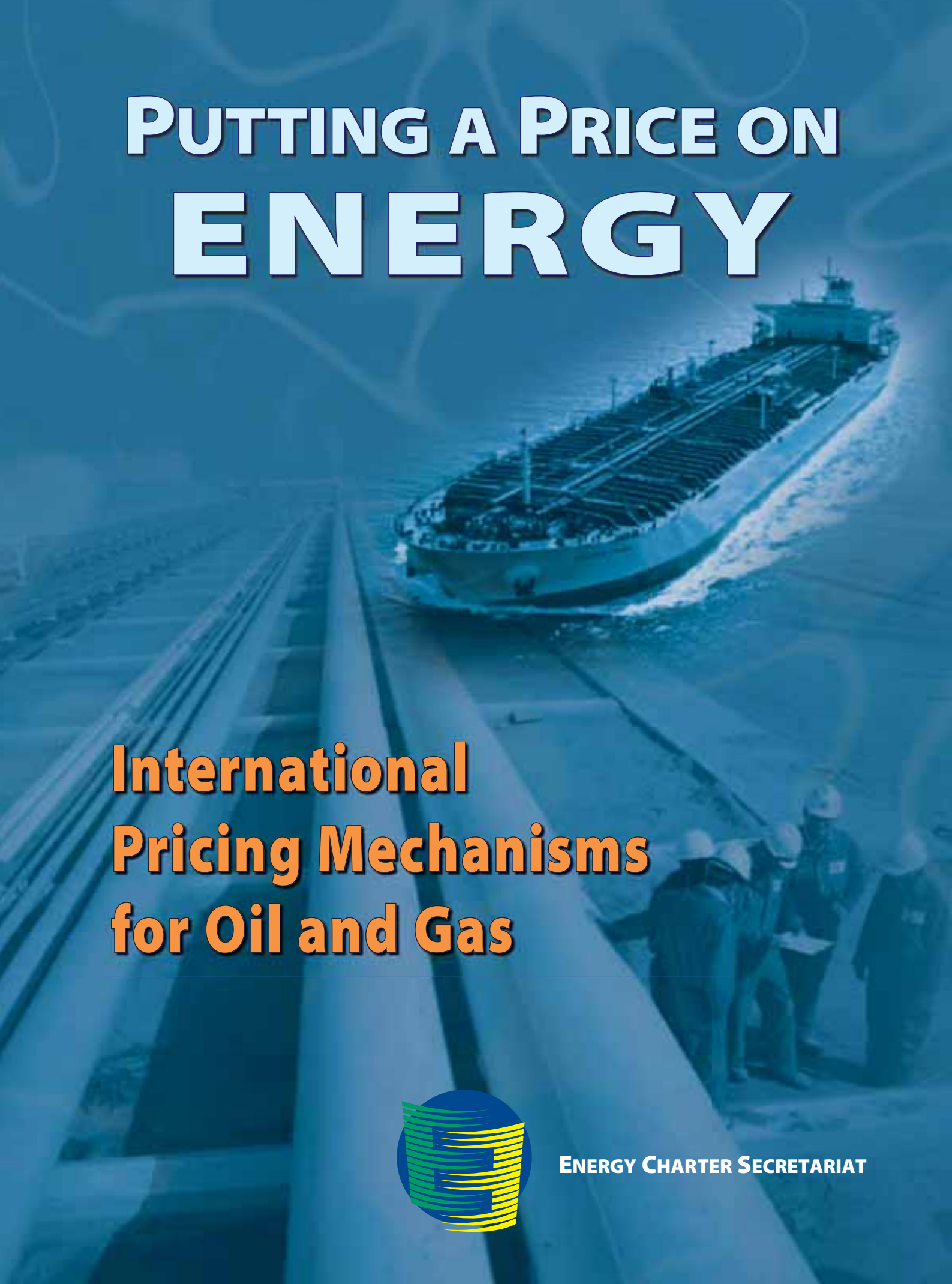
Putting a Price on Energy



International Pricing Mechanisms for Oil and Gas

Energy Charter Secretariat

PUTTING A PRICE ON ENERGY

International Pricing Mechanisms for Oil and Gas



ENERGY CHARTER SECRETARIAT

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Foreword

A core principle of the Energy Charter is 'market-oriented price formation' for the energy sector, within the framework of sovereign rights over energy resources. But this begs the question: how can these two elements be combined and how are they reflected in the formation of oil and gas prices in international trade?

The information provided in this study is essential background for anyone seeking an answer to this question, and provides, for the first time, a comprehensive overview of the development of international pricing mechanisms for oil and gas.

Oil has already been traded internationally for more than a century, and trade in oil has developed all the features of a global commodity market. However, natural gas has not (yet) followed suit, and whether and how a global gas market might emerge is a hotly debated topic in international energy.

What we see instead, in the case of natural gas, are strong variations in the pricing mechanisms for international gas trade into different regional and national markets. This study examines possible reasons for these differences, starting with the physical properties of natural gas and the distribution of gas reserves, and continuing with a detailed consideration of the mechanisms that have emerged to determine gas prices in North America, in the UK and in Continental Europe. It also examines the role of liquefied natural gas in providing a link between different markets.

The aim of this study is to encourage an informed debate about international oil and gas pricing, which itself is a key to understanding many current developments on international energy markets. This is in line with a central objective of the Energy Charter, to promote transparency and provide the foundation for a productive dialogue between both producers and consumers of energy. At the same time, it is worth underlining that neither the study, nor indeed the Energy Charter Treaty, recommends a particular model for national energy markets or for international commercial arrangements.

The study focuses on international oil and gas pricing mechanisms, and examines national regulatory regimes only to the extent that they play a role for internationally traded gas. It is published under my authority as Secretary General and is without prejudice to the positions of Contracting Parties or to their rights or obligations under the Energy Charter Treaty.



André Mernier
Secretary General

1 March 2007

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The report was prepared by the Energy Charter Secretariat team (consisting of Ralf Dickel, Gürbüz Gönül, Tim Gould, Miharu Kanai, Andrei Konoplyanik and Yulia Selivanova) with input from an external expert, Jim Jensen, President of Jensen Associates (US), under the coordination of Ralf Dickel.

The chapters on substance were provided by the following authors:

Chapter 2 (Theoretical and Historic Aspects): Ralf Dickel, Miharu Kanai and Andrei Konoplyanik;

Chapter 3 (Oil Pricing): Miharu Kanai;

Chapter 4 (Gas Pricing): Section 4.2 (North America),[1] Section 4.3 (the United Kingdom) and Section 4.5 (LNG): Jim Jensen; Section 4.4 (Continental Europe): Ralf Dickel, Andrei Konoplyanik and Yulia Selivanova.

The structure and coverage of the report benefited greatly from contributions by Tim Gould and Andrei Konoplyanik.

Valuable comments on the text of the report were received from Energy Charter members and observers, and in particular from representatives of Belarus, the European Communities, Kazakhstan, Russia, the UK and Ukraine.

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1. For the purpose of this study, hereinafter, the term 'North America' refers to the United States and Canada, unless indicated otherwise.

Last but certainly not least: Galina Romanova managed the careful translation into Russian at all stages of the report. Translation of the report was done by Vadim Savin and Valery Zaitsev. Andrei Konoplyanik, Galina Romanova and Olga Sorokina edited the Russian version of the book.

The final responsibility for the book lies, of course, with the authors.

The Energy Charter Treaty

The Energy Charter Treaty provides a multilateral framework for energy cooperation that is unique under international law. It is designed to promote energy security through the operation of more open and competitive energy markets, while respecting the principles of sustainable development and sovereignty over energy resources.

The Energy Charter Treaty was signed in December 1994 and entered into legal force in April 1998. To date the Treaty has been signed or acceded to by fifty-one states plus the European Communities (the total number of members is, therefore, fifty-two).

The Treaty's provisions focus on four broad areas:

- the protection of foreign investments, based on the extension of national treatment, or most-favoured nation treatment (whichever is more favourable) and protection against key non-commercial risks;
- non-discriminatory conditions for trade in energy materials, products and energy-related equipment based on WTO rules, and provisions to ensure reliable cross-border energy transit flows through pipelines, grids and other means of transportation;
- the resolution of disputes between participating states, and – in the case of investments – between investors and host states;
- the promotion of energy efficiency, and attempts to minimise the environmental impact of energy production and use.

The Treaty was developed on the basis of the Energy Charter of 1991, but while this political declaration signalled the political intent to strengthen international energy ties, the 1994 Treaty is a legally binding multilateral agreement. It is the only agreement of its kind dealing with inter-governmental cooperation in the energy sector, covering the whole energy value chain (from exploration to end-use) and all energy products and energy-related equipment.

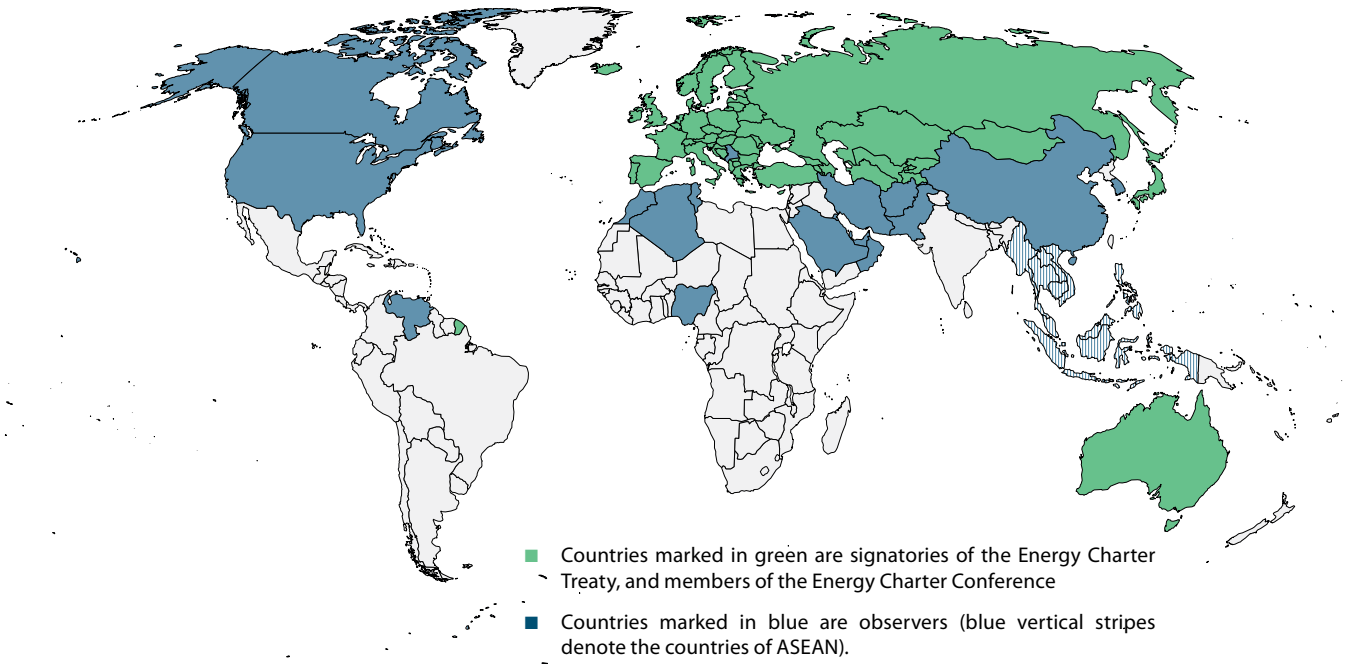


Table of Contents

Foreword . . . 3

Acknowledgements . . . 5

The Energy Charter Treaty . . . 7

Executive Summary . . . 19

Chapter 1 Introduction . . . 33
- 1.1 Issues . . . 33
- 1.2 Approach . . . 33
- 1.3 Questions Investigated in Detail . . . 33

Chapter 2 Explaining Oil and Gas Pricing Mechanisms: Theoretical and Historical Aspects . . . 41
- 2.1 Theoretical Aspects . . . 41
- 2.2 Historical Aspects . . . 52
- 2.3 Market Structure and Pricing Mechanisms . . . 61

Chapter 3 Oil Pricing . . . 65
- 3.1 Summary . . . 65
- 3.2 Introduction . . . 67
  - 3.2.1 Oil – a Commodity Like No Other . . . 67
  - 3.2.2 Crude Oil and Petroleum Products . . . 68
  - 3.2.3 Benchmark Crude . . . 69
  - 3.2.4 Crude Transactions . . . 72
  - 3.2.5 Price Formula . . . 73
  - 3.2.6 Netback Pricing . . . 73
  - 3.2.7 Refining Margins . . . 74
- 3.3 Development of Oil Pricing Mechanism . . . 76
  - 3.3.1 Early Days . . . 76
  - 3.3.2 Majors . . . 76
  - 3.3.3 OPEC . . . 77
  - 3.3.4 Spot and Futures Markets . . . 77
- 3.4 Spot/Forward/Futures/Options . . . 79
  - 3.4.1 Spot Market . . . 79
  - 3.4.2 Forward Market . . . 80
  - 3.4.3 Futures Market . . . 81
  - 3.4.4 Options Market . . . 85

3.5 Hedging and Speculation . . . 86
3.5.1 Hedging . . . 86
3.5.2 Long Hedge and Short Hedge . . . 86
3.5.3 Hedgers, Speculators and Arbitrageurs . . . 87
3.5.4 Regulatory Authority . . . 88
3.6 Current Oil Market Fundamentals . . . 90
3.6.1 Recent Price Developments . . . 90
3.6.2 Demand . . . 91
3.6.3 Supply . . . 91
3.6.4 Refining . . . 93
3.6.5 Stocks . . . 95
3.7 Conclusions . . . 96

Chapter 4 Gas Pricing . . . 99
4.1 Will Gas Follow Oil to Become a Global Commodity? . . . 99
4.2 North America . . . 103
4.2.1 Summary . . . 103
4.2.2 Introduction . . . 103
4.2.2.1 The Integrated North American Natural Gas Transmission System . . . 103
4.2.2.2 North American LNG Import Terminals . . . 105
4.2.2.3 US Natural Gas Demand . . . 106
4.2.2.4 US Natural Gas Supply . . . 108
4.2.2.5 Canadian Supply and Demand . . . 109
4.2.3 The Development of US Natural Gas Regulation . . . 110
4.2.3.1 The Historic Basis of US Gas Regulation . . . 110
4.2.3.2 The Natural Gas Act of 1938 . . . 111
4.2.3.3 The Supreme Court's Phillips Decision . . . 111
4.2.3.4 The Natural Gas Policy Act of 1978 . . . 112
4.2.3.5 Industry Response to the NGPA . . . 112
4.2.3.6 FERC Order 380 . . . 114
4.2.3.7 FERC Order 436 . . . 115
4.2.3.8 The Pipeline Take-or-pay Problem . . . 115
4.2.4 Canadian Gas Regulation . . . 115
4.2.5 The Evolution of North American Gas Prices . . . 116
4.2.5.1 Pre-NGPA US Gas Pricing . . . 116
4.2.5.2 The NGPA and Partial De-regulation of Gas Prices . . . 116
4.2.5.3 The Effect of US Regulatory Policies on Canadian Prices . . . 118
4.2.6 The Current North American Pricing System . . . 119
4.2.6.1 The Emergence of Henry Hub as the Centrepiece of North American Pricing . . . 119
4.2.6.2 The Operation of the North American System . . . 119
4.2.6.3 Gas Price Formation in North America . . . 120

4.2.6.4 Current North American Price Relationships . . . 123
4.2.7 Conclusions . . . 125
4.3 The United Kingdom . . . 126
4.3.1 Summary . . . 126
4.3.2 Introduction . . . 127
4.3.2.1 The History of UK Gas Regulation . . . 127
4.3.2.2 The UK Tax Regime . . . 128
4.3.2.3 The Natural Gas Transmission System . . . 129
4.3.3 UK Supply and Demand . . . 131
4.3.3.1 Gas Demand . . . 131
4.3.3.2 Gas Supply and Trade . . . 132
4.3.3.3 Future UK Gas Supply . . . 134
4.3.3.4 The LNG Terminal Third-party Access Issue . . . 136
4.3.4 Natural Gas Pricing . . . 137
4.3.4.1 Pricing before Industry Restructuring . . . 137
4.3.4.2 Pricing in the Restructured Gas Market . . . 138
4.3.4.3 How Do Prices in the UK Interact with Continental Prices? . . . 140
4.3.4.4 The Experience of the 2005/2006 Winter . . . 141
4.3.5 Conclusions . . . 142
4.4 Continental Europe . . . 143
4.4.1 Summary . . . 143
4.4.2 Development of Market Structure and Imports . . . 144
4.4.3 The Groningen Concept of Replacement Value and of Long-term Minimum-pay Export Contracts . . . 146
4.4.4 Gas Import Contracts Following Groningen . . . 152
4.4.5 Price Review Rounds . . . 163
4.4.6 Regulatory Change . . . 164
4.4.7 Cross-border Gas Deliveries in Former COMECON States . . . 166
4.4.8 Conclusions . . . 173
4.5 LNG . . . 175
4.5.1 Summary . . . 175
4.5.2 Introduction . . . 176
4.5.2.1 The History of World LNG Trade . . . 176
4.5.2.2 The Role of Long-term Contracting in Traditional LNG Trade . . . 179
4.5.2.3 LNG Costs . . . 180
4.5.2.4 The Emergence of More Flexible LNG Markets . . . 181
4.5.2.5 Arbitrage . . . 185
4.5.3 LNG Pricing . . . 187
4.5.3.1 Regional Differences in the Logic of LNG Pricing . . . 187
4.5.3.2 Early Atlantic Basin LNG Pricing . . . 188
4.5.3.3 Early Pacific Basin LNG Pricing . . . 189
4.5.3.4 Mounting Pressures for Change in Pricing Formulas in the 1990s . . . 191

4.5.4 New Approaches to LNG Contracting in the 1990s 191
4.5.4.1 New Patterns of Asian LNG Contracting 191
4.5.4.2 China and India Enter the Asian Market 192
4.5.4.3 Oil Price Escalation and its Impact on Northeast Asian Prices 193
4.5.4.4 Recent Asian Market Developments 195
4.5.4.5 The Emerging North American West Coast Market 196
4.5.4.6 New Patterns of Atlantic Basin LNG Contracting 196
4.5.4.7 Middle East Contracting 198
4.5.4 Contracting for Restructured Gas Markets 199
4.5.5.1 North America 199
4.5.5.2 The UK 199
4.5.6 Conclusions 200

Chapter 5 Overall Conclusions 203

Bibliography 213

Abbreviations and Acronyms 219

Glossary of Terms 227

List of Figures

Figure 1: International Oil and Gas Value Chain 37
Figure 2: Rents of Oil Production 46
Figure 3: Hydrocarbons Markets: From Non-competitive to Competitive Structures 53
Figure 4: Development of World Oil Market Structure and Types of Transactions 58
Figure 5: The Dynamics of Gas Markets Development 60
Figure 6: The World Primary Energy Mix in 2005 67
Figure 7: Net Product Worth and Crude Prices — Comparison between Brent (1997-2005) and Urals (1997-2005) 69
Figure 8: Benchmark Crude Prices 71
Figure 9: Refining Margins (1995-2006) 74
Figure 10: Profit vs. Price of Long - Short positions 82
Figure 11: Price vs. Delivery Date for Contango – Backwardation 83
Figure 12: Profit vs. Price Curves for Long Call – Long Put / Short Call – Short Put 85
Figure 13: Convergence of Futures Price and Spot Price 87
Figure 14: WTI Futures Positions at NYMEX as of 20.02.2007 88
Figure 15: World Crude Spot Prices 1986-2007 90
Figure 16 FSU Oil Production 92
Figure 17: OECD Industry Crude Stocks (1990-2005) 95
Figure 18: Location of main US Regions and their Consumption and Production in 2004 (Bcm) 104
Figure 19: Location of main Canadian Regions and their Consumption and Production in 2004 (Bcm) 105
Figure 20: US Gas Demand since 1950 (Bcm) 106
Figure 21: Comparison of US EIA Annual Energy Outlook Projections of US Gas Demand by Year of Projection 107
Figure 22: Supply Available to US Markets since 1986 (plus EIA Projections) 108
Figure 23: Canadian Gas Demand and Net Exports to the US 109
Figure 24: Wellhead Price History through the Period before and after Passage of the Natural Gas Policy Act of 1978 113
Figure 25: US Natural Gas Annual Consumption during the 'Gas Bubble' Period 114
Figure 26: Vintage Gas Pricing under NGPA Partial De-regulation Showing the Effect of Cross-subsidising De-regulated Gas (Prices as of August 1982) 117
Figure 27: The Pattern of Henry Hub Gas Prices since 1991 (based on the NYMEX 'Strip' Price) 121
Figure 28: The Theoretical Behaviour of Supply, Demand and Price; the Textbook Case 122

Figure 29: A More Realistic Short-term Gas Supply/Demand Curve – a Market in Gas-to-gas Competition 122
Figure 30: Another Short-term Gas Supply/Demand Curve – Two Markets with Oil-to-Gas Competition Restored 123
Figure 31: The Relationship between Spot Prices and the NYMEX Strip Price at Henry Hub 124
Figure 32: Basis Differentials (over Henry Hub) for Selected City Gates 125
Figure 33: UK Consumption of North Sea Gas and Net Imports 132
Figure 34: A Comparison of UK North Sea Gas Reserves with Reserves-to-Production Ratio 133
Figure 35: UK Gas Production 133
Figure 36: UK Net Gas Trade 134
Figure 37: Spot Gas Undermines the Costs of Centrica's System Supply in a Liberalised Market with Supply Surpluses 138
Figure 38: UK National Balancing Point Prices 139
Figure 39: Basis Differential – Zeebrugge over NBP 140
Figure 40: Comparison of Zeebrugge and Belgian Border Prices 141
Figure 41: Development of Natural Gas Supplies in Western Europe including Norway and Switzerland 145
Figure 42: Russian Prices to the EU and Countries along the Pipeline 168
Figure 43: Growth of LNG Imports by Market Region (Bcm) 177
Figure 44: Growth of LNG Exports by Source (Bcm) 178
Figure 45: The Middle East Expands and Shifts its Export Focus (Bcm) 178
Figure 46: The Newer 'Self-contracting' Approach to LNG Marketing Compared to the Traditional 'Destination Contract' 182
Figure 47: LNG Trade Showing the Growing Role of Short-term Sales (Bcm) 183
Figure 48: Estimated Contractual Status of Firm and Probable LNG Capacity in Place by 2010 (million tonnes of LNG) 184
Figure 49: Illustrative Netbacks for Selected Atlantic Basin Arbitrage Partners – Trinidad and Nigeria to Spain and the US Gulf Coast 186
Figure 50: Illustrative Netbacks from the US Gulf Coast, Spain and Japan to the Middle East Showing Arbitrage Patterns 187
Figure 51: Illustration of a Northeast Asian S-curve Based on Japanese Customs Clearing Price for Crude Oil (JCC) 190
Figure 52: Japanese Customs Clearing Price for Crude Oil (JCC) Compared with LNG Import Prices ($/MMBtu) 194
Figure 53: Selected Asian LNG Prices Brought back to a Common Middle East Reference Point by Using Basis Differentials from Qatar 195

List of Boxes

Box 1: Economic Implications of the Physical Properties of Fossil Fuels 35
Box 2: Reserves and Resources 44
Box 3: Market Imperfections 51
Box 4: Spot and Futures Prices 84
Box 5: Crack Spread 87
Box 6: Commodity Index Funds 89
Box 7: Biofuels 94
Box 8: Stylised Price Formula under the Netback Concept of Long-term Contracts 154
Box 9: Stylised Provisions of a Price Review Clause 155

List of Tables

Table 1: Evolution of International Oil Pricing Mechanisms 56
Table 2: The World 10 Largest Oil Consumers/Producers/Importers/Exporters in 2005 68
Table 3: Characteristics of Spot / Forward / Futures / Options Deals 81
Table 4: Will Gas follow Oil to Become a (Global) Commodity? 102

Executive Summary



Executive Summary

This report describes and analyses the development of international oil and gas pricing mechanisms. It is organised in a way that each chapter can be read on its own; the factual chapters and sections on oil (***Chapter 3***), gas in North America (***Section 4.2***), gas in the United Kingdom (***Section 4.3***), gas in Continental Europe (***Section 4.4***) and liquefied natural gas (***Section 4.5***) are each self-contained with an executive summary and conclusions.

Over the last twenty years the oil market has developed into a global commodity market. By contrast, natural gas has only developed into a liquid commodity market in North America and in the UK, in both cases based on domestic resources. In Continental Europe and the Pacific region, the development of the gas industry has mainly been based on imported gas (pipeline gas or LNG) sold under long-term contracts.

The ***Introduction*** (**Chapter 1**) raises the following questions: (i) will the fast increasing trade in liquefied natural gas (LNG) lead to the development of gas as a global commodity? (ii) will regional differences, especially the role of long-term contracts in Continental Europe and Japan / Korea, persist? (iii) to what extent can the regional differences be narrowed by regulatory action, and how is any such regulatory influence shared between importing and exporting countries? (iv) do geology and geography favour certain gas pricing mechanisms, like long-term contracts, thereby limiting the potential impact of regulatory action? (v) what are the respective benefits of liquid commodity markets and long-term contracts and what might be an optimal mix of the two? The chapter ends with a short description of the physical properties of oil and gas and the implications of these properties for the development of markets and pricing mechanisms.

Chapter 2 addresses ***theoretical and historical aspects*** pertinent to oil and gas. The first point to underline is that pricing mechanisms (how prices are determined) should be distinguished from underlying market forces (what determines prices). While a liquid market will provide transparency about price formation, and this is an important precondition for competition, this does not by itself create competitive forces that can drive or keep prices down.

Section 2.1 highlights some ***theoretical approaches*** helpful to deal with special characteristics of oil and gas pricing. Oil, and even more so gas, has characteristics not fully addressed by standard economic theory, so this section considers additional pertinent elements of economic theory: transaction cost theory covers the role of long-term contracts as an instrument to deal with the specificity of investment – which is especially high for gas pipelines. It claims that free economies tend to achieve a mix between market places, long-term contracts and organisation by firms which results in an overall optimum of transaction costs.

To understand the particular case of natural resources like oil or gas, the concept of Ricardian rent is useful (describing naturally given rent differentials between producers), while the concept of Hotelling rent (or depletion premium) is helpful to understand the distribution of rent between consumers and producers stemming from a given technology using a finite resource. Disposal of resources and the management of their production are often in two different hands – the principal who owns the resources and the agent producing it. The special patterns of such a decision-making process are addressed by the principal-agent theory. The incentives for the resource owner are usually driven by long-term rent maximisation – also for future generations. The incentive for the

investor is typically profit maximisation for current shareholders. Both players will typically have different time preference rates.

A particularly important question is whether the resource rent should be monetised by governments of resource-owning states, or whether this rent should be passed on to the benefit of consumers (whether domestic or foreign) by providing resources at a cost-plus price. The high inelasticity of demand for oil and gas, especially when combined with supply restrictions, is often underestimated. This combination results in large mark-ups of prices above marginal costs and is at the heart of high price volatility, as can be seen from the formula developed by Cournot and Nash on the relation between the HHI (Hirschmann-Herfindahl index), the price elasticity of demand and the mark-up of prices over marginal costs. As gas can be substituted by other fuels it is also of interest to understand the relationship between a lead commodity (like oil) and its substitutes (like gas). Nowadays, increasing attention is paid to externalities, mainly environmental impacts of energy use. Internalising such externalities can be dealt with, for example, through using the Coase theorem.

Section 2.2 looks at oil and gas pricing from a historical perspective. The development of oil production seems to follow a bell-shaped curve, called Hubbert's curve. Gas production seems to follow the same curve but with a delay of several decades. If it is assumed that different segments of the Hubbert's curve for oil correspond to different stages in development of the market structure, contractual and pricing mechanisms, one might expect that such a correlation would also hold for the development of gas. In this way, the past development of oil could provide lessons for the development of gas market structure. This question is examined here, together with a brief outline of the main historic development lines of the oil and gas market structures. For oil, four major stages of evolution of pricing mechanisms in the world market are briefly examined, starting with the dominance of long-term contracts and of vertically-integrated companies' internal cross-border transactions with transfer prices under 'one-base pricing' based on the Achnacarry agreement of 1928[2] and its 'two-base pricing' modified formula as of 1947, OPEC[3] dominance in the 1970s-1980s with official selling prices and increasing spot-market prices as their reference point, and the introduction of commodity pricing based on exchange trade and the development of oil derivatives since the 1980s.

Chapter 3 describes the development of ***oil pricing mechanisms***. The system of (mainly internal transfer) posted prices for oil set during the colonial era was replaced by the system of official selling prices after OPEC took control in the 1970s. This was followed by a short period of netback pricing during the oil price collapse in the mid-1980s, after which oil finally started to be traded as a commodity. Today, oil is globally traded like other commodities and has developed all the instruments linked to commodity trading, such as spot and futures markets with all the derivatives to hedge and / or to speculate on future price developments.

Different qualities and locations of crude oils are reflected by the three marker crude oils, WTI,[4] Brent and Dubai, allowing for around-the-clock trade. Other crude oils are priced in reference to these quotations plus differentials reflecting different quality and delivery points. Whereas outside OPEC, transactions by single cargoes are typical, OPEC countries in the Middle East tend to sell their oil under long-term contracts (a year with the possibility of prolongation) at a price linked to spot-price

2. For more information on the Achnacarry agreement, *see* Section 2.2 on Historical Aspects (the Seven Sisters).
3. OPEC – Organisation of Petroleum-Exporting Countries.
4. WTI – West Texas Intermediate.

quotations. Crude oil is usually priced free on board (FOB), while oil products are priced including cost, insurance and freight (CIF), with reference to the main import terminals, storage facilities and refining locations ARA (Amsterdam-Rotterdam-Antwerp), Singapore and the Caribbean.

The chapter also touches upon present fundamentals behind the increase in oil prices since 2000. Demand is mainly driven by the increase in world gross domestic product (GDP), which is strongly correlated to energy and oil demand. As developing countries add demand without developed countries reducing their overall oil consumption, the call on world oil production continues to increase. As of early 2007, spare production capacity is less than 3 MBD[5] at a consumption level above 85 MBD, and refineries are running at 90% of their capacity – i.e., at their practical limit. With production moving to heavier crude oils, there is an increasing lack of deep conversion capacity in refineries worldwide.

The development of technology and rising prices have made non-conventional oil production economic, such as the Canadian tar sands, now producing about 1 MBD, as well as production from deep and ultra-deep offshore locations. However, IEA[6] data suggests that in 2005 non-OPEC production remained unchanged (whereas it increased by 1 MBD in 2004). Other factors supposed to have influenced oil price increases since the beginning of the new century are increases in production costs, a political premium linked to instability in some producer countries, a decline in the US dollar exchange rate and an increase in speculative activities in the oil market.

Chapter 4 ***describes the international gas pricing mechanisms*** in different regions of the world, and for LNG, with separate sections on North America, the UK and Continental Europe, as well as on LNG, covering also Japan and Korea.

Section 4.1 starts with an overview of the specific characteristics and regulatory frameworks of different regions, which play a role in determining regional pricing mechanisms for internationally traded gas.

Gas pricing in North America is dealt with in **Section 4.2**. The development of the gas market in North America was based almost exclusively on domestic resources of the US and Canada. Up until the beginning of the century international gas trade in North America was confined to gas export from Canada to the US. However, with an opening supply-demand gap, North America is now expanding existing LNG receiving terminals, as well as building new ones, in order to import increasing volumes of LNG.

Based on a decision by the Supreme Court in 1954, the US developed a system of wellhead price controls for natural gas, which added to shortages in natural gas supply in the late 1960s due to the lack of incentives to develop additional fields. Price controls were abolished only in 1978, by an act of Congress. Canada, which could not escape the price distortions created by the US system, set up its own price controls in the 1970s and followed the US move towards liberalisation in 1985.

The licensing and rent-taking rules both in the US and in Canada are well defined and serve as a basis for the decision-making process of producing companies. North America has a multitude of small and medium-sized fields, and the development of new gas production in North America is based on the reaction by many private investors to price signals. Liberalisation of price controls and

5. MBD – million barrels per day.
6. OECD/IEA, *Oil Market Report*, March 2007.

the introduction of a third-party access (TPA) system have removed obstacles to the marketing of new gas. The gas industry developed several hubs on which gas is now traded as a commodity. The most important hub is Henry Hub in Louisiana, which is the basis for spot trading and in futures trading on the New York Mercantile Exchange (NYMEX).

The increasing volumes of LNG imports into the US are predominantly on a spot or self-contracting basis, with prices referring to the Henry Hub price. Importers of LNG into the US rely on the depth and liquidity of the US market, which has replaced the long-term hedging function of long-term contracts. While a significant share of gas continues to be imported under long-term contracts, the pegging of gas prices under long-term contracts to fuel oil prices has lost its significance. However, the gas price development at Henry Hub, when smoothed for peaks, still follows the trend of fuel oil prices.

The system in the UK described in **Section 4.3** has many similarities with the North American system, but also some important differences.

Like in North America, the UK gas industry was built predominantly on domestic resources, imports from the Norwegian part of the Frigg field were a singular, isolated case. However, in contrast with the US, the UK did not impose a wellhead price control, but established British Gas (BG), which had both the monopoly to sell gas in the UK and the monopsony to buy all gas from the UK Continental Shelf (UKCS). Moreover, the UK's gas reserves were predominantly offshore and under the control of the government. The issue of exploration and production licences and their rent-taking regimes varied over time, determining the path of resource development.

In the mid 1980s, the UK took the first step towards liberalisation of the gas industry by privatising British Gas. As privatisation of a monopoly / monopsony alone had limited effect, the UK government then promoted competition by creating a regulatory agency, introducing TPA, fostering sales to non-incumbent companies, and freeing producers from the obligation to sell to British Gas, even imposing a limit of 90% on production that could be sold to British Gas. In parallel, the power sector was reformed by dismantling the monopoly of the UK power board, which helped to create a strong (price-elastic) demand for gas in power generation.

The TPA regime in the UK was finally organised as an entry-exit system, where all of the UK onshore transportation system is dealt with as one notional trading place, the National Balancing Point (NBP). Gas entering the NBP by one of the entry points can be freely traded and then be taken out by the buyer at any exit point. As in the US, gas is now traded in the UK as a commodity; however, it is traded only on one hub, created by regulatory action. The churn (ratio between traded volumes and physically delivered volumes) on the NBP rose to 15 in 2003, but has since fallen to about 10, compared to the present and past churn at Henry Hub of about 100.

The Interconnector linking the UK gas grid with Continental Europe became operational at the end of 1998. At its inception, it had a capacity of 20 Bcm/year[7] from Bacton in the UK to Zeebrugge in Belgium and of about 8 Bcm/year in reverse flow from Zeebrugge to Bacton. Exports from the UK to the Continent had been agreed under long-term contracts, although – compared to the prevailing model for gas imports to Continental Europe – the UK export contracts were for smaller volumes (each in the order of a few Bcm/year at most) and with a shorter term of 10-15 years. Some of these contracts allowed the seller or the buyer to choose between delivery points in the UK or

7. Bcm – billion cubic metres.

on the Continent, fostering arbitrage between the UK and the Continent, in addition to the use of the reverse-flow capacity. Already in winter 1998/1999, the first physical reverse flow occurred, triggered by the high price differentials between the pricing system in the UK, which reflected scarcities, and the system on the Continent still dominated by long-term import contracts pegged to fuel-oil prices.

With the steep decline in production from the UKCS and continuing increase in UK gas demand a substantial supply gap is opening for the UK, which is being closed by more imports: (i) by increasing the reverse flow capacity of the Interconnector, whose use will be driven by short-term deals induced by arbitrage opportunities, (ii) by the construction of new LNG import facilities used under self-contracting regimes by major oil companies, with deliveries subject to arbitrage on the Atlantic LNG trade and (iii) additional long-term import contracts via pipelines with Norway and the Netherlands, delivered to the UK via the Vesterled pipeline and via the Balgzand-Bacton Line (BBL) pipeline. These contracts have the NBP as delivery point and gas prices are linked to the International Petroleum Exchange (IPE) spot trade quotations on the NBP, in line with the principles of replacement value, only that the yardstick is domestically traded gas instead of competing fuels. Additional gas will be delivered to the National Balancing Point by the Langeled pipeline from the Ormen Lange field in Norway.

Section 4.4 deals with the pricing mechanism in Continental Europe, both in the Western and in the Eastern part.

The find of the super-giant Groningen gas field in the Netherlands in 1961 triggered the development of an import-based gas industry in the then European Community (the Netherlands, Belgium, Luxembourg, Germany, France and Italy) plus Switzerland. The Dutch government decided to maximise the rent income from the field and developed, together with the licence holders Esso and Shell, a concept that allowed controlling the depletion rate of the field as well as the rate of market penetration. For export use and for domestic use, gas would be sold based on the replacement value defined by substitute energies, thus breaking with the previously usual cost-plus approach. (The elements of the price formula are discussed in detail in *Box 8* in *Section 4.4*).

The replacement value concept became possible due to earlier penetration of the energy market by oil products that allowed for inter-fuel substitution and competition. Contrary to the cost-plus approach, the market, or replacement, value would change over time in line with changes in prices and shares of replacement fuels. This concept, therefore, required regular reviews of pricing conditions.

For exports, long-term minimum-pay contracts were introduced, whose main elements were: (i) firm supply and off-take obligations (secured by a minimum pay), (ii) a pricing mechanism (netback, based on the concept of replacement value), which allowed the gas to compete with its substitutes while maximising the income for the producer, and (iii) the possibility of a regular review of the price formula to reflect changes in the market structure, with arbitration in case of disagreement. Thus the producers (and finally the resource-owning state) would take the price risk, while buyers would get a margin and take the marketing risk. Under this concept, gas for export at the Dutch border was delivered at different prices dependent on the replacement value of gas in the customer's market.

The concept of long-term minimum-pay was originally accepted by buyers based on (i) the agreement that gas would be priced at a level which made it clearly competitive with competing

fuels, and (ii) exclusive concessions to market the gas, whether by national companies or through exclusive marketing within regions or municipalities.

The system of long-term contracts developed for the sale of Groningen gas was the blueprint for subsequent projects supplying Continental Europe, including the major supply projects from the Soviet Union, Norway and Algeria, and LNG supplies from Nigeria. The regular price reviews under already existing contracts made sure that their pricing was kept in line with new developments, which were also taken into account when concluding new contracts. New elements introduced into the price formulas since the conclusion of the contracts for Groningen gas were: the abolition of the capacity charge against the introduction of an annual minimum-pay obligation representing a high annual load factor to account for long-haul gas, a gradual increase of the share of cleaner and lighter fuels, a shortening of reference periods and time lags, and, since the mid-1990s, elements to reflect the (limited) use of gas for power generation and gas-to-gas competition. The development of the gas industry in Continental Europe was largely based on imports under the Groningen concept and, as of 2007, more than 250 Bcm/year – a dominant part of the imports into EU countries[8] – are traded under long-term contracts that are derived from the original Groningen export concept.

Trading hubs have been developed in Continental Europe by the gas industry in Zeebrugge, Bunde and for the Netherlands (TTF).[9] Trading at hubs on the Continent, and imports under spot deals from the UK, are emerging as a complement to imports under long-term import contracts. However, liquidity at these hubs has remained relatively low, with a churn in the order of 5, and the volume of spot gas imported by countries on the Continent remains small so far. Only Belgium has a substantial share of gas imported on a spot basis (~ 25%) due to access to the UK gas market via the Interconnector and to the possibility to import spot LNG cargoes via the Zeebrugge LNG terminal.

The system of long-term contracts has proved durable in handling two oil-price shocks in 1973/1974 and 1979/1980, the reverse oil-price shock in 1985/1986, the Cold War period, the fall of the Berlin Wall and the dissolution of the USSR.[10] Long-term import contracts have also retained their importance during a period of significant regulatory change in the EU gas sector. Supply and off-take obligations were fulfilled by both sides, and the parties have solved sometimes very controversial price re-negotiations by agreement, with very few cases referred to arbitration.

While following closely the Groningen concept, the organisation of Soviet (now Russian) gas exports to Western Europe has some specific features. These can be traced to political and geographic circumstances. The political division of Europe at the time of the first delivery contracts, followed by the challenges of the transition period after the fall of the Berlin Wall and the large distance between gas sources and gas markets, created the need to secure the economic viability of an extended pipeline system, as well as transit arrangements for all gas exports to the West. The transit issue for Russian gas exports became even more pronounced with the emergence of the newly independent states as a result of the dissolution of the USSR.

These elements were reflected in specific modifications of the original Groningen concept, notably the minimum-pay obligation with a high annual load factor in order to ensure a high utilisation rate of the high investment in the pipeline system. Delivery points were established at the political border between 'East' and 'West' (i.e., Waidhaus at the German-Czech border and Baumgarten

8. EU – European Union.
9. TTF – Title Transfer Facility.
10. Union of Soviet Socialist Republics.

at the Austrian-Slovak border, later – Frankfurt / Oder at the German-Polish border). Where the delivery point was upstream of the border of the buyer's market (mainly France and Italy) the gas-price formula provided for compensation of the additional transport costs incurred by the buyer. To exclude potential arbitrage by the buyer such contracts often restrained the use of gas to the destined market for which it was priced (destination clause).

Since the fall of the Berlin Wall in 1989, there has been an adaptation of the former arrangements for transit and gas deliveries in the area formerly covered by the COMECON,[11] firstly for the states of Central Europe and the Baltics, and since 2005 also for other countries of the former Soviet Union. Gas exports from the USSR to COMECON states were originally arranged as part of the coordinated central planning process, with gas supplied at favourable or notional prices, frequently defined on a barter basis, as compensation for the participation in the building of the pipeline infrastructure or for transit services.

Deliveries to Central Europe were transformed in the 1990s and brought into line with the standard concept of long-term contracts. Transit arrangements were separated from gas supply arrangements; for example, deliveries as compensation for transit both with the Slovak Republic and the Czech Republic were re-arranged in 1998 by creating separate long-term supply and transportation agreements, similar to the respective contracts in Western Europe, with a duration until 2008 (with possible prolongations).

Since 2005, Gazprom has also taken initiatives to re-settle its gas supply and transit arrangements with neighbouring countries in Eastern Europe and the Caucasus, as well as with Bulgaria and Romania, along similar lines, with the stated aim to reach financial returns at equal level for all its gas export markets. This pricing approach is based not on the individual replacement value of gas in each country along the pipeline, but takes the price in the main EU markets at the end of the pipeline (Germany, France and Italy), as a reference point, and then deducts the difference in transportation costs. (In the case of westward exports, the value resulting from the netback value in the main EU markets by deducting the transportation costs would be higher than the application of the original Dutch netback approach for the countries in between).

The pricing mechanisms of ***LNG and its role for global gas trade*** are dealt with in **Section 4.5**.

The first commercial LNG deal was between Algeria and the UK, starting in 1964 on a fixed-price basis. However, LNG trade developed mainly in the Pacific basin for the supply of Japan, and later Korea, from Alaska in the United States, Indonesia, Malaysia and Brunei, with price formulas indexed to crude-oil import prices. The Algerian request for FOB crude oil parity at the beginning of the 1980s for all of their LNG deliveries failed in the United States and brought the Atlantic LNG trade virtually to a halt. However, European customers of Algerian gas – Belgium, France and Italy – which were more dependent on Algerian gas deliveries, largely accommodated the Algerian request, although it overpriced Algerian gas, and part of the difference was subsidised by the importing states. This was corrected when oil prices came down in 1985/1986.

Deliveries of Algerian LNG to Europe continued and evolved further. The contracting pattern for LNG has been that of long-term take-or-pay contracts – similar to pipeline-import gas – with a peg to crude oil in the Pacific and to fuel oils and partly to crude oil in Europe. The possibility of regular price reviews is foreseen in Europe and to a lesser extent in the Pacific.

11. Committee on Mutual Economic Cooperation.

With the expiry and prolongation of long-term contracts in the Pacific region starting at the end of the 1990s, more flexible LNG trading features emerged, like FOB instead of CIF, shorter-term contracts and a lower minimum-pay percentage. The crude oil linkage was weakened in some contracts, by introducing price ceilings and bottoms, called the S-curve.

Substantial reduction of costs in the LNG chain occurred during the 1990s due to economies of scale and better contracting schemes for the construction of LNG plants, and some more temporary reductions in the prices for LNG tankers due to the Asian economic crisis. This meant that not all the capacity of an export project needed to be sold under long term minimum-pay contracts in order to service the original financing of an LNG project. Triggered by increased demand from power generation, this allowed for more spot deals and the share of spot deals has increased substantially since 2000. These cost reductions also allowed for a global economic reach of LNG from the Gulf region, which has a share of about one third in global gas reserves.

Since the beginning of the century new gas trade patterns emerged with the need for substantial imports by the North American and UK gas markets, based on a considerable increase of gas demand for power generation. Traditional oil linkage does not work well in liquid commodity markets or for power generation which is subject to economic dispatch scheduling. Self-contracting is becoming the predominant pattern for imports into North American and UK markets, while long-term contracts still prevail for other LNG trade.

The flexibility of LNG transportation combined with the new trading pattern allows arbitrage by re-directing LNG cargoes – mainly between destinations in the Atlantic basin – and thus to transmit price signals between different regional markets, which creates demand-on-demand competition for LNG. However, while price signals are being transmitted between regional markets through LNG trade, this does not imply that gas is heading for a liquid global market in the foreseeable future.

Chapter 5 draws the following conclusions:

I. In the 1980s, the market for oil emerged as a liquid global commodity market.

The physical properties of oil, especially its high energy density, make it easy to transport by ship and to store, and this has underpinned the rise of oil into a globally traded commodity. However, the emergence of oil as a global commodity took some time. At the beginning of the international movement of oil, prices were essentially internal prices of the vertically integrated major oil companies. For a long time they were fixed at a low level and protected by the 'Seven Sisters'[12] through the pricing mechanisms established under the Achnacarry agreement.

With the end of the colonial era, the sovereignty of national states over their resources was affirmed in 1962 by UN resolution No. 1803 (and re-affirmed in 1994 by Article 18 of the Energy Charter Treaty). Some years later, when OPEC countries took control over their oil resources, oil was sold under long-term contracts at official selling prices defined by OPEC countries. Two steep oil price increases posted by OPEC triggered investment both in oil saving and oil substitution, as well as in extra oil production outside OPEC. The resulting competitive pressure led to an absolute decline in world oil consumption in the early 1980s and to the oil price collapse of 1985/1986 and to exchange-based pricing. Since that time, oil has developed all the features of a global liquid commodity market. Oil price developments since 2000, however, demonstrate that a liquid market alone is not sufficient

12. *See* Section 2.2 on Historical Aspects.

to create downward price pressure on a non-renewable energy resource like oil when demand is inelastic and growing.

II. By contrast, the market for gas has not developed into a global commodity market, and only in North America and to a lesser extent in the UK has the gas market developed into a liquid commodity market.

Examining possible reasons for the differences in pricing mechanisms between oil and gas, this report suggests that:

a. the differences between oil and gas pricing mechanisms are related to the respective physical properties of oil and gas, notably the differences in energy density and the resulting cost differences for transport and storage;

b. the regional differences between gas markets can be attributed in large measure to differences in geology and resource endowments, which have implications for import dependence, market structure, regulation and pricing;

c. thus far, natural gas prices in liquid markets continue to follow the price tendency of substitute fuels;

d. there are different pricing mechanisms associated with liquid markets, with long-term contracts and with vertical integration (the latter, for example, in the LNG chain). Changes in technology, market structure and regulatory conditions will modify the balance between these mechanisms in a given region or marketplace, but are not likely to make any of these instruments obsolete.

The four points (a) to (d) above are explained in more detail below:

a. The substantially lower energy density of gas compared to oil and resulting cost differences for transport and storage explain why there is a global oil but no global gas market: differences in location and time of production and consumption are much more important for gas than for oil, a major hindrance for flexibility of trade and for regional markets to merge into a global market. In spite of substantial cost reductions for LNG and increasing price transfers by arbitrage, no global marketplace for LNG is in sight, either on the production side or on the receiving side.

b. The main causes for regional variety in the pricing mechanisms for gas, for OECD countries, are explained by the differences in ***(1) import dependence, (2) the size of supplying fields, (3) the composition and price elasticity of gas demand, and (4) the implications of points (1)-(3) for downstream and upstream regulation.*** In non-OECD countries, notably in the former Soviet Union, ***(5) pricing mechanisms have so far depended strongly on historical and political developments, although there is a trend towards market-oriented price formation.***

    1. Countries whose gas consumption is predominantly covered by domestic production have regulatory control of supply (upstream) and demand (downstream) and thus a major influence on the gas pricing mechanism. By contrast, import-dependent countries have little influence on the supply side.

The main supply decisions are taken by the resource owners, usually the governments of the countries. The objective of gas exporting countries is typically to maximise their resource rent from gas exports. The upper price limit is given by the competitive situation on the export market, usually by competition with substitute fuels. This leads to the concept of netback prices based on the replacement value in the importing country.

2. Countries with many small gas fields can optimise their resource rent by an adequate licensing and taxation regime, which leaves decisions on development and depletion to producing companies. However, countries with super-giant fields have been inclined to develop a depletion policy for those fields, to avoid the risk of over-supply. The attitude of producing countries towards selling gas into the power sector is particularly sensitive to such considerations. Minimum-pay commitments give a strong incentive for the buyers to avoid over-supply of their market from other sources.

3. The main factor affecting the price-demand-elasticity of gas is demand for gas in power generation, as all other sectors have little price elasticity. The role of gas for power generation varies significantly from country to country, since national power policies and sector regulation vary according to the availability of domestic energy resources and preferences for power generation.

4. Points (1) to (3) have had implications for regulation of the gas sector and the development of pricing mechanisms:

   De-regulation in the US and Canada started with the abolition of price controls for domestically produced gas. This was later complemented by the introduction of rules on third-party access which removed obstacles to the marketing of gas; there has been a strong increase in the demand for gas from the power sector since the turn of the century.

   The UK addressed upstream and downstream issues in parallel: upstream – by abolishing the monopsony of British Gas; downstream – by abolishing the monopoly of British Gas, introducing TPA, establishing a regulatory agency and de-regulating the power sector.

   Developments in Continental Europe have been shaped by the regulatory reform at EU level. However, this reform is limited to the downstream: the abolition of exclusive concessions, removal of the ban on gas for power, the introduction of mandatory TPA and of legal and organisational unbundling. The EU does not have direct leverage on upstream regulation of its natural gas supply; it has limited regulatory authority in this area, and the main EU suppliers – with the exception of Norway – fall in any event outside the EU's regulatory space. Indirect leverage on suppliers for the EU is linked to its attractiveness as an export market.

5. Gas exports from the USSR to COMECON states were originally arranged as part of the coordinated central planning process, with gas supplied at favourable or notional prices, often as compensation for participating in the construction of the pipeline infrastructure or for transit services. These arrangements are being unwound in favour of separating gas supply and transit agreements, and a pricing mechanism for gas based on the gas prices in major EU markets netted back to the respective country by deducting the transportation costs in between. This process took place for Central Europe and the Baltic States in the

1990s, and since 2005 it has been evident also in Russia's relations with other former Soviet countries.

c. The use of gas in liquid markets remains subject to short-term and longer-term competition with substitute fuels, which form price ceilings (like gas oil) and can form a market clearing bottom price where there is enough demand for the substitute fuel (like for coal in power generation in the UK). The movement of gas prices continues to follow the tendency of oil product prices in North America and the UK, despite the fact that formal pegging of gas import prices to oil product prices has been abolished.

d. Changes in technology (mainly cost reductions for LNG), market conditions (like the success of CCGTs)[13] and regulation are reflected in an evolving new balance between the pricing mechanisms in liquid markets, long-term contracts and vertical integration. Liquid national/regional markets developed where conditions were favourable (domestic reserves from a multitude of smaller fields). For internationally traded gas long term contracts remain the prevailing instrument. Where specificity of investment is high, mainly for pipeline gas, long-term contracts will continue to play the major role. They have been adapted to substantial changes over the past decades to the satisfaction of both sellers and buyers. Experience has demonstrated that long-term contracts for imports and liquid national gas markets can co-exist.

13. Combined-cycle gas turbine.

Chapter 1

Introduction



Chapter 1 Introduction

1.1 Issues

"Within the framework of State sovereignty and sovereign rights over energy resources and in a spirit of political and economic cooperation, (the signatories) undertake to promote the development of an efficient energy market throughout Europe and a better functioning global market, in both cases based on the principle of non-discrimination and on market-oriented price formation, taking due account of environmental concerns."

Title I (Objectives) of the 1991 Energy Charter, the political declaration that marked the start of the Energy Charter process.

The aim of this study is to investigate the principles of market-oriented price formation both for the global oil market and for gas in a global and regional context, and to look into the evidence of how pricing mechanisms work in an attempt to elaborate on what this means in practice in the case of oil and natural gas. The study focuses on the international aspects, i.e., cross-border trade of oil and gas, and addresses the national level only where the national pricing mechanism forms the basis for internationally traded gas, namely in North America and the UK. The intention is to inform the debate across the Energy Charter constituency on issues related to international energy pricing and pricing mechanisms.

1.2 Approach

On the basis of a consideration of relevant economic theory and detailed background on the operation of international pricing mechanisms for oil, this report describes and analyses the way that prices for natural gas are formed in different regional gas markets. This analysis looks at the context and characteristics of the respective markets that are relevant for the pricing of international trade, and also addresses the impact of the growing international trade in liquefied natural gas (LNG).

1.3 Questions Investigated in Detail

Over the last 20 years, the market for crude oil has been developed as a global open and competitive market with all the pricing mechanisms typical of commodity markets. This provides for transparency but does not preclude high prices as a result of an oligopolistic supply structure combined with low elasticity of demand. Gas is closely linked to oil in its production process and can be replaced by oil in most applications. The major question for gas is thus:

Will gas follow oil on the way to a worldwide commodity pricing mechanism? If yes, then how? And if not, why not?

A liquid market for natural gas has so far developed only in North America and to a lesser extent in the UK. To date, these markets have had only limited involvement in international gas trade. In spite

of reform efforts by the European Union, the development of liquid trading places on the European Continent is still in its infancy, while long-term supply contracts continue to play the dominant role for imports. LNG contracts, which until the 1990s were even less flexible than pipeline contracts, now provide more flexibility with regard to off-take obligations and destination. As costs have decreased, so a larger number of shorter-term LNG deals have developed. However, long-term contracts continue to dominate LNG trade and a global LNG spot market has not yet developed.

The report analyses possible reasons for the differences in the development of gas markets and pricing mechanisms, and whether these differences are linked purely to uneven progress with gas market liberalisation or whether other factors play a role, for example:

- geography and geology;
- import dependence on a small number of exporting countries who are interested in optimising their rent from natural resources and whose production is concentrated in a few super-giant fields;
- long-term entrenched choices for power generation of fuels other than gas (e.g., nuclear power in France);
- the impact of and approaches to resource rent optimisation by gas exporting countries.

In relation to long-term contracts for natural gas, the discussion examines:

- Import dependence and rent seeking behaviour of resource owning countries as a rationale for concluding long-term contracts;
- the core elements of long-term contracts and the room for adapting these contracts to new market developments;
- the future role of long-term contracts in energy supply.

For trade in LNG, the report addresses:

- the continued predominance of long-term LNG contracts, especially in the Pacific, even as LNG trade has become more flexible;
- the impact of the opening of the highly liquid and deep US gas market on the contracting pattern for LNG imports;
- the interaction between LNG trade in the Atlantic basin and the markets for natural gas in Europe and North America: what trade patterns for LNG will develop in the Atlantic basin, what will be the role of Henry Hub for LNG prices;
- the question of whether arbitrage by LNG will foster a global LNG and ultimately a global gas market.

Box 1: Economic Implications of the Physical Properties of Fossil Fuels

Energy density and composition of fossil fuels

Oil has the highest energy density of all fossil fuels, about 40-45 GJ/t or 35-40 GJ/m3, with some variation due to gravity and sulphur content.

Coal, by contrast, has only about 20-30 GJ/t, varying largely depending on the ash content, which for hard coal can be as high as 40% and even higher for lignite.

Gas, which has methane as its main component, has only one thousandth of the energy density of oil under atmospheric pressure, i.e., 35-45 MJ/m3, with a lower value depending on the share of inert gases like nitrogen, or a higher value depending on the share of components higher then methane, typically ethane, propane and butane.

It is possible to increase the energy density of natural gas by putting it under pressure, e.g., by a factor of 100 if pressurised to 100 bar, but this still leaves a differential in energy density in the order of 10 compared with oil. It is also possible to liquefy natural gas by cooling it down to minus 162 degrees Celsius. The energy density of liquefied natural gas (LNG) is about half that of oil, but the technology necessary to liquefy, ship and re-gasify LNG is much more costly than that for handling oil.

Noxious components like sulphur, which can occur in all three fossil fuels, need treatment to protect the environment. Handling the ash contained in the coal requires substantial additional equipment for the combustion process and depositing the ash is a costly operation.

The use of coal is so far confined to boilers alone or combined with steam turbines (except for transforming it into a manufactured gas by a process of hydration), while gas and oil are easy to handle and can also be used in internal combustion engines (cars) and in gas turbines.

Oil and coal can be transported and stored in vessels without entailing high specific costs, making it easier to establish marketplaces for oil and coal trading. The high energy density of oil, combined with easy handling, storage and transportation, make it suitable for small applications like cars.

This does not apply for coal and only to a lesser extent for gas. Due to its gaseous aggregate and low energy density, and unless it is transported as LNG, gas requires a fixed pipeline infrastructure for transportation and distribution Establishing a physical trading infrastructure for gas is more difficult because of its high specific costs.

Gas has a substantial advantage on GHG emissions: the CO_2 emission factor from burning fuel oil is about 35% higher and, for coal, about 55% higher than for gas. In addition, gas and oil can be used in gas turbines and in CCGTs, where the exhaust heat of a gas turbine process is used to run a steam turbine with a substantially higher electric efficiency (more than 55%) of the combined process than a standard coal-driven steam turbine, which has a maximum electric efficiency of 45%.

Oil can always replace gas, at the price of a higher CO_2 emission factor, while gas can replace oil but is not well suited to fuel individual cars. All three fossil fuels can be used for power generation, gas and gas oil performing similarly, while burning heavy (residual) fuel oil causes more handling problems, and burning coal requires a different treatment and substantial higher investment than for oil or gas.

Character of the deposits of fossil fuels:

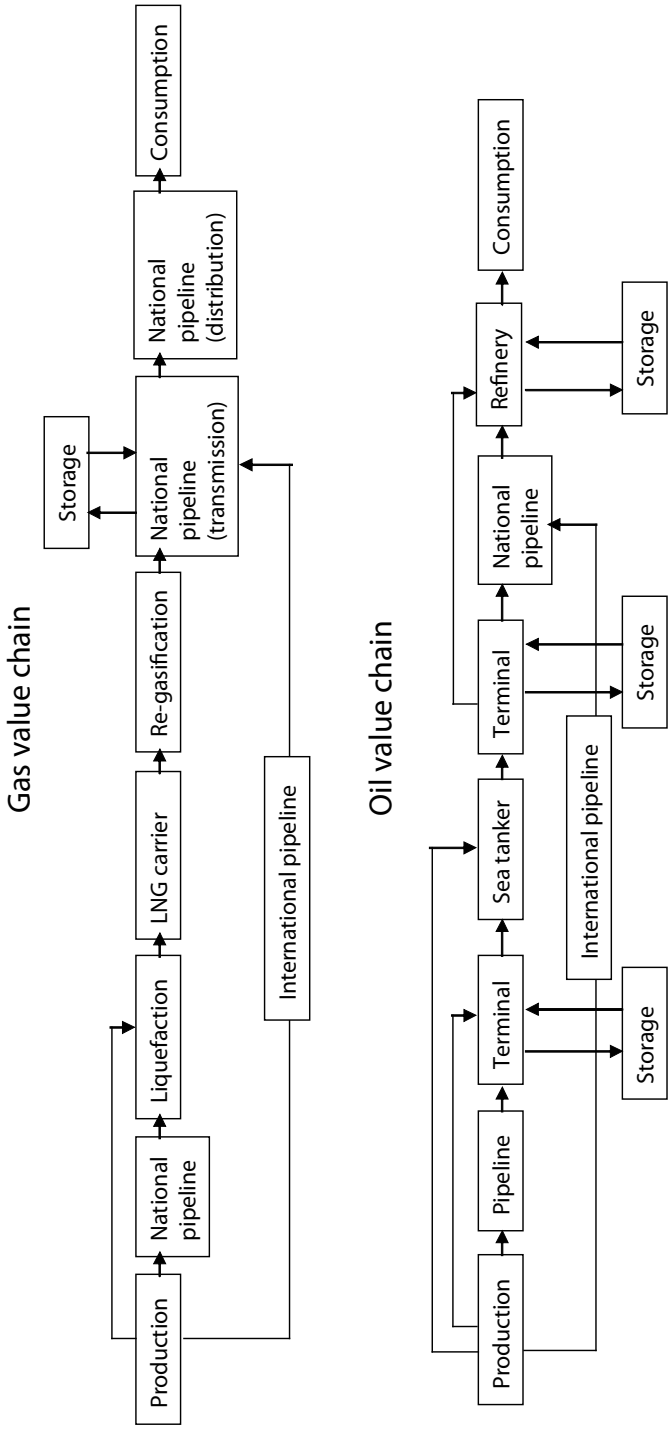
Oil and gas fields are subject to hydraulic communication; production from one part of a structure leads to a pressure reduction for all of the structure with repercussions for overall recovery. It is, therefore, common practice to unitise deposits that stretch across the borders of several licences and to have oil or gas fields under a uniform operating regime, even the very large ones. By contrast, large deposits of solid minerals like coal can be produced at several places in parallel, without interference with each other. However, there are usually economies of scope and scale stemming from a coordinated development of large coal deposits.

At large onshore oil fields with good production characteristics the drilling of additional wells to add production capacity is often not very costly. In such cases spare capacity can be kept in reserve or created at relatively short notice. As access to extra oil-tanker capacity is usually possible, large oil producers can react quickly to fluctuations in demand. By contrast, spare production for gas capacity is not expensive for large onshore fields, but the spare infrastructure to bring it to the market is very costly because of the low energy density of gas. For coal, spare production capacity would be costly because of the substantial idle equipment and the need to have enough qualified workforce at hand, while extra shipping capacity may be available on the mass freight-ship market, subject to competition with other users.

The consequence is that oil storage downstream is minimised except for strategic stocks, while, for gas, storage close to the market is usual for seasonal storage to avoid unnecessary capacity in the pipeline, and for coal many power plants have a coal stock close to the plant.

Generalised cross-border energy value chains in oil and gas are presented below:

Figure 1: International Oil and Gas Value Chain



Source: Energy Charter Secretariat

Chapter 2

Explaining Oil and Gas Pricing Mechanisms: Theoretical and Historical Aspects



Chapter 2 Explaining Oil and Gas Pricing Mechanisms: Theoretical and Historical Aspects

To begin with, it is necessary to distinguish between pricing mechanisms and the underlying forces which determine prices, or, in other words, to distinguish between how prices are determined and what determines prices. The first is about the organisation of trade, exchange and marketplaces, including access, and the ways prices are negotiated, communicated and made public. This does not necessarily give an insight into what influences decision-making by buyers and sellers, nor about the resulting market balance and price level.

The price mechanism for a commodity can lead to a transparent and liquid market (as for crude oil) without any pressure for lower prices. However, the underlying structure of oil and gas trade will have an influence on pricing mechanisms: a prominent question is the role of long-term contracts compared to liquid markets. As oil and gas are special commodities, it is useful to look at the range of economic paradigms, as well as the historical development of oil and gas markets, in order to find ways to interpret the developments of oil and gas pricing described in *Chapters 3* and *4*.

2.1 Theoretical Aspects

The standard case of economic textbooks is based on an atomistic structure of suppliers and customers, both following a price-elastic supply and demand curve. A typical example is crop production by small farmers or the production of textiles.

Price signals are visible to both producers and consumers and both sides follow them with their decisions on production (output) and consumption to optimise their profit or overall benefit. This not only presumes clear and visible signals but also the capacity and the willingness to transform these signals into action. This is put into question once demand reaches a certain inelasticity because consumers may have little choice for a given time horizon and it may then depend on the incentive on the producers' side to compete with each other for a larger share in the market. Those incentives may be distorted in the case of high enough market concentration, but also as a function of risk perception or simply by the investment time-lag needed to adjust the production level, or eventually by regulatory or technical bottlenecks.

Price is a signal from the market. It represents scarcity of the commodity in the market. When the price rises, demand is reduced to a level where supply matches demand (and vice versa). It also indicates a foresight of supply and demand, as expectations are factored in both supply and demand curves.

Price is also a key signal for an efficient allocation of capital. A higher price relative to cost signals the need for new investment in production capacity, as the price signals a potential reward to investors. On the other hand, a low price discourages investment. It is worth noting that the oil and gas sector

competes for capital with investment opportunities in other sectors. Therefore, a certain level of returns is needed to attract capital.

Oil and gas have many characteristics that distinguish them from other commodities, such as:

i. the high uncertainty linked to resource development and the high specificity of investment all along the energy chain from production to consumption,

ii. the character of a natural resource,

iii. the finiteness of the resource, exacerbated by the high concentration of reserves in about a dozen countries,

iv. the involvement of two decision makers on the production side: producing company and resource owner,

v. the often highly inelastic demand for energy and its interaction with concentration and capacity restrictions on the supply side, and

vi. market imperfections such as unavoidable externalities.

These characteristics are explained in more detail below, together with an indication of elements of economic theory which might help to address them.

