 2007/2008 there was an opportunity for some buyers to reduce their prepaid volumes, and even take some “Carry Forward” (see below) into the over-contracted situation of 2008/2009. Given the Annual Deficiencies that materialized at the end of October 2009, the worry for the large purchasers in 2009/2010 was the fear of rapidly expanding Take-or-Pay banks, with potentially limited opportunity for future monetization of the banked volumes at commercial prices. In other words, the problem was bad, and it was growing.

Another (probably unforeseen) side effect of the Take-or-Pay terms is on the wholesalers’ choice between alternative suppliers. In 2009, it was noticeable that Russian contracts suffered greater downturns than those from Norway, notably in the German market. A contributing factor to this is likely the difference in the payment terms for “Annual Deficiencies.” Norwegian contracts generally call for 100 percent of the Annual Deficiency to be paid for at the end of the prevailing contract year, whereas Russian contracts call for 75 percent of the Annual Deficiency to be paid for at the end of the contract year, and the remaining 25 percent in a subsequent year when the gas is taken. Where a purchaser has the choice between Russian and Norwegian oil-indexed supplies, the immediate Annual Deficiency payments are lower on the Russian contracts, incentivizing the buyer to nominate the Norwegian volumes first and defer the Russian supplies.

Minimum Daily Quantity

Many contracts do not specify a minimum daily take, and where it is required it is generally for operational reasons. Where the gas stream is dedicated to infrastructure that requires a minimum throughput to operate efficiently (or at all) then a minimum throughput requirement may be a necessity. This is more

likely to apply to field depletion contracts where a figure of 50 percent of DCQ is commonly used, but range is wide.

Maximum Annual Quantity (MAQ)

MAQ is typically expressed as a percentage of the ACQ. In European contracts, the MAQ is often 110 or 115 percent of the ACQ, the percentage being negotiable.

Increasing the MAQ in relation to the ACQ increases the buyers' volume flexibility, and this inevitably results in a higher cost to the seller. In return for increased MAQ, the seller will almost certainly demand a higher price.

Maximum Daily Quantity (MDQ)

The definition of MDQ is an essential component of a pipeline GSA, critical to both seller and buyer. MDQ is often defined as the MAQ divided by 365 but may be higher, by negotiation.

A higher MAQ may add a considerable amount to the seller's cost of supply, as the additional capacity required at the delivery point may need to be provided along the gas chain from the wellhead. Where possible, the capacity will be provided by gas storage proximate to the delivery point.

For the purchaser, the flexibility derived from a higher MDQ is often an essential component of daily balancing strategy, and of meeting the seasonal needs of end-customers. It is not unusual for the customer's initial daily nominations to be at or near the MDQ across the entire winter period, balanced by a correspondingly low level across the summer period.

Carry Forward Quantities

Carry Forward Quantities are volumes that can be deducted from the Adjusted ACQ and hence the Take-or-Pay volumes for subsequent years.

The intention of Take-or-Pay is to ensure a minimum cash flow rather than a gas flow. The cash-flow target is fulfilled if an annual payment in excess of the Minimum Bill Quantity can be offset against future payments. Carry Forward is a mechanism whereby future payment obligations are reduced in line with quantities or money already paid in excess of a negotiated threshold amount. In some cases, the threshold amount is the minimum bill quantity, but more commonly the threshold is reached when the customer has taken and paid for

the ACQ. Therefore any payments for volumes in excess of the ACQ will be carried forward and can be offset against the ACQ for a subsequent year.

Where the threshold for Carry Forward is based on the Minimum Bill Quantity, make-up rights often elapse on a “first in, first out” basis after a negotiated period of, for example, three to five years, sometimes ten years. The expiration periods used in European contracts are usually of the same duration as those set for make-up rights. Where the threshold is based on the ACQ, the Carry Forward may be unlimited and any unused volumes will simply lapse at the termination of the contract. Maximum Carry Forward volumes that can be used in any contract year will generally be limited to a percentage of ACQ, typically 10 or 15 percent.

Limited Carry Forward volumes may have been accumulated by some players during the 2007/2008 contract year but these are not expected to have been substantial.

Price Reopeners

There are various types of price reopener clauses under a variety of guises. Some are written to address a specific problem; others are much broader and less specific. They generally fall into several categories:

- Tax increases
- Proposed legislation
- Hardship clauses
- Market value
- Voluntary bilateral negotiations

Clauses related to tax increases aim to address potential problems related to new fiscal measures and their impact on the prevailing contract price. These clauses are present in most European contracts. The intention of price indexation clauses is to pass changes in commodity prices on to the gas purchaser. Therefore price indexation clauses generally operate exclusive of taxes on the index commodities. Any increases in existing taxes will automatically be excluded. However, the possibility remains that new taxes will be introduced, or that tax changes will significantly affect the inter-fuel competition rankings in the buyer's market. These matters can be addressed in taxation clauses.

Clauses about proposed legislation address a key question: what happens if a proposed law has a significant impact on prices or markets? When a contract is negotiated under the cloud of proposed legislation it is prudent to include a clause that defines a remedy in the event of an anticipated adverse outcome.

What happens if either party finds that the prevailing contract price is sub-economic and is suffering hardship? This question is addressed through Hardship Clauses. Such clauses recognize that contracts are signed in a specific set of circumstances and that prevailing market conditions can change to cause hardship to either party. These clauses are wider than the Tax Change or Proposed Legislation clauses but narrower than Market Value clauses (see below). The main difference between Hardship and Market Value clauses is that the former requires the party to prove hardship. The latter only requires the claimant to show that the market has changed and that the profit sharing between the parties has shifted.