(i) Risk and High Specificity of Oil and Gas Investment (Transaction Cost Theory)

The development of energy resources into a useful energy service is a risky business requiring high investment along the chain from resource development to the final customer. It requires not only high investment but often investment specific to the site or to a special link in the chain (specificity of investment). Interfaces along the energy chain may have many players on both sides of the interface (so that players do not care who their counterpart is, and the interface will best be managed as a marketplace). Other interfaces – especially onshore cross-border pipelines – may have only very few players on either side, so that risk and rewards have to be shared between fixed counterparts, typically through long-term contracts.

The implications of specificity of investment are at the core of transaction cost theory:

In his famous article, 'The Nature of the Firm', Ronald Coase[14] made the case that, in free economies, transactions are not only ruled by markets, but also, sometimes even on a very large scale, by hierarchically organised firms. The theory of transaction costs initiated by this article also addresses the role of long-term contracts as one possible instrument of economic interaction other than firms and markets. Each of these three instruments comes with specific transaction costs: e.g., markets with the costs of acquiring information and managing risks, firms with the costs of a hierarchical organisation and control, depending on the size of a firm, long-term contracts with the costs of their negotiation and enforcement. Transaction cost theory claims that free economies will tend towards an optimum of overall transaction costs to deal with the elements of uncertainty, opportunism by the players and asset specificity. For example: firms will outsource functions to

14. Accessible at <http://www.cerna.ensmp.fr/Enseignement/CoursEcoIndus/SupportsdeCours/COASE.pdf> (visited 24 January 2007).

markets when keeping them within the firm becomes too expensive relative to buying them on the market. Conversely, if the risk management costs of market interfaces become too costly they may be reduced by horizontal integration or by managing the interface by long-term contracts. This optimisation depends on and develops with technological and institutional development.[15]

The specificity of investment is especially large for gas: while gas can in almost all applications be replaced by oil products, it has a much lower energy density than oil (by a factor of 1000 under normal pressure and by a factor of about 10 when pressurised up to 100 bar). Consequently, specific transportation and storage costs for gas are substantially higher than for oil. The transportation cost differential between different locations, as well as the storage costs to bridge a time span between supply and use, can be critical for gas and impede the creation of marketplaces, favouring long-term contracts instead.

(ii) The Character of a Natural Resource (Ricardian Rent)

The production of oil and gas, like that of other fossil fuels or, more generally, of any other primary production, depends on the naturally given quality of the production site. Costs of production differ from field to field, e.g., between onshore and offshore, between small and large fields, or between conventional production and non-conventional resources such as tar sands. The site of oil and gas production is given by geology which imposes site-specific distances to markets. By contrast, no naturally given cost differences exist for manufactured goods: their production combines only factors which can be bought by everybody on markets, and their production site can be chosen freely. Differences in production costs of manufactured goods are mainly due to differences in the technology and organisation of production.

The cost differences given by the quality of the production site and by its location relative to markets give rise to differential rents, called Ricardian rent after the 19th century British economist David Ricardo (his theory is based on the example of farming and cattle-raising but his insights apply to mining as well). An example is the higher production costs of offshore oil: production costs for a reservoir in the North Sea are in the order of 10-15 $/bbl, compared with lower costs for oil from onshore reservoirs in the Gulf states with otherwise similar production characteristics; these costs are estimated to be less than 5 $/bbl.

Production sites are not only of different qualities; their varying locations relative to the market result in differential rents as well. An example is the difference of gas transportation costs to the Northwest European market between the Groningen field (short haul: some 100 km) compared to Russian gas (long haul: 4000-5000 km) and Norwegian gas (medium distance of 1000 km, but offshore) or Qatar LNG. The differential rent itself is subject to technological development, e.g., reduction in the costs of offshore production, or reduction in the costs of gas transportation (reduction of pipeline transportation costs by higher pressure pipelines using higher quality steel, or reduction in LNG transportation costs due to economies of scale of liquefaction plants and LNG tankers).

15. O.E. Williamson, The Economic Institutions of Capitalism: Firms, Markets, Relational Contracting (The Free Press, New York, 1985). *See* also articles by O.E. Williamson on the topic at <http://groups.haas.berkeley.edu/bpp/oew/> (visited 24 January 2007).

(iii) Finiteness of Resources, Hotelling's Theorem

While the depletion of proven oil and gas reserves can be replenished by transforming additional resources into reserves through additional investment into exploration or improvement of existing production (*see Box 2*), the fact remains that oil and gas are finite resources. Views differ strongly as to when the peak of oil production (the peak of the so-called Hubbert's curve – *see* also *Section 2.2*) will be reached. The IEA World Energy Outlook of 2004 seems to indicate that additions to proven global oil reserves as of the 1980s fell short of compensating for production, especially due to a decline in proving new reserves in the FSU and the Middle East.[16] This may, however, be due more to policy decisions than to geology.

A group of geologists and industry experts claim that oil production will peak soon. They maintain that OPEC's published reserve figures are inflated, because of OPEC's quota system. Meanwhile, in its World Energy Outlook 2006, the IEA predicts that total oil production will not decline during the prediction period to 2030,[17] although non-OPEC production will peak in the next decade.[18]

Box 2: Reserves and Resources

Conceptually there are differences between 'reserves,' 'resources' and 'resource base'. Reserves are the oil and gas volumes that have been discovered and are thought possible to produce under prevailing technological and economic conditions. Resources include the oil and gas volumes that are thought to exist and be recoverable, whether they are discovered or not. Resource base means all hydrocarbon molecules that are thought to exist on the earth, whether they are recoverable or not. Reserves are a subset of resources and resources are a subset of the resource base. The borders between these categories are not static but dynamic.

It is important to note the different concepts of 'reserves' and 'resources' in relation to the oil peak theory. Scarcity in oil and gas reserves is defined not only by limited physical availability but also by technical feasibility, legal aspects and economical viability.

In the 'reserves' category, the following three criteria are standard. They are also adopted in financial statements of publicly traded companies in many industrialised countries.

- Proved reserves: the estimated quantities of oil which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years with existing technologies from known reservoirs under prevailing economic and operating conditions. A probability of 90% (P90) is sometimes used to define proved reserves.
- Probable reserves: Probable reserves are designated as 'indicated', and estimated as having a better than 50% chance of being technically and economically producible.
- Possible reserves: Possible reserves is designated as 'inferred' reserves or referred to as P10 or P20 reserves, reflecting a 10% or 20% chance respectively.

16. OECD/IEA, World Energy Outlook 2004 97 (IEA, 2004).
17. OECD/IEA, World Energy Outlook 2006 492 (IEA, 2006), *see* table with the World Reference Scenario.
18. Id., at 39.

It is common that probable and possible reserves are upgraded to proved reserves over time as operating history reduces the uncertainty. There are also subtle differences in the categorisation among the institutions that estimate reserves. One example is Canadian tar sands. The Oil and Gas Journal puts them under proved reserves, which brings Canadian oil reserves almost on a par with those of Saudi Arabia, while the British Petroleum (BP) Statistical Review includes only a part of the tar sands reserves in this category.

The reserve-to-production (RP) ratio (proved reserves divided by annual production, normally expressed in years) is commonly used as an index to represent scarcity in oil and gas resources. According to BP, since the late 1980s the world RP ratio for oil has been just above the 40-year level (40.2 years in 2005) and for gas between 65-70 years (65.4 years in 2005), remaining stable even during a period of substantial growth of oil and gas production. But these figures should not be used as an indicator of the remaining time-span for the oil era, contrary to the perception of the famous "Limits of Growth" (Meadows et al.), published in the early 1970s. RP ratios are based on the estimates of proved recoverable reserves, i.e., only this portion of the resources that are considered to be profitably recoverable under current economic conditions with existing technologies; companies tend not to invest into large spare production capacities since this will diminish their return on capital. That is why, throughout the 20th century, the RP ratio of the US for oil was constant at around 8-10 years, but oil was never exhausted during this period.

For some time to come, mobilising more reserves on a world scale seems to be rather a question of mobilising the investment to transform resources into reserves; the finiteness of global resources may not yet play a role. For an individual country the perspective is different and the finiteness of resources may be important for its decisions: For example, despite many small finds in the UK, reserves and production of the UKCS are on the decline and efforts to discover more hydrocarbons to the west and northwest of Scotland have so far yielded disappointing results. While the UK's decline of reserves and production will be compensated on a global scale, the UK, which was an important net exporter of hydrocarbons, now faces the need for substantial hydrocarbon imports.

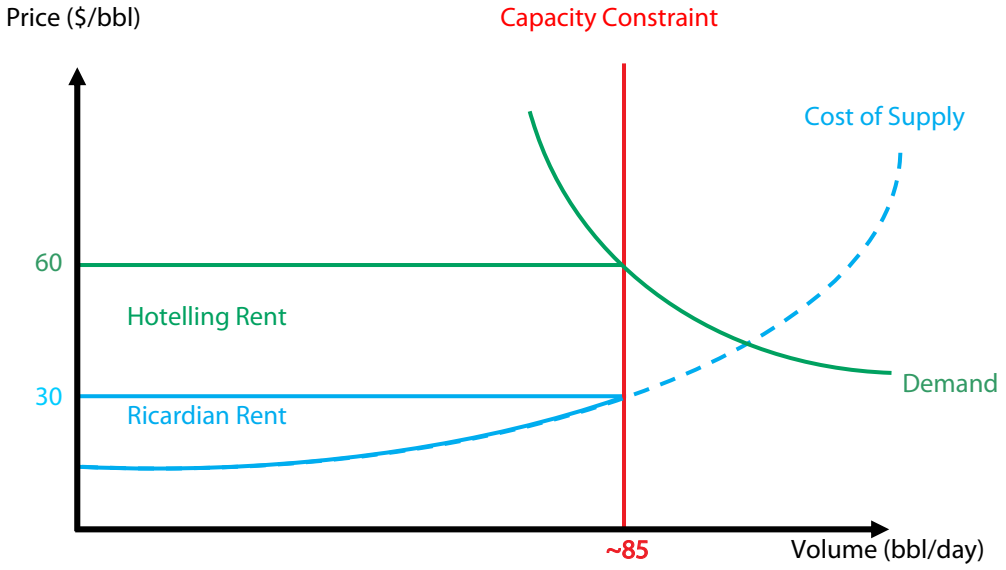
There are two different approaches to the economy of finite resources. The Ricardian approach does not emphasise the limits on resources, but rather focuses on the recognition that, as resources become more difficult to exploit, their development requires greater capital spending and technological development, and that a resource rent results only from cost differences between different production sites. This approach is often used as a justification for a cost-based energy-pricing system.

The Ricardian approach is contrasted with the approach of the US economist Harold Hotelling, who assumed finiteness of a given resource and investigated the consequences for the inter-temporal optimisation of resource development (Hotelling's theorem). This approach provides the conceptual basis for an energy-pricing system based on replacement value. All further development of the economic theory on finite resources is based on Hotelling's theorem. It claims that the depletion path for a finite resource will be such that the annual revenue follows the interest rate, and that the resulting price path is such that an alternative (backstop technology) will be an economic substitute when the finite resource is depleted.

The first element can be recognised in the decision-making process of companies about investment and depletion of oil and gas fields, which will use some kind of discounted cash flow analysis. The

second part gives rise to the notion of the Hotelling rent, which describes what a resource owner gets for the depletion of a finite resource and, conversely, what the consumer is prepared to pay (out of his consumer rent) beyond the marginal costs of production. This rent is determined by competition between consumers for a limited supply. *Figure 2* below illustrates the difference between the Ricardian rent and Hotelling rent. For an individual resource owner we refer to the sum of both as the resource rent (in shorthand, a 'depletion premium').

Figure 2: Rents of Oil Production



Source: Energy Charter Secretariat

Capacity limitations may be temporary and can be overcome by investing to remove bottlenecks; in the longer run output limitations may also be due to decisions by the resources owner on the depletion path of the resources. This presupposes a certain concentration of resources in the hands of a few players who can effectively act as an oligopoly, and to some extent also the concentration of these resources in large reservoirs where uniform handling is appropriate.

In that context, it is important to recall the high concentration of global hydrocarbon resources. A dozen countries own about two-thirds of both world gas and world oil reserves, while being home to about 5% of world population (these are the Gulf States, together with Russia, Venezuela, and Canada, based on its tar sands).

(iv) Producing Companies and Resource Owners: Principal-Agent Theory

Because the right to natural resources is usually vested in the state, the exploitation of natural resources is dependent on two players, the resource owner (the state, represented by its government) and the producing company, which have different economic interests and whose relative negotiating power changes during the lifetime of the project. Whereas, at the beginning, producing companies, who are asked to provide risk capital, have a stronger hand, the situation changes as knowledge about a deposit increases and the investment progresses. The yardstick of economic success is also different between the two players; governments usually have a lower time

preference rate than companies and with a longer time horizon. Governments have to account for future generations; private companies have to satisfy today's shareholders. This may result in different attitudes towards the exploitation of resources: Oil companies may tend towards a faster depletion path than governments, even more so if the companies fear political changes in the rules guiding their activity. The necessary split of risk and rewards has to be managed between the resource owner and the producer.

These issues are addressed by principal-agent theory. Kirsten Bindemann elaborates the application of the principal-agent theory to oil and gas and illustrates it by an analysis of known production sharing agreements.[19] The principal-agent theory deals with knowledge owned by the agent (the producing company) on technology, and later on the resource, the sharing of the investment risk (but also risks of reservoir management), the risk of marketing and price development, and the sharing of the reward, i.e., the income.

Historically, there have been several forms of contractual relationship between oil-producing countries and oil companies – concessions, leases, production sharing agreements, risk-service and pure service contracts, joint venture agreements.[20] Rents are shared; through royalties, taxation and participation by the countries; and through money and in kind paid by the companies. Negotiations between the two sides always centre on the rent-sharing.

Today, it seems that exploration and production skills are offered on a competitive basis, and, therefore, countries offering attractive exploration areas can attract competent companies who will provide the service of exploring and producing the resources of a country against a risk-corrected profit, plus a relatively small share of the resource rent. Some producing countries (most OPEC countries) have organised the business of oil and gas exploration and production exclusively by their own agent, a national company, hiring service companies like Halliburton or Schlumberger for exploration work or geophysical consultants for reservoir modelling. Contrary to earlier times, producing companies have increasingly the character of technology companies providing a service to the resource owner.

Behind every producer who is supplying a natural resource to the market there is an owner of the resources who takes the principal decision on the volume and development speed of its resources. To explain the fundamentals of oil and gas supply, it is necessary to examine not only the incentives for potential investors, but also in particular the incentives for the resources owner to develop its resources for export.

Governments representing the resource-owning country will be under explicit or implicit obligations to exploit and deplete the finite resources to the benefit of their population. The pricing for natural resources used for domestic consumption may in that regard look relatively neutral as long as costs (inclusive of adequate interest on capital employed) are covered, even though low energy prices may foster inefficient energy use. Such a pricing policy is often justified by governments based on

19. K. Bindemann, *Production-Sharing Agreements: an Economic Analysis*, WPM 25 (Oxford Institute for Energy Studies, October 1999).

20. *See* K. W. Blinn, C. Duval, H. Le Leuch, A. Pertuzio, International Petroleum Exploration & Exploitation Agreements: Legal, Economic and Policy Aspects (Barrows Company Inc., 1986); A.A. Конопляник, *Основные виды и условия соглашений, действующих в нефтяной промышленности капиталистических государств между ТНК и принимающими странами*, 3-23 "Бюллетень иностранной коммерческой информации" (БИКИ) Приложение no. 10 (1989).

social arguments. At times, even import-dependent countries dedicate their domestic production to the supply of specific market segments –typically households – without taking a resource rent, thus subsidising these segments in kind instead of in cash, e.g., by social policy instruments.

However, when depleting finite resources for exports, governments will seek to maximise the overall resource rent accruing to the country from such exports. This right is confirmed in Article 18 of the ECT. This will usually lead to an approach which tries to sell hydrocarbons at a price as close as possible to what consumers are prepared to pay: at the market price in liquid markets, otherwise it will be at the replacement value determined by the costs of alternative choices available to the customer. A decision by a producer to stay below the price that can be achieved in a specific market means transferring a part of the resource rent to the consumer. There may be commercial motivations for such behaviour, like aiming at a higher market share or to ensure a speedy penetration of a market. In other cases, such deals have been and continue to be done for political reasons.

Governments will also consider a policy to restrict production / export volumes where they can influence the overall supply and demand balance and thus the resulting price. This is true for OPEC members, but also for many gas exporters.

As the international gas trade is usually bound to a long-term fixed infrastructure, gas exporting countries have to make a deliberate decision (i) which countries, and (ii) which segments of their export markets they want to serve. Gas-exporting countries will focus on countries with attractive markets both in volume and price terms. Less attractive countries may be served to the extent that this would still result in an attractive resource rent for the exporting country, subject, however, to the export earnings from other countries not deteriorating as a consequence. This can be achieved by ensuring that cheaper gas will not be re-exported (destination clauses – *see* in more detail in *Section 4.4.7* – were one of the contractual instruments for preventing such re-export), or by exporting at a price with the same netback. Gas-exporting countries will tend to concentrate on the premium segments of the import country and, if exporting to non-premium segments, try to isolate these segments to avoid a deterioration of their average export price.

(v) Inelastic Demand Combined with Supply Restrictions

Oil has the highest energy density of all primary energies, with relatively low environmental impacts; it is, therefore, easy to store, transport, and apply, even in small volumes, and so far has a great advantage for automotion (which has to carry the energy source with it) or for applications in scattered and remote sites. The main substitute is more efficient cars and the extra investment that comes with them. By contrast, because of its gaseous state, gas is even easier to handle in burning processes, but due to its low energy density it requires a fixed infrastructure and a rather high minimum consumption rate in order to reduce specific costs through economies of scale.

Energy, especially oil, is an essential good for production and for the quality of life in industrialised societies. This is reflected in a high inelasticity of demand, while demand so far grows in line with economic growth. The use of energy usually requires some device, like power plants, cars or heating systems, representing long-term fixed capital, even for private users, adding to the short-term inelasticity of energy demand. Oil and gas are indeed perfect targets for the taxman. According to Frank Ramsey, commodity taxes should preferably be raised on goods with an inelastic demand.[21]

21. F. Ramsey, *A Contribution to the Theory of Taxation*, 37 Econ Jl 145 (1927).

Demand is a function of many factors. In addition to prices, it has to do with income level, technology, government regulations and individual preferences. Short-term oil and gas demand is very inelastic below a certain quantity, as oil and gas are essential for human social and economic activities. The demand curve becomes elastic as quantity increases. The long-term demand curve is more elastic than the short-term demand curve. A timeframe of a few years is needed for an economy to adjust its oil and gas consumption behaviour in response to higher prices.

There is a firm linkage between economic growth and energy demand. The oil and gas demand curve shifts outwards as an economy grows. Technology is an important factor in the demand function. Improvement in energy efficiency moves the demand curve inwards. Fuel substitution technology makes the demand curve more elastic (*see Figure 2*).

Reaction to price changes is difficult because parts of the overall costs of energy services are fixed by a decision about the device using the energy, such as a car or a heating system or a production process. Compared to the costs of changing the device (like a car or a heating system) it is easier to accept a higher price. On the other hand, there are also limits to reaction to lower prices: even if heating energy becomes very cheap nobody would heat in summer and even if petrol (gasoline) becomes cheap there are natural limits to the increase in the use of petrol (gasoline) for transportation by car.

An important character of the oil and gas supply curve is the existence of capacity constraints. The curve is elastic below the capacity constraint but becomes drastically inelastic as supply quantity approaches the constraint. It is almost vertical at the capacity limit. The oil and gas supply curve is very different from one in a perfectly competitive market (e.g., agricultural products), which is horizontal.

As of 2007, there is only a 3 MBD surplus production capacity on the supply side in the oil sector, against an 85 MBD consumption. Therefore, interception with the demand curve is thought to be at the inelastic part of supply curve. Under such a circumstance, the price rises quickly and volatility increases with a small change in quantity. It takes a few years for new production capacity to come on-stream, thus moving the capacity constraint outwards.

The extra rent achieved by expansion (or contraction) of production of a specific supplier depends on the price reaction due to the increased (decreased) supply.

This depends on the elasticity of both the supply and demand curve at the price equilibrium. If either of them is low then the impact of changes in production volumes on the rent income of such a producer are roughly proportionate to the volume effect. However, if both supply and demand curves are inelastic, the effect of a volume increase on the rent may easily be outweighed by the impact of price change. One of the cases of an inelastic supply curve is the case of a capacity constraint (either on production or on any part of the chains to bring the product to the market). Such a constraint may result in cases where the demand and the supply curve meet at a production level beyond the capacity constraint, so that price is determined by the intersection of the demand curve and the capacity limit and this way part of the consumer rent goes to the producer in addition to the differential rent (*see Figure 2*) Such limitations may be the result of various parts of the chain not adapting to price signals in time to expand capacity, but also a result of regulatory restrictions. Often they may stem from oligopolistic or parallel or coordinated action of some large producers.

This raises the question on the price impact of a highly inelastic demand combined with high concentration on the producers' side.

The impact is shown by the formula developed by Cournot and Nash:[22]

(Price - Marginal cost) / Price = HHI / ε

where:

HHI = Hirschmann-Herfindahl index
ε = demand price elasticity

The formula indicates that the price differential to marginal costs depends on market concentration expressed by the HHI and is inversely related to price elasticity of demand.

High market concentration has little effect on price as long as demand is elastic, and, vice versa, inelastic demand has little effect on price in a market with low concentration. But consumers may have to pay high extras beyond costs of production in markets with a high concentration on the producers' side and highly inelastic demand, typical of energy markets.

Policy makers may try to reduce the concentration on the producers' side, which is difficult when the producers are sovereign countries, which own a large share of the global resources in case of oil, or in the case of gas of the resources that are within economic reach. Development of alternative energies, e.g., biofuels, will kick in at a certain price level and in the longer run may have the effect of increasing the supply basis of liquid fuels and decreasing the concentration on the production side. Demand elasticity can be increased by promoting energy saving, which moves the intersection of the demand curve with the supply curve more into the elastic part of the demand curve and by promoting substitution. A challenge is, however, that the global demand curve for energy, as well as for oil, so far moves absolutely in line with economic growth.

(vi) Market Imperfections / Externalities

The market does not necessary work all the time. When market mechanisms alone do not allocate resources correctly, the occurrence is called 'market imperfection' or 'market failure', described in *Box 3*. (The word 'failure' does not mean an economic collapse or a breakdown in the market. The term is normally applied to situations where the inefficiency is particularly dramatic.)

22. J. Nash, *Non-cooperative Games*, 286-295 Annals of Mathematics, vol. 54, no. 2 (September 1951).

Box 3: Market Imperfections

Market imperfections typically occur, due to:

(i) imperfect competition arising from monopoly,

(ii) price distortion caused by lack of information,

(iii) the existence of externalities (e.g., environment, health / medical care) and

(iv) non-rivalry and non-excludability of public goods (e.g., national security, fire-fighting) in which non-market institutions are more efficient than private companies.

Energy markets are often characterised by

(i) imperfect competition,

(ii) the existence of externalities and

(iii) the presence of public goods.

Price distortion caused by lack of information is increasingly excluded by the development of liquid markets and transparency initiatives by governments, like JODI.

By the laws of physics, energy cannot be recycled (contrary to mineral resources) and the burning of fossil fuels inevitably produces CO_2, with negative externalities as a greenhouse gas. Security of supply of energy – especially for electricity but also for gas – has the character of a public good.

Internalising of externalities is addressed by Pigou taxes (which try to assess the negative externalities and charge them as a tax on the player causing it). Pigou taxes have been criticised by Ronald Coase (Coase theorem) as potentially suboptimal and contrasted with a system of tradable rights, which produce optimal results in the absence of transaction costs (this is the theoretical basis for the trading of emission rights).

2.2 Historical Aspects

Current energy markets developed on the basis of non-renewable energy resources, prominently oil and gas, thus the development of their resource base is a fundamental feature. Oil production has a limited life span; its production over time can be illustrated by the so-called Hubbert's curve, a bell-shaped distribution, initially proposed by M. King Hubbert in 1949 in relation to US oil production based on statistical methods.[23]

Many seek to utilise Hubbert's curve in order to predict the end of the current oil era (peak oil debate / theory). Caution is warranted here, as on a global basis the peak of the curve has moved up and to the right because exploration activities and new technologies have expanded the resource base (and proven reserves).

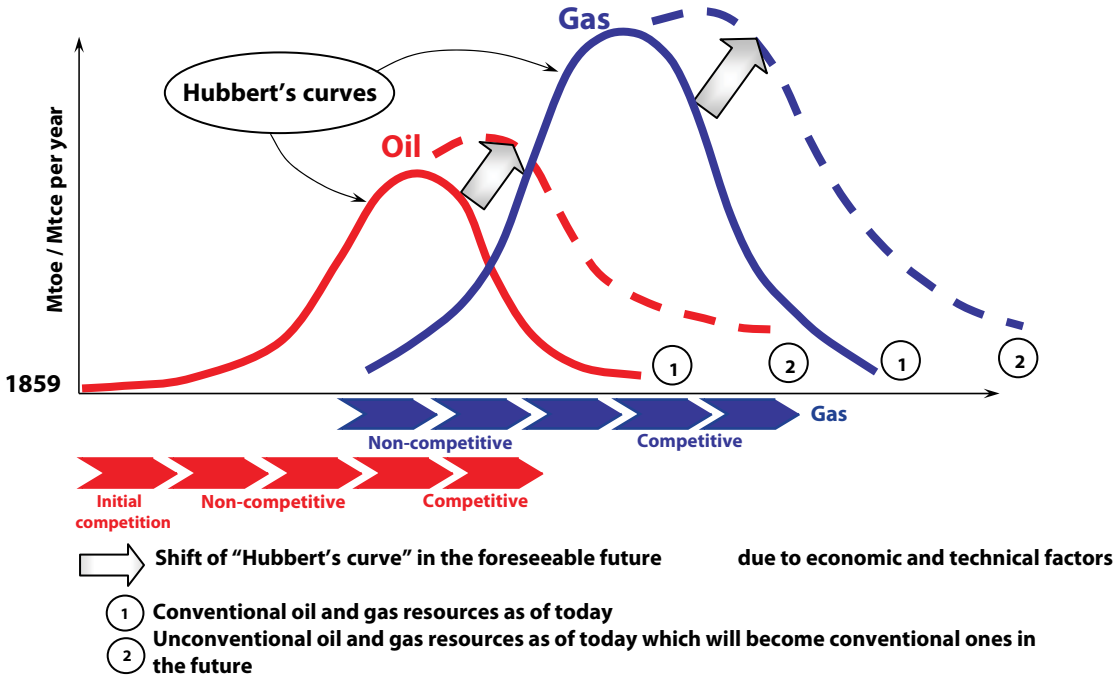
For oil and gas it has been suggested that the different segments of the curve can be correlated with different stages of market development (*see Figure 3*), and that there is an inherent tendency for oil and for gas markets to move towards more competitive structures (with contractual structures and pricing mechanisms corresponding to the particular stage of market development).[24] This might stem from the tendency both for oil and gas to start production from large fields and to produce smaller fields later, thereby increasing the number of players and transactions, and from over-investment into the supply infrastructure evolving over time. The Hubbert's curve could thus be employed as a tool to identify the stage of development of institutional structures within energy markets. The Hubbert's curve for gas is similar to that of oil at an earlier stage, as gas demand and production developed only after a delay of several decades compared to oil. The main factors in support of such an approach are the similar (uneven) distribution of field sizes for oil and gas and their similar (hydraulic) production characteristics as non-solid minerals. This may suggest that the development of gas market structures will follow those of oil, but with the respective delay.

History of oil pricing

Until the beginning of the 1970s, energy and oil market development was described by the ascending branch with accelerated growth of Hubbert's curve. Production growth was based on the discovery of major new low-cost oil fields primarily in the Middle East. The international market was closed to any outsiders, first split between the Seven Sisters[25] under the 1928 Achnacarry Agreement, and, by the end of the 1960s, increasingly dominated by OPEC, especially after re-nationalisation of their resources in the mid-1970's following the end of colonialism in the 1960s. However, the embargo in 1973/1974 and the oil price increases in 1973/1974 and 1979/1980 triggered investment in oil outside of OPEC, the development of new technologies, oil substitution by other energies especially in power generation, more efficienct energy use, and substitution of energy by other productive

23. M.K. Hubbert, *Energy from Fossil Fuels*, 103-109 Science, vol. 109 (1949); American Petroleum Institute, *Nuclear energy and the fossil fuels*, 7-25 in Drilling and Practice (1956).
24. The development of oil market contractual structures and pricing mechanisms is examined in more detail in a series of articles by A.A. Konoplyanik published in 'The Oil of Russia' magazine ('Нефть России') in 1999-2001. *See* also A.A. Konoplyanik, World Oil Market: Comeback of the Low-price Era? (consequences for Russia) ('Мировой рынок нефти: возврат эпохи низких цен? (последствия для России)'), published in 2000 by the Institute for Macroeconomic Forecasting, Russian Academy of Sciences (in Russian); and also, Russia within an Emergent Eurasian Energy Space: Issues of Competitiveness ('Россия на формирующемся Евроазиатском энергетическом пространстве: проблемы конкурентоспособности'), published in 2004 by Nestor Academic Publishers (in Russian).
25. The Seven Sisters initially included Exxon, Mobil, Gulf, Texaco, Standard Oil of California (SOCAL) from the US, British Petroleum from the UK, and Royal Dutch / Shell from the UK and the Netherlands.

Figure 3: Hydrocarbons Markets: From Non-competitive to Competitive Structures



Source: based on Andrei Konoplyanik

resources, firstly by capital. This finally led to the decrease of absolute volumes of world oil consumption in the early 1980s and to the oil price collapse in 1985/1986, to more competitive structures and finally to a liquid oil market (described in detail in *Chapter 3*).

The development of the oil market, its contractual structure and pricing mechanisms can be divided in four major time-periods from a historical perspective (*see Table 1*). Different forms of oligopolistic pricing dominated during the first three periods: prior to the 1970s (at the first two stages) it was the oligopoly of international oil companies (with the strong back-up of their home states), at the third stage – it was the oligopoly of 13 major producer states (OPEC). It was only after the oil price collapse in 1986 that pricing set by an oligopoly was substituted by exchange-based pricing.

The Seven Sisters (1928-1947)

Prior to the 1970s, the vertical value chain for internationally traded oil was almost under the full control of the Seven Sisters. They received their oil mostly through long-term concession agreements with host (mostly developing) countries and exported it under long-term contracts (the trade arm of concession agreements) either to affiliates in their home countries (up to 70% of total oil export) or to independent non-integrated downstream companies. Transfer pricing dominated during this period (*see Figure 5*). Posted prices (*de facto* the transfer prices of international oil companies) were established by the majors as a basis to calculate the royalties to be paid to host states and thus were understated since the international oil companies had their centres of profit in their respective home states. This helped to expand oil consumption, especially in competition with other energies, like coal, for electricity production. Competition happened in the end-user markets, but for crude

oil itself a free market played only a very limited role (3-5% of world oil trade), used to fine-tune the volume balance of supply and demand, based on the posted prices set by the Seven Sisters.

The Achnacarry agreement of 1928 assigned to each company a specific quota of oil sales in the segments of the market outside the US. Its central element was the so-called 'one-base pricing formula' known as 'Gulf plus freight' (Gulf referring to the Mexican Gulf) which dominated the oil market until 1947. It increased the profitability of oil operations of the Seven Sisters by establishing a single price formula for all oil buyers outside the US, calculated as oil price FOB US Mexican Gulf coast, plus freight rates in force from this coast to the delivery point, independent of the origin of factual deliveries. According to the agreement each company was to physically deliver within its quota to markets outside the US, and usually the companies provide these deliveries from the nearest production area of that company. Under this system any buyer would pay the same price in the given location independent of the factual origin of the purchased oil; the savings on freight for deliveries from areas closer to the buyer than the Mexican Gulf, as well as the difference between the posted price at the factual origin of the purchased oil and the price FOB Mexican Gulf, was extra profit for the International Oil Companies.

The Achnacarry agreement was not applicable within the domestic US market as it would have violated the US anti-trust law. But in accordance with the US Webb-Pomerene law of 1918, American companies were allowed to act abroad by means that would have been illegal under the anti-trust law in the domestic US market.

The Achnacarry agreement allowed oil majors to fix oil prices based on the high domestic US oil price level and thus provided extra profits due to the exploitation of the uniquely cheap oil reserves in the Middle East. In the domestic US market, a great number of small non-integrated American oil producing companies operated with high marginal costs. In order to keep up a high number of companies in the domestic market, the US government protected small producers by regulating domestic prices at the 'marginal cost-plus' level, thus providing them with acceptable profitability. That is why the Achnacarry formula, based on Mexican Gulf FOB oil price, protected both the interests of American majors and of small and medium-sized American oil companies.

The Seven Sisters (1947-1971)

When, during World War II, the American and British Navies bunkered their ships from the local refinery in Abadan, in the Persian Gulf, they were to pay the price equal to the residual fuel oil (RFO) price FOB Mexican Gulf, plus fictive freight from the Mexican Gulf to Abadan. American and British administrative investigations after World War II forced the Seven Sisters to change the 'one base' oil pricing formula. In 1947 the international oil companies accepted Persian Gulf as a second base for price calculations. As a modification of the initial Achnacarry agreement, the 'two base' oil pricing formula was introduced, under which freight rates were calculated either from the Mexican Gulf or from the Persian Gulf, but in all cases the oil price used for the calculation was the oil price FOB Mexican Gulf. Under this new formula the extra profits of the International Oil Companies were diminished by the deletion of virtual transportation costs, but the difference between the marginally low production costs in the Persian Gulf area and marginally high costs in the US (price FOB Mexican Gulf) remained. Through the transfer pricing mechanism of posted prices, the companies escaped taxation of their extra profits in the host states and transferred them to their profit centres in their home states. This formula is known as 'two Gulfs plus freight' (but should more accurately be

labelled as 'Mexican Gulf plus two freights').[26] That is why WTI was the marker crude during both of the two first pricing stages of oil market development (*Table 1*).

OPEC set prices (1971-1986)

In the 1970s, control over domestic oil economies in the producer countries (upstream part of the energy value chain – resources, production, sales and selling prices) was acquired by the OPEC states. The upstream assets of the international oil companies (IOC) in the major host (OPEC) countries were nationalised and formed the basis on which the new National Oil Companies (NOCs) were created. Almost all oil supplied to the world market at this time was no longer purchased on the basis of intra- or inter-company transactions (barter deals), but by commercial transactions between independent players at the official selling prices of the OPEC member-states. These prices began to play the role of world oil prices. These conditions triggered a disintegration of the previous structure as more companies entered oil trade operations downstream and upstream. While during the periods of the Seven Sisters (stages one and two in *Table 1*), the only point of competition had been at the customers downstream, with OPEC dominance (stage three in *Table 1*) competition also developed for crude oil supplies.

This stimulated the appearance of new contractual forms in the oil trade and an increased variety of trade operations (*see Figure 4*). As the share of volumes traded under long-term contracts diminished, their prices began to be established on the basis of spot deals. By contrast, volumes traded on the spot market increased significantly. The spot market began to balance supply and demand and began to be used as a reference point for price levels both for exporters and importers. It was during the first oil crisis of 1973-74 that the spot market first played its price-defining role as a reference point for OPEC to set official selling prices. Spot market volumes developed strongly during the period 1971-1986: from 5-8% of the international oil trade at the beginning of the 1970s and 10-15% in the middle of the 1970s – to not less than 40-50% in the mid-to-late 1980s.

After the introduction of OPEC official selling prices, oil pricing was converted to the 'Persian Gulf plus freight' formula. The marker crude for official selling prices at this time was usually Light Arabian crude FOB Ras-Tanura, geared (by regular updating by the OPEC states) to the development of spot market prices.

Sharp fluctuations in spot oil prices stimulated the introduction of risk management techniques into oil operations. Demand to standardise oil trade operations (as one of the risk-management instruments) was among the driving forces for introducing contracts for oil and petroleum products at the existing commodities exchanges (NYMEX) and for the establishment of specialised oil exchanges (IPE). Managers from financial markets became involved in the oil markets, introducing the techniques of financial markets and specialised oil derivatives (oil futures and options). By the end of the 1980s, the current complex contractual structure of the oil market was in place (*see Figure 4*). It is now the oil exchange where world oil prices are determined (*see Chapter 3*), though all other contractual forms, determining oil prices at earlier stages, are still present, albeit without their former dominant role.

26. For a detailed history of oil market developments at their earlier stages, *see* J.-M. Chevalier, Le Nouvel Enjeu Pétrolier (Calman-Levy, Paris, 1973); C. Tugendhat and A. Hamilton, Oil: the Biggest Business (revised edition, Eyre Methuen, London, 1975); D. Yergin, The Prize: the Epic Quest for Oil, Money and Power (Simon & Schuster, New York-London-Toronto-Sydney-Tokyo-Singapore, 1991); and other publications.

Table 1: Evolution of International Oil Pricing Mechanisms

Periods	1928-1947	1947-1971	1971-1985/1986	1986-today (see Chapter 3)
Pricing principle and main players	CIF selling prices set by an oligopoly (Seven Sisters) established by the Achnacarry agreement; FOB buying prices set de facto unilaterally by the Seven Sisters as posted prices within their concession agreements with host states		FOB selling prices set by an oligopoly(13 OPEC countries) established by OPEC agreement used in the long-term deals and at the spot market for spot transactions (spot quotations were later used by OPEC as a reference point for establishing its official selling prices)	Prices set by competition on market exchanges (mainly by oil traders)
Points of competition	Only in the end-user market		In the end-user market and for crude deliveries	At all parts of the chain
Trends in demand	Stable growth		Growth / short temporary decline	Slowed growth
Trends in production costs (major factor of their dynamics)	Decline (natural: moving to larger fields)		Growth (natural: moving to smaller fields and more challenging areas) / decline (technical progress)	Decline (technical progress) Increase as of early 2000's (e.g., costs of steel)
Prices: trends and levels ($/bbl, current prices)	Around 2 $/bbl		From 2 to 40 $/bbl (1981), then to 30 $/bbl (1985), then to 10 $/bbl (1986)	Within 15-20 $/bbl (prior to 1997), within 10-30 $/bbl (prior to 2004), up to 60-70 $/bbl (2005-2006), then to 50+ $/bbl (2006)
CIF price calculation at the delivery points worldwide	CIF = FOB Mexican Gulf plus factual or virtual freight from Mexican Gulf ('One-base pricing' based on Achnacarry agreement)	CIF = FOB Mexican Gulf plus factual or virtual freight: (a) either from Mexican Gulf (to the west of the 'neutral point'), or (b) from Persian Gulf (to the east from the 'neutral point') ('Two-base pricing' based on modified Achnacarry agreement)	Until end-85: CIF = Light Arabian FOB Persian Gulf plus freight; End-85- 86: Light Arabian FOB Ras Tanura = spot prices of petroleum products netted-back to Ras Tanura (net-back pricing	CIF & FOB futures quotations
Marker crudes	West Texas	West Texas, Light Arabian	Light Arabian, West Texas	West Texas Intermediate (NYMEX), Brent (IPE), Dubai (SIMEX, until 1999)
Dominant trade contracts	Long term (volume & price)		Long term (volume) + spot (price)	Spot (volume) + long term (volume) + exchange (price)
Dominant types of prices	Posted (used as transfer price)		Official selling, market, posted	Market
Type of the market	'Physical oil' market (physical deliveries dominate in international pricing)			'Paper oil' market (oil financial derivatives dominate in international pricing)

Based on: А.А. Конопляник. Россия на формирующемся Евроазиатском энергетическом пространстве: проблемы конкурентоспособности. Москва, «Нестор Академик Паблишерз», 2004, с. 105.

Stages of oil market development and pricing mechanisms

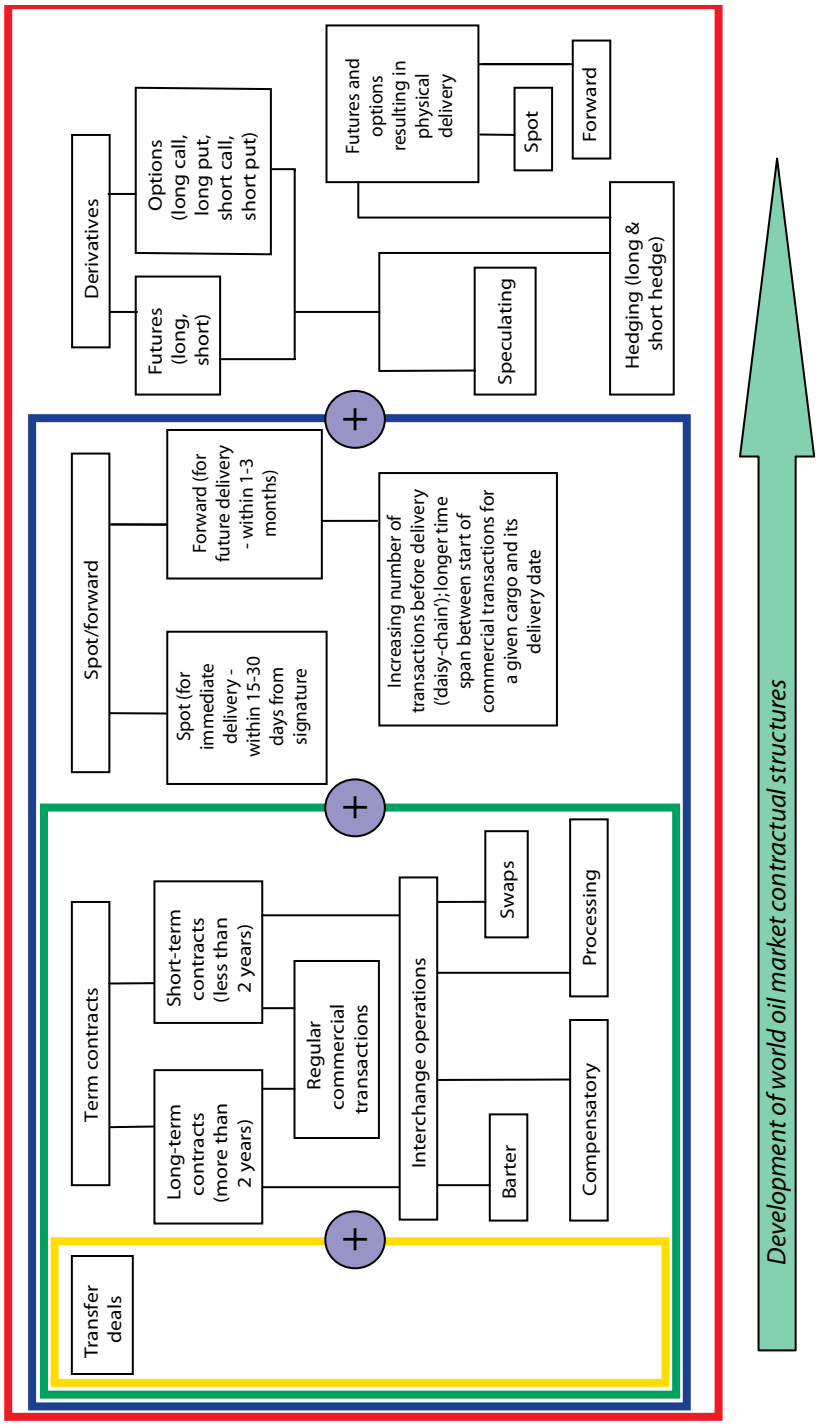
In line with oil markets, the dominant types of oil prices and oil markers developed as well. At the initial stages (*see Table 1*) those were posted prices defined under the transfer pricing principle based on the cost-plus approach (however, often even subsidised), providing a minimum rent /tax payments to the resource-owners. They were used to determine tax payments to the host states. Market prices were used at that period only within the small segment of the market with independent players.

At the third stage, spot pricing began to dominate. However, OPEC official selling prices and posted prices continued to exist at this time (mostly up to 1977 – to the peak of the nationalisation wave in the OPEC states) for tax calculation within the still existing concessions, and as transfer prices within the vertically-integrated operations of the concessionaires.

At the first three stages (*Table 1*) prices were established based on CIF price calculations on a cost-plus basis (where both real and fictitious costs were incorporated). At the end of the third stage, in 1985, in order to defend its market share, Saudi Arabia implemented a netback pricing principle by which FOB prices were calculated back from product prices (*see Chapter 3*). Since then, FOB prices dominate in the crude oil market, although derived from the CIF prices at the oil exchanges.

Each stage of development of the world oil market has added new contractual structures to the previously existing ones: new structures appeared in addition to and not instead of previous structures. *Figure 4* presents from left to right the development of world oil market contractual structures. After each major change a new equilibrium within the broadened contractual structure of the market was reached, with new proportions between different contractual segments. The general trend is that the market has been moving from trade in 'physical' oil to trade in 'paper' oil, and it is oil derivatives (oil-related financial instruments) that now play a predominant role in establishing world oil prices (*see Chapter 3*).

Figure 4: Development of World Oil Market Structure and Types of Transactions



Source: based on Andrei Konoplyanik

History of gas pricing

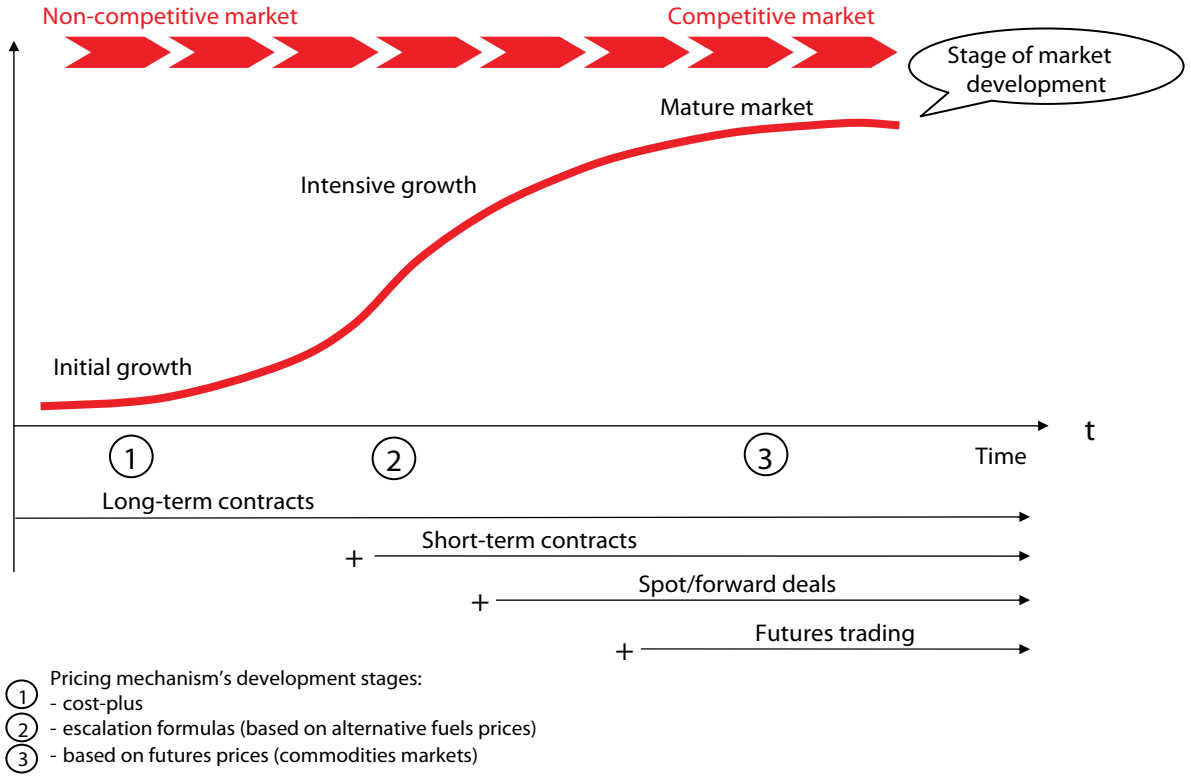
The development of gas markets and their transaction instruments and pricing mechanisms may also be seen as being linked to the Hubbert's curve (*see Figure 3*), yet gas has clearly lagged behind oil. In the beginning gas was discovered as a by-product of the search for oil, either as a gas deposit or as associated gas; its use was rather limited at first – due to a lag in building gas marketing infrastructure – and large amounts of associated gas were (and still are) flared. The use of gas has historically been confined to stationary applications replacing oil products, its use for automotion still being in its infancy. While it took some time to develop a market and a marketing infrastructure for oil, it took much longer for gas. Gas needed a fixed and more expensive marketing infrastructure and needed to secure the use of land for pipelines and distribution systems.

Due to a much lower energy density than oil, and the resulting higher transportation and storage costs, the markets for gas evolved only in a regional context. It took some time before exploration for gas as such became economically attractive. Most large gas structures were only found after World War II, and developed for national use, if at all. The Groningen field in the Netherlands was the first large field from which gas was produced for export.

The development of the market and transaction structures in the various regions may suggest that gas transaction instruments follow the same sequence as for oil, although not the same path or at the same speed in each region (*see Figure 5*).

The North American gas industry was the first to develop, first for ad hoc sales, later based on long-term contracts. In the 1980s North America's gas markets were the first to be organised as liquid gas market places; a similar market structure then emerged also in the UK. Significantly, the development in both regions was based on domestic gas production, which is now on the decline, and characterised by production from a multitude of medium-sized to small gas fields. Structures in other regions continue to be characterised by long-term import contracts and super-giant gas fields. The development of the gas sectors in the regions and their underlying dynamics are investigated in detail in *Chapter 4*.

Figure 5: The Dynamics of Gas Markets Development



1 Pricing mechanism's development stages:
- cost-plus
2 - escalation formulas (based on alternative fuels prices)
3 - based on futures prices (commodities markets)

Source: based on Andrei Konoplyanik

2.3 Market Structure and Pricing Mechanisms

Liquid markets provide transparency by price discovery and instruments to hedge risks. The question is what the necessary and sufficient conditions for a liquid market are. It seems that a necessary condition is the emergence of a market place where real transactions take place as a reference point for all kind of derivatives. Low storage costs can favour the emergence of such a market place. So can low transportation costs, as different but proximate market places can then be treated like one large market place in view of low transportation costs in between them, like ARA.

Liquidity, as represented by the number of financial transactions referring to a given physical market place, is likely to increase with the number of players in the sector. The increase of the number of producers which comes with the development of smaller fields which historically developed after the large fields were discovered and exploited thus would favour more financial transactions. However, the number of players itself is not a yardstick for market concentration, which is not so much a function of the number of players but rather of the shares of large players (as reflected in the Hirschmann-Herfindahl Index). This would explain why over time oil and gas transactions have a tendency to be traded on liquid markets which nevertheless can come together with market power due to the concentration of production in large single fields or of large resources in a few countries. However, where no market places for physical transactions develop, either because of too high transaction costs for storage and transportation or because of a too small number of participants, hedging will be done by other instruments like long-term contracts and forms of vertical integration.

Chapter 3

Oil Pricing



Chapter 3 Oil Pricing

3.1 Summary

The size, scope, and complexity of global crude trade are unique among physical commodities. Currently more than 80 million barrels of oil are produced and consumed everyday. Beyond the scale of trade in oil, the strategic importance of oil and the crucial role that it plays in the economy make it a commodity like no other.

This chapter looks into pricing mechanisms in the oil sector, particularly into its commodity-type pricing mechanism, which has developed since the official selling price system within long-term oil contracts established by OPEC came to an end in the mid-1980s. Commodity pricing in the oil sector is well established, and spot markets for oil have developed the full range of commodity pricing instruments. Nonetheless, long-term oil contracts still play a significant role, albeit with different pricing mechanisms compared to previous periods.

The current spot markets have been developed since the early 1970s. At the beginning they were aimed at fine-tuning oil demand and supply and covered not more that 3-5% of international oil trade. In the 1980s, rising oil production from non-OPEC areas went into the spot markets. Key benchmark grades, West Texas Intermediate (WTI), Brent and Dubai / Oman, emerged, and served as the reference for crude of similar qualities and locations. Previously the role was played by Arabian Light under OPEC's official selling price system.

Spot transactions are mainly conducted by telephone or computer network between two parties. It is an over-the-counter (OTC) market as opposed to an exchange. Spot markets do not necessarily have trading floors. The term 'spot market' applies to all spot transactions concluded in an area where strong trading activities in one or more trading products take place.

The main spot markets or trading centres for crude oil are Rotterdam for Europe, Singapore for Asia and New York for the United States. Their benchmarks are: Brent, Dubai and WTI.

At the same time, futures markets have also developed in Western countries. These arose from a desire on the part of oil companies to reduce risk in light of high price volatility. Developments in information technology, developments in financial theory and a political climate favouring markets over government administrative guidance led to the creation of financial derivative markets, including futures and options. The New York Mercantile Exchange (NYMEX) and the International Petroleum Exchange (IPE) are two major financial markets for oil. World oil prices are led by these markets.

Long-term contracts are still widely used. OPEC countries in the Middle East sell their crude exclusively to refiners through long-term contracts, which usually have contract duration of one year with renewal clauses. The pricing formulas in the long-term contracts are linked to benchmark grades. There are no long-term fixed-price contracts, which existed between the two oil crises in the 1970s and prior to that time.

Oil prices were hit hard by the Asian financial crisis in 1997 and 1998. They fell to below $10 at the end of 1998. In March 1999, OPEC countries agreed to cut production, joined by Russia, Norway and Mexico. With the Asian economies recovering from the financial crisis, prices increased during 1999. In 2003 and 2004 oil prices rose strongly in view of the war in Iraq and the fear of terrorist attacks on oil facilities in Middle East. This was also a result of under-investment in the international oil industry. Strong demand increases from the US and large developing countries, which were not followed by a similar expansion of supply, resulted in further increases in crude oil prices. That attracted speculators, who moved from financial and currency markets into commodity markets (oil) and contributed to the rise in prices. Crude prices reached as high as $78 per barrel in summer 2006, although they fell from this peak later in 2006.

Looking into the oil market, increases in oil consumption are closely linked to economic growth. Where economies are growing, oil demand growth is taking place – China, India, the Middle East and the US. Global oil demand is expanding at around 1 MBD every year. 2004 saw a particularly strong increase in demand – 3.2 MBD.

On the supply side, there is an ongoing debate called 'peak oil theory'. One school claims that oil production will soon peak and that the consequences for the world economy will be severe. Others consider that the peak oil production will still be a moving target for some time, as new reserves become recoverable due to exploration and improvements in technology (*see Section 2.2*). The United States Geological Survey (USGS) considers that there are enough remaining petroleum reserves to continue current production rates for another 50 to 100 years. OPEC's 11 member countries produced 36% of the world's production in 2005, but hold 78% of oil reserves. OPEC ministers meet every three months to discuss production levels. In 2005, non-OPEC production remained unchanged from the previous year, compared to a 1 MBD growth in 2004.

Ethanol and biodiesel are two main biofuels which are used as transportation fuel. Growth in biofuel production in 2005 and 2006 is a clear example of a supply and policy response to high oil prices.

The refining sector faces many challenges. Refineries in industrialised countries have been running at around 90% of capacity for more than a decade. Nonetheless, it is difficult to expand or upgrade refineries in the industrialised countries, due to environmental regulations and local opposition. This results in increases in product imports and expansions in refining capacities outside of the industrialised countries. Furthermore, refineries were suffering from low margins. In addition, new, more stringent fuel specifications have come into force, and there is an increasing mismatch between product demand, which is shifting toward lighter products, and crude quality, which is becoming heavier.

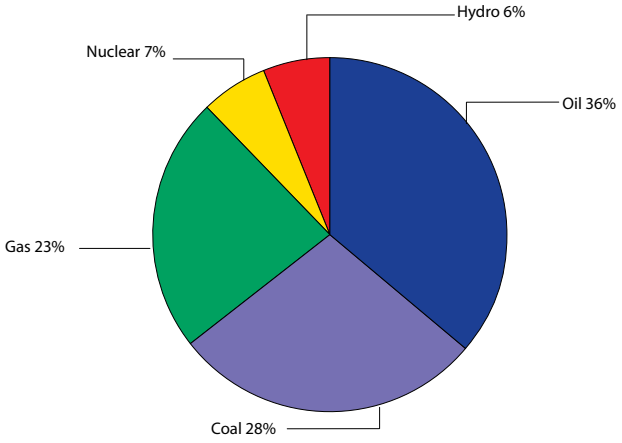
3.2 Introduction

3.2.1 Oil – a Commodity Like No Other

This section looks into pricing mechanisms in the oil sector, particularly into the commodity-type pricing mechanism. The oil market developed commodity pricing mechanisms in the mid-1980s, replacing the system of official selling oil prices determined by OPEC. The commodity pricing mechanism in the oil sector has evolved technically from the spot trading to the futures market and financial derivatives (*see Figure 4*), which are typically found in all commodity markets. This section looks into the history and mechanism of the oil market.

Oil is the most important energy source, accounting for more than a third of the world primary energy mix (*see Figure 6*). It is expected to continue to hold the largest share in the coming decades, although the share will decline marginally. In volume terms, oil production / consumption fell after the second oil crisis in 1979 and bottomed in 1983. Since then, however, the volume has been continuously increasing, despite variations in the price.

Figure 6: The World Primary Energy Mix in 2005



Source: BP

Crude oil is a global commodity. It has been traded internationally since soon after the modern oil industry started in Pennsylvania, US, in the 1860s. Oil trading has come a long way from the stable, controlled system of the Majors, which ended in the late 1960s, through OPEC's quota system in the 1970s and the first half of the 1980s to the market mechanism since the mid-1980s. Crude trading represents the key link between the two poles of the industry: upstream (exploration and production) and downstream (refining and marketing), and crude prices give signals to both upstream and downstream operations.

The size, scope and complexity of global crude trade are unique among physical commodities. As of 2005, more than 80 million barrels of oil are produced and consumed everyday (*see Table 2*). Beyond the scale, oil has played a significant role in world history in the 20th century. The strategic importance of oil and the crucial role it plays in the economy make oil a commodity like no other.

Table 2: The World 10 Largest Oil Consumers/Producers/Importers/Exporters in 2005

	Consumer	MBD	Producer	MBD	Importer	MBD	Exporter	MBD
1	US	20.8	Saudi Arabia	10.9	US	13.0	Saudi Arabia	8.8
2	China	6.6	Russia	9.5	Japan	5.4	Russia	6.8
3	Japan	5.4	US	7.3	China	3.1	Norway	2.7
4	Russia	2.7	Iran	4.2	Germany	2.5	Iran	2.7
5	Germany	2.6	Mexico	3.8	Korea	2.2	Venezuela	2.4
6	India	2.3	China	3.6	France	1.9	UAE	2.4
7	Canada	2.3	Canada	3.1	India	1.7	Nigeria	2.4
8	Brazil	2.2	Norway	3.0	Italy	1.7	Kuwait	2.2
9	Korea	2.2	Venezuela	3.0	Spain	1.6	Iraq	1.8
10	Saudi Arabia	2.1	UAE	2.9	Taiwan	1.0	Algeria	1.7
	World	**83.6**	**World**	**84.4**	**World**	**50.0**	**World**	**50.0**

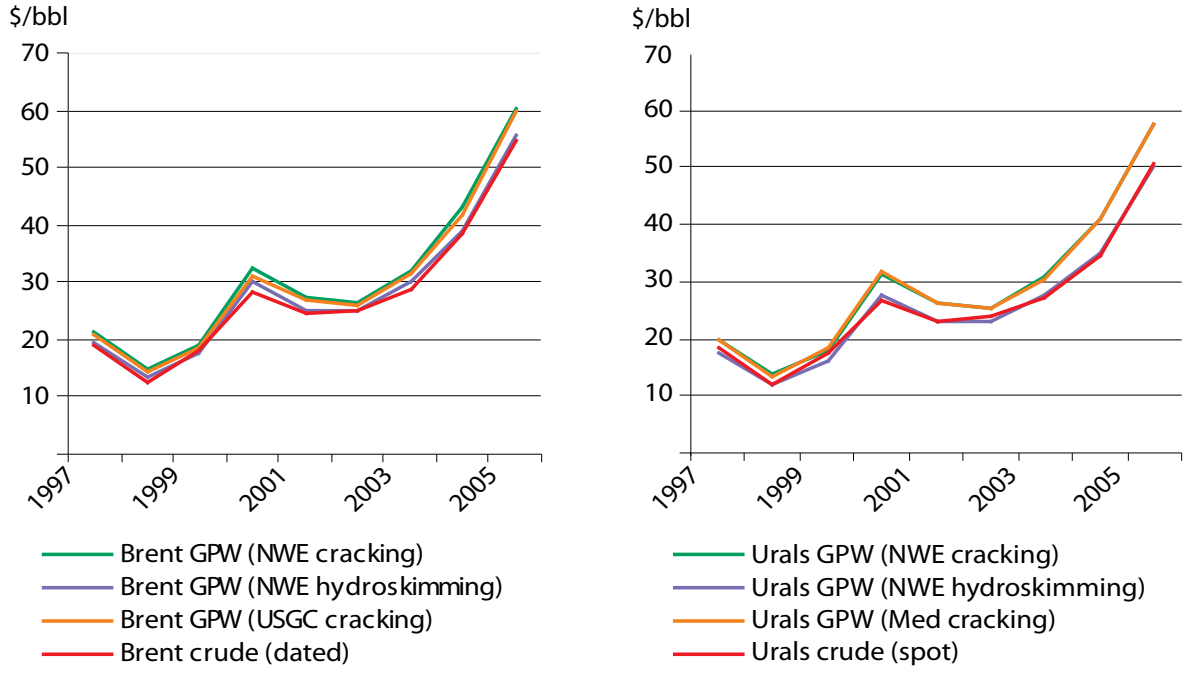
Source: IEA, Deutsche Bank

The global crude oil market has been in a constant process of transformation. The impact of burning fossil fuels (including oil) on the environment became a serious issue in the late 1980s. The rise in terrorism and political uncertainties in the Middle East have revived supply security concerns. Higher oil prices are encouraging the development of non-fossil fuels, such as nuclear, fuel cells and biofuels. These and other factors will affect future prices and pricing mechanisms.

3.2.2 Crude Oil and Petroleum Products

There are over 130 crude grades around the world. However, crude oil itself has almost no direct end use (one exception is direct burning of light, sweet Southeast Asian crude at power plants in Japan and China). Crude oil needs to be refined into petroleum products (gasoline (petrol), heating oil and other) to be consumed. It is the total value of the products processed from crude (called gross product worth or GPW) that determines the crude value. (This does not mean that product prices set crude prices. The two are interactive). From the refiners' viewpoint, GPW defines the upper limit of crude price. Each stream of crude has its own property and each generates different combinations of products (*see Figure 7*).

Figure 7: Net Product Worth and Crude Prices — Comparison between Brent (1997-2005) and Urals (1997-2005)



Source: IEA

Crude oil that has a low sulphur content (less than 0.5%) is called 'sweet' and one with a high sulphur content (more than 1.5%) 'sour.' To measure crude gravity, the API (American Petroleum Institute) standard is often used. Heavy crude is under API 22°, while light crude is above API 33°. Medium grades are in between. Some crude streams contain metals. All of these factors affect crude prices.

FOB (Free on Board) is a price for crude or products at the loading port, while CIF (Cost, Insurance and Freight) is one at the destination. Buyers have to pay the additional costs of transport when buying crude or products at a FOB price, while CIF prices include costs of transportation. Furthermore, the timing of the pricing is different. FOB prices are taken on the loading date and CIF prices on the unloading date. Since tanker transportation normally takes between a few days and a few weeks, the difference is often appreciable. It is more common for crude to be traded at a FOB price and for products at a CIF price. This means that crude buyers normally hire tankers to pick up crude at the terminal of oil exporting countries and product sellers usually deliver products to buyers.

3.2.3 Benchmark Crude

In the late 1970s and 1980s, new benchmark crude grades emerged. A benchmark crude grade serves as the reference for crude of similar qualities and locations. Arabian Light, with its 5 MBD production volume, was the benchmark crude under OPEC's official selling price system. However, in light of the development of spot and futures markets, the role of Arabian Light was taken over by West Texas Intermediate (WTI) and Brent.

North Sea **Brent** possesses all of the vital criteria for a benchmarker: security of supply, diversity of sellers and broad acceptance by refineries and consumers. Although Brent was not the largest field in the North Sea and had faced production problems in the past, its satellite fields provided enough production volumes for market trading liquidity. An important factor is that production is shared by several participants and is not concentrated in a single producer. This was the main reason why Forties, whose production was dominated by BP, did not become the North Sea benchmark, despite it being the first major North Sea oil field to come on stream, and that its production was larger than that of Brent.

WTI was selected as the reference grade for crude oil futures contract at the New York Mercantile Exchange (NYMEX) in 1983. Its landlocked delivery system and the distance from international markets may not best suit the conditions for a benchmark grade. Nor does it have a large physical production. Nonetheless, trading at the NYMEX saw a huge success. With large trading volumes, WTI gained worldwide recognition.

While the financial-market oriented WTI reacts immediately to market perceptions, Brent's linkage to the physical markets provides a picture on the international supply-demand relationship. Benchmark grades are critical in defining the prices of other related crude. They became the key price variables in many pricing formulas. In addition, since the two benchmarks are the reference for trade in the futures markets, they also became the basis for most hedging and risk-management operations and attracted more trading interests in the markets.

As Saudi Arabia sold its oil only under long-term contracts, **Dubai** displaced Arabian Light as the Middle East benchmark. Dubai became a benchmark because there was the need for a Middle East reference and for a heavier, high-sulphur international benchmark. The Dubai trading now faces declining physical production and liquidity problems. As a result, Oman plays an increasing role in supporting Dubai. Dubai in combination with Oman is linked to other Middle East crude. The monthly average of Dubai / Oman is a basic ingredient in retroactive pricing formula for the sales by large OPEC Middle East producers, such as Saudi Arabia, Iran and Kuwait.

Crude from various fields in Russia and the former Soviet republics is mingled when transported by Transneft's pipeline system and becomes the **Urals** grade. Urals exports are currently around 4 MBD, the second largest physical trading grade after Arabian Light. There was also another grade called Siberian Light, which was transported by a separate line of Transneft to the Black sea port of Tuapse. Its export volumes were several hundred thousand barrels per day. The problem Urals is facing is that its markets are limited. Urals is sold mainly to Eastern Europe via the Druzhba pipeline, Northwest Europe by tanker from the Baltic Sea ports and the Mediterranean by tanker from the Black Sea ports through the Turkish straits. It is currently sold at a larger discount to Brent than the quality difference.

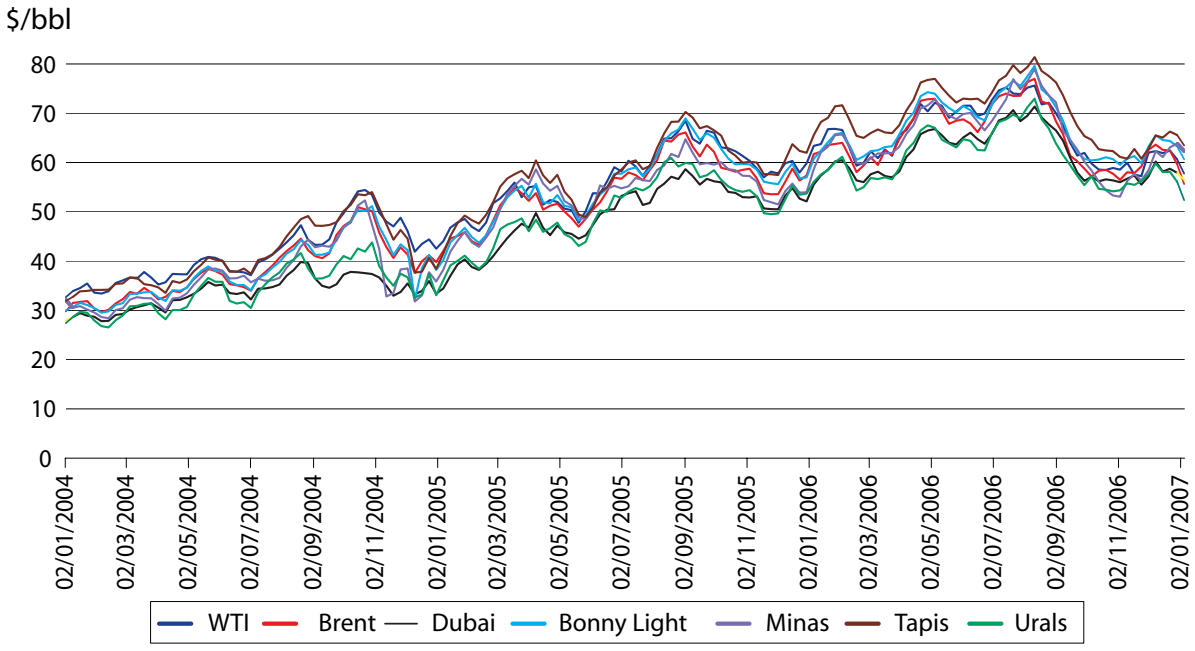
Most market places for crude oil are linked to ports. However, markets can be developed even in inland areas. Various market places for crude oil on the North American Continent and the market for Russian Urals are good examples. There has been heavy trading of Russian Urals along the Druzhba pipeline between crude oil producers and buyers (mainly refineries in Germany, Poland, Hungary, Slovakia and the Czech Republic). This has created a spot market and prices are quoted by reporting agencies.

There are other regional benchmark grades, such as Tapis (Malaysia), Minas (Indonesia) and Bonny Light (Nigeria). The **Tapis** field off Malaysia is operated by Exxon, and Malaysia's state-owned Petronas is a regular seller of spot Tapis. Most trading activity takes the form of swaps between regional producers and refiners. Indonesian **Minas** is traded regularly in the spot market, although not as much as Tapis. Minas is middle grade in its quality, and production volumes are the largest in the region. Minas production is in the hands of Caltex and Indonesian state-owned Pertamina.

OPEC Basket price is a reference price – made up of 11 grades: Saharan Blend (Algeria), Minas (Indonesia), Iran Heavy (Islamic Republic of Iran), Basra Light (Iraq), Kuwait Export (Kuwait), Es Sider (Libya), Bonny Light (Nigeria), Qatar Marine (Qatar), Arab Light (Saudi Arabia), Murban (UAE) and BCF 17 (Venezuela).

While the benchmarks play the key role in defining the absolute price levels, most other crude are traded in the form of spread trading. The preference for spread trading reflects a natural reaction to the volatility that is common in international oil markets. The differences between prices tend to be less volatile than absolute price levels (*see Figure 8*). Spread trading reflects a need for markets to constantly adjust inter-market relationships in price fluctuations.

Figure 8: Benchmark Crude Prices



Source: US DOE/IEIA

3.2.4 Crude Transactions

Barter deal

Barter deals remain important, and are said to account for around 10% of total trading volumes. These transactions typically involve trading of crude oil or petroleum products in exchange for goods, services or finances. Middle Eastern countries use barter deals to acquire industrial facilities (e.g., desalination plants) in exchange for oil. Other countries pay for petroleum products, e.g., with cargoes of sugar or cashew nuts. Financing agreements can be part of these deals. Typically under these agreements, hard currency loans are provided and the principal and interest are paid by crude cargo deliveries. Countries which have difficulties in accessing international financial markets can benefit from this technique.

Closely related to barter deals are crude-for-product swaps and processing arrangements. They are used by oil exporters to meet domestic needs for refined products beyond their refining capacity. Under crude-for-product swaps, a certain volume of crude is swapped for refined products. A processing deal usually involves refining an amount of crude at a plant in a third country in return for products at pre-agreed product yields. Some products are taken back, while the rest is sold to the refiners or on the spot market. In some cases, these arrangements look like netback sales.

Cargo transaction

Spot and forward contracts are based on cargo-by-cargo transactions. Forward transactions (i.e., sales at a fixed price for a fixed future delivery) cover purchase and sale of cargoes with delivery scheduled typically for one to three months ahead. Spot transactions mean those with schedules within 15 days to one month (oil trading for delivery on the same day is rare). Volumes of oil traded on a spot basis are thought to amount to about 30% of international oil trade.

Long-term contract

After the integrated system of the Majors, OPEC developed long-term contracts in the early 1970s. Producing countries took control of the upstream sector and, as a result, the oil industry was transformed. Upstream concessions were replaced by contractual relations and then expropriated. Contracts were typically FOB-priced since tanker transportation remained with international oil companies (IOCs). New national oil companies were emerging. The Majors lost control of oil prices, and oil prices were set at OPEC meetings as official selling prices. This official selling price system lasted until the mid-1980s. Against this background, long-term contracts offered some degree of supply security.

Long-term contracts are widely used in international crude trading today. Although comprehensive data are scarce, it is thought that more than 50% of internationally traded crude is under long-term contracts. OPEC countries in the Middle East sell their crude exclusively to refiners through long-term contracts. The situation is similar for Russian crude oil, which is transported to refineries by crude oil export pipelines. The duration of the contracts is normally one year with renewals, in terms of the trading volumes. For producing countries, long-term contracts guarantee market access for their crude. Refiners in the consuming country can enjoy stable supply volumes and crude qualities provided by long-term contracts. On this basis, refiners can optimise their operation by buying residual volumes through spot trading.

3.2.5 Price Formula

Prior to 1979-80, long-term contracts accounted for most international trade. In the 1970s, crude was sold at official selling prices, which were set according to differentials to Arabian Light. The differentials were based on physical properties of the grades and distances to the markets. However, the official price system, which was the basis for most long-term contracts then, was no longer working in the mid-1980s under the decreasing call for OPEC oil due to increased non-OPEC production and diminishing oil demand in the early 1980s. Saudi Arabia, which played the role of swing producer within the OPEC quota system, established the netback pricing system in late 1985 to defend its market share, and abandoned the official prices. The netback pricing system tied the value of crude oil to the spot market prices of refined products (*see Section 3.2.6*).

The netback pricing system was followed by a brief, unsuccessful return to the fixed official price system. In late 1987, however, geographically specified pricing formulas were introduced. This system is still in place today. It has a direct reference to the global crude markets. It also permits sellers to target specific areas and customers by modifying formulas and other aspects of the contracts to meet individual needs. These adjustments have resulted in highly individualised contracts and price formulas. Although the use of tailor-made formula reduces transparency of prices, pricing formula has proved to be an effective, durable and flexible tool.

If a price formula is only linked to one benchmark crude, the particular characteristic and special market circumstances of the referred crude can have large effects. To avoid this, the use of crude baskets involving more than one benchmark is common. For instance, common formulas for crude sales of Arabian Light to the Asia-Pacific market (eastbound sales) are linked to the Dubai and Oman grades. Meanwhile, those for Europe and North America (westbound sales) refer to IPE Brent futures price (IPE BWAVE). Normally the eastbound sales prices are higher than the westbound sales prices (the difference is called the 'Asian premium').

3.2.6 Netback Pricing

Although netback pricing was a brief episode in the history of crude oil pricing mechanisms, the concept is often used in pricing other fuels than oil, e.g., natural gas. The netback pricing in the oil sector was developed by Saudi Arabia in 1985. By 1984-85 the official selling price system, which was the basis for most long-term contracts, had broken down. Buyers were finding the strict conditions and official prices unacceptable, in the face of a global supply glut. At the time, Saudi Arabia was acting as swing producer within the OPEC quota system, lowering its production volumes so that total OPEC production could be kept within the volume to support the prices set by OPEC. However, under this policy, the country's production had to be cut back from 10 MBD to 3.5 MBD, coming to the lower limit Saudi Arabia had to produce in view of associated gas needs. In addition, Saudi Arabia's efforts were not necessarily shared by the other OPEC countries. Finally, in 1985 King Fahd decided to increase production and recover his country's market share. Netback pricing was introduced as the instrument to implement this production increase. It proved to be a very effective tool for Saudi Arabia to quickly regain market share.

The netback pricing formula was:

Crude oil price (FOB) = GPW in the spot market – fixed refining margin – transportation costs (from the terminal in the oil-exporting country to the refinery in the oil-importing country)

This netback pricing system introduced the concept of market prices for crude oil, although it was based on petroleum products.

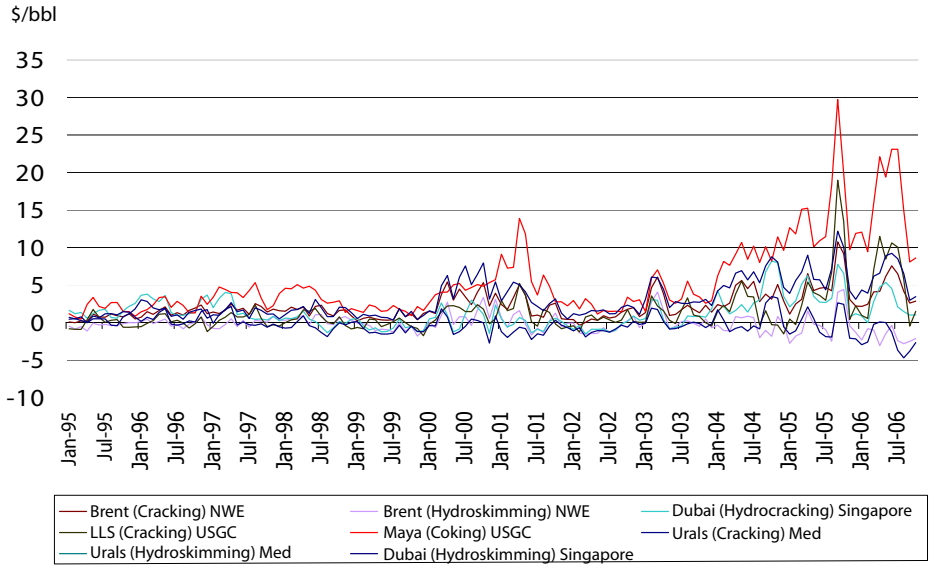
Netback pricing was also attractive to the buyers (refiners), which otherwise were suffering from unstable, low margins. However, the success of netback pricing and the increase in Saudi Arabia's production led to a huge drop in oil prices in 1986, plunging below 10 $/bbl. This is sometimes called 'the counter oil crisis' as opposed to the two previous oil crises. Netback pricing was blamed for the price crash. After a brief period of netback pricing dominance, the fixed official selling prices returned briefly in late 1987. Producing countries stopped posting the prices in 1988.

3.2.7 Refining Margins

Refining margins represent monetary gains or losses associated with crude oil processing operation. To make comparisons possible by crude grade, refinery operation or region (*see Figure 9*), calculations normally assume standardised refinery configurations. The margin calculation takes into account wages, construction and other associated costs incurred in refinery operation, together with variable costs including buying and processing crude oil. Although margin calculations are more reflective of economics of processing a marginal barrel rather than returns from base-load operation, refining margins can suggest indications of financial returns to a refinery.

Refining margin = GPW - crude costs - transport costs and applicable fees and duties - financial costs - variable costs - fixed costs.

Figure 9: Refining Margins (1995-2006)



Source: IEA

There are four main types of refining operation; hydroskimming, catalytic cracking, hydrocracking and coking. The hydroskimming refineries are the basic, standard ones in which crude components are separated at atmospheric pressure by heating, condensing and cooling. The hydroskimming refineries are equipped with atmospheric distillation, naphtha reforming and hydrodesulphurisation facilities. The catalytic cracking refineries have, in addition to the above, vacuum distillation, catalytic cracking and alkylation processes. The catalytic cracking process breaks down the larger, heavier and more complex hydrocarbon molecules into simpler and lighter molecules by heat and the presence of a catalyst, but without adding hydrogen. Hydrocracking is similar to catalytic cracking, but, with hydrogen and higher pressure. The hydrocracking process can convert heavy oil (fuel oil components) to lighter and more valuable products (notably naphtha and middle distillate components). A coking unit thermally de-composes residues under high temperature and pressure, and produces lighter products (gasoline (petrol), naphtha, gas oil).

There are several refining centres in the world, including Northwest Europe, Mediterranean, US Gulf Coast, US West Coast and Singapore. To calculate regional refining margins, it is common to reflect regional characteristics into the background assumptions. Brent and Urals are normally assumed to be crude inputs in Northwest Europe, and Urals and Es Sider from Libya in the Mediterranean. Refineries in the US Gulf Coast are typically equipped with cracking and coking process facilities. Refineries in the US West Coast are designed to process heavier crude. Singapore refining margin calculation is often based on the Dubai crude and hydroskimming and hydrocracking refineries.

3.3 Development of Oil Pricing Mechanism

3.3.1 Early Days

The modern oil industry started with the first oil drilling in Titusville, Pennsylvania, in the US in 1859. In the early days oil prices went up and came down violently every time a field stopped production and a new field was discovered. Oil production in the US was concentrated in the Appalachian area until 1901, when a drilling on Spindletop in East Texas found a huge quantity of oil.

John D. Rockefeller established the Standard Oil Company in Cleveland, Ohio, in 1870 and proceeded to swallow up competitors, or drive them out of business. In 1911, however, Standard Oil was broken up into smaller companies in a famous US anti-trust case under the Sherman Anti-trust Act of 1890, which made monopoly illegal. Three (Exxon, Mobil, Chevron) of the Seven Sisters were born out of the break-up. Although many countries are moving towards competition now, it has to be noted that dominant players rose one after another in the oil sector throughout its history. Rockefeller was followed by the Seven Sisters, and subsequently by OPEC.

In other parts of the world, Royal Dutch started producing oil in Indonesia in the 1890s and Shell Transport and Trading distributed and sold kerosene in a vast area including Russia and the Far East. Before the turn of the 20th century, Standard Oil and Shell were already competitors in the world market. Shell and Royal Dutch merged in 1907 and became the Royal Dutch / Shell Group. The Nobels and the Rothschilds started their ventures in Baku, Azerbaijan, under the then Russian Empire. However, their assets were expropriated during the Russian revolution of 1917. Before World War I, Winston Churchill (to become British Prime Minister during World War II) saw the need for oil to fuel the British fleet, and the UK government participated in Anglo-Persian (which was to become British Petroleum).

3.3.2 Majors

As oil prices plunged in the 1920s after World War I, Standard Oil of New Jersey (Exxon), Royal Dutch Shell and Anglo-Persian (BP) met at Achnacarry, Scotland, in 1928 and agreed to share the world markets. This cartel agreement came to be known as the Red Line Agreement or Achnacarry Agreement. Four companies (Chevron, Gulf, Mobil, Texaco) later joined them and the seven companies came to be known as the Seven Sisters,[27] also called the Majors. The Seven Sisters managed to stabilise world oil prices and supply.

The Majors held concessions covering vast areas, with only very low royalty payments. During this period, almost all crude oil stayed within the integrated companies, and was transferred among affiliates, from producing via transport to refining-marketing affiliates. Crude oil prices were

27. Later, according to some researchers, the Companie Française du Pétrole joined this group, but the name 'Seven Sisters' was left unchanged.

mostly internal transfer prices, kept low to minimise the rent-taking of producing countries.[28] Only refined products were sold at arms-1ength to final consumers. Therefore, caution is needed when examining historical crude prices, as first mentioned by M. A. Adelman of the Massachusetts Institute of Technology in the US.[29] Crude price data before 1960 were mainly based on isolated observations of arms-length sales. For 1960-1972, price estimates are better, because of the publication of Saudi Arabian Light spot prices.

3.3.3 OPEC

Since 1948, when Venezuela first achieved 50:50 profit-sharing in its concession agreements with foreign oil companies, oil-producing countries looked to this as a baseline for their petroleum arrangements with IOCs. Falling demand from the European recession and the rising world supply caused a major plunge in oil prices in the late 1950s. This caused a reduction in oil producing countries' tax revenue, which was already quite low due to the transfer pricing system implemented by the IOCs within their concession agreements with the host states. Against this background Venezuela, Iran, Iraq, Kuwait and Saudi Arabia formed OPEC (Organisation of Petroleum Exporting Countries) in 1960.

Although OPEC did not manage to increase prices in the 1960s, it was able to start raising prices in 1969-1972 in negotiations with the Majors. In 1973 OPEC raised prices unilaterally from 3 to 12 $/bbl. Prices rose again in 1979, after the Iranian revolution, from about 12 to more than 30 $/bbl. In l981 some crude oil prices hit 40 $/bbl. During this period, OPEC countries nationalised the Majors' producing assets in their countries and broke down the integrated system that the IOCs had created.

This rapid increase in prices, however, caused a reduction in oil consumption and an increase in production in the non-OPEC area. In contrast, OPEC's production fell by a third between 1973 and 1985, and OPEC's share of world oil markets fell from 55% to 30%. Saudi Arabia in particular suffered by reducing its production from a peak of 10 MBD in the late 1970s to 3.5 MBD in 1985. As a result, in late l985 it decided to stop acting as a swing producer within OPEC and to increase its production to 4.5 MBD; oil prices plummeted to close to 10 $/bbl.

3.3.4 Spot and Futures Markets

The current spot transactions have their origin in the first and second oil crises. The OAPEC[30] oil embargo of 1973 and the Iranian revolution of 1979 sparked fears of a shortage in crude supply.

28. It is a difficult task for authorities to assess whether the price agreed by two parties is equal to what two independent parties would have agreed. In the Norwegian petroleum tax system, for example, norm prices may be used for calculation of taxable incomes, instead of actual incomes from the sales. The norm price is determined by an independent panel, the Norm Price Board, based on the sales reports by companies operating in the Norwegian sector and Brent prices. *See* Ministry of Petroleum and Energy, Norwegian Petroleum Directorate, *FACTS, the Norwegian Petroleum Sector 2005*, at <http://www.npd.no/NR/rdonlyres/537038C7-8181-4662-995E-F8FAE12919E7/0/Facts2005.pdf> (visited 12 February 2007).
29. M. Adelman, *World Oil Production and Prices 1947-2000*, in The Quarterly Review of Economics and Finance, vol. 42, no. 2 (Elsevier, 2002).
30. Organisation of Arab Petroleum-exporting Countries.

Crude buyers became nervous and wanted crude at any price. Spot prices rose to higher levels than the official selling prices and supply volumes under long-term contracts shifted to spot markets. At the same time, rising volumes of new oil production from the non-OPEC area went into the spot markets. Cargoes from the North Sea were sold in the 1980s exclusively on a spot basis. Until 1985, most oil-producing countries nevertheless continued to offer long-term fixed price contracts. These contracts increasingly countered resistant from the buyers. Finally, in 1988 long-term fixed price contracts ceased to exist after an episode of netback pricing.

Although spot markets took over the control of oil prices from OPEC, the task remained in the late 1980s to organise spot markets, as there were as many spot markets as crude streams. Gradually Brent and WTI emerged as the two most influential benchmarks. Markets were re-organised in line with these crude grades and the other grades are indexed to them.

At the same time futures markets were being formed in Western countries. There was a desire on the part of oil companies to reduce risk in light of high volatility after 1973. Developments in information technology, developments in financial theory and a political climate favouring markets over government administrative guidance led to the creation of financial derivative markets, including futures and options.

Oil futures markets are not new. Price volatility in the early days of the US oil industry resulted in the first oil futures contracts in Pennsylvania in 1860s, which took the form of pipeline certificates. During the next 30 years, more than 10 exchanges in the US, Canada and Europe traded crude futures. However, when Rockefeller established monopoly control and, later, when the Majors controlled the market, prices became more stable, the need for market risk management disappeared, and the early futures trading disappeared as well.

In 1979 heating oil became the first new futures contract at the NYMEX, and the International Petroleum Exchange (IPE) in London followed in 1981. Gasoline (petrol) futures trading started on the NYMEX in 1981. WTI trading started in 1983 on the NYMEX and Brent in 1988 on the IPE. The NYMEX launched natural gas futures in 1990 and the IPE in 1997. The NYMEX still has an open trading floor, called outcry, but it began electronic trading after hours on NYMEX Access in 1993. At the IPE,[31] the open outcry system was abolished in 2005, and now all contracts of the IPE are traded electronically on screen only.

The NYMEX WTI futures is the most actively traded commodity in the world. Some 230 MBD is currently traded, almost three times as much as the physical oil production / consumption. The contract trades in units of 1,000 barrels and is listed for up to 72 months. The delivery point is Cushing, Oklahoma. Trading volumes of IPE's Brent futures are around 100 MBD. Like WTI, Brent contracts are 1,000 barrels per unit and listed for up to 72 months. The IPE has a delivery system called exchange of futures for physicals (EFP). Under this system Brent contract holders can cancel out a future contract with a physical spot contract. By doing so, the holders can have the same result as physical delivery of the commodity.

31. The IPE was bought by the Intercontinental Exchange Inc. of the US in 2001 and renamed as ICE Futures in 2005. However, for historical reasons, the name of the International Petroleum Exchange (IPE) is used in the text.

3.4 Spot/Forward/Futures/Options

3.4.1 Spot Market

Spot transactions are mainly conducted by telephone or computer network between two parties. It is an over-the-counter (OTC) market as opposed to an exchange. Spot markets do not necessarily have trading floors. The term 'spot market' applies to all spot transactions concluded in an area where strong trading activities take place. A key advantage of the OTC market is that the terms of a contract do not have to have the specifications required by an exchange. A disadvantage is that there is usually a lack of transparency in the market. Counter party risk also exists in an OTC trade, which is otherwise taken by the exchange.

The main spot markets for crude oil are Rotterdam for Europe and New York for the US. These markets have their own benchmarks: Brent and WTI. In particular, Brent was the centre of spot and forward trading in the 1980s. There are other grades which have strong spot trading activities. They are: Ekofisk, Forties, Oseberg from the North Sea; Russian Urals; Dubai (UAE); Oman; Minas (Indonesia); Tapis (Malaysia); Alaska North Slope (ANS) and West Texas Sour (WTS) in the US; and Forcados and Bonny light from Nigeria. Although most OPEC grades are contracted on a long-term basis, some OPEC countries are known to use spot transactions to sell part of their production.

The main markets for petroleum products are located in Northwest Europe (ARA - Amsterdam, Rotterdam, Antwerp), the Mediterranean (Genoa, Lavera), the Gulf, Southeast Asia (Singapore), US Gulf of Mexico (including the Caribbean) and US East Coast (New York).

Spot market participants are refiners and producers where crude oil is concerned. For petroleum products, buyers are traders or large consumers, and sellers are refiners. Traders play an essential middleman role. They buy cargoes from sellers and re-sell them to end-users or other traders. Alongside traders are trading divisions of oil companies. There are also intermediaries and brokers, who help conclude transactions. Although they do not buy or sell cargoes themselves, they earn a commission.

Formation of a spot market requires large trade volumes and various market operators. The Rotterdam market, sometimes referred to as the ARA area, ideally matches these conditions. It has both the European consumption centres and the North Sea production region nearby. The area itself is heavily industrialised, with many refinery plants. There are also large storage capacities available. The area is the largest port in Europe. It has access to the northern European market by sea. Also, barges go to Germany, Switzerland and France via the Rhine and other rivers and channels. Many financial institutions and oil brokerage houses (Eurol, Frisol, Transol, Vanol and Vito) are based in the area. Overall, the open Dutch and Belgian economies helped establish a large crude and product market place.

Spot transactions take place in a similar manner from one market to another. A buyer who seeks a cargo of crude available within one month contacts different producers and traders working in the area. Negotiations take place normally by telephone. Telephone conversations are recorded in case of disputes. Payment is made thirty days after loading of the ship for crude oil (payment deadlines are normally shorter for petroleum products). Spread trading mechanism governs most crude spot sales, in which negotiation does not centre on the price in absolute terms but on the price

differential between the crude traded and the benchmark. Prices of North Sea crude (e.g., Ekofisk or Forties), for instance, are normally indexed to that of Brent.

In the OTC market, transaction prices are normally known only to the two contracting parties. This can become a major obstacle to active and fluid spot trading. Therefore, there are publications which list price records. They are called reporting agencies. Platt's Oilgram (McGraw Hill) and Petroleum Argus are the two most famous. To track prices, Platt's journalists contact sellers and buyers in the market and interview them on transaction prices during the day. Platt's accordingly publishes the previous day's quotations. As this price reporting is an estimate based on the survey, there is a risk of price manipulation.

3.4.2 Forward Market

Spot trading generated an additional risk of high price volatility. To hedge this risk, forward and futures markets were established. In Europe, however, crude futures exchange started trading only in 1988. Instead, forward markets were developed around Brent crude in the 1980s. Therefore, Brent has three price quotations. Spot markets handle cargoes within fifteen-day availability, called 'dated Brent,' while forward markets were developed for more distant future deliveries, named 'fifteen-day Brent.' Brent traded on the IPE futures market is called 'IPE Brent.'

The forward fifteen-day Brent market has more standardised operation than the spot dated Brent market. The cargo size is fixed at 500,000 barrels ± 5%. The delivery takes place at the Sulom Voe terminal in the North Sea. In the fifteen-day Brent trading, only the month of delivery can be designated (e.g., January delivery Brent, February delivery Brent, March delivery Brent, etc.). The buyer specifies the month and the volume and the seller indicates the delivery date of the cargo at least fifteen days prior. The name came from this practice. When a fifteen-day Brent cargo is named and dated, it becomes a spot dated Brent transaction. In addition to the Brent crude, there are forward markets of gasoline (petrol), diesel, kerosene, naphtha and heavy fuel oil in Europe.

Forward contracts are in between spot and futures contracts (*see Table 3*). In a hedging operation, a position is taken in the forward market in an opposite direction to a position in the physical market. However, speculation also takes place in the forward market, when an operator takes a position in order to gain profit from price fluctuation. A cargo of crude oil can be transferred from one trader to another many times between loading and delivery. Series of consequential transactions in the forward market are called 'Daisy Chains'. Most transactions are cancelled out by reversed transactions.

Participants in the fifteen-day Brent market are normally limited to oil companies and large traders, because of the high risks involved in trading. One standard fifteen-day Brent cargo of 500,000 barrels costs around $30 million at early 2007 prices.

Forward contracts are traded in OTC markets, which are not as well organised as the exchanges. Many elements are in the hands of the two parties in the deal. There is less price transparency in the forward market than in the futures market, despite the fact that Platt's, Petroleum Argus and other news services survey and report daily prices. Furthermore, unlike in the futures market, there is no clearinghouse system. Therefore, there is the counter-party risk and all transaction records have to be kept track of individually.

3.4.3 Futures Market

Futures markets have grown considerably since the mid-1980s. Oil companies and traders as well as financial institutions use the futures markets for hedging against the risk of price fluctuations.

Table 3: Characteristics of Spot / Forward / Futures / Options Deals

Contract	Spot	Forward	Futures	Options
Trading	OTC	OTC	exchange	OTC / exchange
Derivatives	no	yes	yes	yes
Delivery	yes	(yes)	(no)	(no)

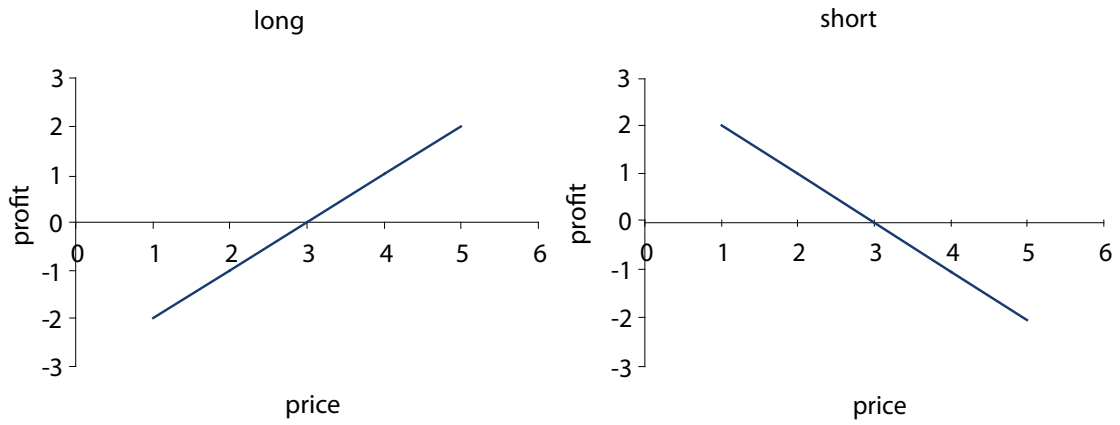
A futures contract is an agreement between two parties to buy or sell an asset at a certain future time for a certain price. Meanwhile, a spot contract is an agreement to buy or sell an asset today. A futures contract is a derivative. A derivative is defined as a financial instrument whose value derives from the values of underlying assets. Like a futures contract, a forward contract is a derivative, too. While a forward contract is traded in the OTC market, a futures contract is traded in the exchange. Less than 5% of futures contracts result in physical delivery. A futures holder normally has the opposite position in the market, so that the two contracts cancel out.

A derivatives exchange is a market where individuals trade standardised contracts. Derivatives exchanges have existed for a long time. In the US, the Chicago Board of Trade was created in as early as 1848, trading agricultural derivatives. The exchange specifies certain standardised features of the contract and acts as an intermediary, so that the two parties in the transaction do not necessarily have to know each other. The exchange also provides a mechanism that gives the two parties a guarantee that the contract will be honoured (counter party risk). The following sections explain some technicalities of the derivatives and exchanges.

Long and Short

A party assumes a *long* position in the futures market when it agrees to buy an underlying asset on a certain future date for a certain specified price. Conversely, when a party agrees to sell an underlying asset on a certain future date for a certain specified price, the position it assumes is called *short*. Pay-off charts are shown in *Figure 10*.

Figure 10: Profit vs. Price of Long - Short Positions



Convenience Yields

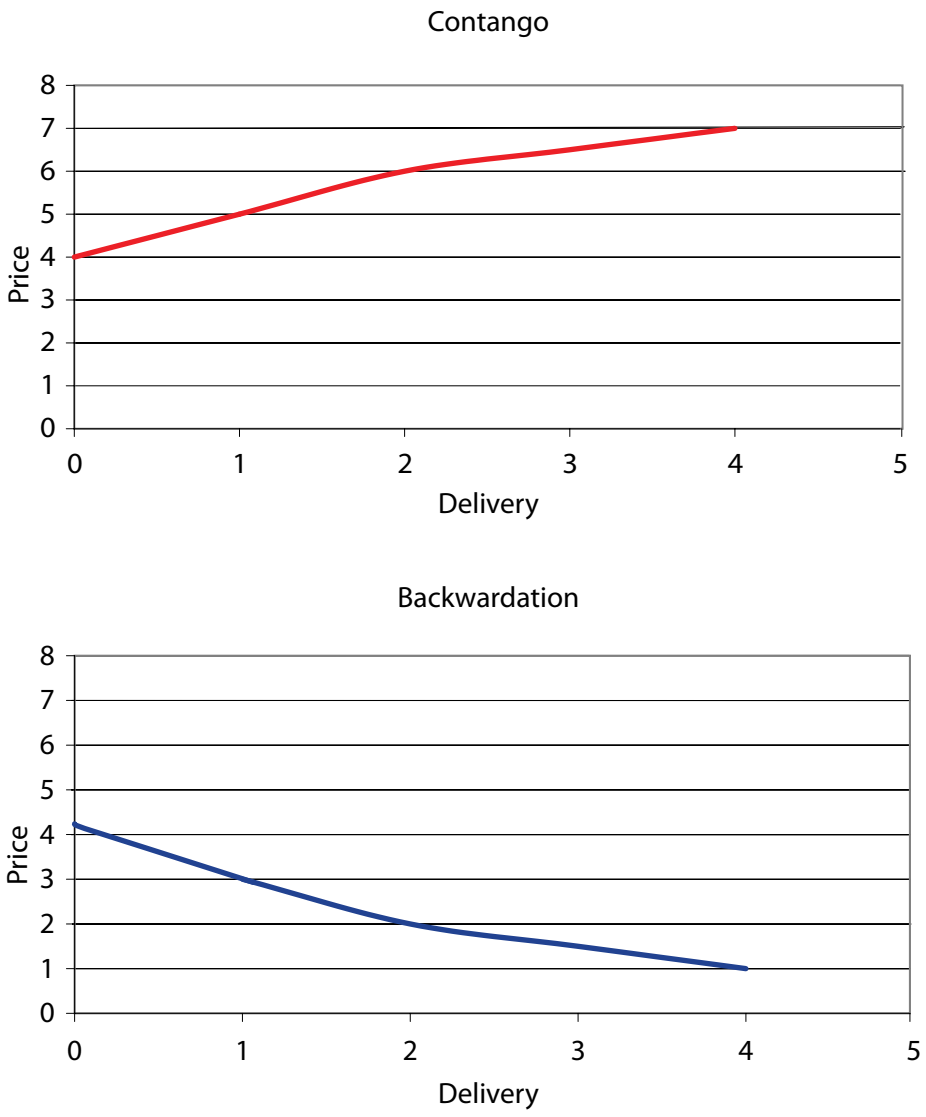
For commodities which are bought and sold for consumption, instead of as an investment into a futures contract, there are additional benefits from holding physical inventories. This additional benefit is called convenience yield. For example, inventories can smooth out the production process by filling in during shortages, or when there is higher-than-anticipated demand. Futures contracts cannot do the same. A convenience yield would reflect the difference between the costs of physical inventories and the costs of using a financial instrument (*see Box 4*).

Contango and Backwardation

When the convenience yield is smaller than carrying costs (interests and storage fees), the market is in *contango* (the further out the delivery is, the more the futures price increases – *see Figure 11*). When the convenience yield is larger than carrying costs, the market is in *backwardation* (the further out the delivery is, the more the futures price decreases – *see Figure 11*). If there is a supply or demand shock with low inventories, the convenience yield is high and the market is in backwardation. Conversely, if inventories are high, the convenience yields are low and the market is in contango.

The crude market is normally in backwardation. During the period of the Gulf Crisis, crude prices were high and the market was in steep backwardation. Prices and convenience yield were falling in 1997 and most of 1998, as Asian countries were hit by economic crisis. The market went into contango. In early 1999, OPEC agreed to cut production and Norway, Mexico and Russia joined OPEC's production cut. With production cuts and a recovery from the Asian financial crisis, prices and convenience yields once again commenced upward and the market returned to backwardation. The crude market has been in contango since the beginning of 2005.

Figure 11: Price vs. Delivery Date for Contango – Backwardation



Box 4: Spot and Futures Prices

The relation between spot and futures prices is expressed in the following equation:

$F_t^T = S_t * e^{(r+u-y)*(T-t)}$

Notation F: forward or futures price T: delivery date T t: trading date t

S: spot price r: risk-free interest rate u: unit storage cost y: convenience yield

According to this model, futures price of the trading date t for the delivery date T is given by the product of the spot price of the trading date t and $e^{(r+u-y)*(T-t)}$ means continuous compounding at the rate of r+u-y for the duration of T-t. Here, r+u can be interpreted as the cost of carrying physical inventory and y as the benefit of it. As described above,

If $r+u-y>0$, $F_t^T > S_t$ and the market is in contango

If $r+u-y<0$, $F_t^T < S_t$ and the market is in backwardation

Furthermore, the relation between forward price curves (contango / backwardation), upward or downward movements of spot price and stocks are normally as follows.

When there is not much benefit of holding physicals (which means the market is in contango), people do not buy physical commodity and spot prices go down. Therefore, stocks will be built up.

Conversely, when there is much benefit of holding physicals (which means the market is in backwardation), people buy physical commodity and spot prices go up. Therefore, stocks will be drawn down.

Marking to market

An important feature of the futures markets is 'marking-to-market'. At the exchange a broker requires a (financial) investor to deposit funds in the margin account so that contract defaults are avoided. The funds, known as the initial margin, must be deposited at the time a contract is entered into. Gains and losses of the investor associated with their positions are settled at the end of each trading day.

Clearinghouse

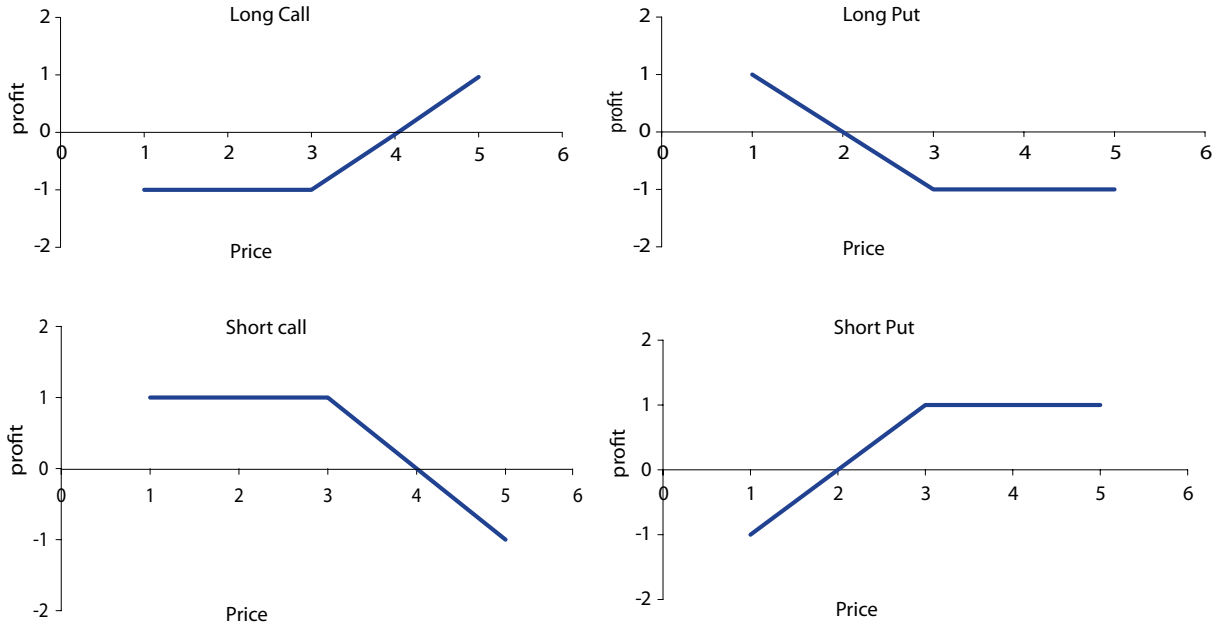
A clearinghouse acts as an intermediary in an exchange. It ensures performance of a contract by buying a contract from a seller and selling the contract to a buyer. Brokers have to be clearinghouse members themselves, or must channel their business through a member. Another important task of a clearinghouse is to keep track of all the transactions that take place during trading hours of the day so that it can calculate the net position of each of its members.

A financial investor is required to maintain a margin account with a broker, while a clearinghouse member is required to maintain a margin account with the clearinghouse. This account is known as a clearing margin. Brokers who are not clearinghouse members must maintain a margin account with a clearinghouse member.

3.4.4 Options Market

Options on tulips were traded as early as the 1600s in the Netherlands, while the London Stock Exchange listed options on stocks in the 1820s. The first energy options were WTI on the NYMEX in 1986.

Figure 12: Profit vs. Price Curves for Long Call – Long Put / Short Call – Short Put



Options are traded both on the exchange and in the OTC market. There are two basic types of options; call and put. A call option gives the holder the right to buy the underlying asset by a certain date for a certain price. A put option gives the holder the right to sell the underlying asset by a certain date for a certain price. This price is known as the exercise price or strike price. The date is known as the expiration date or maturity. American options can be exercised at any time up to the expiration date, while European options can be exercised only on the expiration date. Please note that 'American' and 'European' here are just labels and have nothing to do with the location or the market.

In addition, there are two positions to an option contract. Therefore, in total there are four option positions; long call, long put, short call and short put (*see Figure 12*).

Entering into a forward or futures contract costs nothing, while the purchase of an option requires an up-front premium. There are models to determine the theoretical options premium. The most famous is the Black and Scholes model. In general, models take account of the relative position of strike prices with respect to market prices, and options premiums depend on such factors as strike prices, maturity dates, volatility of the market and interest rates.

When the strike price of a call option is lower than the market the option is 'in the money'. When the strike price is higher, a call option is 'out of the money'. When the strike price is very close to the market price, a call option is 'at the money'.

3.5 Hedging and Speculation

3.5.1 Hedging

Derivatives (including futures) contracts are developed as an instrument to reduce price risks. Many participants in the futures market are hedgers. Hedging means reducing a risk of loss in the business, resulting from an unexpected change in the value or cost of a product. This section looks into how futures contracts and futures markets are used to hedge risks.

Companies hedge and fix unknown variables in order to concentrate on their main activities. Take a manufacturing company as an example. If the company has no particular expertise in such areas as interest rates, exchange rates and commodity prices, then it makes sense for the company to hedge the risks associated with these variables and fix them. By doing so, the company can focus on its main manufacturing activity which it knows very well.

It is important to know that hedging sometimes results in a decrease in profit. As a result of a hedging operation, a company may earn more or less profit than it would without hedging. However, the objective of hedging is to fix unpredictable variables, and is not to make more profit. Therefore, if a company engages in a hedging operation, it needs to have clear understanding of how hedging operations work. It is also important to recognise that there is no such a thing as a perfect hedge in practice. No hedges can completely eliminate the risk.

If hedging is not a norm in an industry, then companies in the industry should be careful about how they hedge. This is because there is competitive pressure in the industry, which in the long-run adjusts the raw material costs, interest rates and exchange rates as well as the prices of goods and services the company produces. A company that does not hedge can, therefore, expect its profit to be roughly the same, while the profit of a company that hedges may fluctuate. In such a case hedging can have the opposite effect to the intended one.

In 1998, when the crude oil price was declining, several oil companies arranged and entered into long-term oil price hedging contracts. Although the NYMEX and the IPE provide futures contracts up to 72 months ahead, it is not very common for companies to hedge crude oil prices further than several months. Few companies went bankrupt in 1998-99, as oil companies made efforts to reduce costs and streamline operation to adjust themselves to the low-oil-price business environment. However, some of the companies that had entered into a hedging contract were acquired by their competitors a few years later when oil prices started moving upwards.

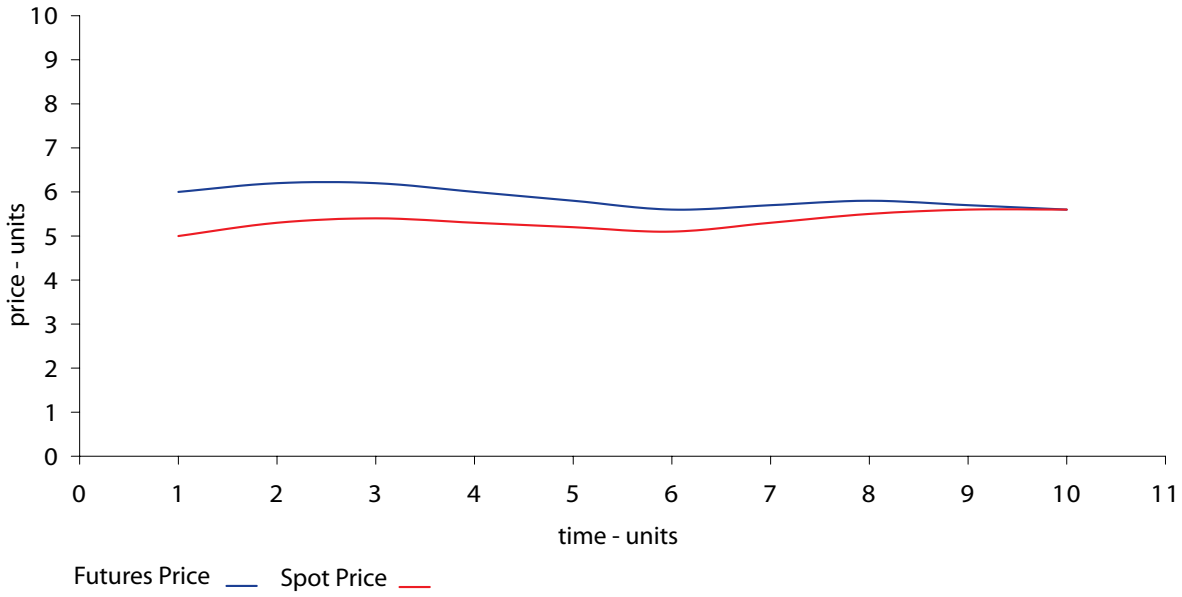
3.5.2 Long Hedge and Short Hedge

Hedging operations use the property that futures prices converge with spot prices at the time of delivery (*see Figure 13*). That is, when the delivery takes place, the futures price equals the spot price. Therefore, in hedging on the futures market, the operation goes in the opposite direction to the physical transaction. If one buys a physical commodity, it sells a futures contract (long hedge). If one sells a physical commodity, it buys a futures contract (short hedge).

Example (long hedge): A refiner who needs to buy crude in the physical world buys a futures contract on the futures market now and is going to sell a futures contract on the futures market at the time of purchase of the physical. Note that, when a hedging operation is completed, the refiner does not have a futures contract in his hand.

Example (short hedge): A producer who is going to sell crude in the physical world sells futures contract on the futures market now, and is going to buy futures contract on the futures market at the time of crude sales. In order to sell a futures contract now, the producer (who does not have a futures contract) borrows one from someone (there are brokers in the exchange who arrange borrowing deals). When the producer buys a futures contract, the producer will return it to the lender. If there is no-one willing to lend a futures contract, the situation is called squeezed. This is one reason why liquidity is important in the market.

Figure 13: Convergence of Futures Price and Spot Price



Box 5: Crack Spread

Derivatives can be combined in one trading strategy. One such strategy is called crack spread. A refiner, who buys crude and sells gasoline (petrol) / heating oil, makes money on price differentials. Refiners are, therefore, more interested in the price differential between crude and gasoline (petrol) / heating oil than in the absolute price levels. A refiner can simultaneously long hedge on crude and short hedge on gasoline (petrol) / heating oil, to lock in the spread.

3.5.3 Hedgers, Speculators and Arbitrageurs

One important reason why derivatives markets have been successful is that they have attracted many different types of traders and have had large liquidity in their trading. In order for a transaction

to be agreed upon, it is necessary to have players on the both ends of the deal, a buyer and a seller. In the market, there are three categories of players; hedgers, speculators and arbitrageurs.

Hedgers use futures and other derivatives to reduce the risks that they face from potential future movements in market variables. A hedger is a buyer or seller of a physical commodity, such as an oil producer or refiner, who takes the opposite position in the forward or futures market.

Hedgers want to avoid an exposure to the price risk, while **speculators** wish to take a position in the market. Speculators bet that the price will go up, or, that the price will go down. A speculator neither buys nor sells the physical commodity but takes on a risk for a profit in the futures market.

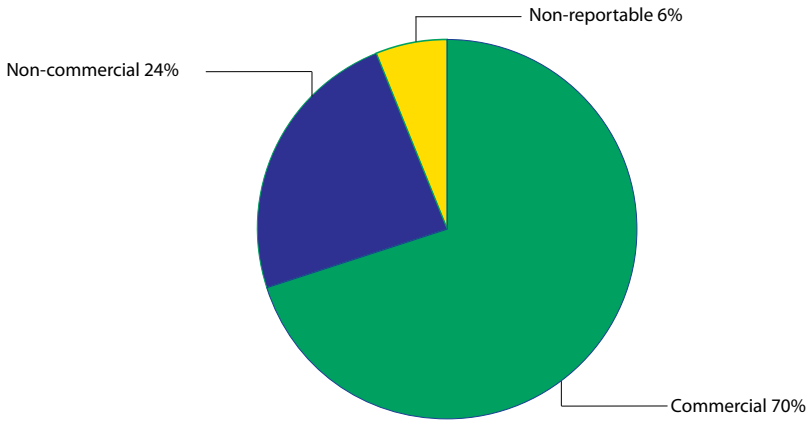
Arbitrageurs take offsetting positions in two or more instruments to lock in a profit. In other words, arbitrageurs lock in a riskless profit by simultaneously entering into corresponding transactions in two or more markets.

3.5.4 Regulatory Authority

In the US, the Commodity Futures Trading Commission (CFTC), established as an independent agency in 1974, regulates commodity futures and options markets. The mission of the CFTC is to protect market users and the public from fraud, manipulation and abusive practices related to the sale of commodity and financial futures and options, and to foster open, competitive and financially sound futures and option markets. The CFTC is also responsible for ensuring that prices are communicated to the public and that futures traders report their outstanding positions.

Various data on the futures and options markets in the US are available at the CFTC. One interesting area of data is outstanding positions by trader category, which shows the speculative activities. Under the CFTC categories a trader is classified as commercial (hedger), if the trader is 'commercially' engaged in the physical business activity hedged by the use of the futures or options markets. Non-commercial and non-reportable are regarded as speculators. *Figure 14* below is the situation in the NYMEX on 20 February 2007. Normally speculators hold a 25%-30% share in the NYMEX.

Figure 14: WTI Futures Positions at NYMEX as of 20.02.2007



Source: US CFTC

Many analysts point to the influence of speculative money on the oil market, particularly of commodity index funds, which started around 2004 (*see Box 6)*.

Box 6: Commodity Index Funds

Commodity index contracts are a financial vehicle linked to performance of commodity markets including energy, precious metals, industrial metals, agricultural products and live stocks. The returns are calculated based on the composite of benchmarks from these commodity markets. Since the oil portion weighs heavily in the composite, the movement of the index looks very much like that of oil prices

A large amount of money goes into the oil markets from institutional investors and pension funds by way of commodity index contracts. Some estimates suggest that commodity index funds account for more than 20% of the entire crude oil futures market. However, there are no clear data available which show activities of commodity index funds. There are two reasons for this: firstly, because commodity index contracts are traded mostly in the OTC market, there is no reliable data on this aspect; and, secondly, since some of the financial institutions which trade commodity index contracts have shareholdings in the companies engaged in the physical commodity business, they are categorised as 'Commercials' under the CFTC data and cannot be separated from pure hedgers.

One visible effect of the commodity index funds is, perhaps, the current contango crude market. The crude market has been in contango since the beginning of 2005, except for autumn of 2005 when hurricanes hit the US. As mentioned earlier, prices are normally depressed and stocks are built in the contango market. However, it was in this contango market that the record-high crude price of 78 $/bbl was posted in August 2006.

Commodity index funds have a so-called 'long-only' strategy, in which they hold a long position in distant delivery contracts for a long time. This is contrary to hedge funds and other traders (categorised as 'Non-commercials') which buy and sell contracts in prompt delivery months. There is a working theory that speculative money from commodity index funds has gone into distant delivery contracts where liquidity is thin and the prices there have gone up. In addition, this 'long-only' strategy requires a backwardated market to produce profits when roll-overs of the contract take place. The funds, therefore, invest in further delivery months which still remain in backwardation and, as a result, the contango portion of the market expands further from the prompt month.

The crude market in the summer of 2006 was fraught with unusual factors. In addition to commodity index funds, there were multiple conflicts in the Middle East, record-high speculative long positions by non-commercials and high levels of stocks, against the background of small OPEC spare production capacity, high gasoline (petrol) prices and tight refining situation. Furthermore, the US dollar, in which crude oil is denominated, was weakening against the Euro. By autumn 2006, tensions were easing slightly in the Middle East and the speculative positions turning to short. And crude oil prices started to fall as the fundamentals suggest.

3.6 Current Oil Market Fundamentals

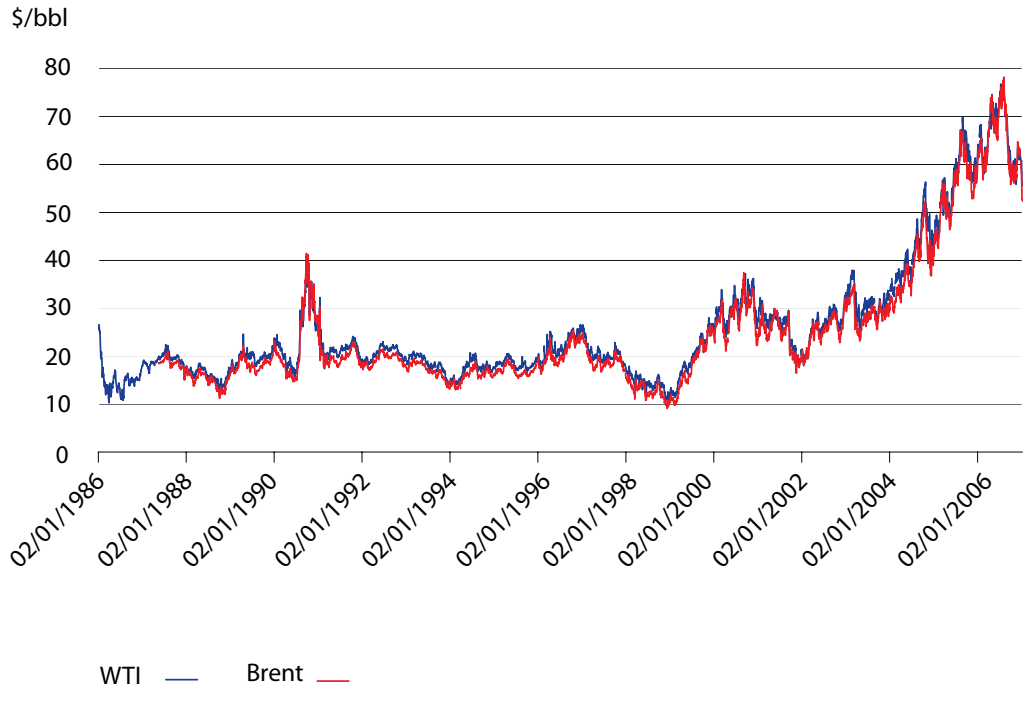
3.6.1 Recent Price Developments

This chapter looks into forces at work in the current oil market, and examines trends and developments in demand, supply, refining and stocks.

In August 1990, Iraq invaded Kuwait and oil prices started a steady increase. However, within a week after the US and allies began air attacks on Iraq in January 1991, oil prices fell back under 20 $/bbl. Both Iraqi and Kuwait oil was out of the market. Iraq has been outside of OPEC's quota since 1990. During the same period, production and exports from the FSU were decreasing, due to political and economic transition. But production increases from OPEC and the North Sea made up the drops, and oil prices were sliding.

In 1996, the strong world economy pushed up oil prices. However, oil prices were hit hard by the Asian financial crisis in 1997 and 1998. Nonetheless, OPEC decided to increase production at the meeting held in Jakarta in November 1997. Oil prices fell to below the $10 level, OPEC countries re-united and agreed to cut production in March 1999. Norway, Mexico and Russia joined this production cut. With recovering Asian economies, prices once again commenced an upward movement in 1999 and 2000. After 2004 prices exceeded the price band between 22 and 28 $/bbl set by OPEC.

Figure 15: World Crude Spot Prices 1986-2007



Source: US DOE/EIA

Although oil prices did not react immediately to the terrorist attacks in New York and Washington on 11 September 2001, they rose strongly in 2003 and 2004 in the wake of the war in Iraq and growing fear of terrorist attacks on oil facilities in the Middle East. Market fundamentals also played a major role in this oil price increase. Global oil demand grew at the highest rate in recent years in 2004. On the supply side, spare capacity was just 2 MBD against an 80 MBD consumption. Bottlenecks in the refining system, notably for gasoline (petrol) production in the US, also added pressure to product and crude prices.

In summer 2006, oil prices posted another record-high of 78 $/bbl in the wake of escalating conflicts in the Middle East. However, prices fell in autumn as the political tensions eased and the speculative money withdrew from the markets (*see Figure 15*).

3.6.2 Demand

Economies need energy to sustain their activities. Increases in energy consumption are closely linked to economic growth, although changing consumption patterns and improvements in the efficiency of energy use (diminishing 'energy intensity') can mitigate the growth in demand. In relation to oil, the linkage between economic growth and oil consumption has been established econometrically and is often used to forecast oil demand. Geographically, oil demand is increasing in China, India and the Middle East. Oil demand is also rising in the US as its oil intensive economy continues to expand. Meanwhile, oil demand is stagnant in Europe and OECD Pacific.

In industrialised countries oil demand growth is coming mainly from the transportation sector. The share of the transportation sector in oil demand has been increasing for the last few decades. Although governments promote such alternative fuels as compressed natural gas (CNG) and biofuels, it is difficult to entirely replace oil as transportation fuel. Oil demand for power generation is decreasing in industrialised countries, as shares of natural gas and coal are increasing. Demand for transportation fuels is also growing in developing countries, as income levels rise and infrastructure is developed. In addition, other sectors, including power generation, are contributing to growth in developing countries.

The year 2004 saw a huge demand increase. World oil demand grew by 4.0% or 3.2 MBD. China accounted for a quarter of the growth, or 0.8 MBD in the year. On the other hand, high oil prices have had a certain impact on oil demand for the last two years. Growth rates are lower than those of a decade ago. Nonetheless, oil demand is expanding by more than 1 MBD every year.

3.6.3 Supply

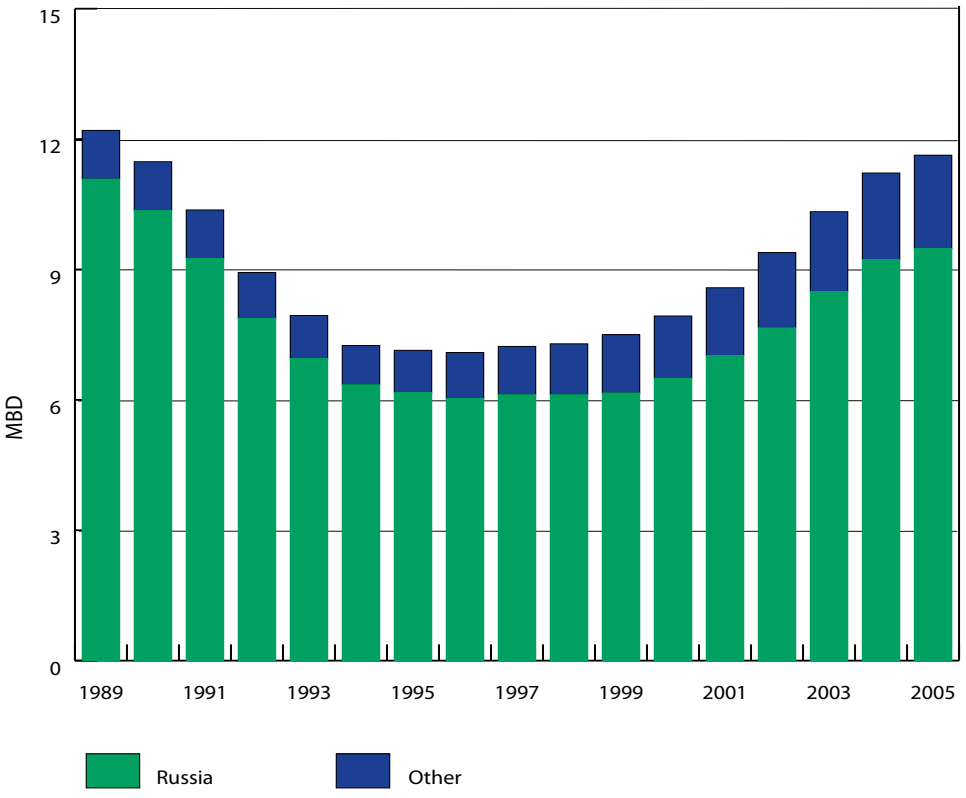
The earth has a finite amount of hydrocarbon resources. The debate on how large hydrocarbon resources are and how soon mankind will run out of oil reserves has been going on for a long time. A key point of contention is the prediction (made at various times) that the peak of oil production is nearing (called 'peak oil theory'). American geologist Marion King Hubbert originally wrote about the peak oil theory in the 1950s, and this theory has drawn wide attention. One school of thought claims that oil production will soon peak and that the consequences for the world economy will be dire, as humankind is dependent on oil. On the other side of the debate, another school of thought argues that the peak of Hubbert's curve will continue be postponed for some time due

to new explorations and improvements in technology. The United States Geological Survey (USGS) says that there are enough remaining petroleum reserves to continue current production rates for another 50 to 100 years.

There are not enough scientific data available to settle the debate authoritatively one way or the other. Enough data simply do not exit, and much of the existing data is kept confidential due to security and commercial reasons. Furthermore, the amount of exploitable reserves (including extra-heavy oil, bitumen and oil shale) are dependent not only on physical existence but also on technological and economic factors. Therefore, the amount of the reserves will change, as technology progresses and economic conditions change.

OPEC's 11 member countries produced 30 MBD in 2005, equivalent to 36% of world production, but hold 897 billion barrels of oil reserves, equivalent to 78% of world reserves. Currently OPEC ministers meet every three months prior to the start of a quarter, to discuss production levels. Among the members, Iraq has been outside the quota system since 1991 and Indonesia became a net oil importer in 2004. OPEC's surplus production capacity, currently around 3 MBD (there is none in non-OPEC countries), is set to expand due to increased investment. In addition to crude oil, OPEC countries have over 4 MBD of natural gas liquid (NGL) production, which is outside the OPEC quota. In January 2007 Angola took up full membership in OPEC, which has now 12 member countries including Iraq.

Figure 16 FSU Oil Production



Source: IEA

The Soviet Union was the world's largest oil producer in the 1980s. Its production peak exceeded 12 MBD in 1988. In the wake of political and economic transition, however, output fell to 7 MBD in the mid-1990s. It started to recover in the late 1990s and has shown robust growth over the last ten years (*see Figure 16*). Although increases in Russian production slowed in 2005, Caspian output has been increasing with the start of three pipeline operations (CPC, Kazakhstan-China and BTC) to transport crude out of the region, and is set to increase further with expansion of the Tengiz field and development of the Kashagan field.

IEA data suggest that non-OPEC production remained unchanged in 2005, compared to a 1 MBD growth in 2004. Some may see this as an early symptom of forthcoming irreversible decline in the non-OPEC area. Looking into the detailed breakdowns, however, two factors affected this under-performance. Hurricanes heavily disrupted operation in the US Gulf of Mexico, and Russian oil production achieved a lower growth in the aftermath of Yukos and Sibneft acquisitions. On the other hand, investment is increasing in the light of high oil prices, to arrest declines and develop new capacities. Active drilling rig count, which is an indicator for upstream activities, is on the rise.

In the non-conventional oil category, Canada's tar sands production exceeded 1 MBD in 2005. Given the high production costs for oil from tar sands (higher than 25 $/bbl), high oil prices have created an improved environment for this non-conventional source. Canada has the second largest oil reserves (including tar sands) in the world after Saudi Arabia. Canada plans to expand its tar sands production to 3 MBD by 2015. Venezuela's extra-heavy oil output is averaging 0.6 MBD at this time. Meanwhile, biofuel production is growing rapidly in Brazil, the US and in Europe (*see Box 7*).

3.6.4 Refining

The refining sector faces many challenges. Refineries have been running at around 90% of capacity, virtually the upper limit, in industrialised countries for more than a decade. The question is how much longer it will continue to keep up with ever-increasing demand. Historically, oil demand was dampened by two oil crises in the 1970s, creating excess refining capacities. The refining sector suffered from the excess capacities until the early 1990s. Since then, however, the difference between refining capacity and demand has been tightening.

Currently it is very difficult to expand or upgrade facilities in refineries in industrialised countries, due to environmental regulations and local opposition. This results in increases in product imports and expansions in refining capacities outside of industrialised countries.

The introduction of new, more stringent fuel specifications has created the need to upgrade refining facilities. Furthermore, product demand is shifting toward lighter gasoline (petrol), diesel and jet fuel, while crude quality is becoming heavier and more sour. This mismatch was one driving force behind the oil price increases since 2000.