Market Value Price Reopeners are the most comprehensive type of clause, encompassing all of the above clauses and broader market value issues. They aim to address circumstances that have an economic effect on the energy market and are beyond the control of the party requesting the price revision. Basically, anything that upset the balance of the market from the day the contract was signed could be included in the price reopener discussions.

Examples of issues that could be discussed in the reopener negotiations vary. Typical arguments by purchasers for a lower price include:

- Gas-on-gas competition (increasing competition from lower-cost supplies)
- Imposition by government or regulator of maximum prices or price cuts
- Declining gas sales show that gas is too expensive for end-customers to maintain existing purchase levels
- National or EU legislation that is likely to cause some weakening of gas prices

On the other hand, sellers' arguments for a higher price are focused on:

- LSFO decline in market share (argument for higher gasoil percentage)
- Market competition causing decline in mid-stream (transportation and storage) margins
- Increasing share of gas use in domestic heating market or other high-value markets

- Green premium (carbon taxes increase the value of gas relative to other fossil fuels)
- Increasing market share for gas against other fuels shows that gas is too cheap
- Discounting by the gas purchaser to win a greater market share

Either party may trigger a price reopener, and in some cases both parties may notify their intention to start discussions at the same reopener. The reason for this is that at any given point in time there are both upward and downward drivers on the gas price, and sometimes the best defense is an attack. Both sides might employ teams of in-house experts and specialist advisors where appropriate, in anticipation of a process that would often last for several months.

This type of price reopener is used extensively in the Dutch–German market areas and surrounding countries, including the Mediterranean market areas.

During the 2008/2009 contract year, in the areas affected by the wide differentials between oil-indexed and market-based gas prices, there were universal calls for downward price revisions. A minority (about one-third) of existing contracts will already have a price reopener scheduled during that contract year, and others chose to activate the optional “joker” clause. The following round of renegotiations in 2009/2010 also saw an unprecedentedly high level of price renegotiations. In Eastern Europe, where competition from spot market supplies is absent or minimal, there is no similar argument for downward price revisions.

Following the disaggregation of multiple-seller/multiple-buyer contracts earlier this decade, there may now be a structural problem given that dozens of contracts are involved and it may be impossible for producers, wholesalers, lawyers, and arbitrators to manage the workload in the timeframe required under the contract terms.

Finally, it should be noted that irrespective of the reopener clauses in gas contracts, voluntary bilateral negotiations could also serve as a means to resolve a dispute. In the event that the parties do not reach agreement by bilateral negotiation, price reopeners generally revert to an expert or to arbitration.

Destination Clauses

Destination clauses forbid wholesalers from reselling the commodity outside the countries where they are established, thereby guaranteeing the seller a form

of protection. These clauses helped to maintain price differentials between markets and thereby served as market partitioning devices.

In the broadest sense, destination clauses can include:

- Explicit prohibition of resale
- Restrictions on sales to specific market sectors, across national borders, or outside specific geographical areas
- Consent clauses
- Any clause that discourages buyers from selling gas to any customer within the EU

The EC has argued successfully that such clauses are not in line with competition law within the European Union, as they restrict the resale and flow of gas between EU countries and thus violate basic provisions of the 1958 Treaty of Rome regarding free movements of goods.

Nigeria LNG, in December 2002, was the first external supplier to remove destination clauses from existing and future contracts with European customers. Gazprom agreed in July 2002 to drop the destination clause from all future contracts. In October 2003, the European Commission announced a settlement between Italy's ENI and Gazprom over destination clauses in their existing contracts. ENI would no longer be prevented from re-selling Gazprom purchases outside Italy, and Gazprom would be free to sell to other customers in Italy without ENI's consent.

Sonatrach, in its role as major LNG supplier, held out against the EC for longer than the major pipeline producers. Because of the greater destination flexibility of LNG, profit-splitting mechanisms (where the buyer and producer share the profits of re-sales) became a central issue. Sonatrach justifiably felt entitled to a share of any profits that arose as a result of the intrinsic qualities of its product through the diversion of cargoes to higher value markets. The end result was that the EC agreed to allow profit-sharing clauses in the specific case of delivered ex-ship contracts and on that basis reached agreement with Sonatrach in July 2007.

Today, this elimination of destination clauses is now being exploited by a number of players seeking to build or expand marketing businesses outside their historic core areas. Examples include ENI, which has made a specific commitment to the EC to market volumes outside Italy, and GDF SUEZ, which is able to exploit its Russian gas delivery points at Waidhaus and Baumgarten.

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Anthony J. Melling is an established authority on gas contracting issues. He has three decades of international gas contracting and market analysis experience, with particular emphasis on the UK and continental Europe. Melling gained early experience in British Gas exploration and production, modeling the full range of oil-indexed GSAs, pipeline, and terminal agreements. In the mid 1990s, as the UK oversupply began to revolutionize the UK gas industry, he drafted an influential analysis of the situation that helped shape management's response. Subsequently, in European gas marketing, he studied and analyzed contracting practices across the continent. Over a number of years he developed the contract modeling database used to generate cost and revenue streams under a wide range of oil-price scenarios that was employed in the company planning model. On leaving BG in 2000, Melling focused on European gas contracting practices and, as a consultant, was active in several areas, including energy marketing, energy purchasing for large industrial plants and power generators, and LNG.

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