Refining margins have improved since 2004, in particular for complex refineries with upgrading capacity (which produce only gasoline (petrol) and middle distillates and virtually no fuel oil). These refineries have higher utilisation rates than those with simpler facilities. According to the IEA, growing oil demand will continue to be covered by new refining capacity additions in the near future. Capacity expansions are expected to take place in China, India and the Middle East. New refineries in China and India will be for domestic consumption, while those to be built in the Middle East will serve for both domestic customers and export.

Box 7: Biofuels

Ethanol and biodiesel are the two main biofuels, which are derived from biological sources and used as transportation fuel. Cereals, grains and sugar crops are fermented to produce ethanol. Rapeseed, soybeans and sunflowers are converted into methyl esters which can be used as biodiesel. Growth in biofuel production is a clear example of a supply and policy response to high oil prices. Biofuels are popular because they are renewable energy sources with less negative environmental impacts than traditional transportation fuels. Biofuels can also contribute to energy security by diversifying energy sources. Furthermore, biofuel production supports the agriculture sector.

Biofuel plants are relatively small and inexpensive, and can be brought on-stream quickly. Large producers are Brazil (ethanol), the US (ethanol) and the EU (biodiesel). According to the IEA, ethanol output grew by 14% in 2005 and accounted for 2% of the world gasoline (petrol) market, while biodiesel production increased by 80% in the same year and supplied about 0.2% of the world diesel market.

Production costs of biofuels vary with feedstock and location. Prices of feedstock (sugar cane, corn, etc.) themselves rise and fall. In general, ethanol production from sugar cane can become economically feasible when oil price reaches 40 $/bbl. However, other biofuels can compete only when oil prices are above 70 $/bbl.

Brazil started commercial-scale production of ethanol from sugarcane in 1975 under a government policy in response to the oil shock of 1973. Having faced difficulty in its production economics for a long time, the rise in oil prices since 2000 changed the situation completely. Ethanol production in 2005 increased by 50% from five years earlier, to 280,000 barrels per day. Ethanol accounts for 20% of domestic gasoline (petrol) demand and some volumes are exported. Gasoline (petrol) sold in Brazil now contains between 20% and 26% ethanol by volume. Introduction of the flex-fuelled car (a car that can run on ethanol or gasoline (petrol) or a combination of the two) in March 2003 has been a key driver for demand growth. Some 70% of the cars sold in Brazil were flex-fuelled in 2005.

Ethanol produced from corn has been used as a transport fuel in the **US** since the early 1980s. The US produced 250,000 barrels per day of ethanol in 2005, accounting for 2.7% of total gasoline (petrol) demand. The volume is likely to surpass that of Brazil in the near future. Ethanol has a high octane number and is used to increase the gasoline (petrol) octane value. MTBE (methyl tertiary butyl ether) was used to increase the Octane value, but, due to safety and environmental reasons, it was banned in California, New York and Connecticut in 2004.

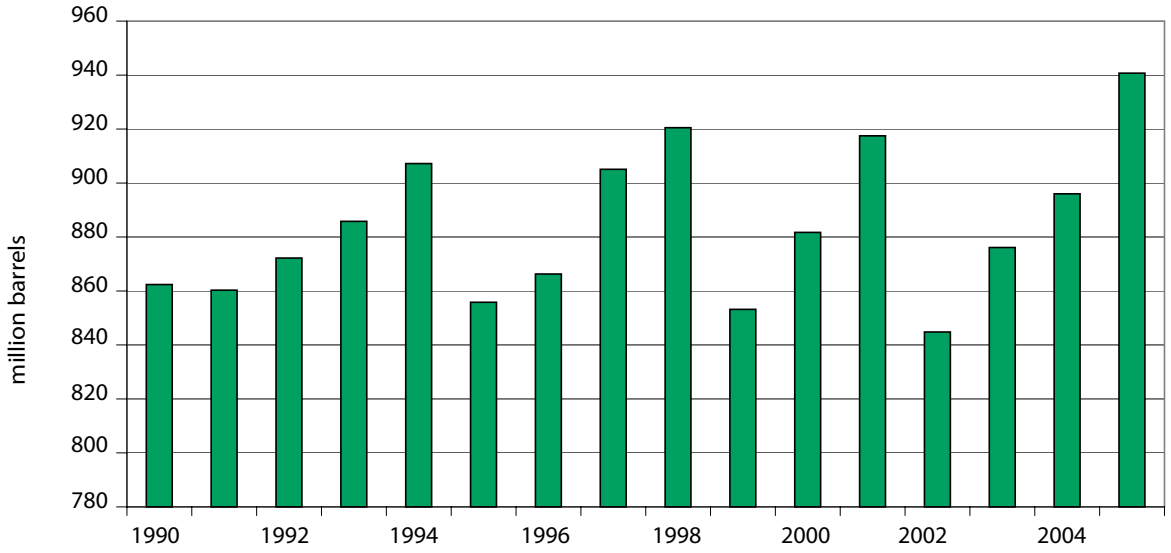
Europe's biofuel production is dominated by biodiesel (64,000 barrels per day in 2005). Only a limited amount of ethanol (16,000 barrels per day) is produced. This is because of the dieselisation of the car fleet and structural deficit in diesel production. Biodiesel production in Europe grew by 60% in 2005 alone. This production increase stems from the target set by the European Commission for 5.75% biofuels in transport fuels by 2010. Biodiesel's zero-sulphur emission quality also helps the expansion. Large producers in Europe are Germany, France, Spain and Italy.

3.6.5 Stocks

Stocks have a close relation to prices. Price is where supply curve and demand curve meet, while changes in stocks equal supply quantity minus demand quantity. Therefore, markets are very responsive to stock level movements. Markets react immediately to stock data releases from the IEA (for OECD countries), API (for the US) or DOE / EIA (for the US).

Oil stocks are held in the form of both crude and products. Oil stocks are held by industry as commercial running stock, by IEA governments as strategic stocks, and by the military. The OECD / IEA reports on industry and government stocks in OECD countries (*see Figure 17*).

Figure 17: OECD Industry Crude Stocks (1990-2005)



Source: IEA

There is no systematic reporting system for non-OECD countries today. Because of the increasing significance of non-OECD counties like China, India and the Caribbean countries, there have been calls to establish a global reporting system. There are also independent storage facilities held by producers in non-OECD countries. Stock movements involving these facilities are thought to be a part of 'missing barrels' which are not caught in the OECD / IEA oil statistics.

Industry stocks held by refineries, port facilities and terminal operators are defined as primary stock holding, which is counted as stocks. However, secondary stock holding held in distributors' storage facilities and tertiary stocks held by consumers are not counted as stocks. When oil (normally in the form of products) moves from primary storage to secondary- and tertiary-level storage, it is regarded as consumed, thus falling into the demand category.

To improve transparency of the market, covering not only stocks but also all the other activities in the oil sector, the International Energy Forum in Riyadh, Saudi Arabia, is working to establish a worldwide statistics reporting system, called the 'Joint Oil Data Initiative' (JODI). This effort was supported by the G8 Summit in St. Petersburg, Russia, in July 2006.

3.7 Conclusions

The typical commodity-pricing mechanism of spot and futures markets took over as oil pricing mechanism from the OPEC system of official selling prices in the mid-1980s. Despite criticism of manipulation and speculation, these commodity pricing mechanisms are firmly in place, and these pricing mechanisms have been evolving, with the progress in finance theories and information technologies.

Nonetheless, new challenges arise. The most important is how to tackle environmental issues. Environmental factors like SO_2 and CO_2 emissions are externalities and need to be internalised. SO_2 emission rights have been traded at the Chicago Board of Trade (CBOT) and trading of CO_2 emission rights has started at the IPE.

As a result of oil industry development since 1986, oil has developed into a global, liquid commodity market with all the pricing and trading mechanisms of a global commodity. However, market liquidity is not the only factor affecting prices. While liquidity provides for transparency and also creates instruments for the hedging of risk, it does not necessarily provide for the competitive pressure to drive prices down. Market structure and the shape of the demand curve are also important to explain the level of prices.

Chapter 4

Gas Pricing



Chapter 4 Gas Pricing

The physical properties of oil and the fact that it is relatively easy to transport and to store facilitated the emergence of commodity pricing mechanisms in the oil sector. However, these considerations do not apply in the same way to natural gas. The question is whether gas will follow the same development as the oil sector. In North America and in the UK the movement toward a commodity-type market pricing mechanism is already well advanced in the natural gas sector. Natural gas spot and futures markets have developed in the US and the UK. LNG is starting to be traded on a spot basis, even though long-term contracts are still the dominant feature.

However, it is open to question to what extent physical, technical, and economic differences, as well as different traditions, will result not only in a delay but also restrict the application of these pricing mechanisms for gas outside of the US and the UK, and what will be the relationship between commodity pricing mechanisms and traditional long-term pricing mechanisms.

Chapter 4 describes in detail the various pricing mechanism in North America, the UK, and Continental Europe, as well as for LNG, keeping in mind the following question:

4.1 Will Gas Follow Oil to Become a Global Commodity?

While oil has developed into a global commodity market, the situation with gas is more complicated (*see Table 4*).

The supply side

In North America and the United Kingdom there was a certain similarity between the development of oil and of gas as a commodity, based on natural endowments of and distribution of resources and on successful sector reform. A liquid gas market has developed in both North America and the UK during the past 20 years.

The indicator for liquidity is usually called 'churn'. Churn is the ratio between traded volumes and delivered volumes. A churn of at least 15 is usually considered to be the threshold for a liquid market. The gas hubs in North America were created by industry at appropriate places, with Henry Hub in Louisiana being the most prominent and important of these. Henry Hub has a churn of about 100, indicating high market liquidity. For comparison: on the oil side the churn of WTI and Brent is about 500.

By contrast, the National Balancing Point (NBP), a notional point at which gas is traded in the UK, was created by regulation. The churn on the NBP rose to about 15 until 2004 and then dropped for some time to 10, placing the NBP at the edge of being considered as a liquid market. European players, who prefer a strategy of vertical integration, have now replaced US firms in the UK power market, leading to lower volumes on the traded market. Both the UK and the North American markets have many players and show substantial demand elasticity based on gas demand for power generation.

There are specific features of the UK and North American gas markets which have favoured the development of gas as a commodity in these markets. Firstly, and most importantly, the development

of the gas industry in these countries was based on domestic resources. North America was self-sufficient until the end of the 20th century. The UK was not only self-sufficient, but was even briefly a gas exporter at the end of the century.

Another common element between North America and the UK is the existence of standardised rent-taking regimes and licensing procedures for the development of new fields. In the US it is the landowner who gets the rent (by law as a royalty limited by 12.5%, and until the 1980s based on a regulated wellhead price). In the UK and in Canada (where resource issues are under the control of the provinces) it is the government which designs a framework for licensing and clearly defines the rules of rent-taking (as extra petroleum tax and royalty regimes). This framework, and especially the rules of rent-taking, has been adapted over time to the changing worldwide competition for upstream investment or to the depletion stage of the respective hydrocarbon province. Both in North America and in the UK the decisions on field development are made by private players reacting to market signals and to market fundamentals within the framework defined by government, but their decision is not directly influenced by government. With the UK and North America starting to import LNG, LNG investments in exporting countries are being developed to target these markets.

It should also be noted that the geology of North America (except for fields adjacent to the Beaufort Sea) as well as on the UK Continental Shelf is characterised by a large number of small to medium-sized gas fields and an absence of giant structures.

In North America and in the UK, gas-to-gas competition is well developed and gas prices are no longer contractually pegged to oil prices but follow a development of their own. However, a de facto long-term average correlation between oil and gas prices remains due to substitution effects over longer periods, even though gas price development is having more peaks than oil price development, reflecting more volatile electricity demand.

In contrast to the situation in North America and the UK, gas markets in the rest of the European Union (excluding the Netherlands), and in Japan and Korea have developed based on imported gas. These markets have been shaped by the wish of exporting countries to maximise the rent from gas exports as a compensation for the depletion of their finite resources, and to sell their gas at a price that allows the marketing of the gas, while maximising their resource rent.

The EU depends for 50% of its consumption on three large gas-exporting countries: Algeria, Norway and Russia. Moreover, gas exports into the EU come largely from eight super giant fields: the Russian fields Yamburg, Urengoy and Medvezhye, and after 2000 also Zapolyarnoye, Groningen in the Netherlands, Hassi R'Mel in Algeria, and Troll in Norway.

In all these fields, governments have been strongly involved in the development and marketing decisions, using state-owned or state-dominated companies as an instrument to implement their policy to collect rents and information. In the Netherlands, this was done via Gasunie and a detailed depletion policy for Groningen; in Algeria via Sonatrach as a national oil and gas company. In Soviet times, ministries were responsible for field development and for gas exports, and in Russia after 1991 this role was inherited by Gazprom, a company under dominant state influence. In Norway, the state-owned company Statoil was created as an instrument of government policy, later complemented by the GFU (Gas negotiation committee) and the SDFI (the State direct financial interest). The giant size of the fields resulted in large export contracts often in the order of 5-10 Bcm/year with a duration of

twenty years and more with a few large gas import companies. Gas import into Continental Europe still continues to be dominated by long-term gas contracts with large volumes.

Imports of LNG into Japan and Korea were also based on large gas fields – in Indonesia, Malaysia and Brunei – whose export was handled by national companies under large contracts.

The structure and concentration of gas supply to Continental Europe and to Japan and Korea, and their dependence on imports, makes these cases very different from North America and the UK. In turn, this suggests that differences in market structure are not only a question of sector reform.

The demand side

There are also important differences on the demand side: In all regions gas is used in the captive sectors, residential and commercial, which not only have little price elasticity but also a demand that is strongly dependent on weather conditions. In North America and the UK, gas is also to a large extent used in a power sector, which has substantial price elasticity. By contrast, gas in power generation plays a different role in Continental Europe, Japan and Korea. In some parts of Continental Europe, gas has only a small share in power generation, as domestic or quasi-domestic energies like nuclear are preferred, based on commercial considerations of the industry and often promoted by policy choices, as in France and Germany. In other countries that have no domestic energy, gas was by tradition imported with a high load factor for base load generation.

Continental Europe, Japan and Korea are characterised by a relatively small number of large players both in the gas sector and in the electricity sector, and by large mergers between gas and electricity companies.

The hubs that have developed in Continental Europe (Zeebrugge, Bunde and TTF in the Netherlands) all have a churn of clearly below 10, a sign of low liquidity. While Continental Europe has developed some hubs, Japan and Korea so far have no hubs at all: Korea only has one gas company, Japan has a maximum of two per region (one gas, one power utility) and there is practically no pipeline connection between the regions, although the companies do swap LNG cargoes with each other in short-term lend / borrow arrangements.

The role of LNG

The fast growing trade in LNG is regarded by some as a factor that will lead to the creation of a global gas market. The fast growing import needs of North America and the UK offer a large potential to absorb substantial amounts of LNG. As a result of substantial cost reductions of liquefaction plants and LNG tankers (which has been partly reversed lately due to buoyant demand for tankers and liquefaction plants), LNG now has a worldwide reach. With a growing number of LNG liquefaction plants and receiving terminals, and with some over-capacity in the LNG tanker fleet, LNG trade has also become much more flexible especially due to the deep and liquid demand from the US. Demand for LNG from the US now competes with demand from the EU and Japan and Korea. By being directed to higher price markets, LNG trade is functioning as a price transmitter for higher prices between regional markets. However, LNG terminals – unlike oil terminals – have not developed into trading hubs of their own, and in view of the high costs of storing LNG this is not likely to happen soon.

Table 4: Will Gas follow Oil to Become a (Global) Commodity?

Will Gas Follow Oil to Become a (Global) Commodity?						
North America and United Kingdom				**Continental Europe and Japan / Korea**		
➢development based on own resources, no initial dependence on imports				➢high import dependence from the start		
➢supply based on small to medium sized gas fields				➢supply based on imports from giant / super giant fields		
➢standardised rent taking development decision by private players				➢rent maximisation of exporting countries development decision by exporting country		
➢demand elasticity from gas to power generation				➢limited demand elasticity		
➢gas-gas competition but price path for gas still tracks oil prices				➢oil prices as reference in price formula		
			Linkages			
market restructuring as of 1980s			⇨ **model for reform**	**market restructuring as of late 1990s**		
North America		**UK**	**LNG trade**	**Continental EU**		**Japan/Korea**
Hubs created by industry, churn 100, many players, high LNG absorption potential.	⇔	NBP created by regulation, churn 15 to 10, many players, limited absorption of LNG.	no LNG Hub but LNG as price transmitter ⇔	few industry hubs, churn <10, few strong players, dominance LTCs.	⇔	no hub so far, few strong players, dominance LTCs.

Source: Energy Charter Secretariat

4.2 North America

4.2.1 Summary

The North American natural gas transmission system is sufficiently interconnected that it operates virtually as a single system. As the continent moves towards heavier reliance on LNG imports, imports into the US, Canada or Mexico will act to supplement total North American supply.

Natural gas demand in the US enjoyed a period of rapid and largely uninterrupted growth from the end of World War II until the late 1960s, when supply shortages developed.

The shortages were compounded by a period of wellhead price controls set in motion by the US Supreme Court in 1954. It required an Act of Congress – the Natural Gas Policy Act of 1978 – and several Orders by the Federal Energy Regulatory Commission (FERC) to reverse the policy and set the US on the road to a liberalised gas industry with full third-party access.

Canada, which could not escape the price distortions created by a failed US wellhead price control system, set up its own gas price controls in the 1970s. The dismantling of the US system in the mid 1980s made the Canadian system unworkable and Canada also liberalised in the 1985 'Halloween Agreement' between the producing provinces and the Federal Government.

The US liberalisation, coming at a time of sharply rising energy prices as a result of the first oil shock, created an extended period of surplus in the US – the 'gas bubble', which lasted until the mid 1990s. Continued growth in US demand beyond that point was increasingly supported by imports from Canada.

This period of perceived growth ran into difficulties in the winter of 2000/2001, when supply shortages led to a sharp increase in prices and a general realisation that North American supply was no longer adequate to support the anticipated high growth rates. Since then, LNG imports are receiving greater attention, not only in the US, but in Canada and Mexico as well.

The North American market system features open trading in gas as a commodity and in pipeline capacity to move the gas to market. The centrepiece of the pricing system is Henry Hub, a pipeline junction in South Louisiana. This is the basis both of spot market trading and in futures trading on the New York Mercantile Exchange (NYMEX). The trade press reports on prices at other hubs and their differences from Henry Hub are referred to as 'basis differentials'.

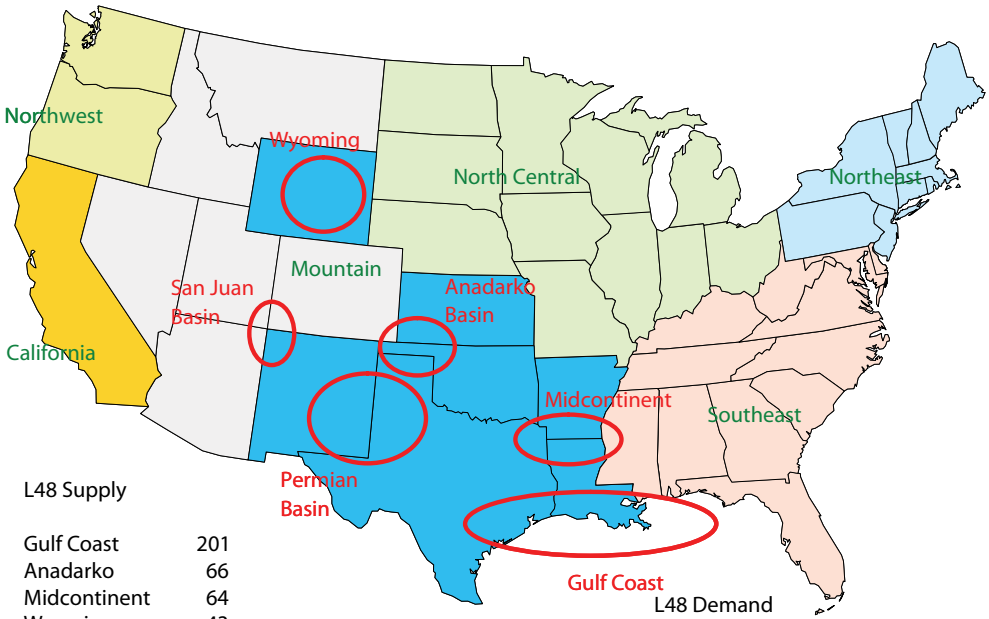
4.2.2 Introduction

4.2.2.1 The Integrated North American Natural Gas Transmission System

The pipeline infrastructure linking Canada and the US operates virtually as an interconnected system. The interstate pipeline system in the US consists of about 340,000 kilometres of pipeline. The Canadian system operates 80,000 kilometres. These systems connect the major gas-producing basins with the principal US and Canadian market centres.

The US Gulf Coast is the most important producing region in the US, as recently as 1980 accounting for 53% of US production in the Lower 48 states (*see Figure 18*). The Gulf supplies the interstate pipelines that serve the eastern part of the US, while the upper Midwest is largely supplied by the Anadarko and Mid-continent regions located north of the Gulf Coast. The Pacific Coast market was originally developed by pipelines originating in the Permian Basin of West Texas and New Mexico and the San Juan Basin of New Mexico and Colorado. The upper Rocky Mountain States, particularly Wyoming, are important producers and supply markets both to the west and the east. It has proved to be difficult economically to build a pipeline to tap the large gas reserves of the Alaskan North Slope.

Figure 18: Location of main US Regions and their Consumption and Production in 2004 (Bcm)



L48 Supply	
Gulf Coast	201
Anadarko	66
Midcontinent	64
Wyoming	43
Permian	42
San Juan	29
Other L48	85
Imports	96
Total	626

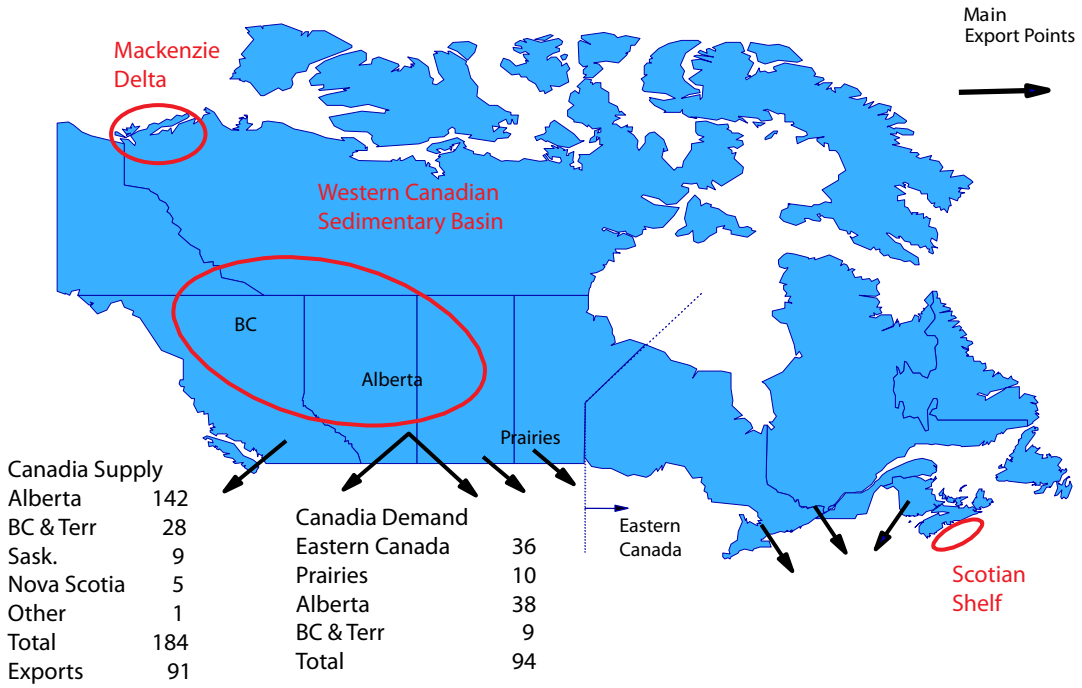
L48 Demand	
Northeast	90
Southeast	94
North Central	132
Moutain	37
Northwest	14
California	69
7 State [1]	188
Total	624

[1] Seven Major Producing States

Source: Jim Jensen

Canada's main producing region is the Western Canadian Sedimentary Basin of Alberta, British Columbia and Saskatchewan (*see Figure 19*). A more recent producing basin, the Scotian Shelf offshore Nova Scotia, initially appeared promising, but has failed to live up to early expectations. There are additional major discoveries in the Canadian Arctic, particularly in the Mackenzie Delta region. As of 2006, proposals to build a pipeline from the Delta to Alberta are in the hearing process.

Figure 19: Location of main Canadian Regions and their Consumption and Production in 2004 (Bcm)



Source: Jim Jensen

Canadian trunk pipelines serve not only Eastern and Western Canada, but increasingly supply gas to the US West Coast, Midwest and East Coast. One branch of the TransCanada system from Alberta to Eastern Canada actually transits the US on its way east. There are eight major Canadian pipeline export points that distribute the Canadian supply to US market regions across the continent.

While Mexico is somewhat less closely integrated with the US system, there is still enough interconnection to provide the necessary cross-border flows. The Mexican system consists of 12,000 kilometres of transmission pipeline.

4.2.2.2 North American LNG Import Terminals

Since 2000 it has become increasingly apparent that the gas resources of North America are not sufficient to supply the expected growth in demand for the continent. As a result, interest in LNG imports is strong, not only in the US, but in Canada and Mexico as well. The fact that the North American pipeline grid is so well interconnected means that LNG imports represent potential additions to total continental supply, independent of the landing site.

The US has five operating LNG terminals with a capacity of 51 Bcm/year. As of July 2006, another seventeen terminals have been approved (including two in the Bahamas), either by the Federal Energy Regulatory Commission or by the Maritime Administration. As of July 2006, another twenty-two proposed terminals are listed in FERC's summary of proposed projects. The approved terminals

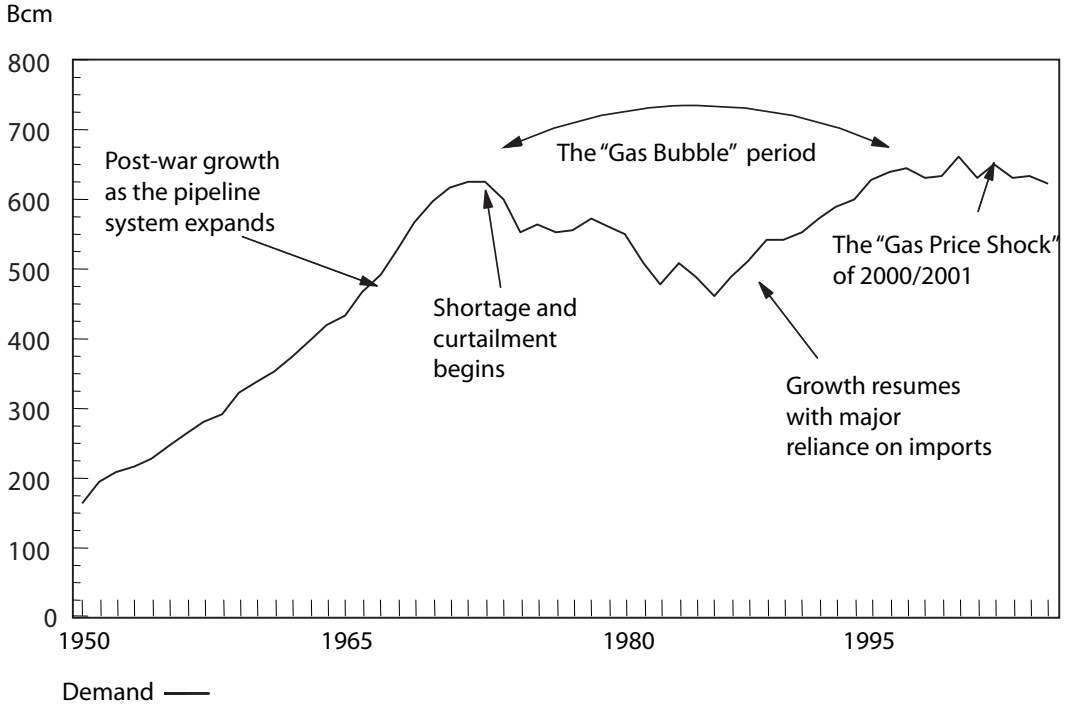
have a capacity of 278 Bcm/year, while the proposals total 250 Bcm/year. The total listing far exceeds the number of terminals that will actually be needed so that most on the list – including many approved terminals – will probably not be developed.

Canada has no operating terminals but has approved two terminals with a capacity of 21 Bcm/year and another five proposed terminals with a capacity of 30 Bcm/year. Mexico also has no operating terminals, but it has three approved with a capacity of 32 Bcm/year and two proposals at 16 Bcm/year. Some of the approved terminals in both Canada and Mexico are to serve markets in the US as well as in the receiving country.

4.2.2.3 US Natural Gas Demand

With the end of World War II, the US pipeline grid began a period of rapid expansion, providing gas supply to all sections of the country. There had been a plentiful supply of gas reserves discovered in the course of oil exploration. Since these lacked a market outlet, gas prices were low. From 1950 until the first evidence of gas shortages appeared, demand enjoyed a period of 6.8% per year compounded-growth. During much of this period wellhead prices were regulated and thus remained low. *Figure 20* illustrates the almost unbroken demand growth during this early period.

Figure 20: US Gas Demand since 1950 (Bcm)



Source: Jim Jensen

But in the late 1960s, the first evidence of gas shortages appeared and pipelines began to ration supplies to customers through a system of 'end-use priority curtailments'. While it was widely

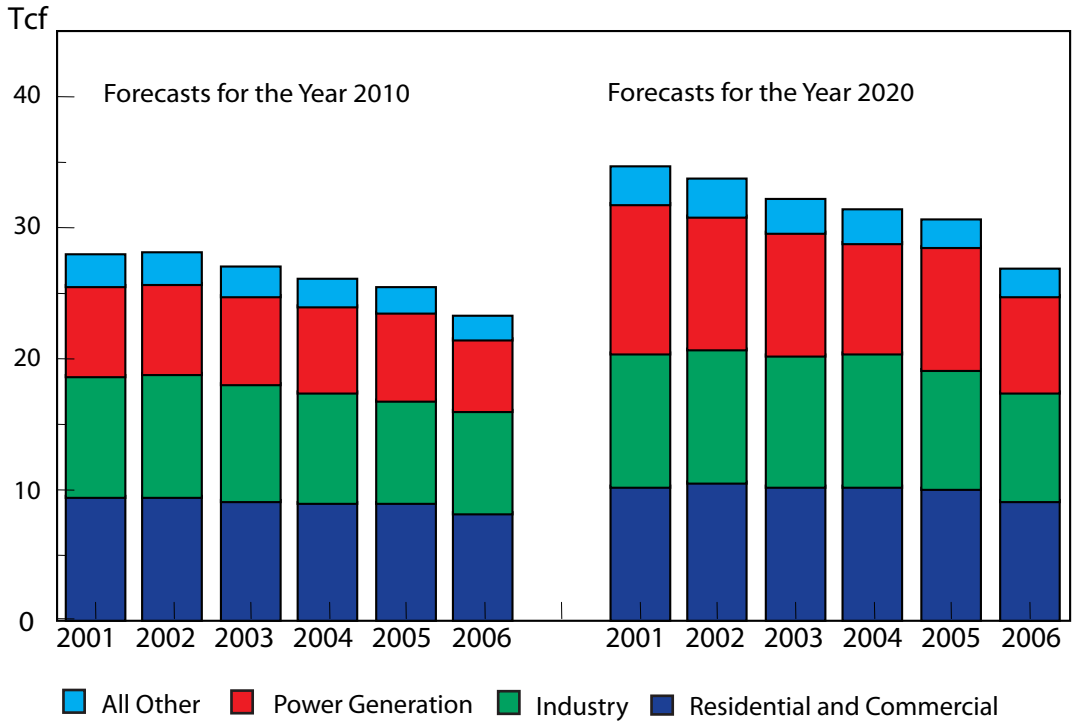
recognised that the wellhead price control system had failed, it took until 1978 before Congressional action created a new market environment for US natural gas.

In the meantime, the world oil shocks had sharply raised international energy price levels. When gas was finally de-regulated, the much higher price levels had a depressing effect on demand, creating a long-term surplus, termed the 'gas bubble', also shown in *Figure 20*.

The market adjustment to de-regulated high natural gas prices was largely completed by 1986 and gas demand began to grow again from a lower level. Between 1986 and 2000, demand rose at a lower rate – 2.1% per year – than that which occurred up until the shortages began.

A 'Gas Price Shock' in the winter of 2000/2001 sharply changed the expectations of the ability of North American supply to support continuing demand growth. Prior to the sharp change in the outlook for supply and demand, most forecasts expected rapid growth in gas demand with particular emphasis on power generation. Since the winter of 2000/2001, most forecasters have raised their price expectations and lowered their future estimates of gas demand. An examination of the annual projections provided by the US Energy Information Administration in its Annual Energy Outlook series illustrates the changing perception of demand growth (*see Figure 21*).

Figure 21: Comparison of US EIA Annual Energy Outlook Projections of US Gas Demand by Year of Projection



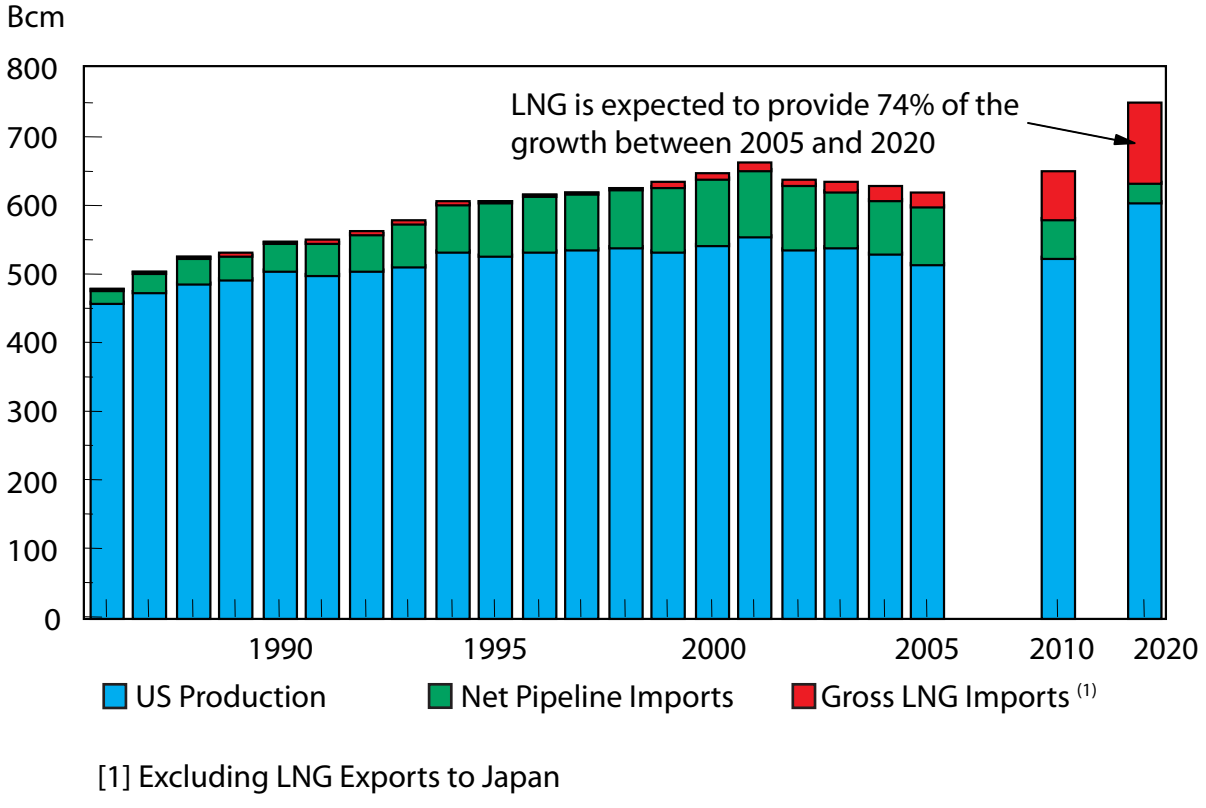
Source: Jim Jensen

4.2.2.4 US Natural Gas Supply

When demand again began to resume its growth rates, limitations on US supply meant that increasing levels of Canadian imports were required to meet demand. Nearly half of the incremental US gas demand between 1986 and 2000 was accounted for by imports, principally by pipeline from Canada.

The pre-shock assumption that the US gas resource base could carry the expected growth in demand was matched by a belief that Canada's growing production could support continued growth in exports to the US. But the realisation that there were supply problems affected not only the US, but Canada as well. Projections of future US gas supply now place greater emphasis on LNG imports to support growth. The US EIA expects imports from Canada to decline, but LNG imports to account for 74% of the incremental supply growth required to support the EIA's 2020 forecast of gas supply (*see Figure 22*).

Figure 22: Supply Available to US Markets since 1986 (plus EIA Projections)



[1] Excluding LNG Exports to Japan

Source: Jim Jensen

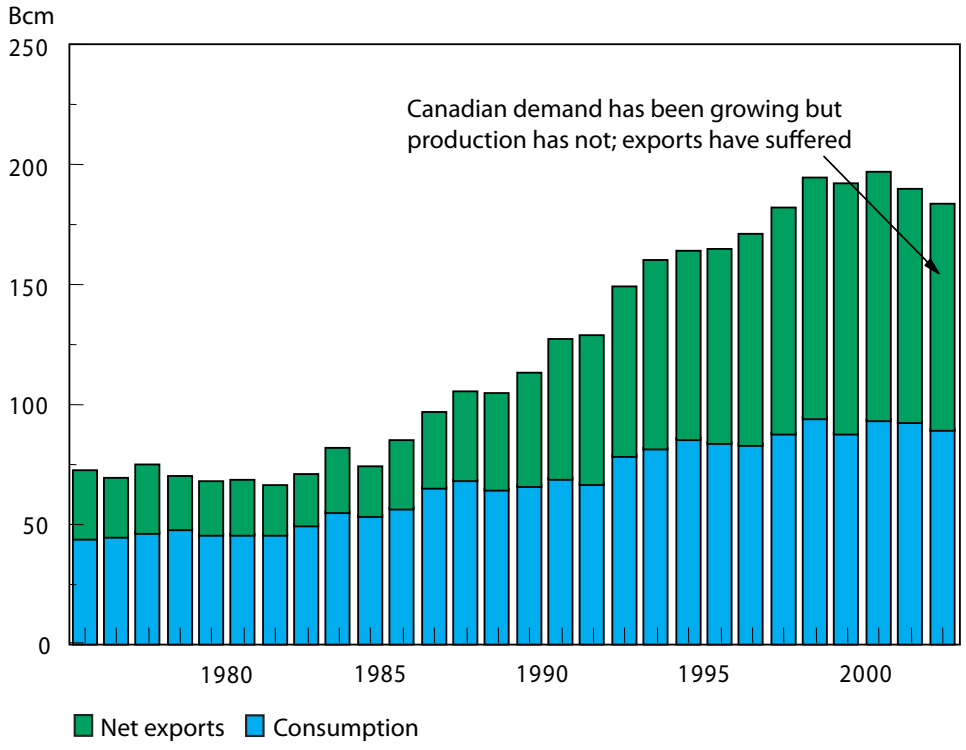
4.2.2.5 Canadian Supply and Demand

Canada has very large hydroelectric resources and never developed the reliance on thermal power (and particularly gas-based thermal power) that had prevailed in the US. Since a significant portion of the US natural gas response to the higher energy prices in the early 1970s was in power generation, Canada – with its limited gas-fired power generation – did not make a similar demand adjustment to the new price levels. There was no 'gas bubble' in Canada.

Nor was there any shortage of supply. Prior to the moves that both Canada and the US made towards market liberalisation in the late 1970s and early 1980s, Canada had in place a gas export policy that attempted to provide for twenty-five years of reserve coverage for domestic markets before it would award export licenses. When this policy was eliminated in 1985, Canadian producers found themselves with extensive infill drilling possibilities to increase gas production without the need for full-cycle exploration. The Canadian RP ratio was 28.3 years in 1985; it had fallen to 8.8 years by the end of 2004.

Canadian exports suffered mildly during the early part of the 'gas bubble' period, but began to grow with the US market from 1986 onward. This growth continued until Canada itself began to experience supply problems in the early 2000s. At the export peak in 2000, Canada exported 18% more gas to the US than it used itself. *Figure 23* illustrates the growth in Canadian consumption and exports since the late 1970s.

Figure 23: Canadian Gas Demand and Net Exports to the US



Source: Jim Jensen

The Canadian National Energy Board has adopted a scenario approach to energy demand projections. According to their estimates, the growth in domestic demand for natural gas exceeds the growth in production for both scenarios under study. This implies a reduction in Canadian exports to the US (of indigenous gas) in all cases.

One major new demand requirement in Canada is for processing applications in its rapidly growing heavy oil production operations in Alberta. These might require the equivalent of as much as 12%-16% of current Canadian gas consumption by the end of the decade.

4.2.3 The Development of US Natural Gas Regulation

4.2.3.1 The Historic Basis of US Gas Regulation

The natural gas industry in the US is made up almost entirely of private-sector companies. The transmission and distribution of gas have traditionally been treated as natural monopolies and are provided by utility companies operating under various state and Federal regulatory jurisdictions. Production, except for a unique twenty-four year period from 1954 to 1978, has always been treated as a competitive industry and has not been subject to utility rate regulation.

The development of natural gas policy in the US has been heavily influenced by the constraints that have been placed on the exercise of Federal Authority by the US Constitution. There are two major constraints. Firstly, although Federal regulatory agencies, such as the current Federal Energy Regulatory Commission (FERC), are a part of the Executive Branch, their powers are created by acts of Congress and their authority is subject to review by the Supreme Court. Secondly, the Commerce Clause of the Constitution reserves jurisdiction over commerce to the states unless that commercial activity crosses state lines and is involved in 'interstate commerce'.

In the case of natural gas, the implications of these restrictions are important. Many matters involving state regulation of oil and gas production and of local gas distribution have traditionally been the preserve of the state governments. It has thus been difficult for the Federal Government to implement a comprehensive gas policy from the wellhead to the burner tip without encroaching on state prerogatives. Unless Congress acts to extend Federal authority over the states under the guise of 'interstate commerce', and ultimately the Supreme Court agrees that the law is constitutional, the government must often work around existing restraints rather than dealing with them directly. There have thus been a number of policies that the Federal Government has wanted to implement, but has often found itself unable to act upon unless it could get Congress to agree.

There have been five major policy turning points in Federal regulation of natural gas in the United States. Two of these were initiated by Congress, one by a Supreme Court interpretation of an earlier law, and two by major policy initiatives undertaken by FERC. They were:

1. The Natural Gas Act of 1938
2. The Supreme Court Phillips Decision – 1954
3. The Natural Gas Policy Act of 1978 (NGPA)

4. FERC Order 380 – 1984

5. FERC Order 436 (and subsequent modifications) – Beginning in 1985

The first of these is the underlying legislation under which the gas industry is regulated. The second, the 1954 Supreme Court decision, ushered in a period when wellhead natural gas prices were controlled by the Federal Government. The third, the NGPA, reversed the policy set in motion by the Supreme Court in 1954 and set the industry on the course of de-regulation. And the final series of FERC Orders now provide the basis for the presently restructured US gas industry.

4.2.3.2 The Natural Gas Act of 1938

The Natural Gas Act of 1938 is the landmark US gas legislation whose provisions still control company behaviour today unless they have been expressly amended by later legislation. The Act established Federal jurisdiction over natural gas companies operating in interstate commerce, and placed the authority to regulate the gas industry in the Federal Power Commission (FPC), later re-organised as the Federal Energy Regulatory Commission (FERC). By requiring that such companies charge 'just and reasonable' rates, the Act effectively subjected the interstate pipelines to the precedents established by the states for utility rate regulation. These, for the most part, are based on historic costs, allowing investors to recover costs plus a reasonable return on investment. This methodology is termed 'cost-of-service' rate regulation. The Act also established that companies obtain a 'Certificate of Public Convenience and Necessity' before expanding facilities or offering services. And it provided the mechanism for authorisation of imports and exports of natural gas. The early effect of the Certificate authority was to give the pipelines merchant monopoly control over the sale of gas in interstate commerce.

4.2.3.3 The Supreme Court's Phillips Decision

In 1954, the US Supreme Court handed down a major decision in the case of Phillips Petroleum Co. versus the State of Wisconsin. Wisconsin had argued that its ability to regulate the rates of local distribution companies could not be effective as long as prices at the wellhead remained unregulated. By agreeing with the argument, the Supreme Court interpreted the Natural Gas Act as requiring 'just and reasonable' rate regulation of producers as well as pipelines. Thus, the Supreme Court effectively placed wellhead price controls on gas moving in interstate – but not in intrastate – commerce. Texas gas sold in Oklahoma was price controlled; Texas gas sold in Texas was not. Since the Court was interpreting existing natural gas law, any subsequent attempt to de-regulate wellhead prices required further Congressional action.

It gradually became apparent that wellhead price controls in their then-existing form were unworkable. By the late 1960s, the system was beginning to develop serious supply problems, and by the early 1970s gas shortages became increasingly severe, leading to supply curtailments of large customers. Gas markets were unable to clear since price-controlled gas was creating excess demand by under-selling higher priced, but unregulated oil and coal. At the same time unregulated intrastate gas buyers in Texas and Louisiana were freely able to outbid regulated interstate pipelines for the limited supply, thereby concentrating the shortages in the interstate market.

The solution to the problems required new legislation from Congress, but the issue was politically charged and Congress was unable to agree on a solution. One group saw the problem as one of too little regulation and advocated the extension of wellhead price controls to the intrastate market. This would have entailed a major Supreme Court test of the Commerce Clause. But a second group viewed price regulation itself as the problem, and advocated complete price de-regulation.

The debate, however, took place as world energy prices went through the upheaval of the first oil price shock, and complete de-regulation would have entailed sharp price increases to gas customers. Congress was not able to resolve the issue until it acted on a number of broader energy policy issues in 1978.

4.2.3.4 The Natural Gas Policy Act of 1978

The Natural Gas Policy Act of 1978 (NGPA) was one of several energy policy laws enacted in that year. It represented Congress's attempt to deal with the breakdown of the wellhead price control system through a 'partial de-regulation' of wellhead prices. The emphasis of the Act was on solving the excess demand problem from the supply side through incentive prices for new supply and on reducing the intrastate purchasing advantage by placing intrastate gas under price regulation. Price de-regulation was to be phased. High cost gas was quickly de-regulated but most of the so-called 'new gas' was not to be de-regulated until January 1985 and old flowing gas was to remain 'forever regulated'.

While a workable market system was the goal of this legislation, it actually imposed more stringent price regulation on many gas categories – albeit in many cases for a limited number of years – and thus was a 'deregulation' bill in name only. Since most gas remained price-regulated through the period when oil prices rose again under the influence of the second price shock, demand response through competition with oil was effectively neutralised.

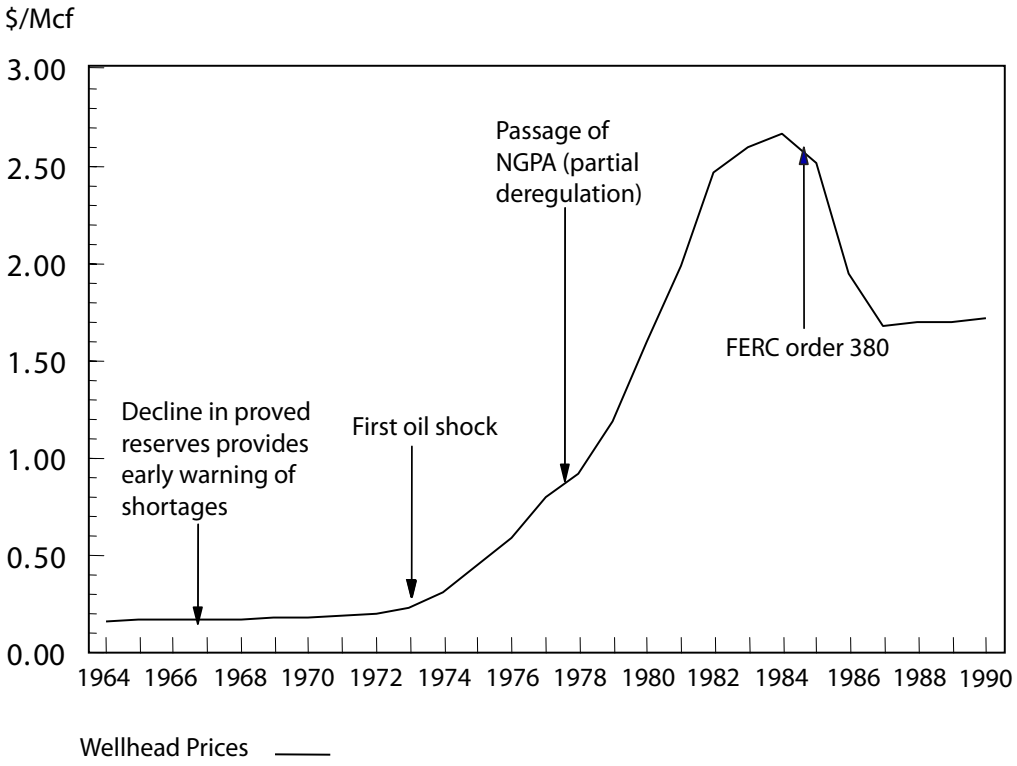
The Act did, however, initiate the ultimate policy goal of market responsive pricing at the wellhead. It also provided for more flexible transportation services on the pipelines, forming the basis for the ultimate transition to third-party access.

4.2.3.5 Industry Response to the NGPA

In retrospect, the behaviour of the pipelines in contracting for new long-term supply during the seven-year NGPA transition period was unwise. They ended up with too high a delivery obligation at too high a price. They quickly found it difficult to sell system supply in competition with oil in the weakening oil markets of the early 1980s.

One of the pipelines' major problems stemmed from the fact that the system encouraged cross-subsidies between price-controlled old supply and the newer contracts for which the pipelines were competing. They thus became very undisciplined in their pursuit of new long-term contracts and average wellhead prices rose rapidly (*see Figure 24*).

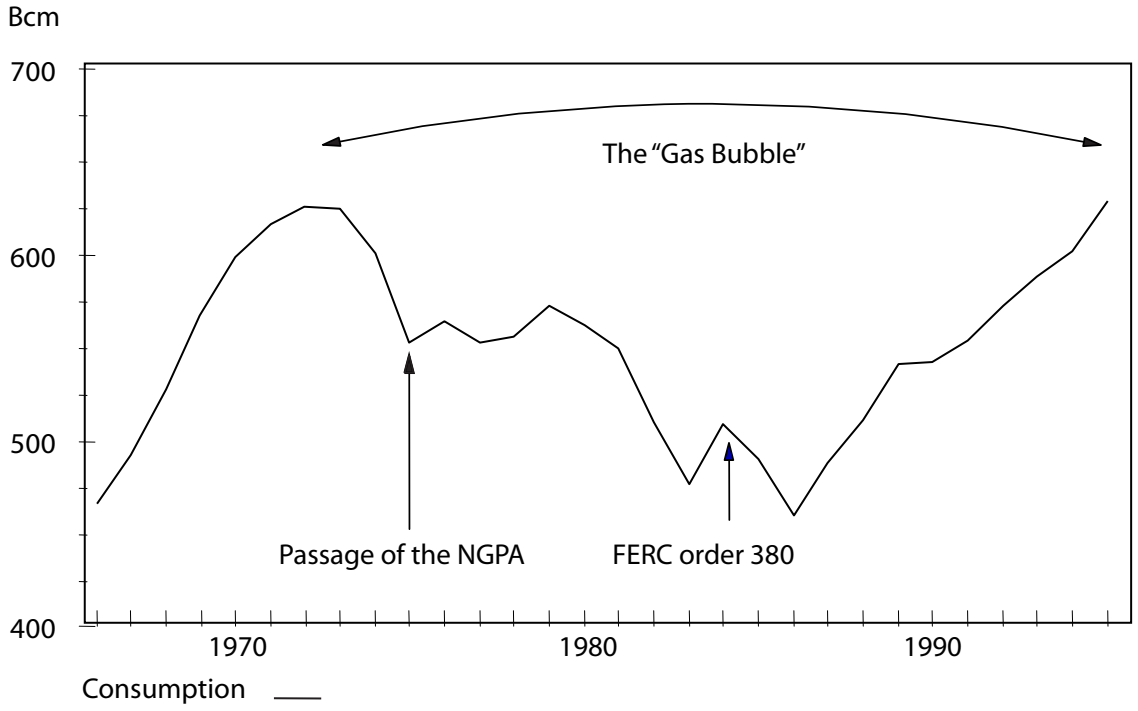
Figure 24: Wellhead Price History through the Period before and after Passage of the Natural Gas Policy Act of 1978



Source: Jim Jensen

In the debate over de-regulation, producers had argued that removing price controls would solve the shortages by increasing supply, and indeed the shortages quickly gave way to a chronic surplus. But the price effect on demand was even greater. US gas demand peaked in 1972 and it did not exceed that peak again until the year 1995, 23 years later. At one point US demand was actually 27% less than it had been in 1972. The result was a substantial – and continuing – surplus that came to be known as the 'gas bubble'. The behaviour of demand and supply during this period is outlined in *Figure 25*.

Figure 25: US Natural Gas Annual Consumption during the 'Gas Bubble' Period



Source: Jim Jensen

Because of the surplus, strong competition developed among producers to sell short-term gas, and spot prices fell substantially, well below most pipelines' costs of system supply (the 'weighted average cost of gas' or WACOG). The NGPA had provided special transportation options for local distribution companies (LDCs) and other pipelines to buy from other than their contracted suppliers. However, in the face of declining overall demand and their long-term contract commitments, many of these buyers could not take advantage of the cheap gas supply. There was low-cost new gas available for purchase and the third-party transportation option to acquire it, but the LDCs and pipelines could take only limited advantage of it.

4.2.3.6 FERC Order 380

In 1984, FERC addressed the issue with its Order 380. The pipeline system consisted of long-term contracts between producers and the merchant pipelines, and these were matched by long-term contracts with utility buyers, such as LDCs and other pipelines. The pipeline re-sale contracts generally had minimum bill provisions that acted in the same way as take-or-pay provisions in the producer contracts.

In Order 380, FERC relieved the utility purchasers from any contractual obligation to the pipelines for minimum bills for system supply they elected not to take. Thus, if the LDCs found their pipeline suppliers WACOGs to be over-priced, they could buy lower-cost spot gas direct from producers and have it moved to them through the transportation flexibility afforded them through the NGPA. As is evident from *Figure 24*, average prices dropped substantially.

4.2.3.7 FERC Order 436

The NGPA had not made transportation flexibility directly available to end users. To further restructure the industry, FERC issued a comprehensive open access policy in Order 436. It required that third-party access be available on a non-discriminatory basis to all comers (thereby putting an end to selective transportation) and specified rate design guidelines under which it would be offered. Although Order 436 was subsequently modified by additional orders, it was the turning point in the development of full third-party access.

4.2.3.8 The Pipeline Take-or-pay Problem

A number of the pipelines had take-or-pay problems before Order 380. The effect of Order 380, however, was to provide contractual relief from revenue guarantees in an unbalanced way. While the LDCs no longer had to honour their guarantees to the pipelines, neither the FERC nor Congress were willing to address the more controversial revenue guarantee issue at the pipeline / producer interface. Hence, Order 380 substantially intensified the pipelines' take-or-pay problems.

Between 1984 and September 1989, the pipelines accumulated nearly $30 billion in take-or-pay obligations. While the FERC encouraged pipelines and producers to work out their contract problems among themselves, the thrust of FERC policy seems to have been to place the pipelines in a vulnerable position where they would be forced to seek relief from the producers by re-negotiating market-responsiveness into their contracts. This is what actually happened, but at a settlement cost to the pipelines of approximately $9 billion.

4.2.4 Canadian Gas Regulation

Canada has regulated its inter-provincial pipelines in much the same way as the US. An Act of Parliament in 1959 established the National Energy Board (NEB) as the regulatory authority. Like the FERC in the US, it regulates rates using cost-of-service methodology and requires Certificates of Public Convenience and Necessity for pipeline investments.

Canadian producers were not originally subjected to wellhead price controls as were US producers following the Supreme Court Phillips decision. Wellhead pricing originally developed on a netback basis from interfuel competition in the marketplace. Thus as competitive fuel prices began to rise, wellhead prices tended to adjust in a way that US prices could not. But the price control distortions of its largest customer south of the border had a distorting influence on Canadian pricing, as well.

In 1974, the NEB decided that "... natural gas being exported to the United States should be priced on the basis of a scarce, non-renewable natural resource..."[32] and established a single border price for exports to the US. In 1975, following the first oil shock, Canada instituted its own price control system on both oil and gas through the Petroleum Administration Act. It assigned the responsibility for administering the agreement on pricing between the Federal and Alberta governments. Thus, Canada, like the US, was operating on a system of gas wellhead price controls from 1975 until it was finally dismantled in 1985.

32. 1974 *Annual Report* of the National Energy Board at 19.

4.2.5 The Evolution of North American Gas Prices

4.2.5.1 Pre-NGPA US Gas Pricing

Until the 1954 Supreme Court decision, US gas prices were unregulated. And until 1954, prices were very low by comparison with competitive fuels. In the early days of US oil exploration, producers had discovered large reserves of natural gas that, in the absence of a national transmission system, lacked market outlet. Prices reflected producer competition for very limited local markets.

The national pipeline system began to take shape in the period immediately preceding World War II. In fact the Natural Gas Policy Act of 1938 was deliberately designed to give pipelines the right of 'eminent domain'[33] at the Federal level to enable them to acquire right-of-way without the often cumbersome and contested eminent domain process at the state level.

While pipeline construction was stalled during the war, it resumed in earnest at the end of the war. The rapid expansion of pipelines began to absorb some of the surplus reserves that had depressed prices. By the time the State of Wisconsin challenged wellhead price regulation in the Phillips case, earlier prices had begun to strengthen (they reached $0.10/MMBtu in 1954 after never having been higher than $0.07/MMBtu before 1952).

The Supreme Court decision, placing wellhead pricing under FPC rate jurisdiction, put that organisation in a very difficult position. Rate regulation of pipelines was based on historic costs associated with investment in individual facilities. But in the oil and gas exploration process, the value of individual investments often bears little relationship to the money invested. A successful discovery may have very low unit costs, but a dry hole has infinite unit costs. In addition, problems of joint costing between unregulated oil and regulated gas posed additional problems.

The FPC took several years to come up with its solution, which it called 'area pricing'. The price limits were set by the average costs experienced over major areas (South Louisiana, the Permian Basin). The flaw in the system was that it violated fundamental laws of economics. For a fungible commodity, prices are expected to clear when the marginal cost of new supply is equal to the marginal price that the buyer is just willing to pay. The effect of the FPC system was to give both sellers and buyers the same price signal based on historic costs. But in a rising cost environment, the marginal cost required to bring forth new supply should be higher than the embedded cost of the historic supply on which buyers are making their purchase decisions. The net result was a system designed to create shortages – which it did.

4.2.5.2 The NGPA and Partial De-regulation of Gas Prices

When Congress finally addressed the failed experiment in controlled wellhead prices, the prices of alternate fuels had risen substantially as a result of the oil shock. Thus, while Congress accepted in principle the concept of ultimate de-regulation of wellhead prices, it found the transition to full de-regulation to be too disruptive to the consumer. It thus adopted an

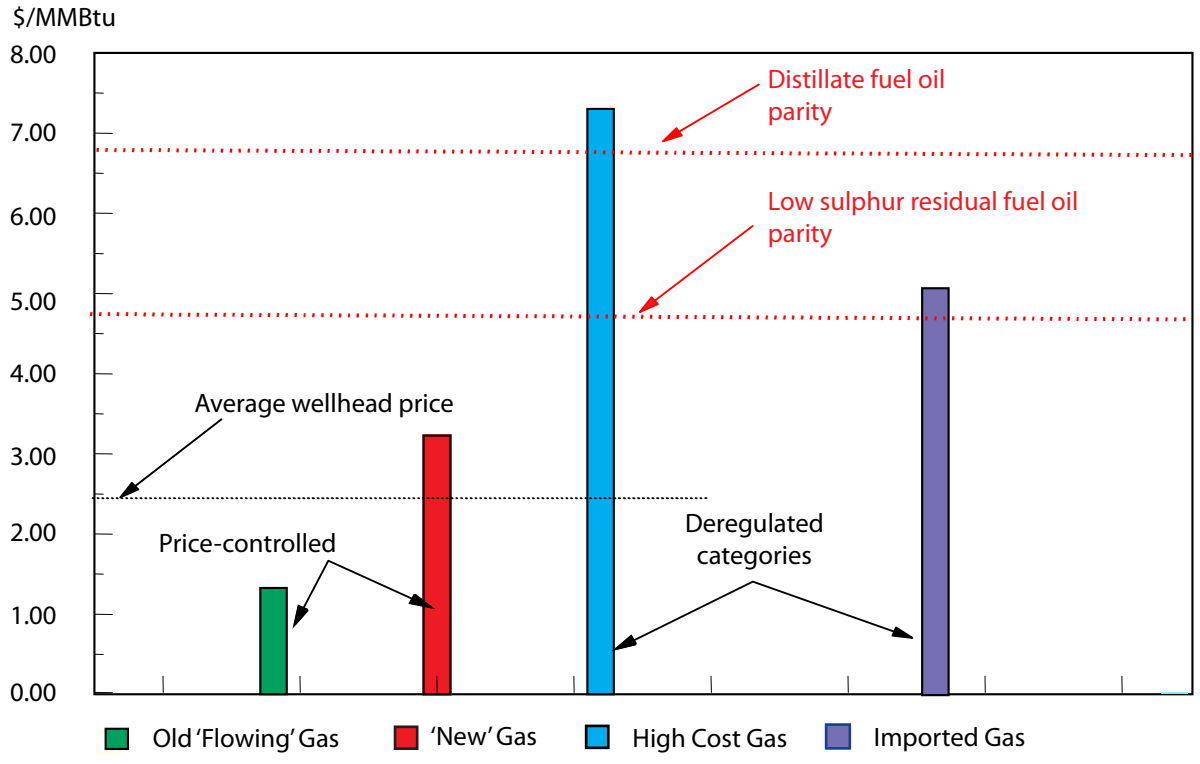
33. The right of 'eminent domain' refers to the right to take private property (with equitable compensation) for the public good.

approach – 'partial de-regulation' – that created a series of categories, each with its own price ceiling. It also extended price controls to the intrastate market.

The composite of the prices of the various categories was designed to cushion the rise increase to customers, but the NGPA addressed the problem of higher marginal prices required for new supply by offering incentive pricing for various categories. While old flowing gas remained 'forever price controlled', 'new' discoveries were to be price-controlled by their discovery vintage. They were to be completely de-regulated in 1985. One category – 'high-cost' gas (such as from very deep wells) was de-regulated immediately. Imported gas was not subject to price controls either.

An unintended consequence of this complex pricing system was to create cross-subsidies between gas that was price-controlled below market clearing levels and de-regulated gas – both high-cost and imported gas. Pipelines that faced shortages showed no price discipline in competing for these de-regulated supplies. During the period, the extent of a pipeline's ability to cross-subsidise de-regulated gas was given the name 'roll-in capacity', denoting how much above market a given pipeline could afford to pay. *Figure 26* illustrates the pricing situation during this period (using prices as of August 1982). At that time both imported gas and high-cost gas were selling above residual fuel oil price parity and high-cost gas was actually priced above distillate fuel oil.

Figure 26: Vintage Gas Pricing under NGPA Partial De-regulation Showing the Effect of Cross-subsidising De-regulated Gas (Prices as of August 1982)



Source: Jim Jensen

4.2.5.3 The Effect of US Regulatory Policies on Canadian Prices

One of the major beneficiaries of the cross-subsidy phenomenon was the Canadian gas producer. Pipelines with shortages had been bidding up the price of Canadian imports – which were not price-controlled – even before the passage of the NGPA. But the NGPA simply locked in the process.

In 1974, the Canadian government, alarmed over the US bidding up of prices for Canadian consumers, established export price controls through a single border price for all exports. Then in 1975, it established price controls for its own domestic oil and gas supplies through the Petroleum Administration Act. Gas prices for Canadian supplies were tied to a netback from price-controlled crude oil in Toronto. But the export price was much higher. Between 1975 and 1980, Canada set the export border price unilaterally.

In 1977, when the Canadian border price was $2.16/MMBtu, Pemex in Mexico negotiated a contract with several US pipelines for Mexican imports at a price of $2.60/MMBtu. The US Administration, alarmed that this contract would set a precedent for a Canadian price increase, disallowed the import contract. Nevertheless, prices continued to strengthen so that by late 1980, when the Canadian domestic price formula provided a wellhead price of $2.60/MMBtu, the single border price for exports to the US had increased to $4.47/MMBtu. In 1980, the US and Canada negotiated the 'Duncan-Lalonde Agreement' that provided a mutually-acceptable set of pricing rules.

To administer this system the Canadian government became the sole purchaser of Canadian gas for export at the prevailing domestic price. It then took the economic rent on export sales and re-distributed it through a system called 'flowback' that was provided pro-rata to each seller according to his production. This system caused distortions of its own as producers in Alberta competed with one another to create new sales that would increase their shares of flowback.

The system of government-dictated export prices began to run into difficulties in the early 1980s as the US gas bubble surplus began to emerge. With less pressure to acquire new supply, US pipelines stopped bidding for new Canadian purchases. From a peak import level of 28.4 Bcm/year in 1979, US imports from Canada had fallen 25% by 1984.

The final blow to the Canadian wellhead pricing system occurred in 1984 when the FERC issued its Order 380. Its provision that utility buyers no longer had to honour their minimum bill provisions applied to US pipelines purchasing Canadian gas, as well as applying to US LDCs buying US supplies. In the face of the bubble surplus and the abolition of the minimum bill provision, the Canadian export pricing system was no longer sustainable.

Negotiations between the Canadian Federal Government and the producing provinces of Alberta, B.C. and Saskatchewan led to the Agreement on Natural Gas Markets and Prices on 31 October 1985 – the so-called 'Halloween Agreement'. This effectively dismantled the earlier price control system, thereby restructuring the Canadian gas industry and providing for competitive market pricing and third-party pipeline access.

As had been the case in the US, the new regulations provided serious take-or-pay problems for the Canadian pipelines. Unlike the US, however, where Congress let producers and pipelines negotiate their way out of the problem, in Canada the NEB stepped in. It made it possible for TransCanada – the biggest victim of the market and policy changes – to finance its take-or-pay

obligations and work them off through an allowable pipeline surcharge. The problem was, therefore, nowhere near as disruptive in Canada as it was in the US or in the UK.

4.2.6 The Current North American Pricing System

4.2.6.1 The Emergence of Henry Hub as the Centrepiece of North American Pricing

The restructuring of the US gas industry by the various FERC Orders has created a highly liquid and transparent market for both gas as a commodity and for the transportation to move it to market. The system has developed around a number of 'hubs' where pipeline interconnections bring gas flows together from different sources and re-distribute it to different market regions. One major pipeline junction in South Louisiana, called Henry Hub, either transports or has interconnections that transport much of the gas to the north and east of the area. Because it is a natural physical gas trading point, it has become the centrepiece of the North American gas pricing system.

The national quotations for physical gas trading utilise Henry Hub as a reference point, much as the oil pipeline junction at Cushing, Oklahoma has become the reference point for the WTI (West Texas Intermediate) oil price quotation system. Not only is Henry Hub the reference point for trading in physicals, but it has become the focus for the Henry Hub futures market trading on the New York Mercantile Exchange (NYMEX).

The Henry Hub futures quotations have the advantage of complete transparency, since they are traded on an exchange. But many other hubs or trading points exist on the system. These are followed by the trade press, although many lack the liquidity and transparency of Henry Hub. The difference between the Henry Hub quotes and those for other hubs are generally called 'basis differentials'. While they tend to reflect pipeline transportation costs that link the flows of gas with the Henry Hub, the basis differentials can change significantly with market conditions.

There are a number of commonly quoted hubs that serve major gas supply areas. These include Katy (for the Texas Upper Gulf Coast), Waha (for the West Texas Permian Basin), the San Juan Basin, Opal (for Wyoming) and AECO-C (for Alberta). The basis differentials for these hubs will reflect the relative supply available in their regions compared to the demand in their normal markets. There has been some tendency of the western hubs to weaken relative to Henry Hub as the gas supplies in the west have outpaced Gulf Coast supplies.

The market hubs are especially important since they tend to be the focus of premium-priced LNG imports. This is particularly true of the East Coast and of California.

4.2.6.2 The Operation of the North American System

In the North American market, both the commodity and transportation capacity are freely traded. Shippers will typically line up capacity for the next transportation month. Although the system is quite flexible, most transactions take place towards the end of the month during 'bid week' when shippers will obtain the supply to ship over that capacity. This makes for a very short-term – and frequently volatile – market.

When investment in new capacity is required, project sponsors will usually hold an 'open season' for potential shippers who are prepared to assume the obligation to cover 'demand charges' that are needed to recover the fixed charges on the investment. Thus the debt service on the investment is protected, not in the form of a take-or-pay contract for combined transportation and commodity, but in the form of a 'ship-or-pay' obligation.

4.2.6.3 Gas Price Formation in North America

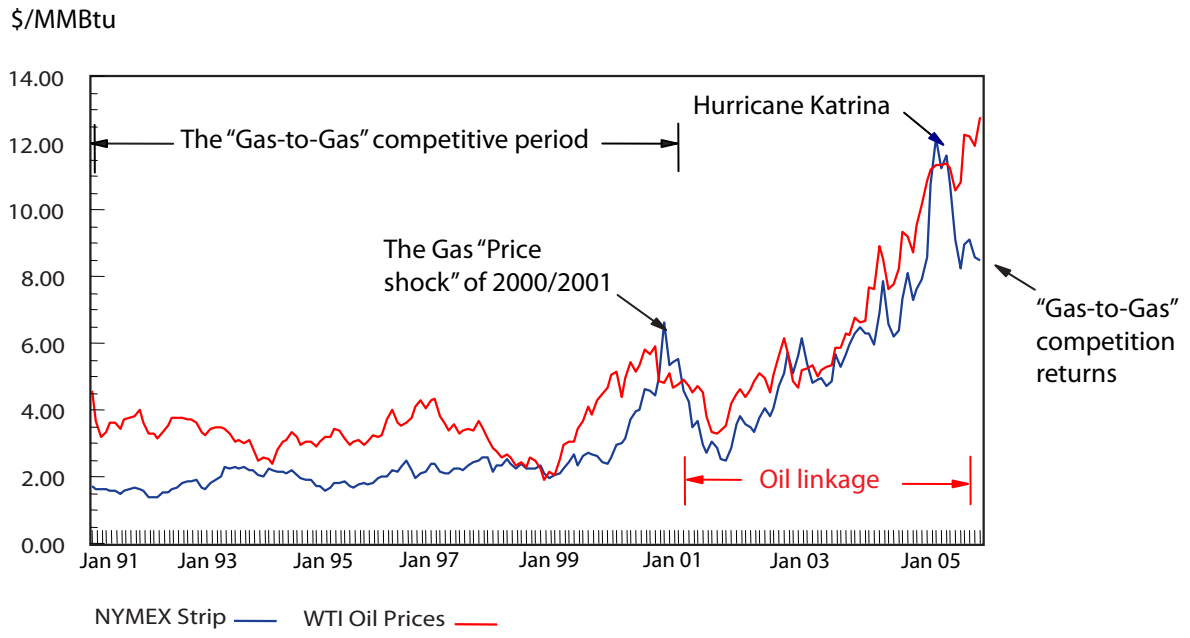
After the restructuring of the North American industry, the common perception was that 'gas-to-gas' competition set prices and oil pricing was no longer relevant. Indeed, during an extended period when gas supplies were in surplus – the 'gas bubble' – that indeed appeared to be true. This placed the restructured North American gas markets in contrast to the contract-dependent markets in Europe and Northeast Asia, where oil-linked pricing was imbedded in long-term contracts.

But the 'gas-shock' of the winter of 2000/2001 eliminated the assumption that oil pricing was no longer relevant in North American pricing. During shortage, buyers quickly bid up gas prices, until dual-fired power generation users found it economical to switch from gas to residual fuel oil. Thus an indirect linkage between gas prices and oil prices was re-established. In fact, for a period in the 2000/2001 winter, the heavy fuel oil switching capability of dual-fired boilers was exhausted and prices quickly moved up in the direction of distillate fuel oil parity.

Figure 27 illustrates the relationship between oil and gas prices since 1991. It compares the monthly average price of WTI (West Texas Intermediate) in $/MMBtu to the average 'strip' price of the Henry Hub futures contract.[34] For the entire period of 1991 to 2000, oil prices were well above gas prices except for those brief periods of substantial oil price weakness. But since that time, the rising oil prices have driven up gas prices through the indirect oil / gas price linkage. Only in the spring of 2006 have gas prices once again broken free of oil. This undoubtedly reflects some demand response to higher prices and the fact that the market has been fully satisfied during this period. This is demonstrated by the fact that underground storage inventories have been at record levels.

34. The NYMEX 'strip' price is the average forward price of the next 12 months of the Henry Hub futures contract. It reflects the price expectations of that month, but dampens the volatility – particularly seasonal – of the spot quotations.

Figure 27: The Pattern of Henry Hub Gas Prices since 1991 (based on the NYMEX 'Strip' Price)

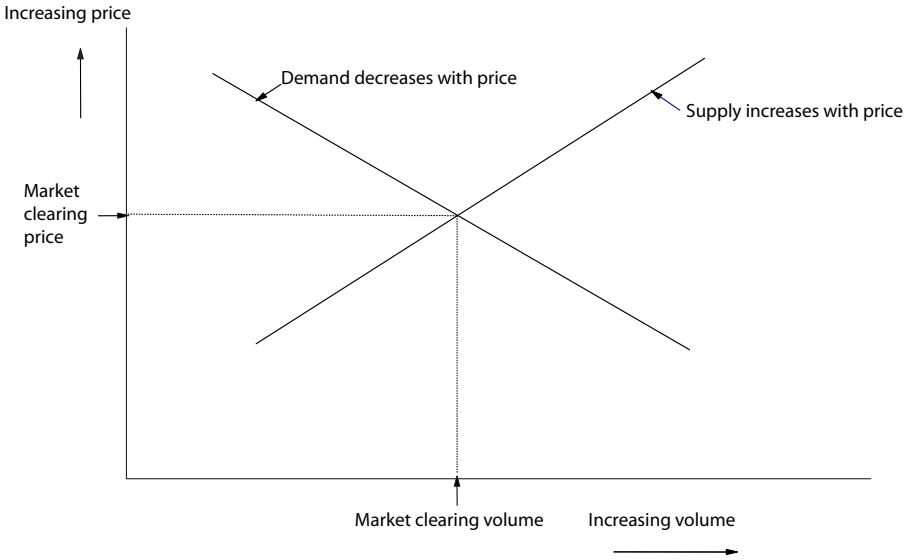


Source: Jim Jensen

There is some question as to how long gas-to-gas competition will remain the pattern. Those who expect it to be temporary expect a hot summer (with substantial air-conditioning demand for electricity) or a return of hurricane damage to production facilities to restore tight markets and their high, oil-linked pricing to gas.

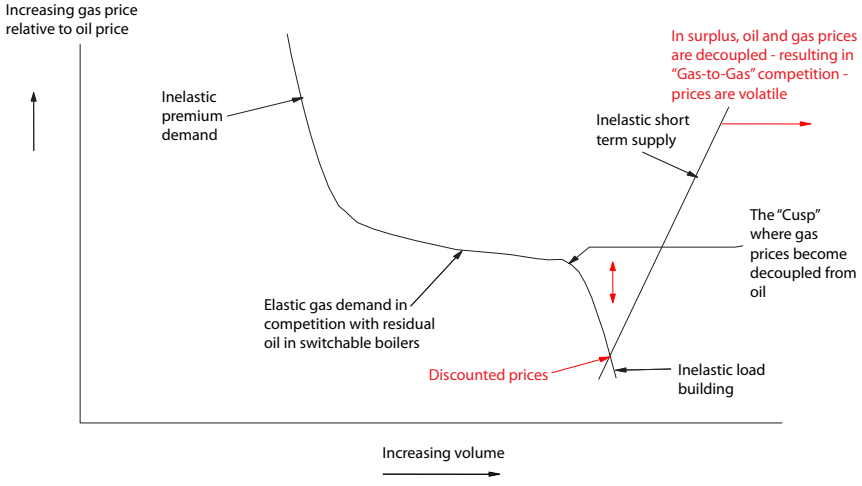
The return of indirect oil-linkage – and its disappearance in spring 2006 – can be explained by fundamental supply / demand economics. In theoretical commodity pricing, supply rises with increasing price levels at the same time as demand falls. At a market-clearing, price demand and supply are in balance (*see Figure 28*).

Figure 28: The Theoretical Behaviour of Supply, Demand and Price; the Textbook Case



Gas markets are much more complex, both because elasticities vary for different portions of the market and because of inter-fuel competition. *Figure 29* illustrates a much more realistic view of North American gas price formation, reflecting both competition with oil and the differing demand elasticities for different parts of the gas market.

Figure 29: A More Realistic Short-term Gas Supply/Demand Curve – a Market in Gas-to-gas Competition

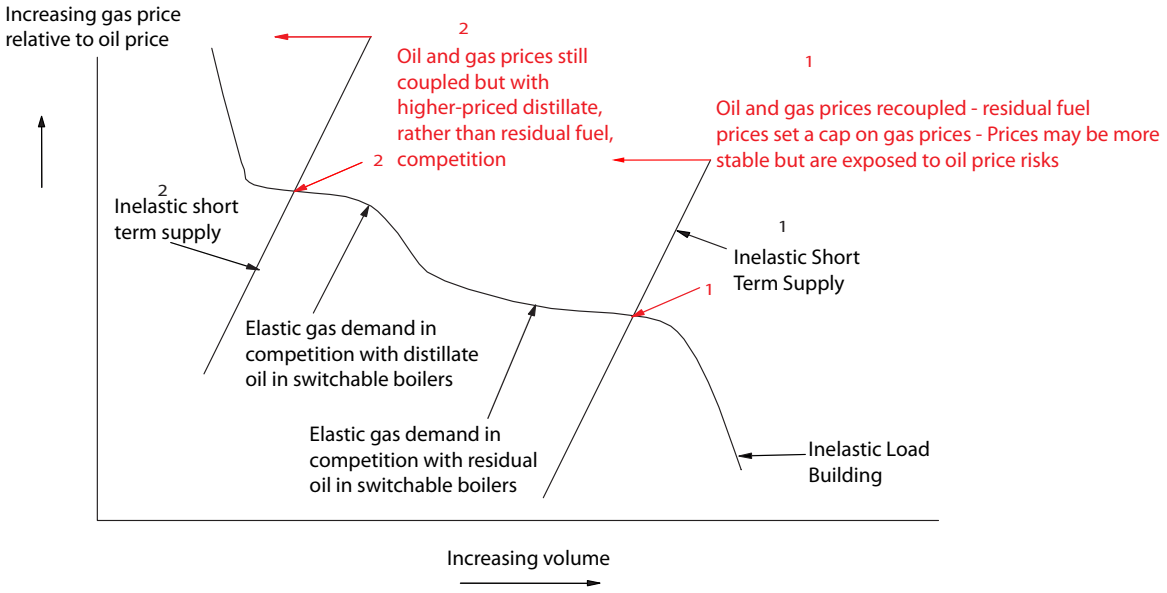


Source: Jim Jensen

Short run supply is comparatively inelastic. In surplus, demand is also inelastic since customers who wish to use gas can get it and the building of additional gas loads through discounting is a relatively slow process. The net result is discounted price behaviour where oil prices do not matter.

But *Figure 30* illustrates what happens to pricing as the market tightens. Competition for short supply quickly bids up prices to a plateau based on heavy-fuel oil price levels (Condition 1 in the Figure). And if the market is tight enough, residual fuel oil switching capacity is exhausted and prices move towards another plateau set by distillate oil prices (Condition 2 in the Figure). This was the market condition that prevailed during the gas price shock period of the winter of 2000/2001.

Figure 30: Another Short-term Gas Supply/Demand Curve – Two Markets with Oil-to-Gas Competition Restored



Source: Jim Jensen

During the extended period of oil linkage from 2001 to early 2006 (except for a brief return to gas-to-gas competition during 2001), prices have tended to float between residual fuel oil parity and distillate fuel oil parity. Tight markets have driven them towards the upper bound, but weak markets have let them fall back towards heavy fuel oil price levels.

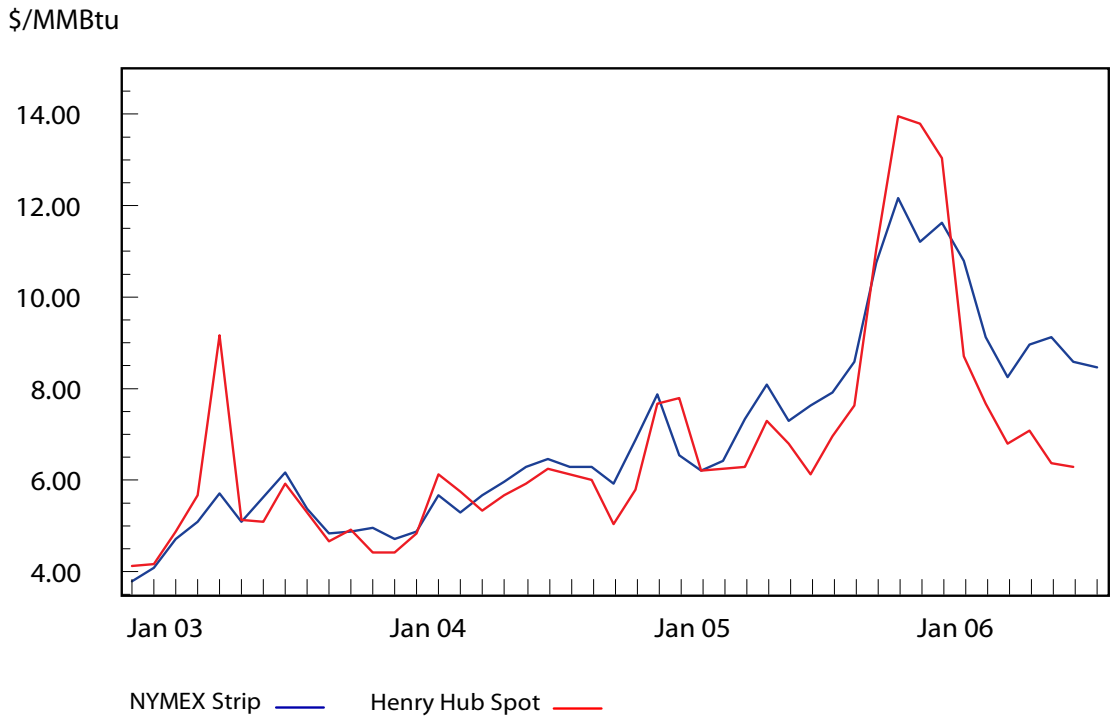
4.2.6.4 Current North American Price Relationships

The physical spot market in North America is highly volatile, but participants in the market make use of derivatives to manage price risk. The New York Mercantile Exchange (NYMEX) offers futures contracts for a seventy-two month period into the future, but the liquidity of the contract deteriorates rapidly for longer-term contract settlement dates. Even longer-term transactions are possible using over-the-counter 'swaps', but again liquidity may be a problem.

Spot natural gas prices and individual month futures prices can be quite volatile and are affected by seasonality. One means of getting a more stable measure of gas prices is to utilise the NYMEX 'strip' pricing series. This averages the next twelve months of futures contracts, effectively eliminating the seasonality of the spot price series. While strips and spot prices roughly follow similar trajectories,

strips eliminate most of the short-term highs and lows. *Figure 31* compares Henry Hub spot prices and NYMEX strips since 2003.

Figure 31: The Relationship between Spot Prices and the NYMEX Strip Price at Henry Hub



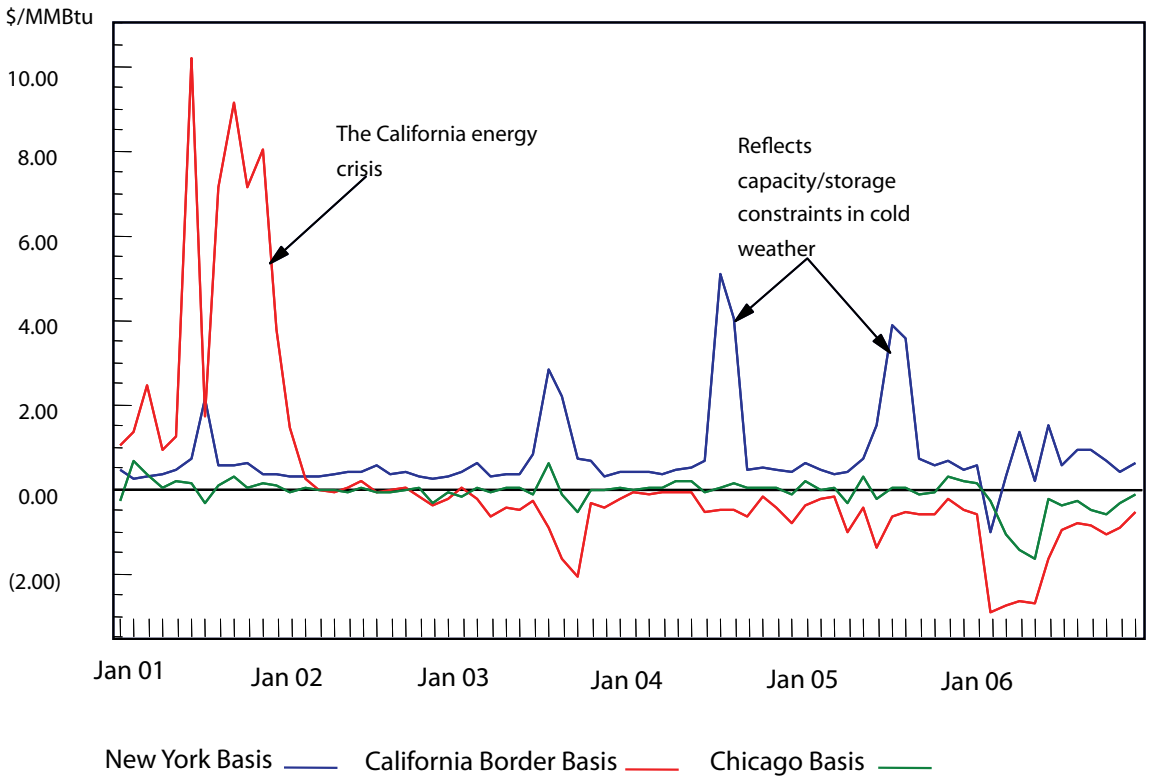
Market basis differentials relate the price at other hubs to the price at Henry Hub. *Figure 32* compares the basis differentials for several market hubs – New York, Chicago and the California border. As is apparent, there is comparatively little variation between the Chicago price and Henry Hub, suggesting a limited price driving force to attract Gulf Coast supply to the upper Midwest.

The gas price shock of 2000/2001 was accompanied by a severe energy crisis in California. *Figure 32* illustrates how high California prices rose relative to prices in other parts of the country. Since that time, however, California border prices have usually been below Henry Hub prices. This suggests that the real physical balancing point[35] lies to the west of Henry Hub.

The fact that Henry Hub is not the neutral pricing point on the system is confirmed by the fact that peaks in New York pricing tend to coincide with sharp negatives in California prices. Cold East Coast weather conditions presumably drive up not only market hub prices, but Louisiana prices, as well. Thus the negative California basis differential is the result of strengthening Henry Hub prices, rather than weakening California prices.

35. A hypothetical 'neutral point' where the costs of moving gas to the East Coast or the West Coast are similar.

Figure 32: Basis Differentials (over Henry Hub) for Selected City Gates



4.2.7 Conclusions

After an extended period of heavy handed regulation, including wellhead price controls for a period, both the US and Canada have completely restructured their gas industries. The liberalisation largely took place during the latter half of the 1980s. Now, gas as a commodity and pipeline capacity rights are freely traded creating a very flexible gas market. Prices tend to be volatile, but financial derivatives such as futures and swaps can be utilised to manage risk.

During an extended period of surplus in US markets – the 'gas bubble' – it was widely assumed that gas-to-gas pricing had taken over markets and oil pricing was irrelevant. But the emergence of shortage conditions during the winter of 2000/2001 had the effect of restoring an oil price linkage by forcing some customers to switch to oil when prices were bid up to oil levels. This oil linkage operated for most of the period from 2001 until the spring of 2006, when gas surpluses again re-appeared and gas-to-gas competition once again prevailed.

The winter of 2000/2001, however, proved to be a watershed. It changed the perceptions in both the US and Canada that North American gas supplies were adequate to support the demand growth rates that market forecasters had come to expect. Most estimates for the period post-2006 assume a much greater reliance on imported LNG, not only for the US, but for Canada and Mexico as well.

4.3 The United Kingdom

4.3.1 Summary

The UK now has one of the most price-competitive gas industries in the world. Its transition from a government gas monopoly in 1986 to the liquid and competitive market today is a product of fortunate conditions and major policy initiatives.

The fortunate conditions were: on the supply side - reliance on domestic gas with an emerging surplus of low-cost gas from the Central North Sea that provided ample supply competition from traditional contracted supply, and, on the demand side – the need to expand the UK power sector in an environmentally friendly way by using gas-fired power plants in a restructured electricity market.

The policy moves included:

- Privatising British Gas, the monopoly company;
- Creating a regulatory body, Ofgas (later Ofgem) to oversee competition;
- Restricting British Gas to 90% of the supply from new fields, thereby creating supplies for competitive sellers;
- Requiring third-party access on the transition system to permit competitive suppliers to gain access to customers;
- Requiring that British Gas free its customers of any obligation to purchase, thereby creating new buyers for competitive producers. This move was accomplished in a series of steps.

The original British Gas has now devolved into three separate corporate activities:

- BG – formerly the parent company, now a major international gas company that is especially active in LNG;
- Centrica – the former marketing arm, now a successful independent gas marketer;
- TransCo – the former transmission company that manages the gas transportation operations and has been acquired by the National Grid, the major UK electricity transmission system.

These moves created substantial financial problems for Centrica, since it was still obligated on take-or-pay contracts for volumes of gas for which it no longer had sufficient customers. These financial problems were resolved by negotiations with the producers. However, the larger part of supplies landed at the beach of the UK under long-term contracts, part of it self-contracting and mainly linked to the newly developed price on the UK National Balancing Point.

The construction of the Interconnector, a pipeline linking Bacton in the UK with Zeebrugge in Belgium, initially served as an instrument for exports of UK gas to the Continent, under long-term contracts, although – compared to the prevailing model for gas imports to Continental Europe – the UK export contracts were for smaller volumes (each in the order of a few Bcm/year at most) and with a shorter term of 10-15 years. The Interconnector also created a basis for price interaction with the Continent by arbitrage, between a system characterised by short-term pricing in the UK and a

Continental system dependent on large import contracts based on the replacement value principle with a firm contractual delivery obligation.

The major transition of the UK – which occurred in 2004 – from a net gas exporter to a net gas importer, has created some uncertainty about the development of liquidity in the UK gas market and about the way in which future prices in the UK will interact with those of the Continent.

4.3.2 Introduction

4.3.2.1 The History of UK Gas Regulation

Between 1948, when the British government nationalised a group of local gas distribution companies, and 1986, when it privatised the British Gas Corporation, gas transmission and distribution operated as a government monopoly with exclusive purchasing rights for gas from the UK. During the 1980s, the Conservative government under Margaret Thatcher embarked on a major programme to divest monopoly corporations by selling them off to the private sector. The Natural Gas Act of 1986, which authorised the sale of British Gas, effectively substituted a private monopoly for a government monopoly. This created a need for government oversight in the public interest.

During the period of government ownership, British Gas oversaw the major transition of the British gas industry from one of isolated local manufactured gas systems to the third-largest natural gas transmission and distribution system in the world. At the time of the first discovery of natural gas in the North Sea in 1965, the UK had the world's largest production of manufactured gas, which accounted for 6% of total final energy consumption in the UK.

Although the Natural Gas Act of 1986 provided for regulatory oversight in the form of the Office of Gas Supply (Ofgas), the agency's policies were slow to develop. During this transition period, British Gas – as an ineffectively regulated private monopoly – was one of the most profitable gas companies in the world.

In order to prevent British Gas from earning monopoly rents from its low-cost contracted supply, the UK government in 1981 had established a North Sea gas levy. Since the terms of the original contracts remained in force, this effectively precluded the producers from sharing in the rents from rising prices, while sharing the rents between British Gas and the government. The gas levy remained in force until it was abolished in 1998.

One of the policy goals of the Natural Gas Act of 1986 was to introduce market competition to the gas industry. Since British Gas was a monopoly seller to all UK customers as well as a monopsony buyer for all North Sea gas, the Act included two provisions that were designed to open up the market to competition. Firstly, it required that all of British Gas' transmission pipelines provide third-party access for all sellers of gas. Secondly, in order to provide new North Sea suppliers with an outlet for their gas, it allowed large users (over 25,000 therms or approximately 70,000 cubic metres) to seek alternate sources of supply. These were largely industrial customers. In 1989 Ofgas limited British Gas's purchase of supply from new fields to 90%. This forced producers to sell the remaining 10% outside the British Gas system.

The market share carved out by independent producers as a result of the provisions of the Natural Gas Act sharply reduced British Gas' market share in the UK wholesale gas market. Since British Gas held all the contracts for production in the UK North Sea on long-term take-or-pay contracts, the company was faced with significant take-or-pay obligations (partly for high priced gas without a re-negotiation clause) for the gas that it no longer supplied to the industrial sector.

In line with government policy, British Gas undertook a major corporate re-organisation in 1987. It 'de-merged' its marketing, services and retail operations, creating a separate corporation which it named Centrica. To provide some cash flow to cope with the new company's financial obligations, it included two offshore production licenses – North and South Morecambe. All other production properties as well as gas transmission and storage operations were retained in the parent company, which was then re-named 'BG'.

In 1989, the UK began to privatise its power sector through the passage of the Electricity Act of 1989. The act created a similar regulatory agency for electricity named the Office of Electricity Regulation (Offer). In 1999, both the gas and electricity regulatory authorities were combined into Ofgem.

The effort to open up the gas market to competition continued. In 1992, medium-sized, principally commercial users (more than 2,500 therms) were allowed to purchase from independent suppliers. In 1995, competition for residential customers was tested in selected market regions. This was followed by the complete abolition of Centrica's marketing monopoly in 1998.

Initially, the transmission pipeline system with its requirement for third-party access was managed by a BG subsidiary named TransCo. But efficient operation of the system posed significant problems. In 1996, Ofgas set up the Network Code, which codified the rules for nominations, daily balancing, pipeline capacity allocation, trading and information systems. This comprehensive set of rules is the basis for the third-party access system and for trading. It was further modified in 1999 to include a computer-screen-based trading system.

After the de-merger of Centrica, BG embarked on a major campaign to invest overseas, and now has become a substantial player in international gas projects, particularly in LNG. Nonetheless, for a time it still retained some regulated activities in the UK, namely the transmission system and underground storage fields. In 1998, it was required to open up its storage fields to third-party use, and in 2000, BG effectively got out of regulated lines of business when it de-merged the regulated pipeline system, TransCo, forming a new company, Lattice. Lattice itself was acquired in 2002 by the National Grid, which owns and maintains the high voltage transmission system throughout England and Wales.

4.3.2.2 The UK Tax Regime

In the UK, petroleum companies operate as private-sector entities subject to the UK tax regime. This complex system attempted to maximise rent capture in favour of the government and it has gone through a number of revisions over the last three decades. "A special royalty and tax system applied to petroleum exploitation since 1975, encompassing royalty, Petroleum Revenue Tax (PRT), and Corporate Tax (CT). Since, the system has been changed many times, generally increasing the tax burden, when oil prices have risen." "…since 1983 the burden for new developments has been

reduced. In its current [i.e., in 2002] shape, there are two different systems for new and for old fields. For fields approved before end-March 1982, the following tax elements apply:

- The royalty, paid at a rate of 12.5% of the value of production.
- The Petroleum Revenue Tax, paid at a rate of 50%.
- The corporation Tax, currently at a rate of 30%.

For fields developed in the period April 1982 to 16 March 1993, the royalty is not paid. For new fields developed since March 1993, neither royalty nor PRT are paid. The effective tax for new fields is, therefore, 30%." "As a part of the 2002 budget, the government introduced a 10% charge on profits from North Sea operations, counterbalanced by a first year capital allowance for capital expenditure, rather than the 25% allowance available previously."[36]

4.3.2.3 The Natural Gas Transmission System

The transmission system that is now managed by the National Grid distributes natural gas throughout the UK. It has five terminals where offshore pipelines connect to the grid – Bacton, Theddlethorp, Easington, Teesside and St. Fergus. It is also connected to two underground storage fields (depleted fields) plus several salt cavity storages and peak shaving installations.

There are several UK gas fields that straddle the median line with other countries. In some cases the combined production is separated and each country's gas is landed in its own market, like for Statfjord. But in some cases, the production is sent entirely to one of the owners. One of these, Frigg, is largely in Norwegian waters but has been landed in the UK. It was the basis for UK pipeline imports until the late 1990s. Another field, Markham, is shared with the Netherlands and is landed in that country.

Onshore, the third-party access system now works on the basis of an entrance charge and an exit charge for each of the receipt and delivery points on the grid plus a fee independent of location. However, unlike the US where the principal point for gas trading created by interested industry is Henry Hub, a pipeline junction point where trading of physicals actually takes place, all UK trading is done at a hypothetical point created by regulatory / legal action, termed the 'National Balancing Point' (NBP). (Once the gas has passed the entry point it is considered to be on the NBP where it can be traded and taken out at any exit point.) The NBP provides a liquid and transparent basis for gas pricing. There is also an active futures market for gas at the NBP sponsored by the International Petroleum Exchange (IPE). Contract trading is done in contracts of 1,000 Therms.

In 1998, the Interconnector, a pipeline that connects Bacton with Zeebrugge in Belgium, finished construction to connect the UK gas market with the Continent. The Interconnector is owned by a series of companies who may also hold capacity rights, although some shippers can acquire

36. All citations from: OECD / IEA, Energy Policies of IEA Countries: United Kingdom 2002 Review (IEA, 2002); for more information, *see* the website of the UK Department of Trade and Industry: <http://www.og.dti.gov.uk>.

capacity even if they do not have an equity position in the pipeline. At the end of 2006 the shareholders were:

BG	25.00%
ConocoPhillips	10.00%
Distrigaz	16.41%
ENI	5.00%
E.ON Ruhrgas	23.59%
Gazprom	10.00%
Total	10.00%

When the Interconnector was first inaugurated, the expectation was that it would serve as a method of exporting UK North Sea gas surpluses to the Continent. Thus the forward flow compressor capacity was designed for 20 Bcm/year towards the Continent, but backflow capacity was only 8.5 Bcm/year (as no compression was installed at Zeebrugge).

At first the Interconnector served as a supply instrument for exports from the UK to the Continent. Such export contracts were very much in line with other classical long-term supply contracts to the Continent (minimum-pay and replacement pricing mainly against fuel oil), except that their volumes were smaller (one to several Bcm/year), their duration was shorter – about 10 years, they contained clauses allowing the seller or the buyer to do arbitrage between Zeebrugge and Bacton (claw back clauses), and included some elements in the price review clause allowing for gas-to-gas competition. But almost immediately upon start-up, the seasonally peaking winter demand in the UK caused reverse flow shipments. Since that time the pattern has been similar – forward flow for much of the year but backflow during the UK's seasonal winter peaks. Thus, in effect, the UK is using storage on the Continent to manage its seasonality via scarcity pricing.

The net flows from the UK to the Continent have been steadily decreasing as North Sea production stopped growing and then started to decline, and as UK demand continued to increase, albeit slowly. In the autumn of 2005, backflow compressor capacity was increased to a level of 16.5 Bcm/year on the assumption that future flows would be net into rather than out of the UK. The backflow capacity of the Interconnector was further increased to 23.5 Bcm/year by the end of 2006 and is expected to increase by 2 Bcm/year more by October 2007.

The Interconnector provides a means for arbitrage between the liquid UK market based on scarcity pricing and the contract-dependent markets on the Continent, but only for volumes which are not contractually bound, short or medium term. Since this physical interaction is so new, it has yet to establish a clear pricing pattern between the UK and the Continent. In fact, the large players will be able to trade in winter some of their surplus volumes subject to their delivery commitment for the rest of the winter. To do so, they will have to take into account the off-take limits on their contracts (including a certain risk of under delivery by their suppliers) together with the gas in their own storage.

The Continental system of load balancing is a managed system, in which the operator must take into account his supplies based on predefined contractual obligations and his access to storage volumes. The UK system is designed more as a market-driven system, in which high prices are expected to

call forth additional short-term supply. If one assumes that Continental gas companies now manage their seasonal loads focused on their contractual commitments towards their own customers, there may not be enough extra capacity to serve the extra needs of the peak UK market despite high UK price signals. However, in the short-run the problem of extra capacity should not arise. For instance, during the abnormally warm winter of 2006/2007 an over-supply of the UK market and decrease in UK prices were also a consequence of increased capacity of Interconnector as well as the launch of the new Langeled and BBL pipelines (*see Section 4.3.3.3*).

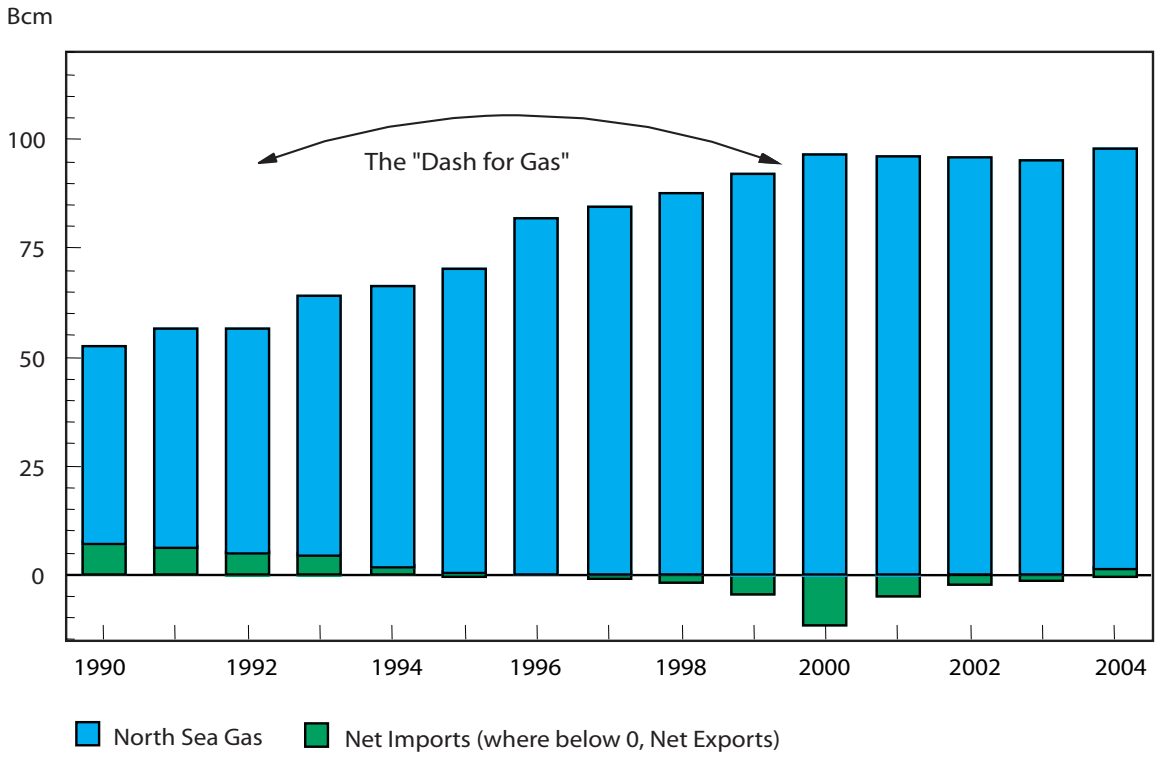
4.3.3 UK Supply and Demand

4.3.3.1 Gas Demand

The privatisation of British Gas in 1986 and the opening up of the large industrial and power generation market to third-party access was designed to create a competitive market in which gas-to-gas competition, rather than monopsony purchasing, set gas prices. Initially, producers began to compete for large users, and Centrica (British Gas's marketing spin off) lost market share. However, the net effect on overall gas demand growth was limited.

The largest change in gas consumption patterns began in 1991, when Enron negotiated a large combined-heat-and-power plant with Imperial Chemical Industries at its Teesside chemical facility. This move followed shortly after the liberalisation of the electric power industry in 1989. The Electricity Act of 1989 broke the monopoly of the Electricity board, freed the electric power generators from the necessity to purchase high-cost British Coal, created TPA to the Grid by the so-called Electricity Pool system, and thus allowed everybody to feed in electricity. Also, British Gas (and the EU) had a policy of not using gas for power generation, so there was a huge latent demand. The availability of gas set off a wave of new CCGT plants competing with and replacing old coal-fired generation capacity (coal-fired power plants had little environmental protection except dust filters). This trend – known as the 'dash for gas' – caused a sharp drop in UK coal consumption and spurred growth in gas demand (*see Figure 33*). Between 1991 and 1999, British gas demand increased significantly at the expense of coal. During this period, coal consumption declined by 55%. The opening of the power sector created a price responsive demand in the power sector which enabled suppliers to market gas in summer if the gas price was competitive with coal-fired power.

Figure 33: UK Consumption of North Sea Gas and Net Imports



Source: Jim Jensen

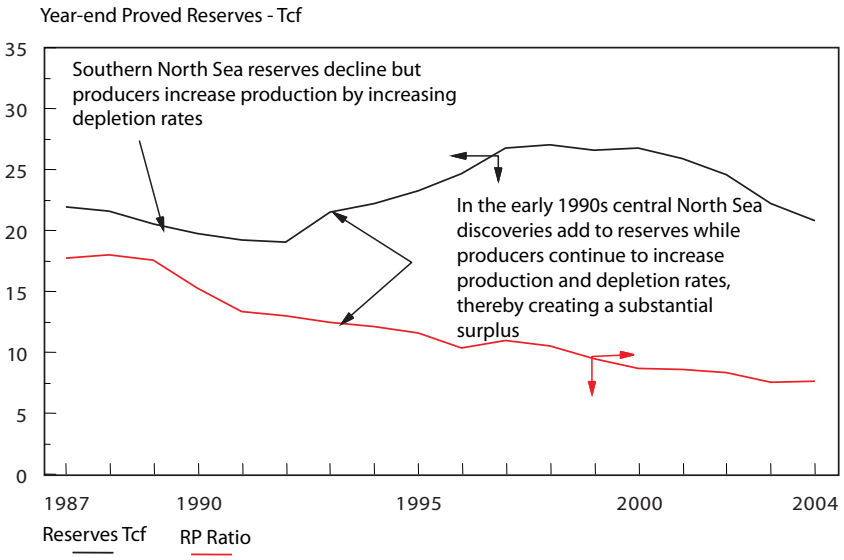
4.3.3.2 Gas Supply and Trade

At the time third-party access first began, the UK had been relying on its early discoveries of dry gas in the Southern North Sea. These reserves were being depleted and overall gas reserves were actually declining. Freed from the constraints of British Gas's contractual requirements, and offered a market outlet even in summer, producers increased their production by increasing the depletion rates on their existing reserves and developing satellite fields. It also helped that the rent-taking regime was changed for new developments by first abolishing the Petroleum Revenue tax as of March 1993.

However, major discoveries were being made and developed in the Central North Sea, which reversed the pattern of declining overall proved reserves. Most of the gas from the central part of the UKCS was from associated and gas condensate fields where liquids carried a large share of the costs of the gas production.

Thus at the time the 'dash for gas' got under way, not only did producers continue to increase their depletion rates, but there were major new gas discoveries with a strong incentive to dispose of the gas to support increased consumption by the power sector. *Figure 34* illustrates the history of proved reserves and the reserves-to-production ratio during the period.

Figure 34: A Comparison of UK North Sea Gas Reserves with Reserves-to-Production Ratio



Source: Jim Jensen

The increased production not only fuelled the accelerated growth of UK gas demand, but it also enabled the UK to become a significant exporter to the Continent in 1998 when the Interconnector was completed. However, both UK gas reserves and production peaked in 2000 and the growth in exports ceased. *Figure 35* illustrates the trend in gas production.

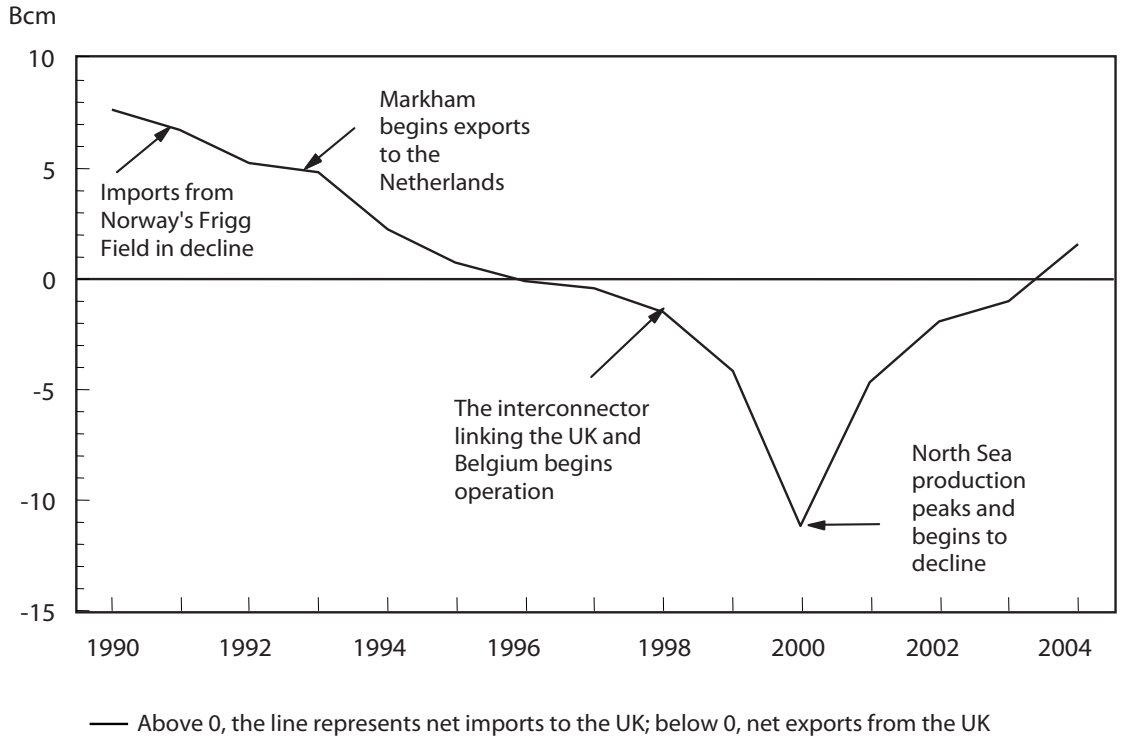
Figure 35: UK Gas Production



Source: Jim Jensen

Figure 36 documents the patterns of net gas imports over the same period.

Figure 36: UK Net Gas Trade



Source: Jim Jensen

4.3.3.3 Future UK Gas Supply

The reversal of the UK to a net importer after a period as a net exporter created a new market environment for both the UK and for Europe. It appears that UK gas demand is continuing to rise as production in the North Sea is beginning to decline. This combination of market forces will clearly make the UK a major importer in the future. But how much the import levels will increase is very controversial, since it depends so heavily on the difference between an uncertain demand forecast (based on gas for power generation, to some extent subject to the renewable energy policy of the UK and to a potential revival of nuclear power) and an uncertain supply forecast.

A number of suppliers are moving to take advantage of this growing import market. The expansion of Interconnector backflow capacity which will be used for arbitrage (and so far not for firm contracts) has already been mentioned. But other new or revived pipelines have been proposed to supply the UK.

The 10 Bcm/year Vesterled line was created by tying the Heimdal field into the pipeline which was originally built to supply gas from Norway's part of the Frigg field to St. Fergus in Scotland. However, Frigg ceased production in 2004 so Norway will use the Vesterled line to feed it at Heimdal from the Norwegian offshore system to add import capacity into the UK. A second Norwegian project

involves the construction of the Langeled Pipeline to provide gas from the Ormen Lange field in the Norwegian Sea to Easington in the UK. This line will have a delivery capacity of 20 Bcm/year. Its first section from Sleipner to the UK became operational in October 2006.

Another major line is the 16 Bcm/year Balgzand to Bacton Pipeline that links the Netherlands with the UK. It is owned by Gasunie, Fluxys and E ON Ruhrgas but is negotiating with Gazprom, as well, for possible Russian future supply. This line started operation in December 2006. Currently 8 Bcm of gas sold by Gasunie to Centrica is transported through BBL. Starting from October 2007, other partners of the project will start supplies to the UK via the BBL pipeline. It has been designed for forward flow from the Continent to the UK so it will initially have an arbitrage role between the two markets only by (virtual) counter flow. BBL is to be largely exempted from TPA under Article 22 of the 2nd EU Gas Directive for the forward flow to the UK.

In 2002, Centrica signed two new long-term contracts with Statoil and Gasunie. The contract with Statoil has a volume of 5 Bcm/year delivered via the Vesterled pipeline. It started in 2005 with a duration of 15 years. The contract with Gasunie is for a volume of 8 Bcm/year and a duration of 10 years. These contracts demonstrate a new approach to long-term contracts, since under both contracts gas is to be supplied from unspecified sources and delivered at the UK National Balancing Point (NBP). Gas will be priced relative to UK gas prices on the NBP, probably using the IPE front month quotation, i.e., the price at which gas is traded for delivery in the UK in the month immediately ahead. According to the trade journal Gas Matters, the core of the contracts could be a pre-determined pattern of daily nominations, rather than the more traditional set of flexible, but linked, daily and annual obligations. This would mean that the contracts include no annual flexibility as is so far typically the case, but rather fixed annual volumes with a firm daily obligation to balance on each side. The Gasunie contract also includes a provision for summer / winter swing, with a summer rate of 0.75 of the annual average and a winter rate of 1.25.

These two contracts came in addition to a smaller contract signed by BP with Statoil in June 2001. Under this contract Statoil commits to supplies of 1.6 Bcm/year to BP over fifteen years, starting on 1 October 2001, also for delivery at NBP. The gas will mainly be supplied via the Vesterled pipeline.

In October 2003, an additional contract was signed with Norway, this time using existing UK offshore infrastructure. Shell UK and Esso Exploration and Production UK (ExxonMobil) signed a deal with Statoil, Norske Shell and Esso Exploration and Production Norge for the exportation of Norwegian wet gas to the UK. The wet gas will be transported from the Statfjord reservoir through the FLAGs pipeline. It is scheduled to start in 2007 and will deliver 4 Bcm/year of gas for 10 years. The gas will land at St Fergus terminal and will then be processed to extract natural gas liquids.

The UK started up its first modern LNG import in late 2005 at the Isle of Grain. Its initial capacity was 4.5 Bcm/year. The National Grid owns the terminal, but BP and Sonatrach control the initial capacity. Two other LNG terminals have been approved for Milford Haven in Wales. The South Hook project of Qatar Petroleum and ExxonMobil would be the world's largest terminal with a capacity of 21.5 Bcm/year. BG, Petronas and Petroplus own the 9 Bcm/year Dragon Project.

There have been several other LNG terminal proposals that are not as far advanced. The Isle of Grain facility has proposed a 9 Bcm/year expansion. In addition, ConocoPhillips has proposed a new LNG terminal at Teesside, and Calor Gas has proposed reviving the original UK terminal at Canvey Island.

There are also two projects involving innovative technologies. Excelerate Energy, the company that acquired El Paso's 'Energy Bridge' technology, has built a terminal at Teesside. This, like Excelerate's first operating terminal – Gulf Gateway in the US – will re-gasify LNG on its specialised tankers and deliver the gas onshore. It became operational in January 2007 but no cargo was unloaded in January probably due to low UK gas prices in January 2007. In December 2006, Excelerate has instead signed an agreement with RWE Trading which would take all available supply that is landed at Teesside.[37]

The second innovative technology, which has never been commercially demonstrated, would be installed offshore in a salt dome cavern by Star Energy. The terminal would utilise the Bishop process (licensed by Conversion Gas Imports) to inject LNG directly into a salt cavern.

4.3.3.4 The LNG Terminal Third-party Access Issue

One of the significant controversies in the regulation of LNG terminals is whether to apply third-party access regulations to terminals in the same way that they are applied to pipelines. In North America and Europe, wellhead prices are not regulated, but pipelines – viewed as natural monopolies or essential facilities – are required to provide third-party access. LNG suppliers have contended that their incentives to invest in these costly facilities would be adversely affected if they were required to open them to other suppliers. Those who view terminals as natural monopolies have contended that they should be treated in the same way as pipelines and should be open to third-party access.

The EU's 2nd Gas Directive of 2003 has taken the latter view and prescribes third-party access to LNG terminal as a rule (in Article 18).[38] However, exemptions may be granted according to Article 22 for new infrastructure, including new LNG terminals. The US Federal Energy Regulatory Commission (FERC), in its 'Hackberry' Decision, took the view that terminals are a part of production and thus did not require open access.

Several new LNG projects have been granted exemptions from TPA on a case-by-case basis by Ofgem under Article 22 of the 2nd Gas Directive. In practice, the regulatory authorities have, therefore, appeared to adopt a position close to that of the FERC, albeit on a case-by-case basis. UK regulators have also been prepared to utilise 'use it or lose it' authority if the terminal operator appeared to be attempting to monopolise terminal operations. The 'use it or lose it' issue was raised again – but not invoked – in the winter of 2005/2006 when BP failed to utilise some of its capacity at the new Isle of Grain terminal.

37. Interview with S. Judisch, Managing Director of RWE Trading, 14 December 2006, published on the website of RWE Trading, at <http://www.rwe.com/generator.aspx/presse/language=en/id=76864?pmid=4001469> (visited 12 February 2007).
38. Directive 2003/55/EC of the European Parliament and of the Council of 26 June 2003 concerning common rules for the internal market in natural gas and repealing Directive 98/30/EC, Official Journal of the European Union L 176/57 15.7.2003.

4.3.4 Natural Gas Pricing

4.3.4.1 Pricing before Industry Restructuring

During the long period during which British Gas was the monopsony buyer in the UK part of the North Sea, prices were set by negotiation with the producers. The only export of UK gas to the Continent was from the Markham field shared with the Netherlands, even though there was strong interest by Continental buyers to buy gas from Judy and Joanne, operated by Phillips via the Ekofisk centre. Since British Gas was itself a producer, it had direct knowledge of North Sea costs in its negotiating stance and because of the monopsony position of BG, sellers of gas had to queue up at BG. There was competition with buyers from the Continent for some Norwegian fields (Ekofisk went to the Continent, Frigg to the UK, Statpipe to the Continent, Sleipner originally to the UK, however, approval of the deal was withheld by the British government, so it finally went to the Continent under the Troll agreements.) British Gas always had the final say on wellhead prices from the UKCS. All of this changed with the passage of the Natural Gas Act of 1986.

The regulations that created third-party access for large users created take-or-pay problems for Centrica, British Gas's marketing spin off. By the early 1990s, Centrica's situation had begun to deteriorate significantly. On the demand side, medium-sized users were also allowed to buy from third parties starting in 1992. But the larger problem occurred on the supply side where producing capacity increased much faster than demand. There were three contributing factors.

Firstly, the major discoveries in the Central North Sea reversed the decline in total UK proved reserves. Secondly, depletion rates continued to increase, accelerating the increase in North Sea production. Between 1986, when British Gas was privatised, and 1992, production increased by 9.9 Bcm/year or 24%. During the following six years, production increased by 38.7 Bcm/year or 75%. And finally, the Central North Sea discoveries included a large number of gas condensate fields, which were rich in natural gas liquids that resembled light crude oil. Some of these discoveries were so rich that they showed 'negative opportunity cost' characteristics.[39]

With the development of the Central part of the UKCS, the volume of associated gas produced in the UK rose from 17% in 1990 to a worldwide unique share of 51% in 2001. Some of the larger discoveries – Brae, Britannia, Bruce, Elgin, Franklin Joanne and Judy – had condensate yields in the range of 40 to 260 barrels of condensate per million cubic feet of raw gas. At a condensate price of 20 $/bbl, that provides a condensate credit of 0.80 to 5.20 $/Mcf (28 to 184 $/1000m3) of raw gas and an even higher unit credit for sales gas after liquids extraction. For many of these discoveries, the ability to get the field into production quickly in order to realise the liquids sales credits was the driving force in price negotiations for gas sales.

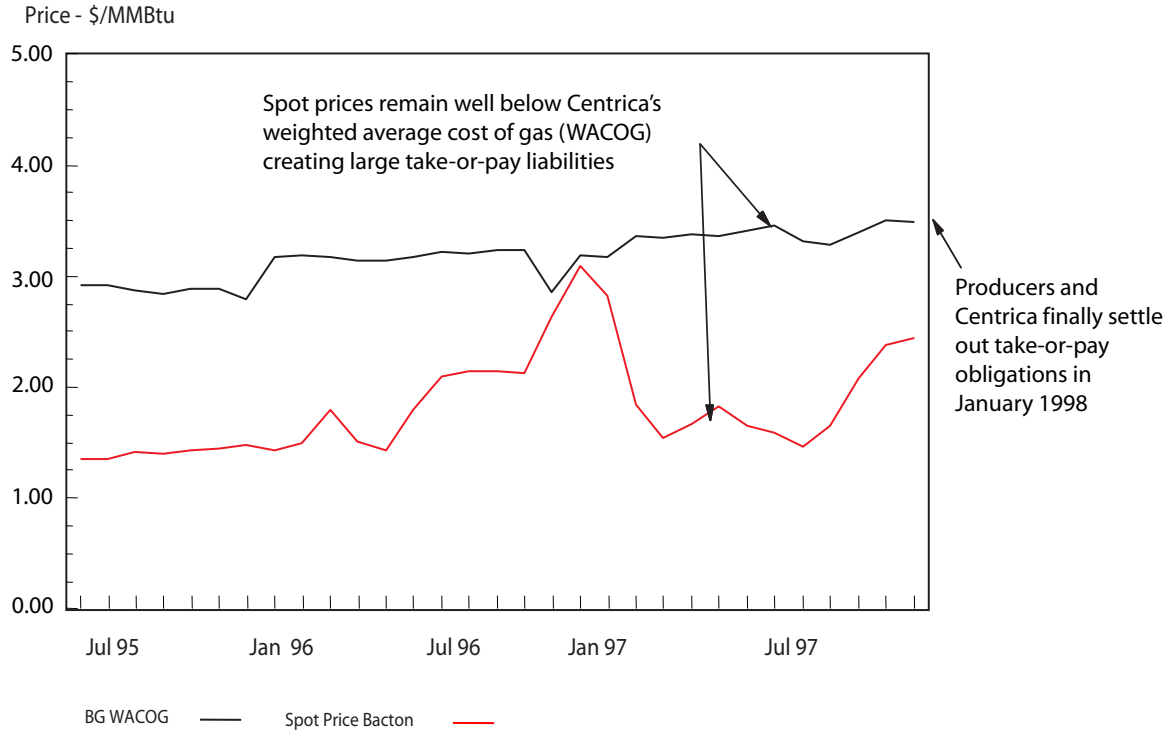
As flaring is not allowed and when re-injection is not feasible or economic, it is important to be able to dispose of all of the associated gas. Otherwise the production of condensates would have to be reduced with a negative impact on the discounted cash flow. There are two principal approaches: either to find a buyer who accepts a strict minimum-take obligation against an attractive low price, or to be sure that the associated gas can always be sold on a liquid marketplace accepting the

39. 'Negative opportunity cost' fields are those that are so rich in condensate that the producer can justify production economically even if he has no outlet for the gas and must flare it. In an environment, where governments will not permit flaring, the alternative is to re-inject the gas at considerable cost.

market clearing price. With the opening of the UK gas transport infrastructure, both options became possible for the sellers of associated gas.

Growing production for newly de-regulated markets and a willingness to sell at a discount led to a sharp drop in spot prices for gas to third-party customers. These spot prices significantly undercut the 'weighted average cost of gas' (WACOG) that Centrica had to pay due to its legacy of take-or-pay contracts. The disparity between spot prices (at the Bacton terminal) and the Centrica WACOG is shown in *Figure 37.* The minimum pay problem of BG / Centrica was twofold: loss of sales volume, combined with a low market price for gas, considerably below their contractual prices.

Figure 37: Spot Gas Undermines the Costs of Centrica's System Supply in a Liberalised Market with Supply Surpluses



Source: Jim Jensen

Centrica was forced by that situation to ask producers for negotiations (lacking a re-negotiation clause) in order to re-work the contracts if it were to avoid bankruptcy. It has been estimated that Centrica paid about $1.2 billion in settlement claims on its take-or-pay obligations before the last cases were finally settled in January 1998.

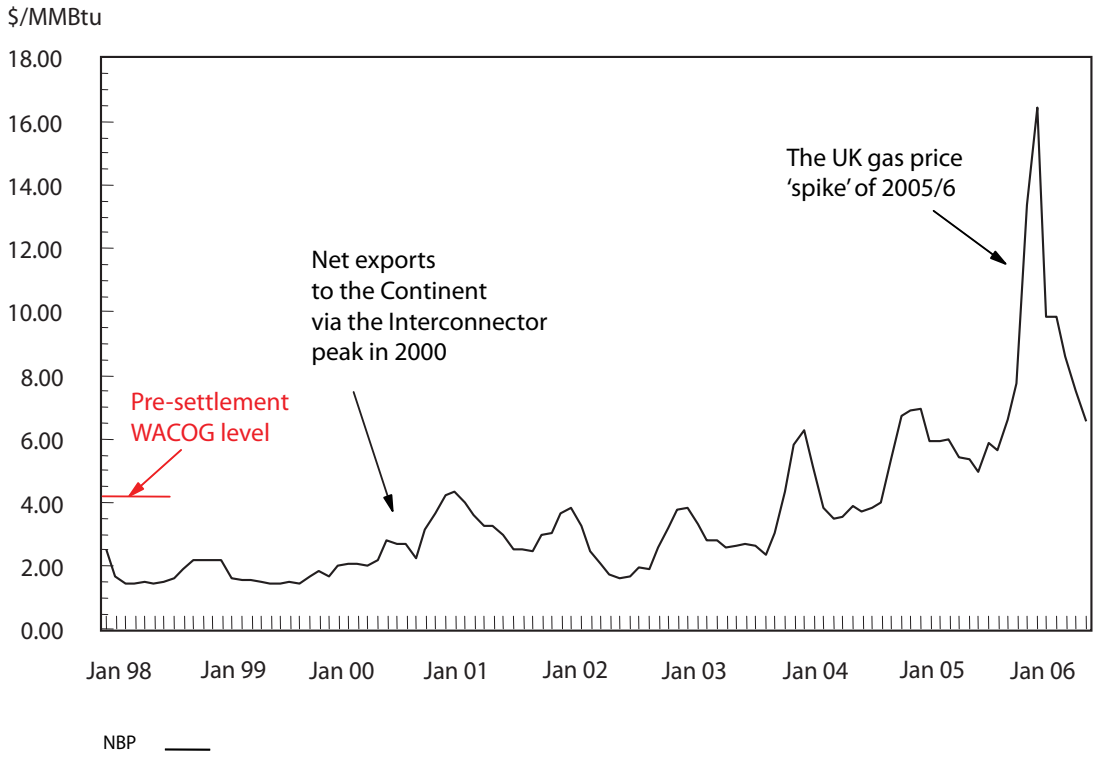
4.3.4.2 Pricing in the Restructured Gas Market

Centrica's monopoly on residential sales was eliminated in 1998, opening the UK market to competitive market pricing. Since that time, price quotations for the NBP have been very transparent, making it, with Henry Hub in the US, one of the two most liquid gas markets in the world.

However, the NBP record on liquidity is far from that of Henry Hub, which has a churn of about 100, while NBP is around 10, but occasionally reaching a churn of 15. It remains to be seen what influence the new import contracts or the self-contracting regime will have on the churn ratio.

Figure 38 traces the prices at the NBP since the inception of full industry restructuring. The initial prices for the liberalised gas market were similar to the spot prices before the final take-or-pay settlements. To many observers, it appeared that this reduction in price was directly attributable to the competition from industry liberalisation. But it also was a result of the gas surpluses created by the major production expansion in the Central North Sea (on a must sell basis). When net exports to the Continent via the Interconnector peaked in 2000 and then began to decline, prices began to strengthen. The final reversal of the net export position to a net import position led to the spike in gas prices during the winter of 2005/2006.

Figure 38: UK National Balancing Point Prices



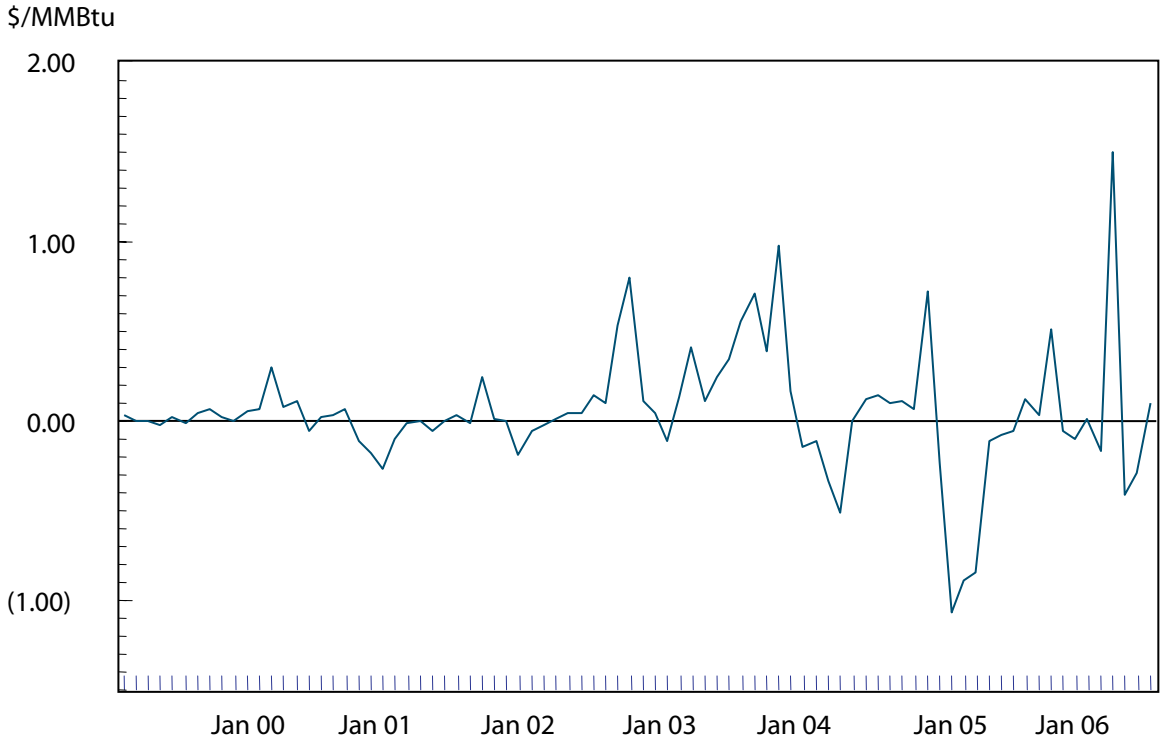
Source: Jim Jensen

It is clear that the UK has a liquid – and volatile – market that responds quickly to supply / demand pressures and to bottlenecks. What is not so clear is how that market will interact with the much more rigid, contract-dependent markets of the Continent.

4.3.4.3 How Do Prices in the UK Interact with Continental Prices?

The construction of the Interconnector provided a channel for gas price signals to travel from the UK to the Continent and vice versa. The Zeebrugge terminal of the Interconnector would be expected to be directly affected by de-regulated gas pricing in the UK. Since flows have typically been from the Continent back to the UK during the heating season, but forward to the Continent the rest of the year, one would expect the basis differential between Zeebrugge and the NBP to flip from positive to negative depending on the season. This is, in fact, what has happened. *Figure 39* shows the basis differential experience between Zeebrugge and the NBP. One should differentiate between the Zeebrugge Hub price, which parallels the NBP price, and the import price of Belgian H-gas, Troll gas and Algerian LNG at Zeebrugge. The overall import price of Belgium also includes purchase of L-gas from the Netherlands, which includes the market swing and spot purchases of up to 25% of imported volumes by Distrigaz from the UK.

Figure 39: Basis Differential – Zeebrugge over NBP

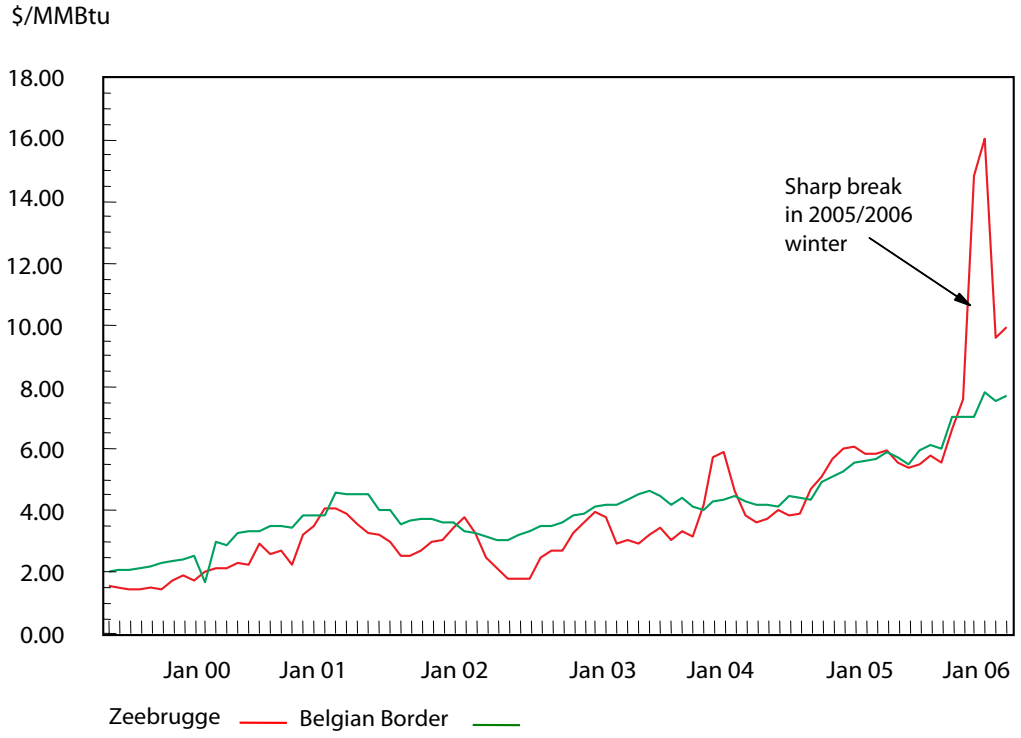


Source: Jim Jensen

Belgian border prices are very different from the NBP price series. Not only do they represent a composite of long-term contract prices, rather than a spot market series, but also there is no liquid and transparent trading at the Belgian border. Thus, one would not necessarily expect there to be a direct relationship between Belgian border prices and Zeebrugge. While they have traditionally not deviated significantly from one another, there has not been an obvious and direct relationship. *Figure 40* tracks the two price series since 1999. During the winter 2005/2006 the development of Zeebruge and Belgian Border prices diverged sharply due to the price spike on the NBP during

the winter 2005-2006. Since April 2006 the correlation between Belgian Border prices and NBP has strengthened again.

Figure 40: Comparison of Zeebrugge and Belgian Border Prices



Source: Jim Jensen

4.3.4.4 The Experience of the 2005/2006 Winter

The substantial spike in both NBP and Zeebrugge hub prices during the winter of 2005/2006 was brought about by shortages in the UK market resulting from the sharper and earlier than predicted decline in North Sea production in the face of strong demand, and a lack of storage capacity. During the early period of the BG monopoly, several pure gas fields of the southern part of the UKCS provided all the swing needed in winter. Subsequently, a small amount of storage capacity was developed using depleted southern fields. But as the new market structure was being implemented, the depletion of the older southern fields and their replacement by the associated and gas condensate fields in the central UKCS reduced delivery flexibility. During the time of the UK surplus, the UK winter peak was solved by the claw back clauses of the export contracts or by arbitrage against Continental surplus capacity in winter. However, there was a relative reduction in storage capacity on the Continent, resulting in less contractually unbound winter capacity. A fire at the Rough storage field in February 2006 compounded the tight situation.

This re-orientation of gas supply towards the UK did not happen as expected. Despite the high early winter prices, backflow shipments through the Interconnector remained well below capacity (at an average of 51% over the reverse flow period) and several anticipated LNG tanker arrivals were missed.

This prompted Ofgem to request that the European Commission investigate whether restrictive market arrangements on the Continent were interfering with the functioning of the market. For LNG, the utilisation of the new Grain LNG terminal increased as of mid-January 2006 after OFGEM imposed a strict application of the 'use it or lose it' principle as of December 2005.

At the heart of the problem was the issue of how the two different approaches to supply management on each side of the English Channel cope with sharp seasonal swings in demand. The UK free market approach relied on market price signals to direct the gas to where the seasonal spikes occurred. The more contract-dependent approach of the Continent placed greater emphasis on long-term supply commitments on the purchase and sales side, including the management of storage to achieve the supply of the – predictable – winter peak at predetermined prices. This episode emphasised the inherent conflicts between these two approaches to markets and the need to reconcile them.

4.3.5 Conclusions

The UK negotiated the transition from government monopoly control of its gas industry to a liquid commodity market by undertaking three essential steps. Firstly, it privatised British Gas while at the same creating a regulatory agency to oversee the private company. Secondly, it required that the transmission system offer third-party access to suppliers and, later on, introduced an entry-exit-system by which all of the UK gas transmission system could be organised as a single market place. And third, it released some of British Gas's customers from their purchase obligations, thereby creating uncommitted buyers as potential customers for producer / suppliers, and in parallel freed producers from the obligation to sell to BG.

It helped that these moves were made at a time when North Sea supplies were in surplus as a result of many new, low-cost discoveries in the Central North Sea, a large part of which was associated gas, which operators had to dispose of to produce the oil or the condensates. In parallel, the opening of the electricity sector, together with a need to provide more environmentally-friendly power generation based on gas, provided for a price elastic demand which could absorb large gas volumes in summer at a price determined by power generation based on coal. The resulting price competition first drove down prices and created take-or-pay problems for Centrica, the de-merged marketing arm of the earlier monopoly company, but these were ultimately resolved. However, prices still largely followed the trend of competing fuels (clearing price coal / heavy fuel oil in summer and gas oil / liquids in winter) and after the surplus gas supply disappeared prices rose substantially: peak prices in winter 2005/2006 exceeded $25/MMBtu while the average price exceeded $10/MMBtu. The liquidity on the NPB which was building up to a churn of 15 then fell to about 10 and recovered at the end of 2006 to between 12 and 14.

With a combination of declining North Sea production and rising gas demand, the UK has now shifted from the position of a net exporter to that of a net importer, in a situation which is characterised by demand-on-demand competition for oil and gas. While the UK met the challenge to stimulate the necessary import investment, it still faces challenges on the future pricing mechanism. The new gas imports are an interesting mixture of some traditional long-term import contracts (some now linked to the gas spot price of IPE, instead of fuel oil indicators), gas flows triggered by arbitrage with the Continent via the UK Interconnector, and LNG supply subject to arbitrage with the US market.

4.4 Continental Europe

4.4.1 Summary

The development of the gas industry in Continental West Europe has been characterised by imports from super-giant fields, starting with the development of the Groningen field.

In order to maximise the rent income from the Groningen field for the Dutch state, the Dutch government, together with Esso and Shell, developed the concept of replacement, or market value pricing (which was also applied domestically), and the concept of long-term contracts with a minimum pay based on a netback / replacement value pricing, with regular review possibilities to adjust pricing to the originally sought balance.

The concept of long-term contracts aimed at maximising the rent income of the exporting state, while keeping the gas marketable, or in other words the seller (the exporting country) was taking risks and chances of price development via the replacement value pricing concept, while the buyer was taking the obligation to market a defined volume via the minimum take-or-pay obligation against earning a satisfactory margin.

The Dutch export contracts served as a point of reference for most gas export contracts to Continental Europe which followed over the next four decades: (i) the first Russian gas export contracts to Germany, Austria, France, Italy in the early 1970s, (ii) Algerian LNG to France and later Belgium, Greece, Spain and also for Algerian pipeline exports to Italy, although with some major distortions during the 'gas battle' in the beginning of the 1980s when Algeria imposed FOB crude oil parity on its customers, (iii) the Norwegian gas export first under the Ekofisk and Statpipe contracts (although without review and under a multiplicative formula), (iv) additional Russian exports under the SGE IV project in the early 1980s, (v) the Troll sales to Germany, the Netherlands, Belgium, France, Austria and Spain, (vi) Algerian gas exports to Spain and Portugal via the Maghreb pipeline, (vii) Nigerian LNG, (viii) Norwegian exports via the GFU to SEP in the Netherlands, to VNG in East Germany and to the Czech republic, (ix) UK exports to the Continent, (x) and Libyan pipeline exports to Italy. Altogether more than 250 Bcm/year are imported by EU countries on the Continent under this concept.

Changes in market conditions were reflected in the new contracts concluded and by regular price reviews for existing contracts.

Adaptations to changed circumstances happened by modifying the original (very large) long-term contracts by changing the price formula to reflect the development in the competitive situation of gas, mainly by increasing the share of gas oil, but also by including elements to reflect the changed role of gas in power generation and later the role of gas-to-gas competition. As a result the currently applied price formulas for imported gas follow similar patterns, as was shown by the report of the Energy Sector Inquiry by the European Commission's DG COMP, published in January 2007.[40]

40. European Commission, *DG Competition Report on Energy Sector Inquiry*, SEC (2006) 1724 (Brussels, 10 January 2007), accessible at <http://ec.europa.eu/comm/competition/antitrust/others/sector_inquiries/energy/fr_part1.pdf> (visited 24 January 2007).

Imported gas is usually not geared towards use for large-scale power generation, except for countries that have no domestic or quasi-domestic (nuclear) energies suitable for power generation, like Italy and Japan. Exporting countries have been hesitant to sell to the segment of large-scale power generation, where domestic resources for power generation existed. Unlike the UK, the evolution of gas to power was limited in Continental Europe and focused on Italy, where substantial capacity of new CCGTs was installed after 2000. In the other countries in Continental Europe the use of imported gas for power generation is so far limited.

Gas hubs were developed at Zeebrugge and Bunde by the gas industry and TTF with regulatory support in the Netherlands, however, so far with a limited liquidity (churn ratio of about 5).

While EU gas market reforms changed the regulatory framework since the end of the 1990s, long-term import contracts persisted as the dominant import arrangement, now complemented by some imports, on a short-term basis from the UK and by some spot LNG mainly to Belgium. Except for the adaptation of the pricing formula to new competitive situations, new import projects kept with the principles of long-term contracts, with some modifications as to the size of volumes, term and more flexibility regarding the delivery point.

Before the fall of the Berlin Wall in 1989 (prior to the disintegration of the COMECON system), gas flows across borders within the former COMECON were determined by a joint central-planning mechanism, amounting to barter deals of gas deliveries as compensation for participation in the construction of the gas infrastructure and as compensation for transit service. After the fall of the Berlin Wall, contracts between the Soviet Union / Russia and former COMECON countries like East Germany, the Slovak Republic and the Czech Republic have been transformed into contracts following the concept of long-term minimum-pay contracts and long-term transportation arrangements. A similar process of splitting gas supply and transit arrangements into separate long-term supply and transit contracts is now under way between Russia and other countries of the former Soviet Union as well as with Bulgaria and Romania. Russia is now heading towards a pricing system for gas exports, where, according to official Gazprom statements, Gazprom's announced intention is to reach a financial return on its export operations to former Soviet states on an equal level to its exports to EU countries.[41] This implies that the netbacks from Russian sales to its immediate neighbours will be on a comparable level with the netback from its main customers in the EU.

4.4.2 Development of Market Structure and Imports

In some parts of Europe, mainly in the Northwest, coke oven gas and methane from coal mines has been marketed as a by-product of the mining process. As far back as the 1930s, the first 'long distance' pipelines were built to market the excess coke oven gas from the Ruhr area first to Frankfurt on the Main (ca. 300 km) and then to Berlin (ca. 500 km). As coke oven gas was a by-product of the process to produce coke for the steel-making process, there was a problem of cost allocation for

41. *See*, for instance, OAO Gazprom, *Transition to the Market Principles of Cooperation with the Former Soviet Union Republics. Oprations in International Gas Markets. Diversification of Gas Export*, at <http://www.gazprom.ru/articles/article19812.shtml> (visited 24 January 2007); interview with S. Kupriyanov, press-secretary of the Head of the Management Board of Gazprom, on 'Echo Moskvy' radio station on 29 December 2006, at <http://www.echo.msk.ru/programs/razvorot/48509/index.phtml> (visited 30 December 2006).

coupled products. The pricing concept that was applied did not refer to costs, but to what could be achieved in the market to contribute to cover the costs of coke production.

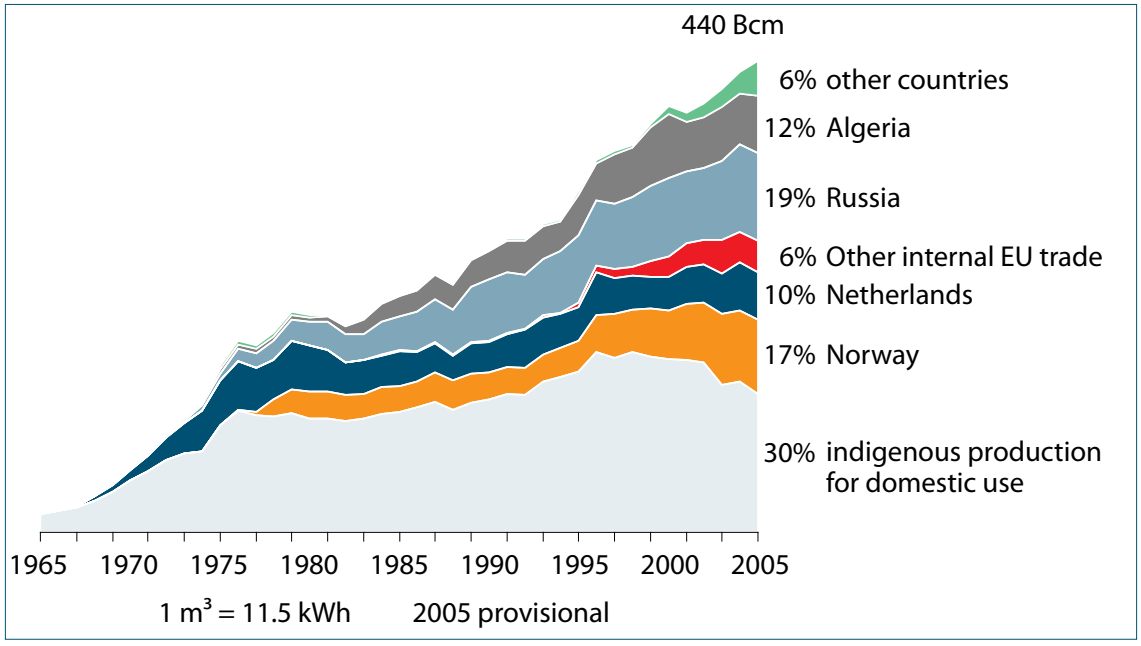
Coke oven gas and manufactured gas were widely used in the cities of countries with coal mining, like the UK and in the area of the coal belt from the Ruhr area to the north of France, but manufactured gas was also used further away from these areas based on transported coal. The use was predominantly for cooking, not for heating.

Natural gas was found and used locally in the middle of the 20th century in the northern parts of Germany, in Lacq in the Southwest of France, and in the Po valley in Italy. Both Ukraine and Russia have a long history of using natural gas.

The development of the modern natural gas industry in the Western parts of Europe started with the discovery of the Groningen field in 1959. Further drilling proved it to be a super-giant field. It was clear that its gas could not solely be consumed in the Netherlands, but that, in order to valorise the gas reserves of the field, part of its production had to be exported. It was certainly helpful that nearby gas had already been used for cooking and that distribution grids had already been built, even though only part of them could be used for handling natural gas. Groningen gas was the first large gas-export project worldwide and became the reference case for all other gas imports into Continental Europe.

Figure 41 below shows the development of gas supplies in Western Europe (EU 15 plus Norway and Switzerland).

Figure 41: Development of Natural Gas Supplies in Western Europe including Norway and Switzerland



Source: e-on Ruhrgas

4.4.3 The Groningen Concept of Replacement Value and of Long-term Minimum-pay Export Contracts

The Dutch government made it clear from the beginning that it wanted to achieve the highest possible rent from the development of the field for the budget of the Dutch government and to valorise it quickly in view of possible upcoming energy technologies, like nuclear power. Based on that objective, the Dutch government developed the main concepts for the marketing of Groningen gas both domestically and for export, namely to achieve a price close to the replacement value of gas: gas should be priced in relation to its competitors so that there would be just enough incentives over competitive fuels to use it.

Gas was exported to the nearby markets of Belgium, the Northeast parts of France and the industrialised parts of Northwest Germany and, later via the TENP system also to Northern Italy and Switzerland.

Origins of the Dutch gas policy

When the Groningen field was discovered it became clear that it was one of the largest fields in the world at that time. The exploration of the Groningen field was carried out by NAM, a joint venture for oil and gas exploration and production in the Netherlands, established by BPM (Shell) and Standard Oil Company of New Jersey (Exxon).[42] NAM found the existing gas exploitation regime inadequate[43] and suggested to the Dutch government that the production concession be re-negotiated.

The decision as to which customers would be offered gas at what price caused some debate. Shell suggested market segmentation and price differentiation. The gas would be sold to small-scale customers through the State Gas Company and the local distributors, under the cost-plus regime. Then NAM would supply other Dutch and large foreign customers in industry and the power sector. This proposal was based on the idea that the segment of large users would be the most profitable to supply.[44]

Exxon believed, however, that the segment of small users could bring in the highest revenues. Once they had converted to natural gas, small users would be locked into the gas market and thus guarantee a relatively price-inelastic demand. Furthermore, gas possessed technical superiority for production processes of energy-intensive downstream industries, such as for chemical, metallurgical and ceramic production. Therefore, gas did not have to compete with lower-priced fuel oil or coal in these market segments.[45]

42. A. Correljé, C. van der Linde and T. Westerwoudt, Natural Gas in the Netherlands: from Cooperation to Competition? 28-30 (Oranje-Nassau Groep, 2003).
43. Under this regime, NAM would have been forced to sell the produced gas to the State Gas Company (SGB), which took care of transport and delivery of gas to municipal gas companies. From 1954, the SGB has distributed natural gas produced by NAM under a twenty-year agreement. NAM produced and sold gas on a cost-plus basis to the SGB. As the small scale of the gas system caused high distribution costs, NAM only received 2-4 Dutch cents with the consumer price as high as 33 Dutch cents. Before the discovery of Groningen, gas was associated with oil production and NAM considered the guaranteed off-take important, so it had accepted this regime.
44. A. Correljé, C. van der Linde and T. Westerwoudt, Natural Gas in the Netherlands: from Cooperation to Competition? (Oranje-Nassau Groep, 2003) at 30
45. Id., at 31.

The Exxon proposal hinged on the following elements:

1. gas should be made available to domestic users on a very large scale;

2. gas should be used in as many appliances as possible.

Traditionally city-gas was used only for cooking and hot water supply. In order to expand the domestic market, domestic customers would need to be persuaded to switch from coal or oil, to gas-fired space heating. In order to achieve this, the cost to users should arguably be equal to the cost for coal or oil-fired heating. The costs for higher levels of use for heating would decline progressively. This approach signified 'a completely new role for gas in energy markets, pricing strategies, and the relation between public and private activities'.[46]

The new Dutch concept of gas pricing

On the basis of this proposal, the main principles of the Dutch gas policy were established in 1962 in a famous note of the then Minister of Economic Affairs, de Pous, in what became known as the Nota de Pous. In order to generate maximum revenue for the state, the 'market-value' or replacement value principle was introduced as the basis for gas marketing, as opposed to the so far prevailing principle of cost plus for natural gas. The price of gas was linked to the price of alternative fuels likely to be substituted by the different types of consumers – for instance, gas oil for small-scale users and fuel oil for large-scale users.[47] On the one hand, the introduction of the market value principle meant that consumers would not have to pay more for gas than for alternative fuels. On the other hand, they would not pay much less.

The market value approach enabled Shell, Exxon and the Dutch government to obtain much higher revenues than by pricing based on the low production costs of gas from the Groningen field. It also made sure that the growing use of gas did not abruptly jeopardise the past marketing success for oil products.

In order to maintain the market-value principle it was essential that alternative supplies of low-priced gas would not become available in the market. Control over gas supply was deemed the responsibility of the government, whereas the exploitation and marketing of the gas reserves should be undertaken by the private concession holders.

What elements influenced this regime? Firstly, the giant size of the Groningen field provided a major long-term position of gas in the energy market of Continental Europe. This justified the investment required for the construction and conversion of infrastructure and equipment.[48] The second factor was the expansion of the European economies that was accompanied by an increase of wealth and a wish for comfort. Thirdly, new oil discoveries were being made in the Middle East. At the same time the costs of coal production were increasing. This led to the worldwide shift from coal to oil.

46. Id., at 30.
47. Id., at 34.
48. Id., at 48.

Domestic supplies

In order to introduce gas into the market, it was necessary to sell gas at a competitive price compared with traditionally used fuels.[49] Production costs of Groningen were very low – about 1 Dutch cent per cubic metre. Gas could be sold at a much higher price. According to the market-value principle, gas was sold at a price just below that of heating oil, anthracite and coke.[50] For households and small-scale users, there was no big advantage to using gas only for cooking or hot water supply. By granting rebates when used for heating, using gas provided a substantial financial advantage in addition to its convenience. For industrial users, the advantage of gas was considerable.[51] Coal was rather expensive to handle and store and gas-fired equipment was easier to handle. Gas supply was independent from water and rail transport. Thus there was no impact of weather conditions on supply. Gas was well accepted in the industry. For industry, the price of gas was calculated on the basis of the prices for fuel and heating oil. Since the cost difference between operating oil-fired facilities and gas-fired facilities was not large enough, the oil-fired facilities were not converted to gas immediately. Additionally built facilities were, however, gas-fired. The increase in the use of gas was largely due to the growth of the industry and the need of additional supplies. In addition to being used as a fuel, gas was also being used as an input for the fertiliser industry.[52]

Originally, gas was sold only to the premium markets of the industrial sector, e.g., chemical, metallurgical and cement producers. In these sectors it would not have to compete with lower-priced alternative fuels. With the growth of reserve estimates of Groningen, there was a concern that gas would not find a large enough market because of the perceived competition by cheap nuclear energy. Gradually, the premium market principle was thus abandoned.

Exports

In parallel to the expansion of gas in the domestic market, large volumes of gas were exported to Belgium, Germany and France under contracts concluded in the mid-1960s which triggered the construction of the international network of high-pressure pipelines in Europe. In 1971, contracts were also signed with Italy and Switzerland.[53]

Until the 1970s there were – apart from domestic production – no other substantial supplies of natural gas in Europe. Importers in Germany, Belgium and France were fully dependent on gas supplies from the Netherlands. At the same time, there was a suppliers' exposure to the economic risk of low revenues.[54] Large investments in construction of transportation capacities as well as measurement and control facilities were necessary. In order to increase security of supply for consumers, and security of demand for the suppliers of the gas and to pay for the use of the infrastructure, long-term gas contracts were introduced, and became an essential instrument of the European gas trade.

The main elements of these long-term contracts were: an obligation by the seller to provide defined volumes of gas and by the buyer to buy a minimum volume secured by a take-or-pay obligation,

49. Id., at 60.
50. Id.
51. Id., at 63.
52. Id.
53. Id., at 67.
54. Id., at 68.

and the replacement value pricing mechanism, meaning in practice oil-parity at the burner tip. The buyer had to pay for the minimum volumes contracted, regardless of actual off-take, and this condition essentially provided the seller with security against the volume risk. Revenues for infrastructure operators were set to cover the costs of the contracted volumes to be transported to the customer. The replacement value principle would allow for the marketing of the gas.

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, introduced to ensure that gas with a low price at the Dutch border, destined for more distant markets, could not be used to undercut higher-priced gas in more proximate markets.

Another important innovation, stemming from the replacement value principle, was the introduction of a price review clause into the export contracts. Contrary to production costs, which are mainly fixed once the investment is done, the replacement value will change over time with technology and the shares and prices of the replacement fuels. To cover these changes the price review clause allowed for regular reviews of the price to reflect those changes (*see Box 9* below).

In summary, the producers took the price risk related to changes in gas prices aligned with movements of oil prices. The Dutch system ensured that the construction of production and transportation capacities was carried out in parallel with the demand growth.[55] It also prevented non-earmarked gas appearing on the market and jeopardising the market-value approach based on oil parity. Gas-to-gas competition was essentially excluded.[56]

Dutch gas exports played the crucial role in developing and maintaining the gas market in Europe. Without the Dutch gas policy, the role of city gas would have been taken over by oil products – the traditional coal-based gas industry would never have been able to survive the competition with low-priced alternatives.[57]

The successful implementation of the Dutch pricing approach showed that gas production and marketing could be attractive business. The attractive price of Dutch gas exports encouraged other gas supplies: from the North Sea (UK, German, Danish and Norwegian producers), the Soviet Union and Algeria. The replacement value principle based on linking gas prices to oil prices enabled a substantial increase in exploration and exploitation for gas and justified a further expansion of the European gas network.

Dutch depletion policy

The Dutch government and NAM / Gas-Export made only a limited amount of gas available for export out of concern for security of domestic supply. At the same time, the importing countries also limited the markets for Dutch gas. The governments of these countries wanted to avoid gas driving out other fuels, such as coal, fuel oil from domestic refineries or nuclear energy from their markets.[58] The gas exports were restricted to the premium market, customers who would be willing to pay the

55. Id., at 70.
56. Id.
57. Id.
58. Id., at 70.

relatively high border price and transportation costs of the gas. Contracts were concluded first at fixed border prices of 4 to 4.25 Dutch cents per cubic metre, subject to regular price review.[59]

The rapid depletion of resources was another concern. In the 1970s, the fears of Groningen depletion prompted adjustments to gas policies. National and export gas sales had to be limited through a revised gas pricing and sales policy.

Previously, domestic prices had been linked to oil products prices, but with a linking (pass through) factor which followed only partly the development of those prices. The Dutch government attempted to re-adjust the domestic price for gas to the price of fuel oil for industry, and heating oil for domestic households and services sectors. In order to achieve oil parity at the burner tip, a law was passed in 1974 that enabled the government to intervene in the negotiations between Gasunie and the distribution companies; the government would also establish minimum prices for supply by producers to Gasunie and for Gasunie's supplies to the distribution companies.[60] Following the increase in oil prices, the price of gas was only allowed to rise after a time-lag and by clearly below 100%. Following the first increase in oil prices in 1973, domestic sales contracts were almost completely adjusted to the oil price. This was also done with a view to re-negotiate the export prices: if Gasunie could show that the Dutch consumers were paying more, it would be easier to negotiate for higher prices with foreign customers.[61]

In parallel to restrictions in domestic consumption, gas exports also had to be limited. New contracts were not allowed for export markets. Existing contracts were honoured. These were long-term contracts with duration of 20 to 25 years to justify investments in transport and distribution infrastructure.[62] Export contracts included a price adjustment clause (except for the export contract with Italy, which did not have a price review clause when concluded in 1971; it was, however, introduced in 1975). Price adjustments were also requested with foreign customers to achieve a closer link with oil prices. By 1974, the average export price for gas had reached 85% of oil parity at the burner tip. It would, however, take much more time before real oil parity at the burner tip could be achieved, because of the many transitional arrangements that had been negotiated.

The government pushed in 1980 to re-open and adjust some contracts covering about 90% of the total gas export volume.[63] Both the base prices and the impact (pass through) factor for oil prices were adjusted and the time lag during which adjustments were introduced was shortened from ten to five months. Had Gasunie been able to offer larger volumes of gas, it would have been conceivable to negotiate higher prices, since due to the oil market situation there was great interest among European customers in increased imports of gas from European suppliers.[64]

Changing position of Dutch gas

Due to a depletion policy based on a paradigm of scarcity, Dutch export volumes declined during the 1980s. European customers were interested in increased imports of Dutch gas and were ready to pay higher prices. These volumes were, however, reduced because of the scarcity-driven policy

59. Id., at 71.
60. Id., at 89.
61. Id.
62. Id., at 92.
63. Id., at 93.
64. Id.

of the Dutch government and the preservation of gas for domestic users.[65] Most contracts provided for a total volume of gas to be delivered within the flexibility and duration of the contract, so-called package deals. In some cases, the duration of contracts was prolonged without adjusting the total volume, thus reducing the annual volume customers could receive. These adjustments of volume reflected the changing role of the Netherlands as a major gas supplier to the Continental European market.

The replacement pricing for gas led to increased investments in exploration and exploitation and to further expansion of the European gas network. In 1970, Dutch gas comprised a major share, or 92%, of cross-border trade of natural gas. In 1975, this share decreased to 76% following increased gas exports from the Soviet Union and later from Norway and Algeria. By 1995, the Dutch share constituted only 10%. The Soviet Union was Europe's largest gas supplier, followed by Norway and Algeria.[66]

The Dutch depletion policy aimed at restricting Dutch gas production to a maximum of 80 Bcm/year and at keeping gas for the duration of one generation in the Groningen field. This was done first of all through the development of small fields that would not be economically viable on their own. Gas from these small fields substituted for Groningen. Furthermore, gas was imported into the Netherlands, mainly from Norway, but later also 4 Bcm/year from Russia.

As a result of the scarcity-driven policy, in the early 1980s national and export sales of gas had fallen significantly. Substantial volumes of imported gas were sold in Continental Europe by Norway, the Soviet Union and Algeria. The Dutch government realised that the market for Dutch gas was diminishing, and so was the state revenue. It decided to terminate looking for gas imports and to withdraw restrictions on the use of gas in power plants, because only this sector was able – through dual-fired power plants – to absorb significant volumes of gas at short notice.[67] This resulted in significant increases in sales and government revenue. Furthermore, export restrictions were lifted.

Gasunie served as a 'Gas Bank' providing for back up flexibility and security of supply.[68] Supply of long-haul gas from the Soviet Union, Norway and Algeria required a high load factor, contracted for a long-term period to justify the massive investments in production and pipeline capacities. Demand for gas varies seasonally and depends on temperature especially for domestic households, which requires buyers to build substantial storage capacity. Flexible supplies of Groningen gas helped to cover peak-demand and to provide back-up capacity in case of supply problems.

With the decline of oil prices in 1985-1986, the notion of scarcity disappeared. With the increased deliverability of gas via an enhanced transmission system between suppliers and markets, gas use in Western Europe has been much intensified.

65. Id., at 93.
66. Id., at 94.
67. Id., at 108.
68. Id., at 109.

4.4.4 Gas Import Contracts Following Groningen

Domestic gas played an important role not only for the UK and the Netherlands but also for France, Italy and Germany and later Denmark. However, domestic output was constant at best, and with no increase in Dutch exports the gas industry needed further imports to expand.

The Dutch export contracts served as a point of reference for most gas export contracts to Continental Europe which followed over the next four decades.

A special feature of the sale of Groningen gas, which was not repeated by other export contracts, was providing daily and annual supply flexibility, high enough to cover seasonal and other market fluctuations. This is economically feasible for Dutch gas because it is short-haul gas, except for gas to Switzerland and Italy. The investment for production and transportation in the Netherlands was covered by a capacity fee which would be paid in addition to the commodity price. In this constellation the minimum pay is not needed to recover the investment (which is covered by the capacity charge for the capacity ordered) but serves to guarantee a minimum rent income to the country and to guarantee it the marketing of a minimum volume in the buyers' market.

However, as other export projects – contrary to the Dutch exports – needed to cover much higher transportation costs (long distance for Russian and Algerian pipeline gas, offshore pipelines for Norway, LNG for Algeria, Nigeria) it was not economic to provide in these export contracts the flexibility needed by the market. Instead, these contracts provide a high annual minimum pay corresponding to a high load factor to secure a high utilisation of the heavy investment of the transportation infrastructure. The minimum pay serves both to guarantee the payback for the investment and a minimum resource rent.

The major elements incorporated in gas export contracts were the following:

- A long-term supply obligation balanced by a long-term off-take obligation (ensured by the minimum-pay concept): the seller would commit a certain amount of gas reserves as well as gas delivery capacity and the buyer would commit a certain market volume via the minimum-pay provisions;
- Pricing based on the concept of netback value calculated on the basis of the value of competing energies backed to the border of the buyer's country by deducting the costs of transportation and distribution of the buyer;
  - Under this concept the base price of gas would be re-calculated at regular intervals (monthly or quarterly) in line with the absolute price movements of the competing energies (*see Box 8*). While gas oil and heavy fuel oil are the most common competing fuels, the concept would also work with a reference to other competing energies, like coal or electricity but also gas itself;
  - Under this concept, the delivery point and the reference point for the price could be different; in fact all Dutch gas is delivered on the border of the Netherlands, however, with compensation for transportation costs where necessary (for exports to France, Italy and Switzerland);
- The possibility to review at regular intervals (typically three years) the price conditions in order to adapt them under defined criteria to changed circumstances in the market, ensuring that the gas would remain competitive; (*see Box 9*);

- The possibility to invoke arbitration in case of disagreement on the price adjustment.

This concept would ensure a reliable sales volume for the seller at prices as close as possible to what can be sold in competition with other energies in the market. This way the netback calculated back to the wellhead provides for the maximum specific rent which can be obtained from the market, supplied without losing competitiveness. On the other hand, it allows marketing of the gas while offering a reasonable margin to the buyer. Risks related to price movements of the competing energies are mainly carried by the producing country (changes would be reflected in the producing country's resource rent, either in the income from petroleum and royalty taxes, or, where petroleum activities are organised by state-owned companies, through changes in their financial results). In this way, the seller takes the price risk, the buyer the volume risk linked to marketing.

Today, more than 250 Bcm/year are imported by EU countries on the Continent under this concept, with prominent examples being the first exports from the USSR (SGE I-III), Algerian exports to Italy via the Transmed pipeline, Algerian LNG to France and Belgium, and later Algerian pipeline exports to Spain and Portugal via the Magreb pipeline, the Norwegian Ekofisk and Statpipe contracts,[69] additional Russian exports under the SGE IV project, the Troll sales to Germany, the Netherlands, Belgium, France, Austria and Spain and later Norwegian exports via the GFU to VNG in East Germany and to the Czech Republic, Nigerian LNG, and later UK exports to the Continent.

Crucial elements of this concept are the price formula (*see Box 8*) and the price review clause (*see Box 9*).

69. In these deals some special features were taken from the UK practice: dedicated field, multiplicative price formula, no review clause.

Box 8: Stylised Price Formula under the Netback Concept of Long-term Contracts[70]

Pm = Po + 0.60 x 0.80 x 0.0078 x (LFOm - LFOo)
+ 0.40 x 0.90 x 0.0076 x (HFOm - HFOo)

(i) The gas price Pm:
applicable during the month m is a function of

- the starting gas price Po
- and the price development of competing fuels compared to the reference month, in this example: Light Fuel Oil (LFO) and Heavy Fuel Oil (HFO)

(ii) 0.60 and 0.40 are shares of gas market segments competing with respective fuels (no dimension):

- Light Fuel oil / Heavy Fuel Oil
- These shares will be different from the shares of these fuels in total energy use; e.g., the share of heavy fuels used in most European markets is now rather small, however, it remains the best available alternative for most of the gas used for industrial purposes

(iii) 0.80 and 0.90: Pass through factors (no dimension):

- Sharing risk and reward of the price development between seller and buyer
- Most of risk and reward for the seller (0.80/0.90)
- May be different for different fuels

(iv) 0.0078 and 0.0076: Technical equivalence factors to convert the units of prices for fuel into units of gas price

In this example:
Gas in kWh (GCV), Fuel oil in t,
Dimension: Euro cts / kWh / Euro / t

(v) Competing Fuels

Quotations reflecting the market
With or without taxes on competing fuels
Time lag and Reference Period to be defined
LFO: Price of Light Fuel oil
LFOo: Price of Light Fuel Oil for starting month o
LFOm: Price of Light Fuel Oil resulting for month m (may refer to an average value of previous months depending on reference period and time lag agreed)
LFO is usually reflecting competition for medium and smaller customers whose alternative is using Light Fuel Oil (typically small industry, commercial, administration, households).

70. For a more detailed description of long-term contracts, *see* ESMAP (Joint UNDP / World Bank Energy Sector Management Assistance Programme), *Long-term Gas Contracts: Principles and Applications*, ESMAP Report No 152/93 (January 1993).

Serving those customers requires also investment into distribution (grid) to medium and small customers, and eventually more instruments to provide the flexibility needed.
That would have to be taken into account in the determination of Po.
HFO: Price of Heavy fuel oil
HFOo: Price of Heavy Fuel Oil for starting month o
HFOm: Price of Heavy Fuel Oil for month m
Reflecting competition for larger customers whose alternative is using Heavy Fuel Oil (typically in boilers)

(vi) Determination / negotiation of Po (starting price in month 0) reflecting the netback to the point of delivery:

Use of Currency (of the sales market)
Po determined (negotiated) as:
Replacement value
minus
costs to bring the gas from the delivery point to the customers
minus
marketing incentives.

Box 9: Stylised Provisions of a Price Review Clause

a. If the circumstances beyond the control of the Parties chance significantly compared to the underlying assumptions in the prevailing price provisions, each Party is entitled to an adjustment of the price provisions reflecting such changes. The price provisions shall in any case allow the gas to be economically marketed based on sound marketing operation

b. Either Party shall be entitled to request a review of the price provisions for the first time with effect of dd/mm/yyyy and thereafter every three years.

c. Each Party shall provide the necessary information to substantiate its claim.

d. Following a request for a price review the Parties shall meet to examine whether an adjustment of the price provisions is justified. Failing an agreement within 120 days either Party may refer the matter to arbitration in line with the provisions on arbitration of the Contract.

e. As long as no agreement has been reached or no arbitration award has been rendered all rights and obligations under the agreement – including the price provisions – shall remain applicable unchanged. Unless otherwise agreed or decided by the arbitral award, differences to the newly established price shall be retroactively compensated inclusive of interest on the difference calculated at a rate reflecting the conditions on the international financing market.

The system of netback / replacement value pricing and destination clauses

The concept of replacement value, combined for export contracts with the concept of a netback price, results in different netback values at the exporting country's border for different customers. In addition, different transportation costs to different customers imply different netback values earned by the exporter at its border, even if the replacement value at the border of the customers would be the same. To make things even more complicated, where the gas does not change ownership at the border of the buyer but upstream of it, the seller would compensate for the transportation costs borne by the buyer by granting a rebate. Further complications come into play when one delivery point serves as delivery point between one exporter and several buyers.

The replacement value concept, whose origin is described in *Section 4.4.3*, creates opportunities for arbitrage by the buyer. The main examples are: (a) when a producer sells at the same point to different countries with different replacement values, and / or (b) where the producer grants a rebate to compensate for transportation costs incurred by the buyer to bring its gas to the market.

The first such cases were the sale of Dutch gas to Italy and Switzerland and Norwegian Ekofisk gas delivered at Emden to Ruhrgas, Gasunie and also to Distrigas and GdF (for whom it was priced with a compensation for transportation to Belgium and France). In some cases, the transfer at a point in between the producer country and the consumer country was politically motivated, as for Soviet gas supplies at the Western border of the COMECON, and for Algerian gas at the Algerian border. Several Soviet / Russian gas contracts with different final destinations further downstream along the pipeline (e.g., for Austria, Italy, France) had / have the same delivery point (Baumgarten) with different selling prices. Norwegian gas sold after Ekofisk and Statpipe was either delivered by a dedicated infrastructure and / or by agreed transit at the border of the customers.

To prevent a rebate granted in the price formula to compensate for transportation being used to undercut prices in markets upstream of the buyer, a so-called destination clause was an instrument often included in the contract. These clauses excluded the re-selling of the gas to a third country, thereby protecting the exporter's position by preventing arbitrage operations to the detriment of the seller on the basis of any price differentials in different downstream markets.[71]

The European Commission has argued that such clauses are not in line with European competition law within the European Union, as they restrict the re-sale and flow of gas between countries of the EU and thus violate basic provisions of the 1958 Treaty of Rome regarding free movements of goods. "Nigerian LNG in December 2002 was the first external supplier to remove destination clauses from existing and also future contracts with European customers. … Russian 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 will no longer be prevented from re-selling outside Italy gas it buys from Gazprom. Equally, Gazprom will be free to sell to other customers in Italy without ENI's consent".[72] Part of the settlement[73] was also that ENI should provide a capacity increase in 2008-2011

71. A.A. Konoplyanik, *Russian Gas to Europe: from Long-term Contracts, On-border Trade, Destination Clauses and Major Role of Transit to …?*, in 282-307 JENRL, vol. 23, no. 3 (2005).
72. OECD/IEA, Security of Gas Supply in Open Markets: LNG and Power at a Turning Point 115 (IEA, 2004).
73. *See* European Commission, *Press-release on Territorial Destination Clauses with Gazprom and ENI*, IP/03/1345 (6 October 2003); European Commission, *Energy Dialogue with Russia. Update on Progress*, Staff Working Paper SEC (2004) 114, Annex 6 (28 January 2004).

of its majority-controlled TAG pipeline (through which 100% of Russian gas to Italy is being supplied through Austria), and is to promote an improved TPA to use TAG for transit.[74] Reportedly, a rebate to bring the gas to the Italian market would only be granted on the volumes consumed in Italy. A similar agreement followed in May 2004 for Gazprom and OMV.[75] As of end 2006 the '…Commission's investigations continue with regards to imports of Italian and Spanish operators of Algerian gas'.[76]

USSR / Russian gas exports: contracting and pricing

While the contracts and pricing of export of gas from the USSR to Western Europe followed closely the Groningen concept, the organisation of formerly Soviet (current Russian) gas exports to Western Europe developed specific features stemming from political and geographic circumstances: the political division between East and West at the time of the first delivery contracts, followed by the challenges of the transition period after the fall of the Berlin Wall, and the large distance between gas source and gas markets required securing the economic viability of an extended pipeline system as well as a multitude of transit arrangements for all Russian gas exports to the West. The transit issue for Russian exports became even more pronounced with the emergence of newly independent states as a result of the dissolution of the Soviet Union.

These elements were reflected in specific modifications of the original Groningen concept, namely: no capacity charge but a minimum-pay obligation with a high annual load factor to ensure a high utilisation rate of the high investment in the pipeline system (like for Norwegian gas and LNG deliveries). The large distance for transportation from source to markets and the geographic location of USSR / Russia also required transit arrangements, for sometimes up to four different transit countries (as for deliveries to France, which needed three transit countries from the USSR and four from Russia). Political considerations meant that the delivery points for gas were at the political border between East and West so that transportation of gas was arranged by the buyer and the seller resepctively for the parts of the gas chain that were in their respective political camp, i.e., at Waidhaus on the German-Czech border and at Baumgarten on the Austrian-Slovak border. There was compensation in the gas price formula for the additional transport costs outside of the COMECON system where necessary (mainly for Italy and France).

Most of the infrastructure for Russia's gas supplies to Europe was created during the Soviet period as part of the integrated system for the gas supply of the Soviet Union and its COMECON partners. The famous 'gas for pipes' or triangular deal of the 1970s (gas supplies based on export pipelines built with pipes imported from Western companies, financed by credits from Western banks, secured by the minimum-pay income of gas export contracts with Western gas companies) and later the Reagan embargo in 1981 on export of compressors to the Soviet Union masked the fact that the largest part of the integrated gas transport system was built using the Soviet Union's and its COMECON partners' own resources. In fact, gas exports to Western Europe were more a complementary effect than a driving force of the gasification of the Soviet Union and the COMECON.

74. As a result of the public allocation procedure for the first tranche (3.6 Bcm/year) of capacity expansion of the TAG pipeline in December 2005, 140 companies, amongst them Gazprom, each received a capacity of just 2500m3/h (equivalent to around 20 million cubic metres per year) for supply to the Italian market.

75. A.A. Konoplyanik, *Russian Gas to Europe: from Long-term Contracts, On-border Trade, Destination Clauses and Major Role of Transit to …?*, in 282-307 JENRL, vol. 23, no. 3 (2005).

76. R. Celli, F. Distefano and C. Riis-Madsen, *Commission Takes Further Action to Speed up Opening of Energy Markets*, in 1-5 Global Competition Review (2007), *see* quote on page 2.

Russian gas exports to Western Europe started with contracts with Austria, Germany, France and Italy which were concluded in the first half of the 1970s. Even though the first Russian export contracts (SGE I-III) had a substantial introductory rebate, their pricing concept was very similar to the Dutch contracts and consequently their price development followed that of the Dutch contracts. As a specific element, the Russian price review clause for some of its customers did also refer to price changes of other comparable import contracts of the same customer as one yardstick for price changes. This reflected that Russia, contrary to the Netherlands whose domestic market was similar to its export markets, did not have the experience of a domestic market-based gas sector as a guide for price review negotiations, and, therefore, used the results of the price reviews of Dutch gas as a benchmark.

Another singularity of the Soviet / Russian pricing concept is the entitlement to gas delivered at a rebated price as compensation in case of under-deliveries. Western European customers are at the end of a very long, complex, integrated system, whose design – unlike for the much shorter and dedicated systems from Norway or the Netherlands – does not always allow to exactly match the demand of the customer.

The round of new exports of Soviet gas SGE IV to Germany, France and Austria in the beginning of the 1980s, which became known because of the intervention by the Reagan Administration and the embargo on US-licensed parts of compressors, had a price level which was comparable with other gas, mainly Dutch gas, taking account of the different supply flexibility. This contrasted with the previous SGE contracts, which included introductory rebates.

In the second half of 2006 Gazprom prolonged the delivery contracts with its main traditional customers OMV, ENI, E.ON-Ruhrgas and Gaz de France. The extended contracts now have expiry dates of between 2027 and 2036, and the deals include different kinds of reciprocal downstream engagement by Gazprom:[77]

***OMV*:** Gazexport and OMV renewed and extended their long term natural gas sales and purchase agreements on 28 September 2006. The contract will now extend beyond the previous expiry date of 2012 and will guarantee gas imports to Austria of around 7 Bcm/year until 2027.

***ENI*:** Gazprom chairman, Alexei Miller, and ENI CEO Paolo Scaroni signed a strategic agreement in Moscow on 14 November 2006. Under the agreement, Gazprom will extend existing supply contracts until 2035, from a previous deadline of 2017, though details of how much will be supplied were not given. Gazprom will sell directly into the Italian market from 2007 from part of the volumes currently sold to ENI. This will build up to 3 Bcm in 2010 and will continue at that level until the contract expiry in 2035.

E.ON-Ruhrgas: Gazprom has agreed to supply 400 Bcm of gas to E.ON Ruhrgas until 2036. The 400 Bcm comprises an extension of the existing contract and a new contract for delivery of gas through the Nord Stream Pipeline. The existing contract for delivery to Waidhaus on the Czech-German border will be extended by 15 years from 2020 to 2035, at an annual rate of 20 Bcm, making 300 Bcm in total, and a contract for deliveries through the Nord Stream will start in 2010/2011 at an annual rate of 4 Bcm, making a total of 100 Bcm.

77. Information provided on these contract extensions is from Gas Matters (monthly editions): information relating to OMV – 34 Gas Matters (October 2006); for ENI – 24 Gas Matters (November 2006); for E.ON Ruhrgas – 26 Gas Matters (September 2006); for GdF – 20 Gas Matters (December 2006).

Gaz de France: GdF signed a deal with Gazprom in December 2006, extending its existing supply contract for 12 Bcm/year until 2030 and allowing for additional supplies of 2.5 Bcm/year from 2010 through Nord Stream. The deal with GdF and Gazprom allows for Gazprom to market up to 1.5 Bcm/year directly to end customers, mostly in France, from July 2007.

Gas exports from Russia to the countries previously belonging to the COMECON, (like the GDR / East Germany, Slovak Republic, the Czech Republic and Poland), were based on earlier barter / compensatory deals from the Soviet times (participation in the construction and the developments of the Yamburg and Orenburg fields and pipelines against deliveries of gas, for transit countries delivery of gas as a compensation for the transportation transiting those countries). They were successively changed into supply contracts similar to the standard export contracts to Western Europe alongside separate transportation contracts first for East Germany and later for countries joining the EU.

The political transformation of Europe (dissolution of COMECON and the USSR and enlargement of the EU) has meant the adaptation of former arrangements of transit and gas deliveries of Soviet / Russian gas for former COMECON and FSU states (this is dealt with in more detail in *Section 4.4.7*). The collapse of the Soviet Union created new energy relationships among the states that had been constituent Soviet republics, and meant the division of the formerly integrated gas system of the Soviet Union into national systems of the various states. The transit arrangements had to be made for all the newly independent states for what was before part of an integrated transport system; the physical gas flows – at least initially – remained the same on a system which was not designed to handle transit separately. The enlargement of the EU in 2004 and in 2007 had an impact on transit arrangements for former Soviet / now Russian gas, since several delivery points were now located inside EU 25/27 so that former transit now became transportation subject to EU rules.

Norwegian gas

The Norwegian development of the North Sea started with the discovery of the fields belonging to the Ekofisk area. The first two licensing rounds in Norway were without direct state involvement. The first round (to which the Ekofisk area belonged) was exclusively developed by private companies, the second round provided for a carried interest which the state could exercise in case of a successful find. As of the third license round the newly formed 100% state-owned company Statoil had a minimum participation of at least 50% (later with a sliding scale up to 80%). In view of a prohibition to flare the associated gas from Ekofisk and other fields of the area, the operator Phillips was looking for an opportunity to market the gas from Ekofisk. The purchasing consortium composed of Ruhrgas, Gaz de France, Distrigaz and Gasunie, in competition with British Gas, finally concluded a contract in 1973 and two years later signed a similar contract for the gas from the neighbouring Eldfisk field. The contract foresaw the dedication of all reserves of the fields to the buyers, with the caveat that the delivery rate would be adapted to the reserve estimates of the fields. The pricing was a relative price formula pegged to heavy and light fuel oil without price review possibility. This pricing and contracting philosophy was apparently influenced by the US and UK concepts. Contractual delivery volumes were later substantially reduced because of unforeseen difficulties with the performance of the reservoirs.

The Statpipe contracts concluded at the beginning of 1981 were supposed to make up for volume reductions under the Ekofisk contract. At the beginning of the 1980s the world was under the spell of the steep price rises for crude oil from 12 to more than $30/bbl, and many serious institutes

expected the oil price to reach $100/bbl. In this climate of growing concerns about scarcity of energy resources, the Algerians triggered a price debate for gas about crude oil parity at the export point (i.e., FOB for Algerian LNG). (This is discussed in more detail in the section on Algerian Gas below.) This was (i) asking for a premium because pricing the gas at the wellhead at parity would leave no margin to pay for all the infrastructure between the wellhead and the consumers – which was more than the margin of the refiners – and (ii) referring to a fuel which was not representing the competition of gas in the market, as the price of crude oil was strongly influenced by the part which was sold on the automotive market with different price dynamics.

While the Norwegian side started with a price request similar to the Algerian price requests at that time, the Norwegian sellers compromised and the discussion on pricing formulas for Statfjord gas ended with a price clearly below crude oil price parity. The relative price formula was pegged by 25% each to (i) a cocktail of OPEC and North Sea crude oil prices, (ii) the German import price for crude oils, (iii) the heavy fuel oil quotation of the Statistical Office in Germany (including a minimum condition), and, (iv) to the light fuel oil quotation, also from the statistical office in Germany. This formula was replaced in 1986 by a formula similar to the new Troll price formula, except for the contracts with the US company Marathon Oil, under which it became the subject first of an arbitration procedure initiated by Marathon Oil, followed later by a court case in Houston, which was finally ruled by the Supreme Court of the United States.[78]

This pricing formula, which was against the principles of the replacement value and did not have a review clause to adjust to changed circumstances, was abolished in connection with the conclusion of the Troll contracts in 1986.

The Troll contract was negotiated between end 1984 and May 1986 between the six license holders of Troll (Troll West in block 31/2 later unified with Troll East in blocks 31/3, 5 and 6) and six Continental gas companies (Ruhrgas, Thyssengas and BEB from Germany, Gaz de France, Gasunie from the Netherlands and Distrigaz from Belgium).

The main elements of the deal were:

- A price review clause, to allow for changes in the market for gas, but also guaranteeing that the gas could be marketed. The first review was scheduled to take place in 1992 before the start of deliveries under the Troll contract.
- A price formula as per 1 October 1985 – i.e., before the price fall in fuel oil prices – based on the different national markets, nominated in local currency, with 50-60% pegging to light fuel oil, the rest to heavy fuel oil, with a special element to reflect competition with electricity in the case of France. There was no part in the formula to reflect sales in large-scale power generation.
- Delivery points were at the national border of the buyer, either by direct pipeline: Zeepipe to Zeebrugge for Belgium, Norpipe to Emden for Germany and the Netherlands, later Europipe I and II to Dornum and using Zeebrugge and a purpose-built transit line to Blaregnies in France for France, later replaced by Franpipe to Dunkirk.
- Deliveries based on the Troll field with the possibility to substitute and with an obligation to substitute if capacity of Troll was not sufficient, provided it was economically reasonable to develop more fields.

78. *See* Decision of the Supreme Court of the United States: Ruhrgas AG v. Marathon Oil Co., 526 US 574, 585 (1999).

- Substantial options for buyers to increase original volumes (by 80% and more), balanced by an obligation to use those options to cover part of additional demand.
- An annual minimum-pay obligation corresponding to an average off-take of about 7000 hrs/year with several additional flexibility elements.
- The base price (Po) was negotiated in a way which was consistent with the price of Dutch gas considering the differences in the flexibility offered. (Dutch gas was delivered with the off-take structure required by the market and had a price formula with a capacity charge and a commodity charge.)

Algerian exports

Algeria first developed LNG exports, also to the US, and later exports by pipeline to Italy and then Spain and Portugal.

Due to the technical challenge of crossing either the Strait of Gibraltar or the Mediterranean between Tunisia and Sicily, which required laying pipelines in water depths of 500 metres and more, the export of Algerian gas started as LNG. Algeria was the pioneer of LNG export, with the first commercial cargo delivered to the UK from the liquefaction plant in Arzew as early as 1964. In the 1970s Algeria concluded further LNG deals with the US, as well as with France and Belgium.

A subsea pipeline linking Algeria with either Italy or Spain has been under consideration since the 1970s. In 1973 ENI and Sonatrach signed an agreement to build a Sub-Mediterranean pipeline to ship 12 Bcm/year to Italy for 25 years, which was finally built at the end of the 1970s and put into operation in 1983, setting a record for water depth for offshore pipelines. It took until the end of the 1990s to build a pipeline linking Algeria and Spain.

The first Algerian LNG deals with the UK and the US were fixed-price deals, e.g., the deal with El Paso in the US started deliveries in 1978 at a FOB price of $0.37/MMBtu. It ran into difficulties, however, because of cost overruns on the Algerian side.[79] Sonatrach then succeeded in the mid-1970s to conclude LNG deals with Spain, France and Belgium on a netback basis with a link to fuel oils with a FOB price of $1.60/MMBtu.

In 1977 the supply contract for the Transmed project was concluded between ENI and Sonatrach, also based on a netback price formula. The price at the Algerian-Tunisian border, where ENI would take the gas, was agreed as $1.00/MMBtu at a time when Gaz de France was paying $1.30/MMBtu CIF for its LNG. Although the price was lower than for France the netback for Algeria was higher, as they did not incur costs for liquefaction and LNG tankers.

After Algerian President Boumedienne died in 1978, opponents used the apparent failure of the El Paso contract in order to raise prices for exported Algerian gas (*see Section 4.5.3.2* for more detail). The new Minister of Energy, Belkacem Nabi, sought a radical shift in gas-pricing policy for Algerian gas, requesting a price FOB – or for pipeline gas at the Algerian border – equal to crude oil parity with light Algerian crude oil. While the concept of crude oil parity (CIF) worked for Japan, which

79. M.H. Hayes, *Algerian Gas to Europe: the Transmed Pipeline and Early Spanish Gas Import Projects*, 13 Working Paper no. 27 (Program on Energy and Sustainable Development, Stanford University and James A. Baker III Institute for Public Policy Energy of Rice University, 2004). Original source: A. Aïssaoui, Algeria: the Political Economy of Oil and Gas at 6, 13 (Oxford University Press, Inc. 2001).

was using light sweet crude in its power plants located near the harbour, gas marketed in Europe would have to carry substantial infrastructure costs to bring the gas from the landing point to the customer and a FOB gas price would not even cover the costs to transport the gas to the border of the customer. It was clear that this pricing formula would not allow the gas to be marketed, but Algeria claimed that the gas should be marketed in segments which would reflect the premium value of gas over oil. As Hayes notes"the new political leadership of Sonatrach would demonstrate unprecedented willingness to withhold supplies to achieve these price demands".[80]

Shortly before the finalisation of the Transmed pipeline in 1980, Algeria asked for $5.50/MMBtu instead of the $3.50/MMBtu that would result from the price formula agreed in 1977. ENI rejected this request and the conflict was quickly escalated by Algeria, which stopped paying its share related to the joint part of the Transmed.

Even though the price with El Paso in the US had been adjusted from $0.37/MMBtu to $1.75/MMBtu in 1978, the Algerian government pushed Sonatrach to pursue price increases with each LNG buyer. Negotiations with the US buyer El Paso ended quickly. Algerian imports were only a minor part of US gas consumption and the US government feared that a higher Algerian price would prompt Mexico and Canada to claim similar increases based on a Most Favoured Nation treatment.[81]

Algerian exports were more critical to France and Belgium, although the delivery contract signed between Sonatrach and Distrigaz in 1975 was only to start in 1982. Distrigaz acquiesced to the Algerian request in 1981, seemingly under the protection of a most favoured buyer clause.

Gaz de France tried to ignore the Algerian price request and continued to pay the old price, which Algeria countered by a corresponding reduction in deliveries. Finally the new socialist French government intervened and promised a subsidy to cover the balance between a commercially viable price and the FOB parity sought by Algeria. (As GdF was a direct part of the French state budget at that time, a subsidy was not really necessary, as the state would carry the difference anyway.) Based on a crude oil price of $30/bbl, GdF signed a 20-year deal for 5.15 Bcm/year at a FOB price of $5.12/MMBtu. In return Algeria guaranteed industrial orders of about $2 billion.

After France accepted to pay a political price backed by the French government, Italy also finally gave in to the Algerian request in September 1982 based on a formula similar to the one imposed on Gaz de France, also fearing an empty Transmed pipeline. The Italian state provided a subsidy of $0.53/MMBtu. Deliveries via the Transmed Pipeline finally started in June 1983.

Other sellers to Western Europe also pursued price increases in the years 1980 to 1982 but accepted more measured increases and did not peg a major portion of the gas price to crude oil.

The 'gas battle' waged by Nabi and Sonatrach ultimately tarnished Algeria's reputation as a reliable gas supplier. By mid-1986 oil prices fell to $10/bbl and the price formula for Algerian gas would have yielded a negative FOB price. ENI re-negotiated the price before that happened and the revised contract price replaced the OPEC official price as an index and used the old and reliable netback formula instead.

80. Id., at 22.
81. Id.

In 1992, Sonatrach concluded another pipeline gas sales contract with the Spanish company ENAGAS which would be delivered by a pipeline crossing Morocco and the Strait of Gibraltar (Maghreb-Pipeline). Deliveries were to begin in 1996. The contract is a minimum-pay contract with a delivery point at the Algerian-Moroccan border (ENAGAS took care of the construction and operation of the pipeline through Morocco to Spain and later on to Portugal.) The gas price is pegged to the fuels displaced (fuel basket and a basket of crudes) with the possibility of regular reviews.[82]

As a left-over of the 'gas battle' Algeria has – unlike the other large exporters to the EU – a substantial part of its price formulas pegged to crude oil instead of to fuel oils.

4.4.5 Price Review Rounds

A cost-plus concept can provide a constant price for gas as most of the costs stem from the investment or are related to the costs of investments, such as financing and insurance costs; even maintenance costs are usually very much proportionate to investment costs.

By contrast, the concept of replacement value requires periodical re-adjustments, as the replacement value changes with market growth and as the prices and the mix of replacement fuels change. The start of Groningen deliveries happened in a still relatively stable oil price environment, so the Dutch export contracts were originally based on a fixed price without pegging to competing fuels, but they included a review clause which allowed for reviews of the pricing provisions every three years.

The Netherlands basically has the same domestic market as its export markets and similar standards on the consumption side, like fuel efficiency, etc. Therefore, a price review discussion between Gasunie and its customers was based on a similar experience of the market for gas. By contrast, Russia and Algeria could not use the experience from their domestic sector as a point of reference as it was embedded into a totally different economy. Nor could Norway refer to its own market as it has small gas consumption of its own. However, the participation of large international oil companies in the Troll field like Exxon, Shell, Total, Conoco, etc., provided a certain hands-on experience for the Norwegian sellers until Statoil and Norsk Hydro gained their own experience by negotiations and additional involvement in their buyers' market.

The concept of regular price reviews resulted in a permanent adjustment of the price formulas to the changing role of gas in the market. This was achieved by price reviews which could be held every three years. At the beginning, the negotiations between Gasunie and its customers were the trendsetters because of the original importance of the Dutch exports, and because the Dutch market itself was similar to the Dutch export markets. After the first Troll price review in 1992/1993 the price review of the Norwegian Troll contracts became equally important because of the number of international oil and gas companies involved in the Troll deals.

In the beginning the competitive situation of gas was dominated to an extent by heavy fuel oil used by large customers needed as an anchor for the developing market. With the increasing penetration of gas in the residential and commercial market, the mix shifted to light fuel oil. Today a gas import price formula would typically have a share of 60-65% pegged to light fuel, with the rest pegged to indices reflecting the competitive position in the industrial and power sector, mainly against heavy

82. ESMAP (Joint UNDP / World Bank Energy Sector Management Assistance Programme), *Cross-Border Oil and Gas Pipelines: Problems and Prospects*, 89 Technical Paper 035 (June 2003).

fuel oil. As gas for power generation became relevant again in the mid-1990s after the cancellation of the EU directive banning gas use for large power generation and the abolishment of the interdiction to use gas in Germany, in the second half of the 1990s the sellers accepted a share of about 10% linked to coal prices to reflect the competition for gas in power generation. With the Interconnector becoming operational in 1998, the issue of gas-to-gas competition was tackled in the price reviews by introducing a limited share in the formula reflecting gas-to-gas competition.

Except for the dispute with Marathon, which held a single position for sale of Heimdal gas to the Continent,[83] and very few cases linked to long-haul gas which were referred to arbitration, all review negotiations were concluded by compromise between the parties, even though some cases took up to 5 years to finalise.

The final report of the 2007 sector inquiry by the European Commission's DG Competition reflects the outcome of that development. It shows a very similar pattern of average indexation for exports from the Netherlands, Norway and Russia to EU 25 countries with indexation to gas oil between 52 and 55% and indexation to heavy fuel oil between 35 and 39%, the total pegging to fuel oil products being between 87 and 92%, with the rest more individually linked to inflation, coal, crude oil or fixed.[84] Also the price level shown by the sector inquiry is very similar between Russia and Norway, while the somewhat higher price for Dutch gas reflects the better delivery structure of Dutch gas.

By contrast, Algerian gas, which is priced at a level similar to Russian and Norwegian gas, is predominantly pegged to crude oil with about 70% against 6% and 19% for heavy fuel oil and gas oil respectively, the rest being inflation.

Gas from the UK has a price level very close to Russian gas. It is not explicitly clear from the sector inquiry but it seems to refer to all gas produced on the UKCS whether exported or landed in the UK itself. Not unexpectedly, 37% are pegged to the gas price on the NBP, while the links to gas oil and heavy fuel oil are 11 and 9% respectively. Surprisingly high is the pegging to inflation, at 28%, which seems to be a left over of early contractual patterns in the UK.

The report also compares the average pegging of import contracts between Western Europe (countries from EU 15) and Eastern Europe (countries from EU 10). While the pegging to gas oil is rather similar, with 50% in Western Europe vs. 47% in Eastern Europe, the rest is almost completely pegged to heavy fuel oil in Eastern Europe (48%) against only 30% in Western Europe, with the rest being pegged to more sophisticated indices.

4.4.6 Regulatory Change

With the gas market reform in the 1990s, exclusive concessions which were originally underpinning the high minimum-pay obligations on the buyer's side were abolished. De facto, they have been replaced by strong gas companies whose strength derives from brand recognition combined with still remaining long-term delivery contracts, especially with municipal customers. The duration of

83. *See* Decision of the Supreme Court of the United States: Ruhrgas AG v. Marathon Oil Co., 526 US 574, 585 (1999).

84. European Commission, *DG Competition Report on Energy Sector Inquiry*, 103 SEC (2006) 1724 (Brussels, 10 January 2007), accessible at <http://ec.europa.eu/comm/competition/antitrust/others/sector_inquiries/energy/fr_part1.pdf> (visited 24 January 2007) .

long-term delivery contracts has been questioned by some regulators, who fear that such contracts with municipalities would impede the development of more domestic competition.

The 2nd EU Gas Directive[85] has introduced mandatory TPA combined with compulsory organisational, legal, management and accounting unbundling. This is seen as a necessary condition to create a liquid market for gas and thereby also help to foster a single EU gas market. By the same token, the UK entry-exit system is now transposed to most countries of the EU, with the objective of creating a single EU gas marketplace.

So far, some hubs have been developed on the Continent at the initiative of (large) industry players, the first at Zeebrugge, followed by hubs at Bunde in Germany, and TTF, a notional hub for all of the Dutch system. So far these hubs serve to balance positions between rather large players. The churn at these hubs has so far been in the order of 5, clearly lower than the 15 considered minimum for a liquid trading place.

Essential elements in the discussion of Continental European gas history as compared to the US and the UK, and the development of imports are as follows:

- High import dependence from the beginning which is further increasing. The development of the gas sector in Continental European countries (except for the Netherlands) was driven by imported gas.
- As the development was driven by cross-border traded gas, rent optimisation by the exporting country always played the dominant role.
- As the main sources of supply come from super-giant fields,[86] rent optimisation for the exporting country is not only a question of netback pricing but also a question of volume. The most important question is whether exporting countries are prepared to sell gas to the power sector, which they only did to a limited extent in the past.
- National difference in regulatory design still persists, even though diminishing as a result of EU directives; substantial differences persist for taxation.
- Price elasticity of demand seems to be clearly lower in Continental Europe compared to the US and the UK, linked to a much smaller role of gas for power generation. Contrary to widespread perception, the use of gas in the central gas markets on the Continent of Europe is rather limited, certainly in Germany and France, so that the gas demand side lacks price elasticity.

Following the restructuring of the Dutch gas industry, Gasunie and its successor companies on the trading side are offering new gas under annual contracts for domestic consumption or export. Such gas is offered either with a fixed price arrangement or with the price being pegged to fuel oil indicators.

The most intriguing question is about the difficulties and risks of transition from a system with strong players to a system with one or several market places with high liquidity. While the necessary

85. Directive 2003/55/EC of the European Parliament and of the Council of 26 June 2003 concerning common rules for the internal market in natural gas and repealing Directive 98/30/EC, Official Journal of the European Union L 176/57 15.7.2003.

86. The Russian fields Yamburg, Urengoy and Medvezhye, and after 2000 also Zapolyarnoye, the Algerian Hassi'R Mel and Dutch Groningen and the Norwegian field Troll – all qualify as super-giants.

conditions for such transition are believed to be known (TPA and unbundling) it is not so clear what the sufficient conditions for a successful transition would be. When there is lack of regulatory control upstream, the question is what the overall cost / benefit balance of the transition would finally look like. As a representative of a gas-producing company mentioned during a session of the Energy Charter's Industry Advisory Panel: producers are interested and know how to supply their gas to a market with deep liquidity, or to a market with low liquidity but with strong players; however, markets with low liquidity and weak players are difficult to supply.

4.4.7 Cross-border Gas Deliveries in Former COMECON States

Development before and after the fall of the Berlin Wall

In the East, gas exports from the USSR to other COMECON states were arranged as a part of the coordinated central planning process of COMECON. A typical example was the participation of non-USSR countries in the development of the Siberian gas fields and the building of the respective pipelines in the framework of the 9th five-year plan of the USSR by providing material resources and labour forces. This participation was compensated by deliveries of defined volumes of gas over a defined time (Orenburg and Yamburg agreements) at no cost or at a favourable price (combination of barter with cost-plus principle).

In addition, most countries of the then COMECON were transit countries. They received gas as a compensation for their transit service, via some notional prices for both the gas and the transport service, which determined the relationship between transported volumes and gas delivered as a payment. (This is also a quasi-barter deal, as the notional prices for both the gas and the transit capacity merely served to calculate the volumes of compensation gas).

After the fall of the Berlin Wall in 1989, the central planning coordination of the COMECON ceased to exist, but the delivery obligations stemming from previous participation in construction work continued to be in force and the delivery obligations were fulfilled by the USSR and then by Russia after 1991. Eventually those contracts, e.g., the Yamburg and Orenburg agreements between the USSR and the GDR, were transferred to VNG on one side and to Gazprom on the other. After the expiration of the original term, they were prolonged and transformed in line with the standard concept of long-term contracts.

Similarly, the arrangements with the Slovak Republic and the Czech Republic, whereby the transit arrangements were paid by gas deliveries, were changed in 1998 and split into a long-term supply contract and a transportation agreement (both in line with the concept of the respective contracts in West Europe) with a duration until 2008 (and possible prolongations). The countries of Central Europe thus made an early adjustment to market-oriented gas import prices, following the same model and level as for the countries of Western Europe.

However, the price of gas supplied by Russia to other former Soviet countries (with the partial exception of the Baltic States) remained significantly lower than the price for export to Central and Western Europe, even if corrected for transportation costs (*see Figure 42*). The steep increase in oil and gas prices in 2005 made this differential between 'political' and 'market' pricing even wider.

Since 2004/2005, Russia has indicated that it is no longer willing to supply gas for export at non-market related prices. In turn, Gazprom has taken initiatives to restructure the arrangements with other former Soviet countries both in relation to gas supply and by separating transit and gas deliveries. The aim seems to introduce a new netback pricing principle for gas supply: in calculating the market price for gas, the Russian side takes as the starting point the price in the EU markets at the end of the pipeline (Germany, France, Italy) and deducts the transportation costs between the importing country in question and the countries at the end of the pipeline.

Gazprom's announced intention is to reach a financial return on its export operations to former Soviet states on an equal level to its exports to EU countries.[87] From a Russian perspective as a resource owner, the EU in this case is the natural benchmark for such netback pricing formula calculations since it is Russia's largest export market with the highest replacement value and a potential for extra demand for Russian gas.

The restructuring of these arrangements has been made more difficult by the fact that for years Gazprom was paying for gas transit in kind, i.e., with gas supplies whose volumes were calculated at notional non-market prices. This contributed to a lack of transparency in gas supply and transit, and has complicated the shift to the market-based principles for both gas sales and gas transit.

A result of the new pricing approach will be that only a smaller part of the gas sector in other former Soviet countries will be able to afford gas at the new import price and that prices for the household sector will have to be raised. This will create significant social and economic challenges, but will on the other hand trigger efforts to use gas more efficiently.

The overall picture is that the area of commercial Russian export gas pricing has been steadily expanding. Prior to 1991, it only covered deliveries to countries within the then EU; after 1991 it also included the former COMECON member-states Poland, Czech Republic and Slovakia plus the Baltic States. In 2006 it included EU-25 plus Ukraine and other former Soviet countries. At the end of 2006, Russia and Belarus reached an agreement separating gas deliveries and transit, and increasing the gas import price to the netback level from the EU market within 5 years (*see Figure 42*).

The average[88] price of Russian natural gas deliveries to former Soviet countries (excluding the Baltic States) in 2004-2006 changed as follows:

2004 –$54.22/1000m^3

2005 – $63.60/1000m^3

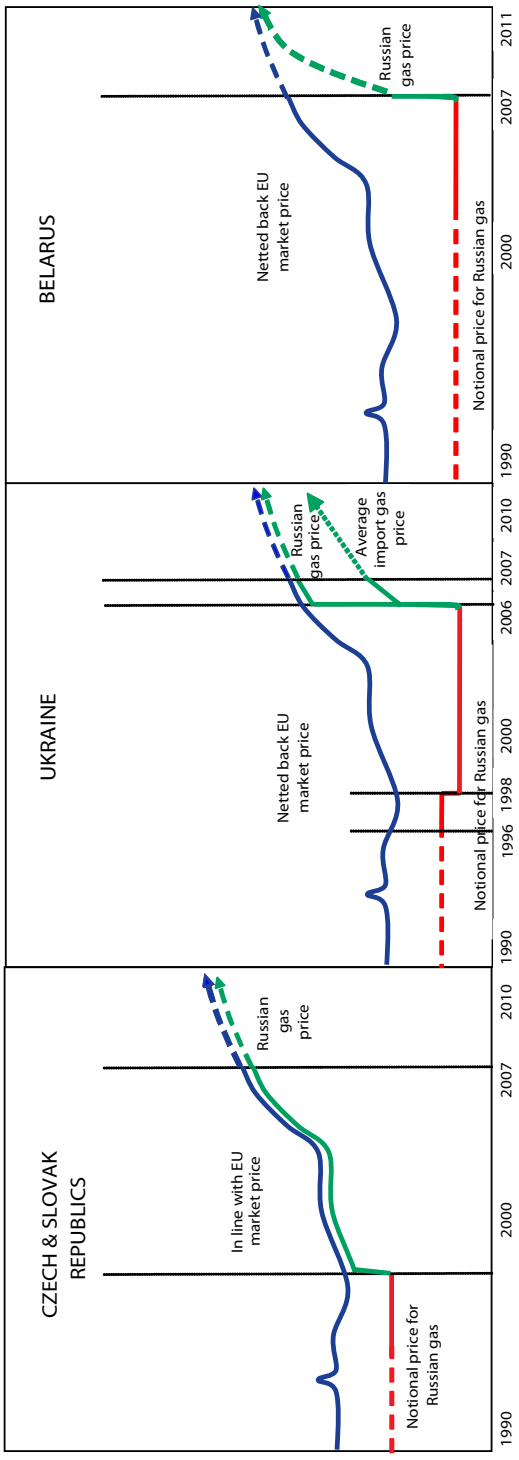
2006 – $115.00/1000m^3

It remains to be seen how the new pricing approach will eventually be adapted to the markets for Russian gas to the South, and also to the potential markets in the East, in particular to China.

87. OAO Gazprom, *Transition to the Market Principles of Cooperation with the Former Soviet Union Republics. Operations in International Gas Markets. Diversification of Gas Export*, at <http://www.gazprom.ru/articles/article19812.shtml> (visited 24 January 2007).

88. Id.

Figure 42: Russian Prices to the EU and Countries along the Pipeline



NB:
1. The figures are entirely for illustration purposes and, therefore, may not fully reflect the actual price levels and movements
2. The illustration for "Netted back EU market prices" are based on the IEA's World Energy Outlook, 2006
3. Estimates for futures gas prices movements beyond 2007 are entirely illustrative
4. Recent actual price figures for Ukraine and Belarus, based on information form public sources, are as follows:
   For Ukraine - Russian gas price: $230/1000m^3 (2006); Average gas price (for a mixture of Russian/Central Asian gas): $95 and $135/1000m^3 (2006 and 2007 respectively)
   For Belarus - Russian gas prices: $100/1000m^3 (2007) It will reach market price level by 2011 in agreed upon steps (67, 80, 90 and 100% from 2008 to 2011, respectively)
5. Notional prices for Russian gas were used to determine volumes of gas as compensation for transit services.
   For Ukraine: $80/1000m^3 until 1998; $50/1000m^3 from 1998 to 2006
   For Belarus $47/1000m^3 until 2007

Source: Energy Charter Secretariat

In the Caucasus, which takes comparatively small volumes of Russian gas, Russia now faces competition from Azerbaijan, which will become self sufficient as the production from the Shah Deniz field in the Caspian builds up. Georgia has the option to take its transit fees for gas transit from Azerbaijan to Turkey as gas in kind, and furthermore is entitled to additional deliveries of Azeri gas at favourable conditions (as of early 2007, $120/1000m^3$ for Azeri gas compared to $235/1000m^3$ for Russian gas).

While China offers a huge potential for the use of gas, especially in its fast-growing power sector, the competitive situation of gas in China is largely determined by competition with coal in power generation and only to a small extent by the value of internationally traded fuel oils, as in Continental Europe. China has abundant reserves of coal and a long tradition of building its own coal-fired power plants with relatively low labour costs. By contrast, gas turbines for power generation have to be imported. As a result, the costs of coal-fired power generation capacity in China are at a similar level to CCGTs, so that gas cannot enjoy its customary investment premium when used for power generation, as in most other markets. So in the Chinese market, the replacement value of imported gas would largely be determined by the thermal equivalence with domestic Chinese coal. While there is certainly an environmental premium for gas over coal, this cannot be easily determined nor realised, so that the netback from gas sales to China may not be more attractive than the netback from sales to Europe.

Selected country-by-country overview of recent developments in pricing and prices

Bulgaria

Bulgaria remains the only country with which Gazprom still has a barter agreement, i.e., where transit is paid for in kind with gas supply. The existing agreement on transit expires in 2010 and Gazprom has started negotiations to shift to market conditions for sales and transit of gas.[89]

Under the terms of the agreement concluded in 1998, Bulgaria pays international prices for some of its gas, in the amount of 1.7 Bcm/year, according to a self-adjusting formula that pegs quarterly the price to oil and other energy commodities. As of 2006, this level constitutes about $257/1000m^3$. According to a second contract for transit fees, Russia pays $1.67/1000m^3/100km$.[90] Transit services are paid not in cash, but in kind, by gas at a fixed rate of $83/1000m^3$. This level is higher than the $75/1000m^3$ average price in Europe at the time of the conclusion of the contract, but much lower than the $240/1000m^3$ that was the price as of end-2006.

Bulgargaz used to roll in the cheap gas received for transit with the more expensive gas received from the suppliers Overgas, WIEE and Gazexport, and offered to Bulgarian gas consumers the gas price 'at the entrance of the system' ($172/100m^3$ in 2006). International economic developments, especially the weakening of the US dollar, higher international gas prices and the large volume of gas transiting through Bulgaria meant that the ratio of gas price to the transit fee became more favourable for Bulgaria.[91]

89. <http://www.bbspetroleum.com> (visited 24 January 2007).
90. <http://www.rusnet.nl/news/2006/01/16/currentaffairs02.shtml> (visited 3 April 2006); original source: M. Brunwasser, *Bulgaria Rejects Bid for New Gas-transit Contract*, in International Herald Tribune, 15 January 2006.
91. Id.

The contract between Gazprom and Bulgargaz will expire in 2010. Gazprom has, however, already requested Bulgargaz to change the terms of the contract signed in 1998 concerning the supply of gas to Bulgaria and the transit of gas through Bulgaria to Turkey, Greece and Macedonia and shift from the in-kind payment to a cash payment.

Romania

Romania imports about 40 percent of its natural gas from Russia with transit through Ukraine. The other 60 percent is produced locally. Romania is also an important transit country for the Russian gas that is supplied to Bulgaria, Turkey, Greece and Macedonia.

In May 2006, a contract was signed for the gas supply from Russia to Romania for the period from 2010 to 2030. The price of gas supplied to the Romanian market by Gazprom intermediates is reported to be around $280/1000m^3$.[92] At the same time, the gas prices of domestically produced gas are $110/1000m^3$. The Romanian gas regulator envisages convergence of domestic gas prices to the level of import prices by 2007-2008.

Baltic States

Since 1999-2000 supplies of Russian gas have been carried out on the basis of long-term contracts until 2015, with the price determined according to formulas based on market quotations of the prices for alternative fuels.[93] In 2000-2004 the price of gas supplied to the Baltic States constituted 90 percent of the West European level.

Since 2004 Gazprom has been achieving adjustments of the prices in contracts to the Baltic States, with the goal of achieving 95 percent of the prices set at the level of Western European supplies. Gazprom aims at a further gradual price increase for gas to Baltic States with the objective of reaching market levels for all customers by the beginning of 2008.

Ukraine

Until 2005 the bulk of Russian gas supplied to Ukraine was delivered as barter payment for transit services for Russian gas. Ukraine was also importing substantial volumes of gas bought in Central Asia (primarily from Turkmenistan), mostly through intermediaries and with a considerable element of barter payment.

In 2005, Ukraine paid a notional $50/1000m^3$ for Russian natural gas and the corresponding transit fee was $1.09/1000m^3/100km$. After intense negotiations in 2005, and a reduction of gas supplies to Ukraine and subsequent reduction of transit through Ukraine from 1-3 January 2006, an agreement on the sales of gas to Ukraine was signed on 4 January 2006 between Gazprom, Naftogaz of Ukraine and the Swiss-based intermediary company RosUkrEnergo (RUE). In addition, an agreement was concluded between Gazprom and Naftogaz of Ukraine regarding the volume

92. Information provided on the website of the Balkan and Black Sea Petroleum Association (BBSPA), *BBSPA Comments and Statements on Recent Gas Price Increase in CIS Countries, Bulgaria and Romania*, at <http://www.bbspetroleum.com> (visited on 9 February 2007). This information was not, however, released or officially confirmed by Gazprom.

93. Information from the briefing by OAO Gazprom on *Transition to the Market Principles of Cooperation with the Former Soviet Union Republics. Operations in International Gas Markets. Diversification of Gas Export* at <http://www.gazprom.ru/articles/article19812.shtml> (in Russian) (visited 24 January 2007).

and conditions of transit of natural gas through the territory of Ukraine to European consumers for the period 2006-2010.

Under the agreement, RUE buys gas from Central Asian countries (Turkmenistan, Kazakhstan and Uzbekistan) at their external borders. In 2006, the price paid by RUE for Turkmen gas at the Turkmen border was $65/1000m^3$. There was also up to 17 Bcm of gas available to RUE from Gazprom at the base price of $230/1000m^3$ at the Russia-Ukraine border (a price based on EU replacement value netted back to the Russia-Ukraine border) The aggregate price of the gas sold by RUE into Ukraine was $95/1000m3 in 2006 and $130/1000m^3$ in 2007 (*see Figure 42*).

Since January 2006, Ukraine is no longer a major consumer of gas produced in Russia (it is not clear what volumes of Russian gas at $230/1000m^3$ were actually sold to Ukraine), and the bulk of imported gas that comes to Ukraine is produced in Central Asia. The price of Central Asian gas supplied to Ukraine by RosUkrEnergo is based on the individually negotiated price at the relevant Central Asian producer-state borders (e.g., on Turkmenistan-Uzbekistan, Uzbekistan-Kazakhstan, Kazakhstan-Russia border), plus the cost of transportation to the Russia-Ukraine border.[94] Since these prices are substantially lower than the netback price as calculated by Russia for its own domestically produced gas for export, the agreements between Russia and Ukraine, therefore, include a ban on the re-export of gas from Ukraine to prevent arbitrage on this price differential.

In relation to transit, the January 2006 agreement stipulated that Gazprom pays Ukraine in cash the fee for the transit of Russian gas to European customers through the territory of Ukraine until 1 January 2011 at the rate of $1.60/1000m^3/100km$. The agreement foresees the possibility of increase of the transit fee by the consent of both sides.

At the end of 2006, Naftogaz of Ukraine had enough natural gas deposited in the Ukrainian underground gas storage facilities in order to satisfy domestic gas demand during the winter period and to provide uninterrupted transit to the European customers.[95]

The price of Central Asian gas supplied to Ukraine has increased in 2007; the price for Turkmen gas purchased for Ukraine at the Turkmen border for 2007 is $100.08/1000m^3$ (up from $65/1000m^3$ in 2006), whereas the price for Uzbek gas has been set at $100.75/1000m^3$, plus $24.6/1000m^3$ for transportation to the Ukrainian border.[96]

Moldova

The relationship of Gazprom with Moldova was based in 2006 on short-term (quarterly) contracts. According to these contracts, in the first half of 2006 Gazprom supplied gas to Moldovagaz at the price of $110/1000m^3$.[97] This price was 37% more than the price paid in the period between 1996 and 2005, reflecting the general shift towards a new pricing approach for exports of Russian gas based on its replacement value in the EU.

94. For more details, *see* А.А. Конопляник, *Российско-украинский газовый спор: размышления по итогам Соглашения от 4 января 2006 г. (в свете формирования цен и тарифов, экономической теории и ДЭХ)* 43-49 Нефть, газ и право no. 3 (2006); 37-47 Нефть, газ и право no. 4 (2006).
95. Information provided by Naftogaz of Ukraine.
96. Information provided by Gazexport.
97. Briefing by OAO Gazprom on *Transition to the Market Principles of Cooperation with the Former Soviet Union Republics. Operations in International Gas Markets. Diversification of Gas Export* at <http://www.gazprom.ru/articles/article20350.shtml> (in Russian) (visited 24 January 2007).

Effective 1 July, Moldova began paying $160/1000m^3 for natural gas supplied by Gazprom. The price for transit of Russian gas through Moldova remains unchanged at $2.50/1000m^3/100km.[98]

Belarus

Belarus was the last former Soviet country to buy gas based on non-commercial considerations, which were also linked to the agreement to create a Union State between Russia and Belarus. Thus Belarus had the most favourable gas supply conditions of all former Soviet republics, with a price of gas at the level of $46.68/1000m^3. This should also be seen in the context of a low transit charge of $0.75/1000m^3/100km.

This price that Belarus paid until the end of 2006 was close to the level of Russian domestic prices in the neighbouring Smolensk area. The price is re-calculated quarterly on the basis of the formula considering the index of price fluctuations for gas oil and mazut (RFO) and monthly re-calculation taking into account the factual calorific value.

In 2006, Gazprom started negotiations to shift to market-based principles in its relationship with Belarus. After long and partly controversial negotiations, Russia and Belarus agreed at the very end of 2006 on a new 5-year contract, under which supply and transit would be handled separately. For 2007 the transit fee will be raised to $1.45/1000m^3/100km and the gas price will be $100/1000m^3.[99] The gas price will be raised over the next 5 years to a level corresponding to the netback from the main EU gas markets (*see Figure 42*). As part of the agreement Gazprom will buy 50% of Beltransgas for a price of $2.5 billion paid over four years. Belarus will pay $30/1000m^3 in shares of Beltransgas, and the remainder of the price in cash.

While prices at the beginning of 2007 were equal to approximately 50% of the EU netback value at the Russia-Belarus border, according to the December 2006 agreement, Russian export gas price to Belarus will reach 67% of the netted-back European level in 2008, 80% in 2009, 90% in 2010, and 100% in 2011.

Caucasus

The price for Russian gas in Armenia, Georgia and Azerbaijan was re-adjusted for 2006 and set at the level of $110/1000m^3. It is reported that for 2007 a number of Georgian import companies agreed to a price of $235/1000m3 for the first quarter of 2007. Russia asked for a price of $230/1000m^3 from Azerbaijan,[100] but as of December 2006 no request for volumes at that price was made by Azerbaijan. In 2006 Gazprom raised the price for supplies to Armenia from $54/1000m^3 to $110/1000m^3, the latter price being valid until 2009.[101]

The gas supply situation in the Caucasus is set to change significantly with the start of production from the Shah Deniz gas / condensate field in the Azeri Caspian, where commercial gas production began in December 2006. The majority of the gas from this field will be piped through the South Caucasus Pipeline to Turkey. However, volumes will also be available both to Azerbaijan and to Georgia. Georgia has indicated that it would like to meet the majority of its gas import needs

98. Moldovan news agency Basapress, 3 July 2006.
99. Gazprom, News, 1 January 2007 at <http://www.gazprom.ru>.
100. International Herald Tribune, 12 December 2006.
101. BBC News, 1 April 2006.

through imports from Azerbaijan. The reported price of the first gas from Azerbaijan to Georgia in early 2007 was $120/1000m^3. However, once transit volumes increase, Georgia is entitled to gas at more favourable conditions under the transit agreement.

Exports from Central Asian Countries

Kazakhstan, Uzbekistan and Turkmenistan are major producers of natural gas, but they are not yet significant players on international gas markets. The only export option beyond neighbouring markets within Central Asia (e.g., relatively small volumes of Uzbek gas exported to Kazakhstan, Kyrgyzstan and Tajikistan) is through the Russian pipeline network.

Gradually, the Central Asian producers (Turkmenistan, Uzbekistan and Kazakhstan) are receiving higher negotiated prices for their exports to and through Russia. In 2006 the prices were increased for Turkmen gas from $44 to $65/1000m^3 and from $44 to $60/1000m^3 for Uzbek gas.[102] For 2007 the border price for gas exported from Turkmenistan was raised to $100.08/1000m^3 and for Uzbek gas to $100.75/1000m^3. At the same time, Kazakhstan was reported to buy 1.6 billion cubic metres of natural gas from Uzbekistan in 2006 at $55/1000m^3.

As mentioned above, the pricing of Central Asian gas supplied, e.g., to Ukraine is based on the individually negotiated price at the relevant Central Asian producer state border (e.g., on the Turkmenistan-Uzbekistan, Uzbekistan-Kazakhstan, Kazakhstan-Russian border). All of the Central Asian gas producers have the stated aim to diversify their export options for natural gas, and there are a number of pipeline projects under discussion that would link the Central Asian countries to markets in China and in Southern Asia (Pakistan, India), as well as the project for a trans-Caspian link that is intended to tie into the South Caucasus Pipeline. New export contracts would enable them to negotiate different pricing models, e.g., based on the gas replacement values in their new export markets.

4.4.8 Conclusions

The development of the gas industry in Western Europe was characterised by early imports, driven by super-giant fields.

The concept of long-term minimum-pay contracts, with pricing based on replacement value, proved to be a successful concept for an increasing penetration of gas in the energy sector in the Western part of Continental Europe. It is applied to more than 250 Bcm/year of gas imported into EU countries.

The concept was able to cope with and to adapt to the substantial changes that have taken place since its development for the export of Groningen gas in the 1960s. It was able to cope with extreme price developments like the two oil price shocks in 1973/1974 and in 1979/1980, as well as with the reverse oil price shock in 1985/1986, with major geopolitical changes like those triggered by the fall of the Berlin Wall, as well as changes in the regulatory framework like the ban of gas use in power generation and its abolition, not to mention the changes linked to the creation of a single

102. Information from the briefing by OAO Gazprom on *Transition to the Market Principles of Cooperation with the Former Soviet Union Republics. Operations at the International Gas Markets. Diversification of the Gas Export* at <http://www.gazprom.ru/articles/article19812.shtml> (in Russian) (visited 24 January 2007).

market in the EU. The concept of long-term contracts has been recognised as a major instrument to create security of supply. However, some questions remain open, for example how to reconcile long-term contracts with the concept of market opening contained in the 2nd Gas Directive, i.e., the questions raised by organisational unbundling, and how to match long-term supply contracts with corresponding long-term transportation agreements.

Imported gas is not really geared towards use for large-scale power generation, except for countries that have no domestic energies suitable for power generation and do not use nuclear power, like Italy or Spain. There seems to be a political tendency by consuming countries to avoid an extra transfer of money corresponding to the Hotelling rent to an energy-exporting country (with consequences on the balance of payments), if the amount corresponding to the Hotelling rent can be kept inside the consuming country by developing its domestic fuels or other productive resources, e.g., by investing in clean coal applications or into nuclear or, more lately, wind power and other renewables. On the other hand, exporting countries have been hesitant to provide gas at prices which would allow competition for large-scale power generation.

Adaptation to changed circumstances happened by modifying the original (very large) long-term contracts, mainly by changing the price formula to reflect developments in the competitive situation of gas, for the most part by increasing the share of gas oil at the expense of heavy fuel oil, but also by including elements to reflect the changed role of gas in power generation and later to reflect the role of gas-to-gas competition. Beyond the adaptation of the pricing formula to new competitive situations, new export projects reflected changed market conditions but kept the framework of long-term contracts, albeit with modifications as to volumes, term and more flexibility regarding the delivery point.

Long-term import contracts do coexist with domestic gas hubs or any combination on the domestic market of long-term contracts and shorter gas trading on hubs.

During 2005 and 2006 Russia took the first step in bringing its deliveries to other former Soviet countries into line with the contractual structures in Western Europe, e.g., by separating transit and supply into separate contracts paid in cash with a duration of several years. Russia agreed with most of these countries on a transition which brings their prices to a level on par with the netback from EU countries (*see Figure 42*). In this way the structure of long-term contracts is also applied to gas deliveries to the Eastern part of Europe, although with a different kind of netback principle compared to the original Dutch concept. The reference point for Russian contracts is not the replacement value at the buyer's market but the replacement value of another importing country at the end of the pipeline, corrected for transportation costs; this yields a higher net-back for Russia.

The prolongation (to between 2027 and 2036) of long-term contracts for Western Europe in the second half of 2006, the transition of supply arrangements in Eastern Europe from annually renewable gas-for-transit arrangements to long-term contracts, and the minor role that spot imports play so far, indicate that long-term import contracts will continue to play a predominant role in continental Europe in the future. This, however, does not mean that single elements that are still usual today, like pegging to fuel oil prices, will play the same role in the future.

4.5 LNG

4.5.1 Summary

Despite initial interest in LNG in the Atlantic Basin, trade growth in the region faltered between the early 1970s and the late 1990s. During this period, the Asia Pacific region dominated world trade. Now, both Europe and North America have returned as major markets, and supplies in the Atlantic Basin and the Middle East are growing rapidly.

The traditional contracting pattern of the industry has been the long-term contract. It provided a method of sharing risks between buyer and seller for these capital-intensive investments. Buyers assumed the volume risk through a take-or-pay contract and sellers assumed the price risk through a price escalation clause that attempted to track changes in energy price levels.

While contracting is becoming much more flexible, long-term contracts have remained as the principal means of sharing risks among venture partners. The new flexibility has come about in two ways; (1) a small, but growing short-term market, and (2) the development of a new pattern, which might be termed 'self-contracting'. In traditional contracting, the venture partners usually market as a group directly to specific customers. In self-contracting, partners in the LNG plant contract with one or more of their own partners (or occasionally other large upstream players) which effectively act as wholesalers to the market. The contract will usually provide a basis for the other partners to share in any rents generated by the self-contactor.

For both Northeast Asia and Continental Europe, traditional contracting patterns remain important. Prices in these contracts have commonly been linked to oil prices. Northeast Asian contracts most commonly use crude oil for the linkage, but Continental European contracts utilise mixes of fuel oil, gas oil, or sometimes crude oil. European contracts typically include review clauses, specifying that either side can request a review – usually after three years. These are less common in Asia Pacific contracts.

The traditional oil linkage of long-term contracts does not function well in the liberalised gas markets of North America and the UK, where prices are set by gas-to-gas competition. Nor do they work well for power-generation customers that are subject to economic dispatch scheduling. Hence, self-contracting is becoming the predominant pattern for these markets. When long-term contracts are used, they most commonly escalate to gas market indicators, such as Henry Hub in North America or the National Balancing Point in the UK Although traditional contracting remains the basis for most Continental trade, self-contracting is becoming more common where power-generation customers are important – such as in Spain.

Both China and India are newcomers to the LNG import market. Both were able to negotiate very favourable contracts during the period before LNG market tightness and high oil prices. However, the earlier prices that they negotiated are no longer regarded as precedents for future contracts to these two emerging LNG markets or for established LNG markets.

A combination of tight LNG markets with very high oil-price levels has revealed problems in the operation of many of the pricing clauses, particularly in Northeast Asia. As a result, contracting patterns have become somewhat unstable. There is a substantial amount of contract re-negotiation

in process, both for those contracts that provide for re-opening at some stated price level or some contracts that are nearing expiration and being considered for renewal. However, the patterns of oil linkage in Northeast Asia are likely to continue, while the Continent will be affected by competition with the UK's liberalised pricing via the Interconnector.

The reliance on self-contracting and long-term contracts with gas market indicators will probably remain the basis for LNG trade in North America and the UK.

4.5.2 Introduction

4.5.2.1 The History of World LNG Trade

The feasibility of LNG tanker transportation was first demonstrated in 1958 by the shipment of LNG from Lake Charles, Louisiana to Canvey Island in the UK aboard an experimental vessel, the Methane Pioneer. It was followed in 1964 by the first commercial trade – the CAMEL project to deliver Algerian gas to the UK and France. By 1969, three more trades had started – an additional delivery from Algeria to France, one from Libya to Italy and Spain, and one from the Cook Inlet of Alaska to Japan, the first Pacific project.

While the first deliveries from Algeria were on comparatively short-haul routes to Europe, the more distant US market was also supplied with LNG in 1972 when shipments began to a small project at Everett, Massachusetts. Deliveries began in 1978 for the much larger Algerian shipments to US terminals at Cove Point, Maryland and Elba Island, Georgia.

The early development of the Atlantic Basin LNG trade took place during a period of unprecedented change in international energy markets. This included the two oil price shocks, the widespread nationalisation of the international oil companies' concession areas within OPEC, and the restructuring of the North American gas industry. While LNG imports into Europe continued a slow increase, the North American trade contracted sharply, thereby blunting what was expected to be a substantial growth in Atlantic Basin demand.

Having experienced two oil crises in the 1970s, Japan increased LNG imports from Southeast Asia, particularly from Indonesia, in an effort to reduce Middle East oil import dependence. LNG was used mainly for power generation.

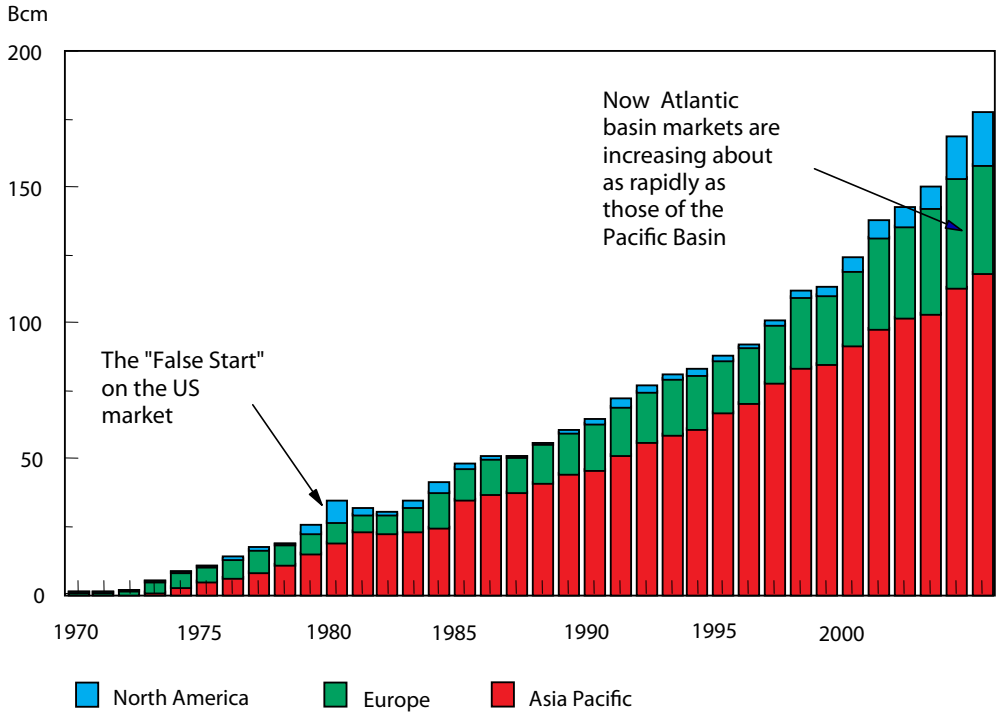
In 1979, the peak year of early LNG imports, the Atlantic Basin accounted for 44% of world LNG trade while the only Pacific market, Japan, accounted for the rest. The US alone represented 21% of world trade, more than twice as much as France, the Atlantic Basin's second largest importer. Despite the fact that two new Atlantic Basin trades – Algeria to Belgium and Algeria to Lake Charles, Louisiana – began operation in 1982, the Atlantic share of world trade had fallen to 31% by that year. And both Italy and the UK, like the US, had sharply reduced their LNG imports.

With the substantial slowdown in interest in LNG in the Atlantic, the balance of interest shifted to the Pacific as Korea in 1986 and Taiwan in 1990 joined Japan as importers. Both Abu Dhabi and Indonesia began shipments to Japan in 1977, followed by Malaysia in 1983 and Australia in 1989. It

was only with the re-emergence of both US and European LNG markets in the late 1990s, that the Atlantic Basin again became a focus for LNG market growth.

Figure 43 shows the growth of imports by region, indicating the strong contribution of Asian markets to demand. Between 1975 and 1996, the Asia-Pacific demand increased by an average of 3.31 Bcm/year (about 2.4 million tonnes, slightly more than the capacity of the typical LNG train at the time). In contrast, Europe and the US increased by only 0.76 Bcm/year.

Figure 43: Growth of LNG Imports by Market Region (Bcm)

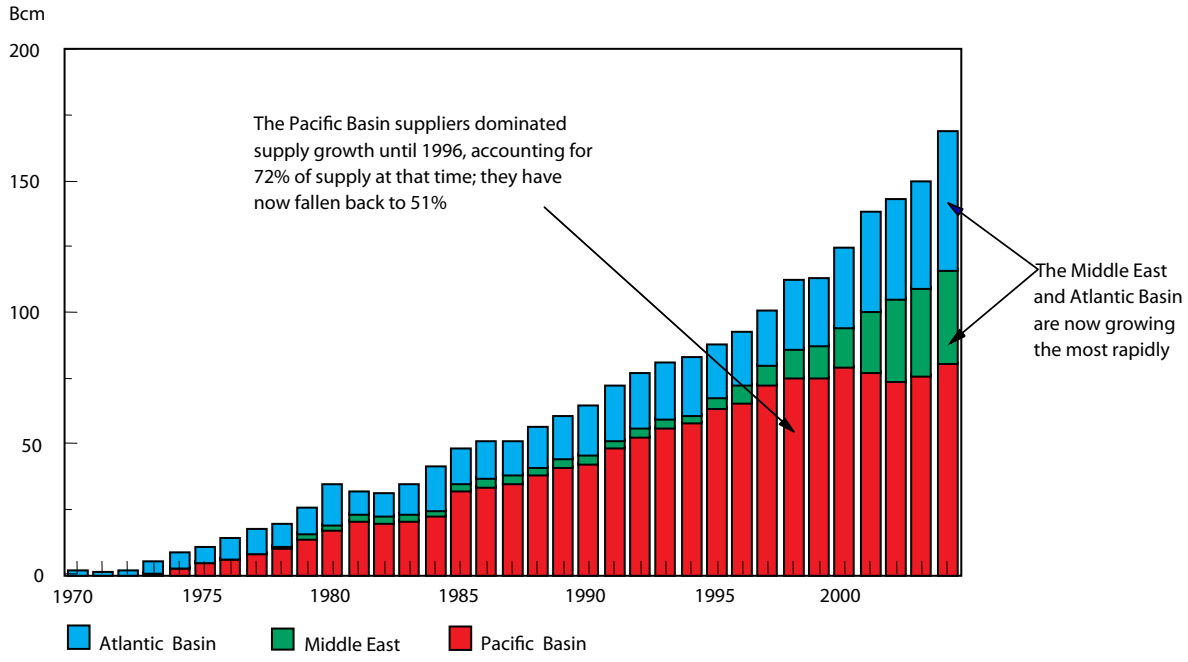


Source: Jim Jensen

The first new regional suppliers emerged in 1997 and 1999. The start-up of Qatar's 'Qatargas 1' project in 1997 represented the first new Middle East project in twenty years, and the initiation of the projects in Trinidad and Nigeria in 1999 provided the first new Atlantic Basin suppliers in twenty-five years. While Qatargas initially served the Northeast Asian market, the two Atlantic Basin projects were designed to serve newly growing LNG demand in Europe and North America. In the period from 1996 to 2004, the proportion of imports for Asia and the Atlantic Basin was much more balanced – 5.03 Bcm/year for Asia and 4.63 Bcm/year for Europe and the US.

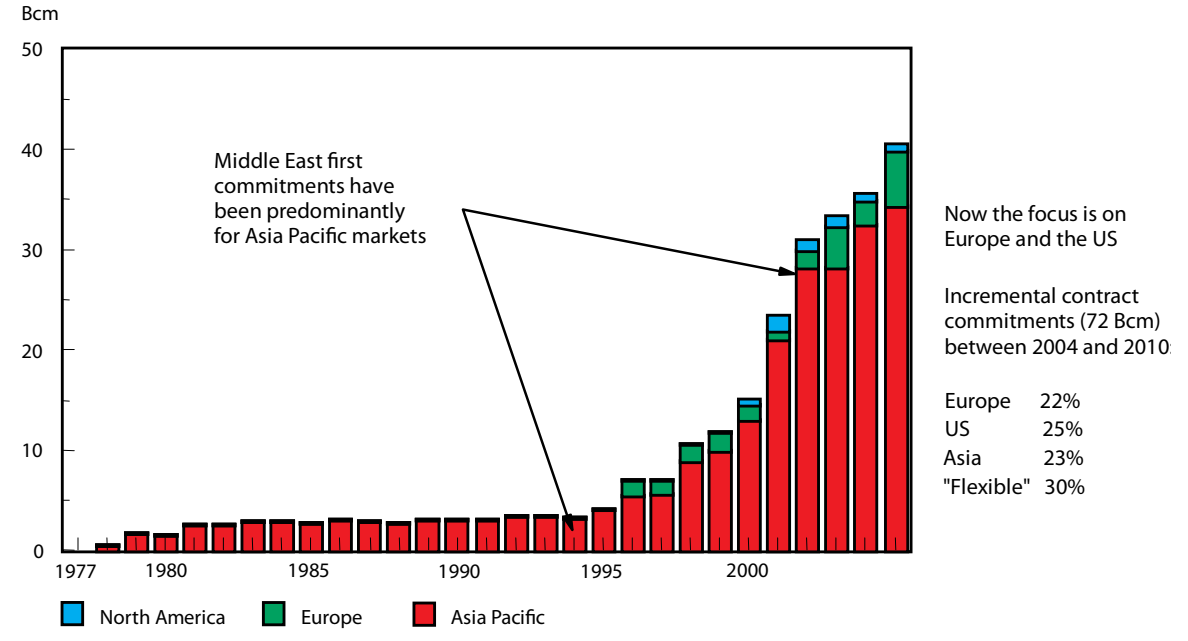
Figure 44 shows the shift from a predominantly Asia-Pacific source of LNG to a more active participation for the Atlantic Basin and the Middle East. While the initial focus of the new Middle East supplies was on Northeast Asian markets, the emergence of Europe and North America as customers is illustrated in *Figure 45*. *Figure 45* also shows the balance of forward commitments for new Middle East supplies out to the year 2010. The regional proportions are similar, although the new category – 'flexible' – will be largely for Atlantic Basin markets.

Figure 44: Growth of LNG Exports by Source (Bcm)



Source: Jim Jensen

Figure 45: The Middle East Expands and Shifts its Export Focus (Bcm)



Source: Jim Jensen

4.5.2.2 The Role of Long-term Contracting in Traditional LNG Trade

An LNG project consists of a 'chain' of capital investments whose ultimate success is at risk to the possible failure of its weakest link. The chain consists of four (occasionally five) links – field development, in some cases a pipeline to the coast, the liquefaction facility, tanker transportation and the receipt / re-gasification terminal. Each element is capital-intensive and the investment is usually front-end loaded so that revenue does not begin to flow until the project is complete. Hence breakdowns and delays in any part of the chain have adversely affected capital recovery and project internal rate of return (IRR).

To manage these risks, the traditional LNG project was based on a carefully-structured system of risk sharing. The centrepiece of the project was the long-term contract between buyer and seller for LNG – known as the Sale and Purchase Agreement, or SPA. Early contracts were typically for 20 years duration, although longer contracts were common. These long contract durations were also required by bank syndicates which financed the projects.

The point of delivery might be either FOB or CIF (ex ship), determining which party assumed the tanker transportation responsibility, but in either case the operation of the receipt and re-gasification terminal was downstream of the point of delivery and thus outside the scope of the contract. Tankers might be owned by buyer, seller or independent ship-owners, but traditionally were dedicated to the specific trade, usually for the life of the contract.

The risk-sharing logic of the contract was embodied in the phrase 'the buyer takes the volume risk and the seller takes the price risk'. Hence most contracts featured take-or-pay provisions to assure buyer off-take at some minimum level and a price escalation clause to transfer responsibility for energy price fluctuations to the seller. The early contracts viewed oil, not gas, as the competitive target and thus 'price risk' in the indexation clauses was principally defined in oil terms.

Most LNG projects have been based on a specific production block containing a large field or group of fields. Unless the project is the sole preserve of a national oil company, the project developers have usually been joint ventures of several companies, bound together in a 'shareholders' agreement' or 'joint venture agreement', depending on the nature of the licence or PSA. The effect of this structure is that the companies have operated as if they were shareholders in a corporation rather than as independent and competitive corporate entities. Marketing has usually been done by the venture rather than by the individual partners.

Petroleum tax regimes are designed to capture a significant share of the revenue from oil and gas production for the producing countries. In many of the producing countries, a national oil company (NOC) is involved, partly as an operating company but also as part of the tax regime. For example, in the common 'production-sharing agreement' form of taxation, the international partners are allowed to recover their costs from the initial revenues, but after recovery, the revenues are split with a substantial share going to the government or its NOC.

For licences where oil discoveries are anticipated, the valuation of the revenue stream is relatively straightforward, since it is assumed that the oil is valued at international prices (adjusted for quality and location). For gas, valuation has usually been more complex, since there has not been a 'world gas price' to act as a reference. Typically, the valuation nets back from the prices set in the sales contract, usually with allowances for liquefaction costs.

Because the costs of gas transportation are commonly higher than those for oil, tax regimes designed for oil discoveries usually over-tax gas. Thus a major part of the discussions with the host government is usually to negotiate a discount of oil tax terms. Thus the PSA may permit the international partners to retain a higher percentage of the gas revenue stream after cost recovery than it will for oil revenue.

Since the tax regime has often been negotiated on the assumption of specific contract-derived cash flow, the increasing destination flexibility of the new markets can create excess rents when sellers find a higher-netback market than that assumed in the contract. The failure of the producing government to share in these additional rents has been an issue in Trinidad, and future contracts will provide that the government shares in these rents.

The traditional LNG contract buyers were either large national or regional gas distribution systems, such as Gaz de France or Tokyo Gas, or major electric utilities, such as Tokyo Electric. Since these entities were almost always national companies or regulated utilities with exclusive concessions, they could reasonably foresee and manage market development and thereby handle the market risk implied by the take-or-pay and minimum pricing clauses.

The SPA was a relatively rigid document. Since it commonly dedicated each link in the chain – specific gas reserves, liquefaction capacity, specific tankers and receipt facilities – to the particular contract, it lacked volume and destination flexibility. As a result, the system did not have the ability to cover for the breakdown in any element of the chain and it was common to build in some redundancy to guarantee system reliability. But the failure of a particular trade – which did occur from time to time – generally idled liquefaction or tanker capacity, since it was difficult to shift capacity to an alternate trade. In the early years of LNG trade, this inflexibility was compounded by the fact that there were relatively few liquefaction plants and receipt terminals.

4.5.2.3 LNG Costs

LNG projects are very capital-intensive, with most projects costing several billion dollars. However, economies of scale are significant. These are particularly important in the liquefaction portion of the process.

Liquefaction plants consist of modular processing units, called 'trains', whose sizes are limited by compressor capacity. In the 1970s and 1980s, when train sizes were typically about 2 million tons, it was common to require at least three trains to justify a new greenfield LNG facility.

The design of Trinidad's first train was sized at 3.3 million tons (later de-bottlenecked to 3.6 million tons). A 3.6 million ton train has unit costs that are 20% lower than a 2 million ton train.

Qatar now has new plant designs that envision trains of up to 7.8 million tons. A plant of such a size should reduce the costs of a 2 million ton train by 43%. However, the trend in cost reduction has been slowing if not actually reversing. In the face of accelerated demand for new plants, a significant demand-pull inflation in costs – particularly for skilled design-construction firms – has been raising unit costs once again. While this inflationary effect may be moderated as new companies enter the business and the learning curve takes effect, as of 2007 the continuous decline in liquefaction costs seems at least temporarily halted.

The scale effect of LNG tankers is much less pronounced. Current designs are in the 135,000/140,000 cubic metre range, while new designs of up to 225,000 cubic metres are on order. A 225,000 cubic metre tanker should reduce tanker costs on a 6,000 nautical mile haul (about the distance from Nigeria to the US Gulf Coast) by about 13%. While, for a time, tanker costs also seemed to be declining rapidly, much of the decline was attributable to intense competition by Korean yards when they entered the business, in competition with the Japanese yards that long dominated tanker construction.

Re-gasification costs have shown much less cost reduction than either liquefaction or tanker costs. Much of this is due to the fact that much of the cost is in storage and infrastructure, which have been less susceptible to cost reduction.

4.5.2.4 The Emergence of More Flexible LNG Markets

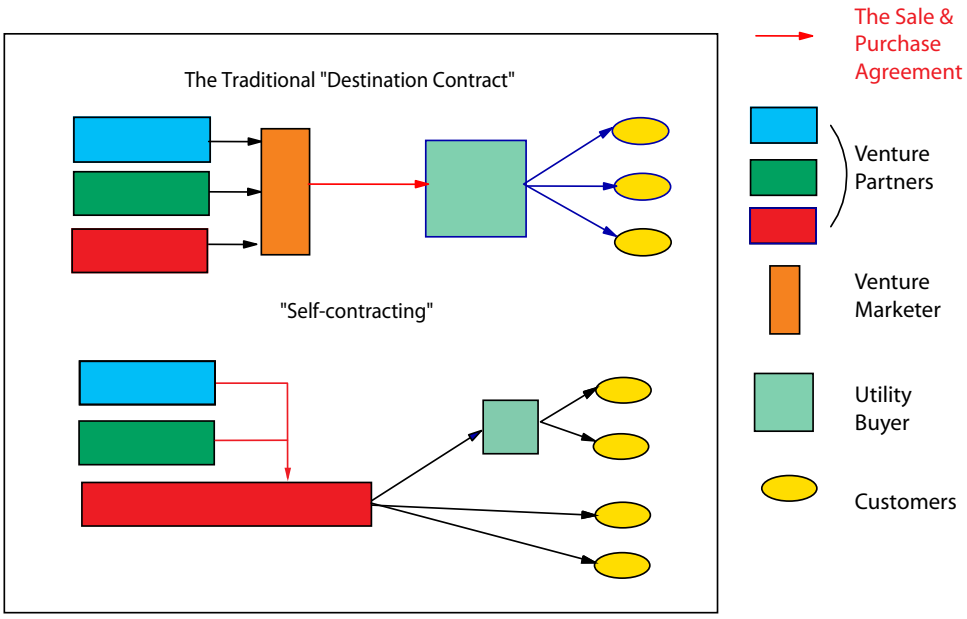
Long-term contracts have all but disappeared in the restructured North American and UK onshore gas markets, and there have been strong efforts to open gas markets within the rest of the European Union. There is also substantial pressure to make LNG contracting more flexible, but suppliers have shown a great reluctance to proceed with a new project without some degree of long-term contract protection. Thus the industry reliance on long-term contracts seems likely to remain and act as the 'filter' that determines the flow of new projects into the market.

The restructuring of gas and electric markets in North America and in the UK has substantially changed the way in which long-term contracts are written for those markets. Short-term contracts now predominate in the North American domestic market, and those long-term contracts that exist utilise gas market price indicators, such as Henry Hub. While long-term contracts still cover the largest existing volumes on the UK beach, the National Balancing Point is emerging as the new pricing standard in the UK.

Where once the major pipeline systems in North America, or British Gas in the UK, were the obvious potential buyers of LNG, their merchant monopoly status has now been eliminated. Buyers are now commonly smaller and much more sensitive to price competition. By seeking to minimise their market risks by relying on gas market indicators, they have effectively transferred more of the project risks to the sellers. The response of the sellers has increasingly been towards 'self-contracting' with their own marketing affiliates, effectively integrating downstream to sell directly to smaller re-sellers or end users.

In self-contracting, one or more of the partners in the venture (or their marketing affiliates) sign the SPA with the venture and assume the marketing risk for the contracted volumes (*see Figure 46*). The resulting volumes commonly become part of the seller's supply portfolio and can be sold under any terms and conditions that he chooses to utilise. Particularly in North America and the UK, where spot markets dominate onshore gas trade, self-contracting permits the seller to participate in this market. Self-contracting has become extremely important in the Atlantic Basin largely because of the competitive nature of North American markets. Traditional contracting is still the dominant pattern in Northeast Asia and remains important on the European Continent.

Figure 46: The Newer 'Self-contracting' Approach to LNG Marketing Compared to the Traditional 'Destination Contract'

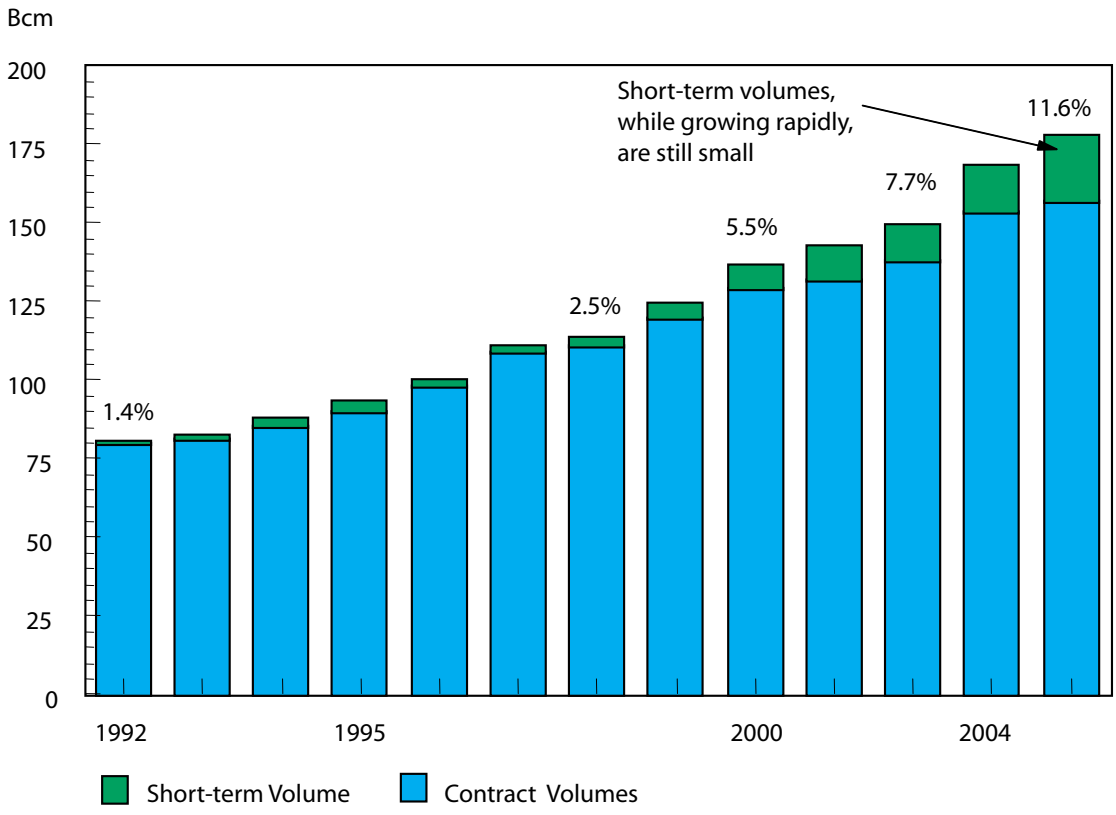


Source Jim Jensen

Despite the continuing reliance on long-term contracts, these changes in contracting patterns have made the LNG market increasingly flexible. The new flexibility has come about in two ways – (1) a small, but growing, short-term market, and (2) the growing importance of 'self-contracted' volumes.

A small 'short-term' market in LNG has existed for some time. Despite the rigidity of long-term contracts, buyers have swapped cargoes from time to time as one customer found himself temporarily long on supply while another was temporarily short. But these balancing trades have been quite different from the active merchant spot markets that operate at Henry Hub in the US or the National Balancing Point in the UK. However, a true spot market in LNG cargoes is increasingly developing and introducing flexibility into LNG trade. *Figure 47* shows the growth of short-term trading in LNG.

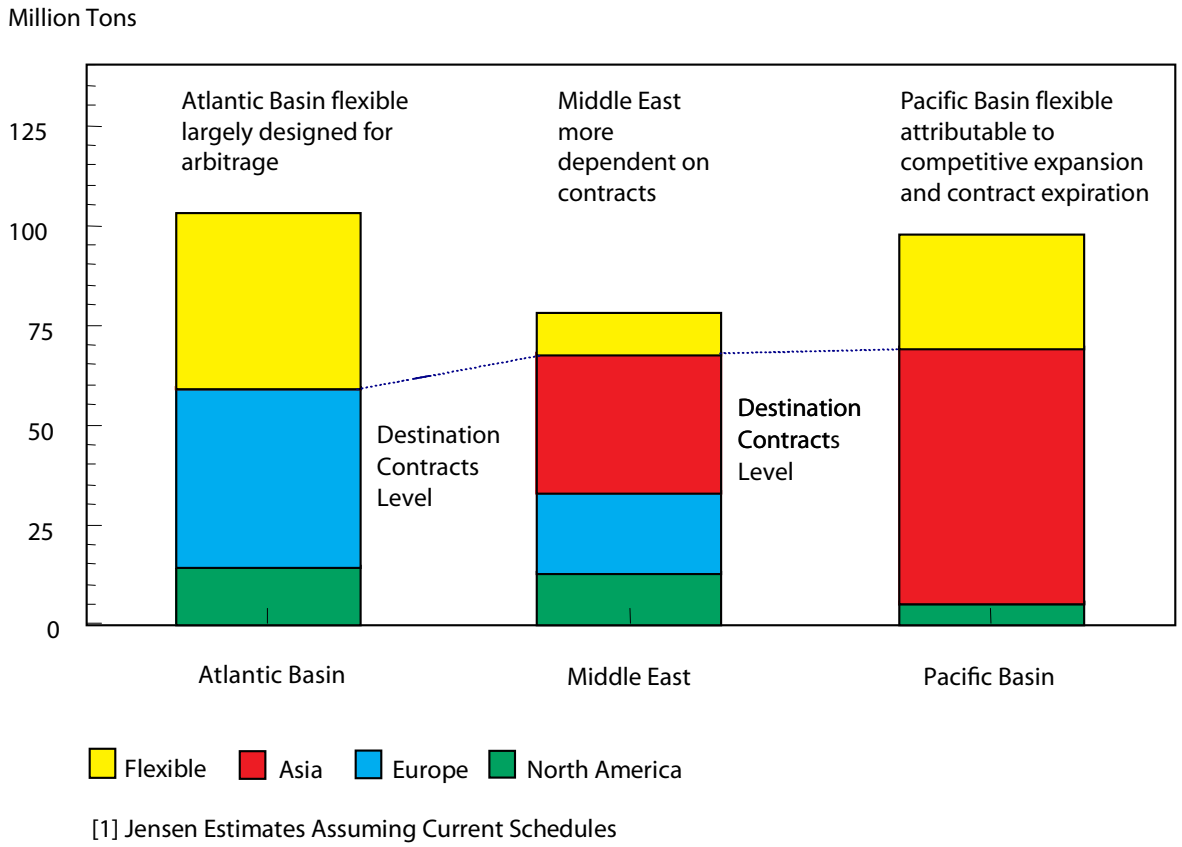
Figure 47: LNG Trade Showing the Growing Role of Short-term Sales (Bcm)



Source: Jim Jensen

The traditional contract can be described as a 'dedicated contract', where the contract designates the destination of the cargoes. Self-contracting gives suppliers destination flexibility that was not available under the traditional contracting system. The ultimate market destinations are defined, not by the terms of the contract, but by the best netbacks available to the supplier, given his portfolio of liquefaction and re-gasification assets. Some idea of the importance of these new flexible volumes is the proportion of the estimated firm and probable capacity for the year 2010 that is still committed to destination contracts, versus that which remains flexible – either as uncommitted or self-contracted volumes (*see Figure 48*).

Figure 48: Estimated[1] Contractual Status of Firm and Probable LNG Capacity in Place by 2010 (million tonnes of LNG)



Source: Jim Jensen

The Middle East remains the most dependent on the traditional long-term contract, but much of its focus has switched from the Pacific Basin to the Atlantic Basin. The Atlantic Basin has become the major LNG arbitrage market, with cargoes being shifted between Nigeria and Trinidad on the one hand and the US and Spain on the other. The UK's growing LNG imports will make it an important arbitrage partner in the future. The Pacific Basin also shows a large flexible volume in 2010. This is a product of competitive expansion of new greenfield facilities, coupled with major contract expiration later in the decade.

The new destination flexibility has raised an additional issue. The regulatory authorities in Europe and North America applaud the new flexibility since it facilitates more liquid markets, and they have been anxious to eliminate 'destination clauses' in contracts where they still apply. But supplier governments have at times become upset since they may not participate in the additional rents that are possible from freer trading. There have, therefore, been some efforts by supplier governments to develop a rent-sharing mechanism between government and the marketing companies.

Rent sharing in the world of price arbitrage is an issue both for the international partners in the project as well as the government. Agreements generally assume a certain market pattern and

derive the pricing clauses to respond to the pricing signals in the destination markets. But when arbitrage presents the possibility of added rents, some mechanism to share those rents is commonly included in the agreement.

Since LNG is a cargo business, any diversion of cargoes to another market to take advantage of arbitrage rents can be relatively easily tracked and confirmed. Some agreements simply split the rents among the partners on some formula basis, for example, in proportion to the partner's share in the venture. Where the buyer controls the cargo and no agreement is in place, the sellers can still attempt to capture the arbitrage rent but may have to negotiate a split with the buyer.

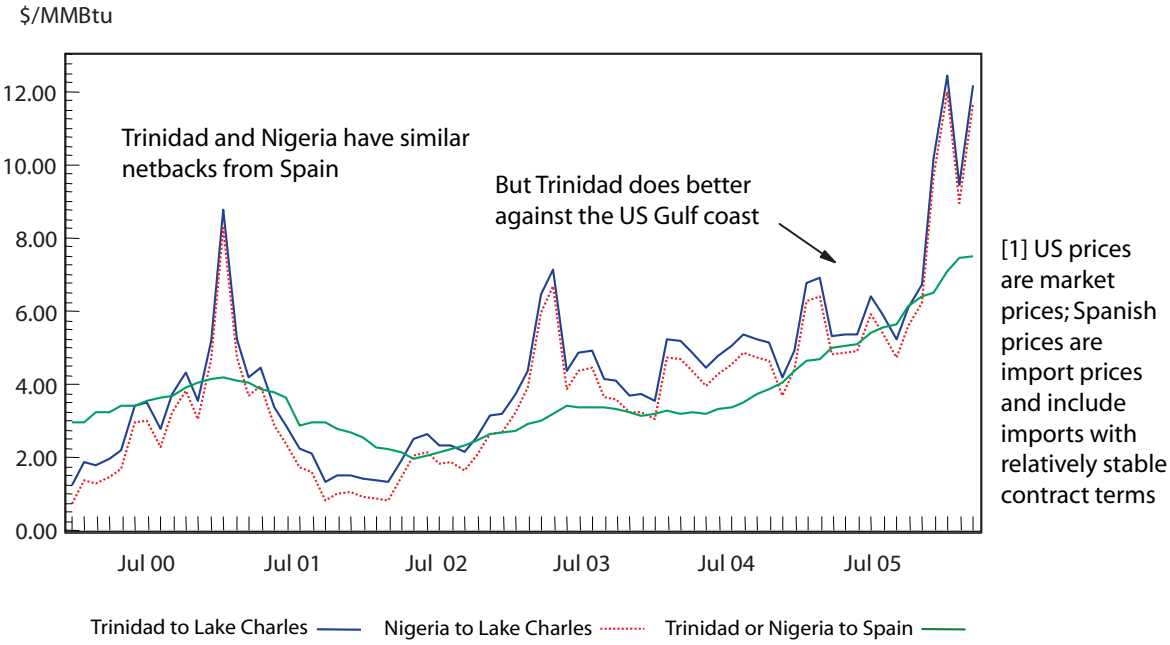
Cargoes destined for the restructured markets – North America and the UK – are usually linked to Henry Hub or the NBP. In theory there might be added rents available ex-terminal for a skilled marketer, but these are usually not a part of the upstream sharing process.

4.5.2.5 Arbitrage

This increased flexibility has made possible the arbitraging of prices among market regions. The Atlantic Basin now has an active arbitrage market involving European and US customers, and the Middle East has become the pricing arbitrage focal point between the Atlantic Basin and Northeast Asia.

Figure 49 illustrates how suppliers in Trinidad and Nigeria might view the prospect of shipping LNG to Spain or to the US Gulf Coast. Assuming the buyer were to offer the prevailing price in his market at the date on the graph, the supplier would 'net back' to the loading dock the values shown in *Figure 49*. At times the Spanish market offers superior netbacks, while at other times the Gulf Coast is better. Trinidad and Nigeria are equidistant from each market and thus achieve similar netbacks, but Trinidad is closer to the Gulf Coast and enjoys better netbacks to that market than Nigeria. It is important to note that, while the US Gulf Coast – with its Henry Hub trading centre – provides liquid and transparent spot-market price data, publicly available prices for most other markets, including Spain, only provide average border prices. Since these average contract volumes with spot trade, they are not on the same basis as the US data. We do not really know the prices at which spot cargoes might trade in Spain, while we do know that for the US Gulf Coast.

Figure 49: Illustrative Netbacks[1] for Selected Atlantic Basin Arbitrage Partners – Trinidad and Nigeria to Spain and the US Gulf Coast

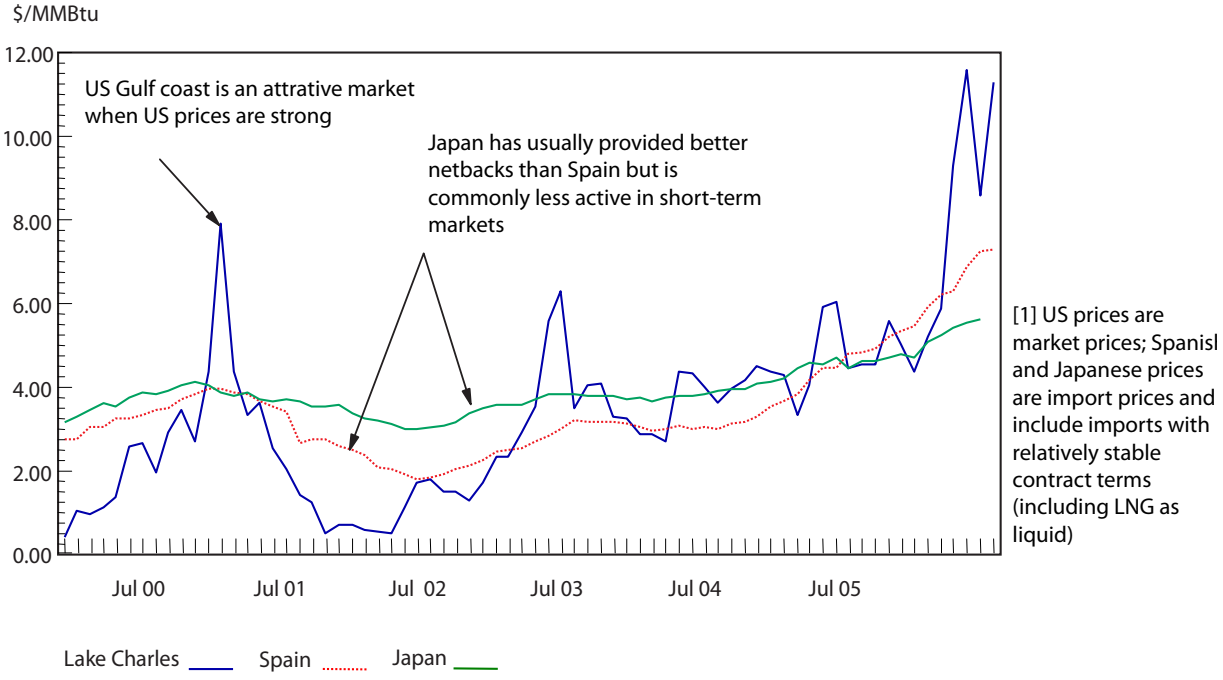


Source: Jim Jensen

As an example of the way in which Atlantic Basin arbitraging worked during the winter of 2000/2001, Distrigaz and Gaz de France (after negotiation with Sonatrach) re-routed five Algerian cargoes from European destinations to the US. The extra profit was reportedly shared equally with Sonatrach. In 2003, Gaz de France re-routed 12 tankers to the US.

The Middle East provides price arbitrage between markets in Asia and those in the Atlantic Basin. Furthermore, by directing cargoes either to Europe or to North America, it also participates in Atlantic Basin arbitrage. *Figure 50* shows the netbacks to the Middle East from markets in the US Gulf Coast, Spain and Japan. The Japanese netbacks, like the Spanish netbacks, are based on border prices and thus do not really measure the netbacks available for specific spot cargoes.

Figure 50: Illustrative Netbacks[1] from the US Gulf Coast, Spain and Japan to the Middle East Showing Arbitrage Patterns



Source: Jim Jensen

4.5.3 LNG Pricing

4.5.3.1 Regional Differences in the Logic of LNG Pricing

There are currently six significant regional markets importing LNG – Northeast Asia, Continental Europe, North America, the UK, China and India. Two of these – Northeast Asia and Continental Europe – have developed their gas industries based largely on imported supplies. Two others – the US and the UK – have developed their industries based on indigenous natural gas, but have become significant potential LNG importers after a history of relative self-sufficiency. The last two – China and India – have had comparatively small gas industries based on local production, but now envision substantial growth based on imported supplies.

Not surprisingly, the markets differ significantly not only in the balance of energy sources that compete with natural gas but also in the logic of regional gas pricing. Gas pricing in Northeast Asia and Continental Europe is a product of the price negotiations that buyers have had over the years with their suppliers who wanted to get the highest possible netback for the depletion of their national resources. On the other hand, both North America and the UK have liberalised their gas industries, and their gas pricing has reflected competition among indigenous suppliers for outlet. Upstream taxation in both countries applies equally to all producers and can be treated as a cost when the seller decides on pricing. China and India – newly emerging LNG importers – have

a history of local gas pricing that has been heavily influenced by regulation and has been largely oblivious of the price structures at which LNG is traded internationally. The concept of a uniform international approach to LNG pricing may be a theoretical ideal, but it is far from a reality in current LNG markets.

4.5.3.2 Early Atlantic Basin LNG Pricing

A major price dispute between Algeria and its customers was responsible for the sharp change in the early outlook for Atlantic Basin markets in the late 1970s (*see* also *Section 4.4.4* on Algerian gas). Upon achieving independence from France in 1962, Algeria continued the active oil and gas exploration programme originally initiated by the French. The new Algerian administration was quick to recognise that the country's large gas discoveries provided the basis for a major gas export programme. While LNG supply to Europe was in theory more expensive than pipelining, deep-water pipe-laying technology was not sufficiently advanced at the time to permit a Mediterranean pipeline crossing, so Algeria utilised LNG to serve Europe.

The initial Algerian LNG sales were either to government monopoly gas companies or regulated gas utilities. Thus, consuming governments were intimately involved in the early price negotiations and were concerned about the effect of LNG imports on their domestic gas-pricing structures. Approvals for the US were especially complicated since the US had not yet abandoned wellhead price controls and was trying to hold the line on gas prices in the face of growing supply shortages.

The Algerian government initially viewed cooperative ventures with the international industry as a key to the development of Algeria's gas resources. Sonatrach, the Algerian national oil company, was willing to set up relatively favourable initial FOB-price contracts with companies that would help it develop the industry, but with the understanding that the contracts could be re-opened later through mutual agreement when the final economics of the ventures were better known.

The death of Algeria's president in 1978 led to a change in government, including a change in the leadership of the energy ministry. This followed shortly on the international energy market upheavals as a result of the first oil shock. The new oil ministry claimed that the early LNG export contracts did not adequately protect Algeria's interests, and seized on the turmoil in international energy markets to re-open them. The ministry contended that Algeria should receive the same revenue per unit of energy for its gas as it did for its oil. It thus attempted to set its FOB price at a heating-value parity between LNG and oil at the Algerian point of export. By linking oil and gas prices directly, it abandoned the common practice of negotiating a mutually-acceptable base price to which the energy price escalation clause could be applied. The proposal had the effect of pricing LNG at a premium over oil, which increased with the transportation distance from Algeria.

The government of France negotiated with Algeria on behalf of Gaz de France, and ultimately accepted a FOB price with a linkage to a basket of eight OPEC crude oils. However, an FOB price that European buyers could still tolerate was much more difficult for the US to accept because of the higher transportation costs to the US.

Following the pricing settlements, Atlantic Basin trade declined and did not regain its 1979 level until 1988. While French LNG imports continued to rise, those of Italy, the UK and the US declined significantly. For Italy, the successful demonstration of deep-water pipeline technology with the

Transmed Pipeline in 1983 replaced LNG with pipeline imports. For the UK, the growing discoveries in the North Sea quickly eliminated the incentive for gas imports.

The major impact of the pricing dispute, however, was on US LNG imports. The US began a major restructuring of its gas industry in 1978. It introduced 'partial de-regulation' of wellhead prices, thereby setting the US gas industry on the path of market-responsive pricing. The market effect of the sharp energy price increases of the late 1970s was to reduce gas demand, creating a 'gas bubble' of surplus gas supply. Prices fell to gas-to-gas competitive levels, well below oil parity. Following the implementation of the FERC Order 380 in 1984 (which relieved buyers of their 'take' obligations on long-term contracts), it became impossible to sell Algerian LNG at oil-linked prices in the US gas market.

All four of the US receipt terminals that were originally built to import Algerian gas were shut down for a period. Two of them – Everett, Massachusetts and Lake Charles, Louisiana – were involved in lawsuits, which – upon settlement – provided them with more market-responsive contracts with Sonatrach that enabled them to continue imports. The other two – Cove Point, Maryland and Elba Island, Georgia – did not operate again for over twenty years.

With the sharp change in LNG pricing in the early 1980s, the broader Atlantic Basin market was effectively reduced to Algerian trade with Continental Europe. Small imports into the US continued to the two operating terminals, but the UK virtually ceased all imports. By 1988, the European Continent accounted for 96% of the imports and Algeria accounted for 96% of the exports in the Atlantic Basin. Thus Atlantic Basin LNG prices were effectively Algerian FOB prices. The US and the UK, which were in the process of liberalising their own gas industries, did not play a part in the determination of Atlantic Basin LNG prices during this period.

4.5.3.3 Early Pacific Basin LNG Pricing

The Pacific Basin market developed in a very different way from the Atlantic Basin market. Whereas LNG deliveries to the Continent, the UK and the US were designed to supplement large existing gas distribution networks, the Japanese gas utilities were 'Town Gas' utilities sending out manufactured gas. Although their gas costs were high, their sendout at this time was relatively small and it was difficult to convert to natural gas. They thus did not provide the economies of scale that were required to justify a new LNG project. Therefore, the first Japanese project from Alaska's Cook Inlet elected to concentrate on the much lower-priced – but far larger – electric utility market.

At the time of the start-up of the Alaskan deliveries, Japanese electric generation was based on oil, coal and hydropower, with heavy fuel oil and crude oil accounting for 43% of generation. Since reducing oil imports was a primary policy issue for the Japanese government, replacing oil with LNG in power generation became a major goal. Japanese concern over sulphur pollution enabled the Japanese utilities to pay a premium for LNG. The obvious competitive price target for LNG imports was oil.

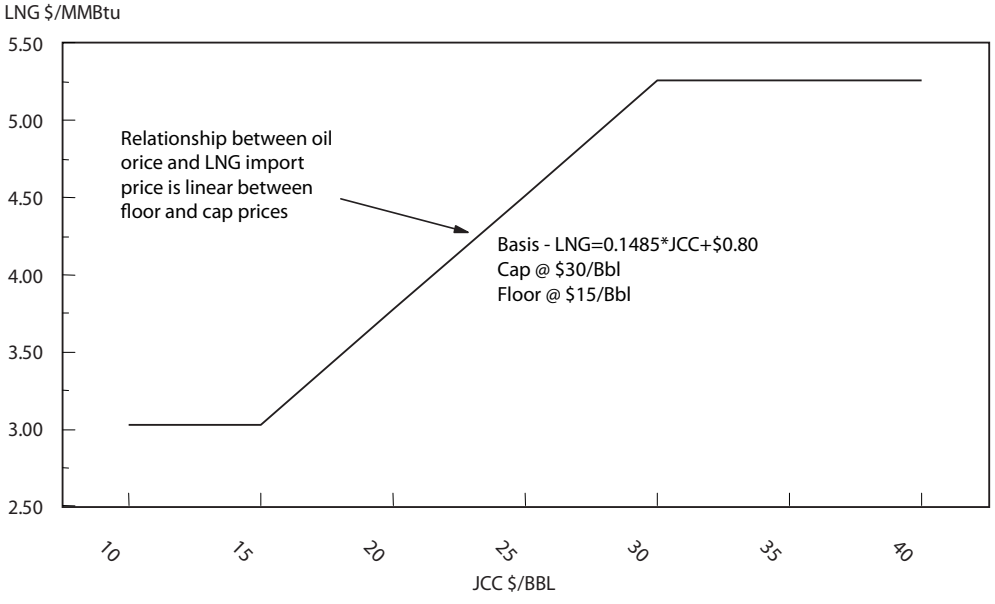
The negotiations generally focused on a base price for LNG delivered as liquid into Japanese re-gasification terminals and then provided a price escalation clause to track changes in world oil prices. Several of the initial projects elected to tie the base price escalation to their own export crude oils. However, during the period in the 1980s when OPEC attempted to maintain a posted crude

oil pricing system in the face of substantial price discounting, a dispute arose over the appropriate prices to use for the escalator. The dispute was settled in 1987, and since then nearly all Japanese contracts use the transparent Japanese Customs Clearing price for crude oil (JCC or the 'Japanese Crude Cocktail'). Only Indonesia retained a reference to its own crude oil in the pricing term. As South Korea and Taiwan became importers, they too adopted the JCC price escalation approach so that it is now common throughout the Asia Pacific region.

The most common form of the Northeast Asian pricing formula has been P=A*JCC+B, where 'A' was a coefficient (or 'slope') linking the JCC quotation in $/bbl with the LNG price and the 'B' term was a constant in $/MMBtu. The JCC price was published monthly, but the contracts commonly averaged the monthly prices over some stated period, so that the monthly volatility of oil prices was dampened. In the negotiations, the parties effectively set the base price by means of the size of the 'B' constant. A theoretical slope for the 'A' coefficient, assuming heating value equivalence between oil and gas would have been 0.172, but actual coefficients used in the contracts used somewhat different slope numbers.

The volatility of oil prices, particularly during international oil market upsets, created problems for utility buyers. At some point it became common for the buyers to insist on including a price re-opener in the contract that triggered when prices reached a certain level. This in effect imposed a price 'cap', which limited the operation of the JCC portion of the pricing formula during periods of high oil prices. Increasingly, sellers began to insist on a floor price to protect them from a price collapse. The resulting upper and lower limits are commonly described as S-curves. *Figure 51* illustrates a typical Northeast Asian formula. In it the coefficient 'A' linking JCC with the LNG price is set at 0.1485 ($0.1485/$ of JCC) and the constant 'B' is set at $0.80. In the illustration the floor is taken as 15 $/bbl and the cap as 30 $/bbl.

Figure 51: Illustration of a Northeast Asian S-curve Based on Japanese Customs Clearing Price for Crude Oil (JCC)



Source: Jim Jensen

4.5.3.4 Mounting Pressures for Change in Pricing Formulas in the 1990s

The first significant infusion of new LNG suppliers outside the Asia Pacific region occurred in the late 1990s. For the Middle East, Qatar's Qatargas I project began exports to Korea in 1997. It was only the second Middle East LNG project since Abu Dhabi's first two LNG trains started up in 1977. In the Atlantic Basin, growth in regional supplies resumed with the start-up of new projects in Trinidad and Nigeria in 1999.

The burst of new Middle East activity occurred as there was growing frustration in Northeast Asia with the existing LNG pricing formulas. The high take-or-pay threshold on long-term contracts was proving difficult for buyers, who were demanding more 'take' flexibility.

In the Atlantic Basin, the US re-emerged as a customer for LNG more than fifteen years after the last new North American contract had been signed. During that time the restructuring of the North American gas industry had established competition with gas – rather than with oil – as the competitive target for pricing clauses. Thus the classic oil-linked European and Northeast Asian contracting patterns were not applicable to new North American contracts.

4.5.4 New Approaches to LNG Contracting in the 1990s

4.5.4.1 New Patterns of Asian LNG Contracting

For Japan, the initial logic of oil price escalation was disappearing as oil had been increasingly phased out as a competitor for power generation and the gas utilities took a growing share of imports. Whereas oil had represented 43% of Japanese generation at the time of the first LNG import project, it had declined to an 18% share by 1997. LNG, which had initially been utilised largely for the intermediate-firing portion of the electric utility dispatch curve, was gradually being forced to absorb more of a peaking role – with resulting variability in utilisation rates. And in Korea, only 27% of LNG imports went for power generation, and the highly temperature-sensitive gas distribution load was difficult to serve with traditional contracts.

The first new Middle East contracts for Korea and Japan, first from Qatar and then from Oman, retained the JCC pricing formulas. The price competition that emerged centred instead on the price capping mechanisms. The first contract for Korea from Qatar's Rasgas 1 project had included a floor price. However, in competition with Oman for a second contract for Korea, Rasgas lost out when Oman offered Kogas a contract without a floor price. Rasgas then removed the floor price from the first contract as a part of subsequent negotiations for expanded deliveries.

In addition to changes in the price-limiting clauses, the late 1990s saw the shortening of contract terms and some additional off-take flexibility as a part of the competitive landscape. Whereas the traditional contract had been for a term of twenty years or more, shorter duration contracts of seventeen to fifteen years began to appear. Even shorter-term contracts were utilised in special situations.

Malaysia placed a large volume of LNG on the market in late 1990s from its Tiga liquefaction project (which went online in 2002). The marketing effort took place during a period of Asian market

weakness as a result of a slowdown in the Asian economies. As a result, Petronas – the Malaysian national oil company – signed a number of innovative contracts to obtain commitments for its volumes. One contract for a group of Japanese buyers provided for three tranches of contract commitment. The base load portion of the contract operated as a traditional 20-year take-or-pay contract. The second tranche rolled over every year with the same terms as the base load, but without any fixed take obligation. And the final tranche was simply an option on supply. A number of other contracts utilise the base load / option approach to commitment, and several are for shorter contract lengths.

There were other competitive changes in contracting practices that occurred during this period. Buyers were able to obtain greater destination flexibility so that they could re-sell cargoes where it was profitable to do so. And the buyers began to negotiate upstream equity positions from their suppliers as a part of new contracts. Examples of such equity positions include Korea's Kogas in Qatar's Rasgas 1, Tokyo Gas and Tokyo Electric in Australia / Timor's Bayu Undan, and China's CNOOC in Australia's Northwest Shelf and Indonesia's Tangguh projects.

4.5.4.2 China and India Enter the Asian Market

China's first planned LNG terminal was developed by CNOOC at Shenzen in Guandong Province. The project began negotiating for supply in the early 2000s during a period of weak Asia-Pacific demand and new competitive supply offerings from Rasgas (Qatar), the Northwest Shelf (Australia) and Tangguh (Indonesia). Both because of competitive market conditions and because suppliers were eager to achieve 'first mover' status in the Chinese market, CNOOC was able to offer its demand on a tender basis in order to negotiate very favourable contract terms. The ultimate winner was Australia's Northwest Shelf project. Trade press reports[103] suggest that the base price was $2.85/MMBtu. The contract retained the S-curve methodology using JCC as the price escalator. However, the slope of the relationship between JCC and LNG pricing was reportedly much flatter than the traditional Northeast Asian contract, rising at about one-third of the rate of the usual relationship. Thus, LNG pricing would be expected to rise much less rapidly with rising oil prices than would be the case with the traditional contract.

Tangguh, which lost out to the Northwest Shelf on Shenzen, managed to win the second Chinese contract with CNOOC for the Fujian terminal in Fujian Province. Press reports suggest that this price was even lower than the Shenzen price, at $2.76/MMBtu FOB. This also utilised the lower slope relationship to JCC and limited price movements by means of S-curves.

The two Chinese contracts were signed at a time when Asia Pacific demand was weak and there was active competition from suppliers. Since that time, Indonesian supply has been adversely affected by problems, the market has recovered and rising international oil prices have put strong upward pressure on oil-linked LNG pricing. As a result, price negotiating positions are at a much higher level and the Chinese contracts are now regarded as the low point in Asia Pacific pricing.

India has proved to be a challenging market for LNG. Many receipt terminals have been proposed, starting with Enron's original Dabhol facility in Maharashtra State. This project was a part of Enron's

103. Details on contract pricing and other terms are proprietary, and trade-press reports often disagree on specifics. The estimates included here represent best judgments based on the information available.

troubled bankruptcy proceedings and, though operational for power generation, was never set up as an LNG receipt terminal.

It has proved difficult to establish new terminals in India because of the problem of providing re-gasified LNG at prices that the Indian power generators will accept. Seventy percent of Indian power generation is based on low-cost coal and, at higher prices, gas-fired generation has trouble competing.

From a large number of proposals, two are now operating – Petronet's Daheej facility and Shell's Hazira facility, both in Gujarat. A third terminal at Kochi in Kochin is well advanced. Hazira is unusual in that it has been designed as a merchant terminal in which Shell and its partner, Total, expect to call on short-term cargoes from their various supply portfolios to provide the LNG. This is an example of downstream re-sale of self-contracted volumes and there is no formal SPA with customers as such. While Hazira has been operational since February of 2005, it has had difficulty providing cargoes at acceptable prices (and has had political problems in its effort to utilise international-flag tankers).

The Daheej project, however, has negotiated a long-term contract with Rasgas. It also breaks with the tradition of typical Northeast Asian contracts in that it has established a fixed price to operate for a period of five years before the oil escalation clause kicks in. The price FOB Qatar is reported as $2.53/MMBtu. After the fixed price period expires, the contract is supposedly pegged to $20/bbl oil, with a 0.13 'A' coefficient in a P=A*Oil Price formula.

India has also been reported as negotiating with Iran for LNG. The reports suggest that the price escalator will be much flatter – a 0.065 'A' coefficient. While the actual base price is not public, it supposedly will reference dated Brent crude in the North Sea instead of JCC.

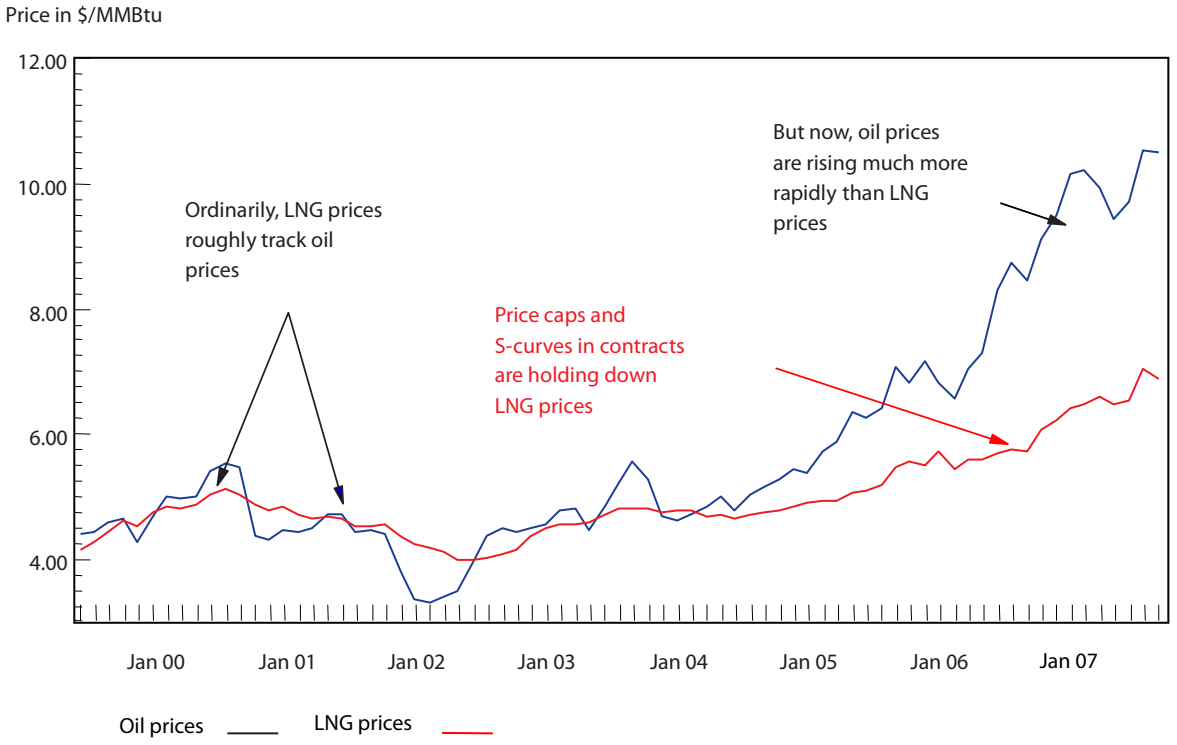
4.5.4.3 Oil Price Escalation and its Impact on Northeast Asian Prices

The first reaction of historic Asian LNG customers to the reports of the Chinese and Indian discounted prices was quite negative. Buyers felt that they should share in the discounts since they had been responsible for financing the development of much of the supply for Asian markets.

However, following the signing of the Chinese and Indian agreements, a number of market developments sharply changed the outlook for LNG supply and demand, and for prices in LNG markets. Asian markets tightened considerably, partly from economic recovery and partly as a result of supply problems at both Indonesia's Arun and Bontang liquefaction plants. Both the US and Europe actively sought LNG supplies as their own markets tightened. Prices in both markets also rose rapidly, and oil prices rose sharply as well, driving up the oil-linked pricing formulas in Northeast Asia. The prevailing perception in 2006 is that the Chinese and Indian contracts represent a low point in pricing and are not likely to be repeated in the foreseeable future.

However, the rise in oil prices has had another major effect. The price caps and S-curves that were designed to prevent oil market upsets from influencing LNG prices had the effect of holding down LNG price increases as oil prices rose. If the new oil price levels are assumed to be permanent, rather than temporary, then the price-capping mechanisms have effectively broken the traditional link between oil and LNG. The way in which LNG prices have lagged the increase in oil prices is illustrated in *Figure 52*.

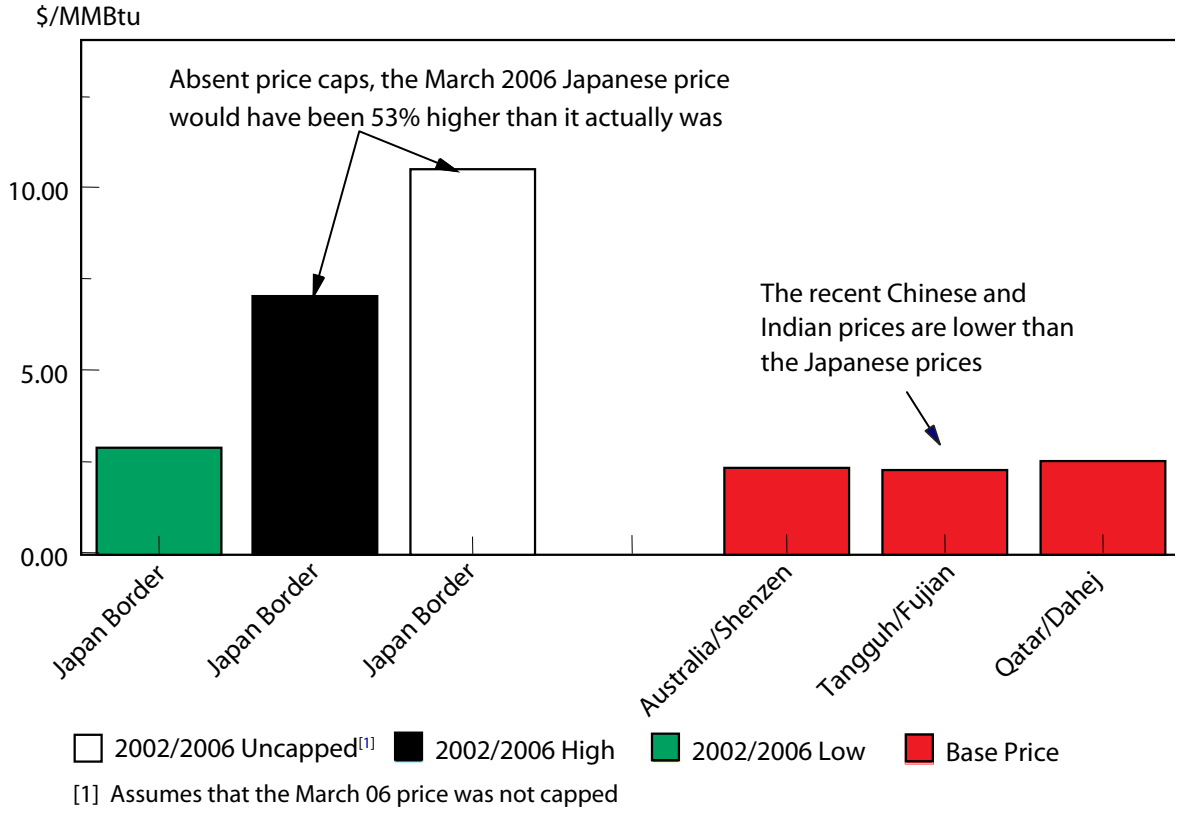
Figure 52: Japanese Customs Clearing Price for Crude Oil (JCC) Compared with LNG Import Prices ($/MMBtu)



Source: Jim Jensen

The discrepancy between the Chinese and Indian prices and Japanese Border prices is illustrated in *Figure 53*, which compares the selected Asian LNG prices at a common Qatar netback reference point. *Figure 53* also includes an illustration of how much higher Japanese prices might have been had there been no price caps and S-curves to moderate the effect of high oil prices.

Figure 53: Selected Asian LNG Prices Brought back to a Common Middle East Reference Point by Using Basis Differentials from Qatar



Source: Jim Jensen

The net effect of these developments has been to create a very difficult environment for the Northeast Asian contracting process. Sellers contend that the new high prices for gas represent the new world market price for gas. Buyers do not see why they should pay such higher prices since they do not appear to be driven by higher costs.

4.5.4.4 Recent Asian Market Developments

The fact that contracting practices are in the middle of their re-adjustment to a higher-priced energy environment and the fact that new contract terms are highly proprietary makes it difficult to be very specific about the way in which new Asian contracts are being written and older ones are being re-negotiated. Initially, the response of market negotiations to the higher oil price environment seemed to be one of trying to moderate the slope of the JCC tracking formula while re-adjusting base prices to reflect the higher oil price level.

For contracts that have been re-opened, some seemed initially to be utilising a much lower slope for the 'A' coefficient above a certain oil price threshold. One contract reportedly switched from a standard 'A' slope at $24/bbl to a 0.07 slope. It then switched again to a 0.055 slope above $29/bbl. One new set of greenfield contracts has been written for the Australian Gorgon project. They have

reportedly have also utilised an 'A' coefficient of 0.07. The lower slope relationship to oil prices seems to be one approach to dealing with oil-linkage in a high-priced oil environment.

There also has been some interest in abandoning the JCC measure of oil price levels. JCC, while transparent, suffers from two problems. First, it does not represent a freely-traded crude oil, such as North America's West Texas Intermediate (WTI) or North Sea's Brent. And second, the average crude oil into Japan is comparatively heavy, while LNG is expected to compete with lighter, low sulphur crude oils. One Asian contract reportedly utilised Brent as a measure of crude oil pricing.

There seems also to have been some effort to eliminate the price capping mechanisms altogether. This would eliminate the de facto de-coupling of oil prices and LNG prices that the caps and S-curves have provided.

4.5.4.5 The Emerging North American West Coast Market

As yet there are no receipt terminals on the North American Pacific Coast, although there are active proposals for Mexico, California, the US Pacific Northwest and British Columbia. Several proposals for Baja California in Mexico envision importing both for local markets and for export to Southern California, where no terminals have yet been approved because of siting resistance. Of these Baja California proposals, one by Sempra – scheduled for completion in 2008 – is the farthest advanced. The project has brought in Shell as a 50% owner, suggesting that half of the capacity will be supplied by self-contracting, possibly from Shell's Sakhalin 2 project. Sempra has also contracted with Indonesia's Tangguh project for supplies. This represents the first exposure of Pacific Basin contract pricing to the complexities of serving the restructured North American gas market.

Although there is very little detail about these contractual relationships – Shell with its affiliated Sakhalin LNG and Sempra with Tangguh – they are reported to be on a netback basis. They would thus reference publicly-reported prices at the California border and deduct formula margins for displacement to the terminal, re-gasification charges and transportation from the liquefaction facility.

4.5.4.6 New Patterns of Atlantic Basin LNG Contracting

For nearly twenty years prior to the development of the Trinidad and Nigerian LNG projects, sales from Algeria to the Continent represented virtually the sole contracting activity in the Atlantic Basin. While the initial Algerian LNG contracts escalated prices based on the value of eight crude oils[104] with a regular contractual opportunity for re-negotiation of the pricing provisions, subsequent contracting became much more flexible to adapt to competition from pipeline supply. Many Continental pipeline contracts utilised escalators based on some mix of high-sulphur heavy fuel oil (only for contracts concluded in the 70s), low-sulphur heavy fuel oil and gas oil. Troll, concluded in 1986, had 55% light fuel oil and 45% low sulphur heavy fuel oil. Later price re-negotiations increased the share of light fuel oil to about 65% and out of the remaining share some new competition was reflected, such as for power generation, and later for gas-to-gas competition.

104. Arab Light (Saudi Arabia), Brass Blend (Nigeria), Kirkuk (Iraq), Kuwait Export, Iran Light, Murban (UAE), Saharan Blend (Algeria) and Zuetina (Libya).

In price negotiations, Algeria was willing to offer comparable indexation terms to customers that were accustomed to oil product indexation in their pipeline contracts. Some customers were also given the option of a mix of crude oil and products. Some attempts were made to include partial indexation to electricity, coal or to an inflationary index. But for most Algerian contracts for Continental buyers some form of oil-indexation remains as the dominant pattern.

Continental pipeline contracts usually utilise a delayed form of indexation in which an earlier data period is used for the index and applied through a delayed re-calculation process. The LNG price response in a rising oil price market may be temporarily similar to that of a price capping mechanism, since it delays the adjustment of the LNG price to the escalating oil price. In a falling oil market, it may delay adjustment of the price clause to the new market conditions. However, the process may not require a re-negotiation to restore the oil linkage, since LNG prices will ultimately re-adjust after a time when the oil price finally levels out. The early Algerian contracts did not utilise this lagged escalation feature, but it is understood that some of the later ones do.

The first two new entries into Atlantic Basin supply in the late 1990s were Nigeria and Trinidad. Although the early negotiations for Nigeria involved possible sales to the US Everett and Cove Point terminals, those contracts were never signed. Thus the output for Nigerian Bonny's first three trains was dedicated to Continental European markets and did not address the problem of competing in the very different competitive climate created by the restructured North American gas market.

The contracting for the first three trains was in the form of a traditional SPA with buyers in Continental Europe. With the exception of the contract with the Italian electric generator, ENEL, buyers were all gas pipeline / distribution companies and their pricing clauses for the most part reflect competition with pipeline supply in their markets and utilise some mix of fuel oil and gas oil pricing. Contracts for electric generation customers pose special problems for contracting in a liberalised electricity market since the relevant units may not be dispatched if their marginal generation costs are higher than other units. The ENEL contract is believed to include coal and inflation in addition to oil prices.

Trinidad's markets, unlike Nigeria's, were primarily in the US. Thus, it had to deal with the issue of marketing in a gas-to-gas competitive market. The first four Trinidad LNG trains are owned by Atlantic LNG, a consortium of BG, BP, and Repsol (Tractebel owns a share of Train 1, but not of the remaining three). The contract for the first train was split between Tractebel and Repsol, and thus could be described as an example of 'self-contracting' by members of the consortium. Thus the contract price terms in the SPA were agreed upon among members of the consortium, not negotiated with a major customer in the target market as it would have been in the traditional Northeast Asian contract.

Tractebel took its volumes to its Everett terminal in the US. And while Repsol had a traditional contract with Enagas in Spain, it retained the right to divert cargoes at its own discretion. Most of its volumes were shipped to short-term markets in the US at presumably higher netbacks than it would have gotten with Spanish deliveries. Like Train 1, Trains 2 and 3 also represented self-contracting by BG, BP and Repsol, but in these cases LNG supply is tolled to the partners.

In a tolling system, some consortium of companies – usually, but not always limited to the holders of the gas reserves – assumes financial responsibility for plant investment and recovery of costs and return. They thus resemble pipeline investors. They will recover their cost-of-service either by a throughput charge or by demand charges to users of the facility.

Both BG and BP control capacity in US terminals and are in a position to market directly to end-users. Repsol has outlets in Spain, and is also attempting to build a new terminal in the Canadian Maritime Provinces for both the US and Canadian markets.

Trinidad's Train 4 represents an even more flexible departure from traditional contracting. Holders of gas at the wellhead will be able to toll their liquefaction through the plant and market the resulting LNG without buying LNG output from the venture partners through a traditional SPA.

Nigeria, like Trinidad, has shifted to a more flexible contracting pattern for later Trains. Bonny's Trains 4 and 5 feature more than 75% of self-contracted volumes sold to venture partners for downstream marketing.

Norway's Snohvit project also features a large portion of self-contracted volumes. Statoil plans to take its share to the Cove Point terminal in the US where it has capacity rights, while the French partners plan to market their volumes themselves. The one traditional customer contract is to the Spanish electric generator, Iberdola.

Egypt represents one of the fastest growing sources of LNG. Two projects – Egyptian LNG (ELNG) and Segas – have operating LNG trains. ELNG's Train 1 is a traditional SPA with Gaz de France, but Train 2 is a self-contract with BG, one of the venture partners. BG initially plans to take its volumes to its committed capacity in the US, but is attempting to develop a terminal outlet in Italy. Supposedly, the contract with BG is based on a netback from the US featuring Henry Hub escalation, but presumably there is an uplift for the other venture partners if the Italian (or other European) sales provide superior netbacks.

The Segas project was initiated by the Spanish electric utility, Union Fenosa, together with AGIP. Unlike most other LNG projects, Union Fenosa is not an equity partner in the upstream and buys most of its gas for Train 1 from the Egyptian Natural Gas Holding Company (EGAS) at government-controlled prices. There is supposedly consideration being given to operate a second train on a tolling basis, similar to the arrangement for Train 4 in Trinidad.

4.5.4.7 Middle East Contracting

The early Middle East contracts were essentially traditional SPAs with Northeast Asian customers. Most of Abu Dhabi's and Oman's volumes remain dedicated to Northeast Asia, although a small portion of each is self-contracted. However, the major new Middle East expansions are coming from Qatar. By 2007, Qatar will overtake Indonesia as the world's largest LNG exporter.

The early SPAs from Qatar were with Japanese and Korean buyers under traditional Northeast Asian terms. The Rasgas contract for Petronet Daheej in India, which set a low price for an Asian deal, has already been discussed in *Section 4.5.3.2*.

Starting in 2001, Qatar began contracting with customers in Spain and Italy, presumably utilising competitive escalation clauses. But increasingly, Qatar seeks outlets in the US and the UK where it is primarily contracting with venture partners who will market the LNG on behalf of the venture. Contracting parties for these Atlantic Basin markets include ExxonMobil, Shell, ConocoPhillips, Total and ENI. In some cases, the downstream marketer was not an original upstream venture partner, but earned a share in the upstream as a part of the negotiation.

4.5.4 Contracting for Restructured Gas Markets

4.5.5.1 North America

Sales into North America and into the UK encounter an environment of gas-to-gas competition where oil-linked pricing does not work. The market indicators in these markets are gas market indicators – Henry Hub in the US and the National Balancing Point in the UK.

Most of the volumes into these markets appear likely to be self-contracted volumes that are marketed by the company's gas marketing affiliate in much the same way as the company markets indigenous gas. While the National Balancing Point in the UK represents a single (and theoretical) transaction point, the North American market has many other transaction points (hubs) keyed to Henry Hub by 'basis differentials'. While these in theory approximate the costs of transportation between Henry Hub and the alternative hub, they can easily differ significantly depending on market conditions. For example, the Boston City Gate hub usually has a substantial positive basis differential over Henry Hub, but it is significantly higher in tight winter markets than it is in summer. And one concern for marketers who try to put too much LNG into a regional market is the 'basis risk' of collapsing the basis differential through regional over-supply.

The contracting that has taken place for the US market appears to be on a netback basis – as were the old re-negotiated Algerian contracts for Everett and Lake Charles. They thus feature a reference price, such as Henry Hub, and may include basis differentials if deliveries are made into a market served by one of the other market hubs. Prices may be adjusted monthly based on the 'bid week'[105] quotation, or they may be adjusted more frequently based on either the daily quotation or on a several day average to dampen volatility.

One feature that is entering North American pricing is the emergence of auctioning of sales, based on a percentage of the Henry Hub price. Thus bidders may bid percentages of Henry Hub as a basis for netbacks. These percentages encompass both the re-gasification margin and the basis differential. The percentages may vary from 84% to 90% of the Henry Hub quotation. There have also been efforts to include a 'terminalling' fee and a marketing fee in some of the contracts.

4.5.5.2 The UK

The UK has only one onshore operating LNG terminal at present – the Isle of Grain – owned by the National Grid but contracted out to BP and Sonatrach. In both cases, the capacity holders are delivering self-contracted volumes into the market. Two other major terminals – South Hook and Dragon, both sited at Milford Haven in Wales – are well into construction. South Hook is jointly owned by ExxonMobil and Qatar Petroleum, and thus will be selling self-contracted gas from Qatar. Dragon is owned by BG, Petronas and Petroplus. Presumably, the BG share of the terminal will be self-contracted.

There are several other proposed LNG terminals that may or may not proceed. Since their sponsors appear to be independent terminal operators, they may be candidates for the more flexible form of

105. Pipeline capacity in the US tends to be committed on a monthly basis. Bid week is that period at the end of the month when pipeline shippers line up their supplies for the following month.

contracting required for restructured gas markets. This would presumably be based on a netback from a National Balancing Point reference price.

A major challenge to European LNG price formation is the growing interaction between gas-to-gas competition in the UK and traditional oil-linked pricing system on the Continent. The Interconnector pipeline linking Bacton in the UK with Zeebrugge in Belgium puts two different pricing philosophies in direct contact with one another. This creates an opportunity for large players on the Continent to arbitrage spot and forward prices on the NBP.

Zeebrugge, which is the landing point of Norwegian Gas and an LNG receipt terminal, is directly linked to the UK market via the Interconnector. Since Belgium is served by traditional supplies from the Netherlands and Norway and by LNG from Algeria, the conflict in pricing mechanisms is centred at Zeebrugge. In the 2001 price review round for Troll, the negotiations included an option for a share in the import price formula linked to the IPE price for NBP to enable gas importers to serve large industrial customers on the Continent with gas pegged to the NBP. With the high prices on the NBP, this has become less attractive.

4.5.6 Conclusions

The history of early gas pricing in each of the major LNG markets has influenced the way in which LNG pricing has developed. For those markets that have been developed largely on the basis of imported supply, such as the European Continent and Northeast Asia, long-term contracts have been extremely important and are likely to remain so. Pricing clauses in these contracts have commonly been tied to either crude oil or products prices and many contracts allow for a regular review of the pricing formula. However, for markets that have historically been largely self-sufficient and have restructured their gas industries, such as North America and the UK, short-term contracting prevails and oil-linked pricing is a rarity. The newly emerging LNG import markets in China and India have had no history before the turn of the century of either negotiated import prices or liberalised competition for indigenous gas.

World LNG markets are in a state of great uncertainty as high oil prices and tight LNG markets have made obsolete many of the assumptions on which LNG contracts have traditionally been based. Many of the oil-linked contracts are being re-negotiated to reflect the new, higher energy-price environment, but there is an increasing trend towards 'self-contracting' in which upstream sellers integrate downstream and sell under the terms and conditions that prevail in their respective markets. This pattern is most prevalent in the Atlantic Basin, particularly for North America and the UK, but it is also becoming a factor on the Continent. The conflict in pricing philosophies between liberalised gas markets and the more traditional contract-dependent markets will give rise to price arbitrage between the UK and the Continent through the Interconnector.

Chapter 5

Overall Conclusions



Chapter 5 Overall Conclusions

This report looks at the pricing mechanisms for oil and gas by also using approaches of some more specialised parts of economic theory, mainly transaction cost theory dealing with different pricing and contract mechanism of open markets, long-term contracts and vertical integration, the theory of finite resources as reflected in Hotelling and Ricardian rent and the principal-agent theory. They suggest the following analysis:

The transaction cost theory suggests that the combination of marketplaces, long-term contracts and vertical integration depends on technology, market structure and regulation, and that it will change to reflect their development. Geology and geography provide the overall context, but the impact of endowments changes with the development of technology, as well as of markets and regulations.

An important element in order to understand differences in pricing mechanisms is that there are two actors on the supply side: the resource owner, usually represented by a national government, which takes decisions determining the depletion of its resources, and the producing company, which takes the decision to invest.

Decisions on developing resources for production rest with the resource owner, and these decisions are influenced by the need to optimise the resource rent and other benefits from depletion of finite resources. If there is sufficient supply, competitive liquid markets may evolve; however, downstream regulation alone will only influence demand and the price elasticity of demand, especially from the crucial power sector, but rarely create supply competition.

For a global commodity market to emerge it seems important to have only small differentials in transportation cost, combined with the possibility to easily change between destinations and sources. This offers the flexibility to transfer price signals, reflecting either competition on the demand side for such a commodity, or – in case of over-supply – competition for customers by suppliers. Small differentials in transportation costs will lead to worldwide uniform price developments. Moreover, ubiquitous storage possibilities and low specific storage costs will add flexibility to the system on the time axis and lead to the creation of market places.

(I) The market for oil has developed all the features of a liquid global commodity market:

Due to its high energy density, oil transportation and storage costs for oil are the lowest among fossil fuels, and specificity of investment is low except for oil pipelines from or to landlocked countries. Most oil trade is by tankers which are easy to re-direct and whose transportation costs are small compared to the value of oil. Also, crude oil and its products can be stored in tanks independent of location, again at relatively low costs compared to the value of the oil.

In view of the physical properties of oil, especially its high energy density, one may ask why it took so long for oil to develop into a globally traded commodity. This must be explained by examining the history of the oil industry and its international trade:

At the beginning of the international movement of oil, prices were essentially internal prices of vertically integrated major oil companies. With the end of the colonial age, the sovereignty of national states over their resources was affirmed in 1962 by UN resolution No. 1803 and later by

Article 18 of the ECT. In mid-1970s OPEC countries took control over their oil resources, and oil from OPEC countries was sold under long-term contracts at official selling prices defined by OPEC countries. Two steep oil price increases posted by OPEC triggered investment both in oil saving as well as in oil production for export outside OPEC, leading to competitive pressure and finally to the oil price collapse in 1985/1986, followed by the emergence of an oil market where oil was priced at exchanges. With more competition from production outside OPEC, price setting by posting a price by OPEC became unworkable. While OPEC still exerts influence by its decisions affecting overall supply and thereby market price, the pricing mechanism itself is free from OPEC influence. Oil has since successfully developed all the features of a global liquid commodity market.

While oil prices are set by a global pricing mechanism, national prices for the consumer are heavily influenced by national excise taxation. Such taxation influences the volume of demand on a national level, but has no influence on the global oil price beyond this demand effect.

Oil price developments since 2000 demonstrate that a liquid market alone is not sufficient to create downward price pressure when demand is inelastic and growing. While part of the lack of response by the supply side can be explained by lack of investment, the possibility to develop resources by investment is only partly in the hands of the investors, but mostly depends on decisions by the resource owners, i.e., governments of resource-rich countries.

(II) By contrast, gas has not developed into a global commodity, and only in North America – and to a lesser extent in the UK – has gas developed a liquid regional commodity market.

Examining possible reasons for the differences in pricing mechanisms between oil and gas, this report suggests that:

a. the differences between oil and gas are related to their respective physical properties; notably the differences in energy density and resulting cost differences for transport and storage;

b. the regional differences between gas markets can be attributed in large measure to differences in geology and resource endowments, which have implications for import dependence, market structure, regulation and pricing;

c. thus far, natural gas prices in liquid markets continue to follow the price tendency of substitute fuels;

d. there are different pricing mechanisms associated with liquid market places, with long-term contracts and with vertical integration respectively (the latter for example in the LNG chain), and, thus far, long-term contracts have been the prevailing instrument for international gas trade. Changes in technology, market structure and regulatory conditions can modify the balance between these mechanisms in a given region or market. However, due to the capital-intensity of energy sector projects and the high specificity of investment in fixed pipeline infrastructure, long-term contracts are likely to maintain their important role.

The four points (a) to (d) above are explained in more detail below:

a. In order to answer the question whether and how gas will develop into a global liquid commodity market, like oil, it is necessary to look at the development of technology and costs for transport and storage, as well as on the structure of the industry.

The substantially lower energy density of gas compared to oil and the resulting cost differences for transport and storage are the decisive element to explain why there is no global gas market. Differences in location and time of production and consumption are much more important for gas than for oil, and are a major hindrance for flexibility of trade and for regional gas markets to merge into a global gas market.

Gas is not only characterised by high specific transportation and storage costs but also by high specificity of pipeline transportation. LNG has high specific transportation costs as well, but LNG transport has lower specificity, as there is no physical reason why LNG tankers cannot be re-directed to different destinations.

Flexibility increases with the number of pipelines and capacity allowing for more change in supply and off-take and by the possibility to re-direct LNG tankers. Substantial cost reductions in the LNG chain allowed LNG from the Gulf region to reach all gas markets economically, even before the surge of energy prices since 2000. Thus arbitrage between regions can be done by re-directing LNG tankers, but the differential in prices must be substantially higher than for oil to make a re-direction attractive. With the liquid US market requiring substantial LNG imports, additional LNG capacity is built relying on the deep liquidity of the US market. Contrary to oil, most LNG tankers are contractually committed to specific projects; the uncommitted LNG capacity is in absolute and relative terms much smaller than for oil.

In addition, the high storage costs of LNG and natural gas suggests volume and price restrictions for the price transmission function of LNG trade via arbitrage, and thereby less uniformity in gas prices and gas price development in between different regions, compared to oil.

Even though costs in the LNG chain have been substantially reduced, and LNG has started to work as a price transmitting mechanism, free spot-traded LNG is only a small percentage of overall gas consumption, and no market place for LNG is in sight either on the production side or on the receiving side. Based on current trends, it is difficult to envisage the emergence of a global marketplace for gas comparable to that of oil.

b. The main causes for regional variety in the pricing mechanisms for gas lie, for OECD countries, in differences in (1) import dependence, (2) size of supplying fields, (3) composition and price elasticity of gas demand and (4) the implications of points (1)-(3) for downstream and upstream regulation. In non-OECD countries, notably in the former Soviet Union, (5) pricing mechanisms have so far depended strongly on historical and political developments, although there is a trend towards market-oriented price formation.

   (1) The development of import dependence – whether the gas sector was developed on domestic gas or based on imported gas – plays the decisive role for differences in pricing mechanisms which developed in different regions. Countries whose gas consumption can predominantly be covered by domestic production have regulatory control of supply (upstream) and demand (downstream) and thus a major influence on the gas pricing mechanism. Import-dependent countries have little influence on the regulation of the supply side.

The main supply decisions – influencing the balance between supply and demand – are taken by the resource owners, based on their sovereignty over national resources. These decisions determine directly or indirectly the volumes and speed of development of their resources. Resource-owning countries will seek to optimise the benefits from depletion of their resources. In the case of resources used for domestic consumption, some countries may not impose a resource rent (depletion premium) since the resources are used for domestic benefit. However, this is not always the case; the Dutch government levied a depletion premium domestically by introducing the market value defined by the use of fuels alternative to gas.

With regard to gas exports, an understandable objective of gas-exporting countries is to maximise the resource rent that they receive (except in the particular case where prices are kept low for political reasons, and here there may be the expectation of an equivalent political 'debt' payable to the exporting country). However, an upper price limit for exports is defined by the competitive situation on the export market, which is subject to competition with substitute fuels in the target market and possibly to competition with domestic gas or other export gas. That upper price limit is addressed by the concept of netback, referring to the replacement value in the importing country. For countries with large resources, especially if concentrated in a few super-giant fields, the depletion and market penetration speed is an important additional element to consider for their export strategy. These elements were addressed by the concept of long-term minimum-pay contracts with netback replacement pricing developed for the sale of Groningen gas, which was the blueprint for all long-term export contracts into Continental European countries.

The pricing mechanism of imported gas is beyond the direct regulatory reach of importing countries. Importing countries may try to influence export pricing via competitive pressure, especially by a large share of domestic production, or by diversification. They may make use of a situation of competing import projects or in a situation of real or perceived over-supply, as for the Guandong LNG Project in China and for the re-negotiation of Japanese LNG contracts resulting in the S-curve pricing.

(2) The size of field also matters for the pricing and contracting mechanism: For countries with many small fields, resource rent optimisation can be achieved by an adequate licensing or PSA regime and the corresponding taxation regime, where development and depletion will be decided by individual profit-maximising producing companies. In this case, the influence of governments on depletion policy is an indirect one, mainly through their licensing policy. However, countries with super-giant fields (or giant fields) will also look at field depletion and market penetration rates so as to avoid flooding the export markets to which they are tied by fixed infrastructure by too rapid development of production from such fields. The attitude towards exporting gas for use in the power sector, in particular, will depend on such considerations.

Minimum-pay contracts not only protect heavy upfront investments in gas production and infrastructure, but also commit a specific share of resources (for export) against the dedication of a defined market volume in the importing country. A minimum-pay contract provides a strong incentive not to flood the market by either side.

Exporting countries will try to maximise their rent income through a combination of selling spot or by self-contracting into deep and liquid markets, and by selling defined long-term volumes under long-term contracts into other markets, keeping a certain influence on total volumes marketed. In a sellers' market characterised by strong demand-on-demand competition, the resulting arbitrage – between the UK and the rest of EU and by LNG mainly within the Atlantic basin – will mainly transmit the high demand-driven price signals.

(3) Prices depend also on the demand side. The main factor for price demand elasticity is the gas demand by the power sector. It varies widely from country to country, as national policies that are driving the power sector depend on the availability of domestic resources for power generation and the resulting regulations.

Gas demand for heating purposes has little price elasticity, but is highly dependent on temperature. Gas for commercial purposes and for smaller and medium-sized industry is rather price inelastic in the short-term, unless dual-firing equipment is installed. In the longer term most customers can switch to gas oil or fuel oil by investing into new equipment. Thus it seems logical that the price of fuel oils, eventually inclusive of some investment, provide an upper limit for gas prices, and that as long as gas is somewhat cheaper than oil products, it will be the fuel of choice for stationary applications.

In general, when the price of gas is lower than for its substitute, the full costs will often also be lower. The situation is different for the power sector, where coal is often the competing fuel on a short- and on a long-term basis. Because of the large investment differential between coal-fired power plants and CCGTs, the average costs of CCGTs can be lower compared to coal-based power generation. However, in the short-term, if gas has to compete, it has to compete on a marginal cost basis against the use of coal, resulting in a lower gas price than for the other sectors. This usually makes it unattractive for the exporting countries to expand volumes by selling into a power sector where gas has to compete on a marginal cost basis, since this risks undermining the price level for the inelastic segments of the market.

A price elastic and deep demand for gas from the power sector, on the other hand, can absorb large volumes of gas at a market-clearing price. This is demonstrated by gas from the UKCS which the producers want to dispose of even in summer, because gas production is coupled to the production of high-value condensates (from gas-condensate fields) or of oil (in the case of solution gas). Tying in demand from the power sector thus brings in price elasticity of demand, which prevails in summer; however, when demand for gas is at its peak in winter, elasticity of demand from the power sector is reduced as most power-plant capacity will be used, leaving less room for fuel optimisation.

The evidence examined in this study suggests that the liquid gas markets that have developed so far are based on liquid electricity markets, which in turn seem to occur mainly in countries which have both domestic coal and gas reserves (like the US, the UK and Australia).

(4) Points (1) to (3) have had implications for regulation of the gas sector and the development of pricing mechanisms:

For countries dependent on imports, upstream regulation is out of their reach. The central issue of upstream regulation is depletion policy, mainly speed and rent-taking by the resource owner. Downstream, the main issues are about concessions for the sale of gas, access to infrastructure (often regarded as a natural monopoly), and unbundling of integrated gas companies. The most important influence on the volume and price elasticity of gas demand is policy and regulation for the power sector.

For countries which use gas for domestic and export purposes, a question is whether to also apply the export-pricing principle domestically (as was done explicitly by the Netherlands or more indirectly by Canada), or, alternatively (as in most non-OECD gas exporting countries), how to deal with the resulting price differential between domestic and export prices. Inversely, for import-dependent countries with significant domestic production, the question is how to price their domestic production: one approach is to avoid price differentials by letting the price for domestic production adopt the price set or influenced by imported gas (as in the US, the UK, Germany, France and Italy); another is to use cheaper domestic production to reduce the average gas supply costs (rolling in) or to allocate it to special consumer groups (this continues to be done by some former COMECON countries; in the past, it was also part of the US policy during price controls).

De-regulation in the US and Canada started with the abolition of price controls for domestically produced gas, removing artificial income limitations for producers. This was later complemented by the introduction of TPA, which removed obstacles to the marketing of the gas.

The UK also addressed upstream and downstream issues by abolishing BG's monopsony on purchase upstream and its monopoly on sales downstream and by the introduction of TPA. These changes were made at the same time as the establishment of a regulatory authority and the de-regulation of the power sector (as the largest additional potential gas market).

In this way, the start of the liberalisation process in both the US and the UK was linked to problems of upstream regulation; wellhead prices in the US, problems with a monopsony in the UK. The same breadth of regulatory influence was not available to other countries because of a lack of natural resources.

Developments in Continental Europe have been shaped by the regulatory reform at EU level and by national policies. However, this reform is limited to the downstream: the abolition of exclusive concessions, removal of the ban on gas for power, the introduction of mandatory TPA and of legal and organisational unbundling. The EU does not have direct leverage on upstream regulation of its natural gas supply; it has limited regulatory authority on this subject even within the EU, and the main EU suppliers – with the exception of Norway – fall in any event outside the EU's regulatory space. Indirect leverage on suppliers for the EU is linked to its attractiveness as an export market; this may attract more suppliers and thereby create more competition, even though the number of potential new suppliers is limited.

(5) In some cases, international pricing mechanisms may be influenced by political considerations: the government of a gas-exporting country would take a lower export price from some importers (thus giving away a portion of its resource rent to a consumer state) in exchange for political cooperation, as was the case between the Soviet Union and other COMECON countries, and between Russia and some former Soviet states. Such exports were originally arranged as a part of the coordinated central planning process, with gas supplied at favourable or notional prices, often as compensation for participation in the construction of the pipeline infrastructure or for transit services. These arrangements are being unwound in favour of separating gas supply and transit arrangements and a pricing mechanism for gas based on the gas prices in major EU markets netted back to the respective country by deducting the transportation cost in between. This process took place for Central Europe and the Baltic States in the 1990s, and since 2005 it has been evident also in Russia's relations with other former Soviet countries. Gazprom's stated aim is to achieve financial results for its exports to former Soviet countries on a par with the financial results for its exports to EU by 2011.

(c) Also in liquid gas markets, the use of gas is subject to short-term and longer-term competition with substitute fuels, which will form price ceilings (like gas oil or distillates replacing gas for individual heating or in the short-term in power generation) and vice versa, they can form a market-clearing bottom price where there is enough demand for the substitute fuel (as for coal in power generation in the UK). This does not exclude gas price spikes beyond the price of the substitute fuel due to temporary bottlenecks and capacity constraints that can only be overcome by investment, which takes time. In fact, a congruent movement of gas and oil product prices can still be observed in North America and the UK, even though pegging of gas import prices to oil product prices has disappeared.

Liquid markets should be able to allocate gas to its highest value use, the counterpart of which is the so-called demand destruction which was experienced in the US where gas price-sensitive industries like ammonia production and other petrochemicals based on gas closed their production in the US.

(d) With changing technology, market conditions and regulations, a new balance between the pricing mechanisms of liquid markets, long-term contracts and vertical integration is emerging. Liquid markets developed where the conditions were favourable (domestic reserves in a multitude of smaller fields) which are now the reference price for spot trade, and self-contracting of internationally traded gas which emerged as a new element for internationally traded gas, mainly in LNG, as a new variant of vertical integration.

Long-term contracts have worked to the satisfaction of both sides in the case of import-dependent countries and for export countries linked by specific infrastructure, and have adapted to substantial changes in the past decades. They continue to be the prevailing instrument of international gas trade. As long as specificity of investment or of trade decisions plays a role, long-term contracts are likely to remain the prevailing instrument. Experience has also shown that long-term contracts and liquid markets can co-exist, even if formerly isolated marketplaces are linked now by arbitrage deals, without forming a uniform global marketplace. However, as long as gas supplies are tight worldwide, arbitrage will rather work to create competition between gas customers, which is unlikely to reduce gas prices sustainably below the level of its alternatives.

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Abbreviations and Acronyms

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ANS	Alaska North Slope
API	American Petroleum Institute
ARA	Amsterdam-Rotterdam-Antwerp
BBL	pipeline from Balgzand (Netherlands) to Bacton (UK)
bbl	barrel
BBSPA	Balkan and Black Sea Petroleum Association
Bcm	billion (10^9) cubic metres
Bcm/year	billion (10^9) cubic metres per year
BG	British Gas
BP	British Petroleum
BTC	Baku-Tbilisi-Ceyhan pipeline
CBOT	Chicago Board of Trade
CCGT	combined-cycle gas turbines
cf	cubic feet (approximately 0.027 cubic metres)
CFTC	Commodity Futures Trading Commission (US)
CIF	cost, insurance and freight
CIS	Commonwealth of Independent States
CNG	compressed natural gas
CNOOC	China National Offshore Oil Corporation
COMECON	Committee on Mutual Economic Cooperation (USSR plus other socialist countries, mostly in Eastern Europe)
CPC	Caspian Pipeline Consortium
DG COMP	General Directorate on Competition (European Commission)

DOE / EIA	Department of Energy / Energy Information Administration (US)
ECT	Energy Charter Treaty
EFP	Exchange of Futures for Physicals
EGAS	Egyptian Natural Gas Holding Company
ELNG	Egyptian LNG, a joint venture to operate the first Egyptian LNG plant
ENAGAS	Empresa Nacional del Gas (Spain)
ENSPM	Ecole Nationale Supérieure du Pétrole et des Moteurs (France)
ESMAP	Joint UNDP / World Bank Energy Sector Management Assistance Programme
EU	European Union
FERC	Federal Energy Regulatory Commission (US)
Flags	Far North Liquids and Associated Gas System (in the northern part of the UKCS)
FOB	free on board
FPC	Federal Power Commission (US)
FSU	former Soviet Union
GCV	gross calorific value
GdF	Gaz de France
GDP	gross domestic product
GDR	German Democratic Republic
GFU	Gas Negotiation Committee (for the export of Norwegian gas)
GHG	greenhouse gases
GJ	Gigajoule = 10^9 Joule = 238 Mcal = 0.278 MWh = 948 MMBtu
GPW	gross product worth
HFO	heavy fuel oil (see RFO)
HHI	Hirschmann-Herfindahl Index

IEA	International Energy Agency
IOC	international oil company
IPE	International Petroleum Exchange
IPE BWAVE	International Petroleum Exchange Brent Weighted Average
IRR	internal rate of return
JCC	Japanese Crude Cocktail
JODI	Joint Oil Data Initiative
L48	Lower 48 States (US 50 States minus Alaska and Hawaii)
LDC	local distribution company
LFO	light fuel oil
LNG	liquefied natural gas
MBD	million barrels a day
Mcf	million cubic feet
MER	maximum-efficient rate of recovery
MMBtu	million (10^6) British Thermal Units
MTBE	methyl tertiary butyl ether
Mtce	million tonnes of coal equivalent
Mtoe	million tonnes of oil equivalent
NAM	Nederlandse Aardolie Maatschappij, joint venture for oil and gas exploration and production in the Netherlands, established by BPM (Shell) and Standard Oil Company of New Jersey (Exxon)
NBP	National Balancing Point (UK)
NEB	National Energy Board (Canada)
NGL	natural gas liquid
NGPA	Natural Gas Policy Act of 1978 (US)

NOC	national oil company
NPB	Norm Price Board (Norway)
NYMEX	New York Mercantile Exchange
OAPEC	Organisation of Arab Petroleum Exporting Countries
OECD	Organisation for Economic Cooperation and Development
Offer	Office of Electricity Regulation (UK)
Ofgas	Office of Gas Supply (UK)
OFGEM	Office of Gas & Electricity Markets (UK)
OPEC	Organisation of Petroleum-Exporting Countries
OSP	official selling price
OTC	over-the-counter
PIW	Petroleum Intelligence Weekly
PRT	Petroleum Revenue Tax (UK)
PSA	production-sharing agreement
RFO	residual fuel oil (see HFO)
ROR	rate of return
RP	reserves-to-production (ratio)
RUE	RosUkrEnergo (Swiss-registered joint venture – exporter of Russian and Central Asian gas to Ukraine)
SDFI	state direct financial interest (Norway)
SEP	Samenwerkende Electiciteits Productiebedrijven (Electricity Company in the Netherlands)
SGE	SoyuzGazExport (external gas-trade agency of the USSR, predecessor of Gazexport / Gazpromexport)
SIMEX	Singapore International Mercantile Exchange
SPA	sale and purchase agreement

Tcf	trillion cubic feet
TPA	third-party access
TTF	Title Transfer Facility (Gas trading hub in the Netherlands)
UAE	United Arab Emirates
UK	United Kingdom of Great Britain and Northern Ireland
UKCS	United Kingdom Continental Shelf
UN	United Nations
UNDP	United Nations Development Programme
US	United States of America
USGC	Unites States (Mexican) Gulf Coast
USGS	United States Geological Survey
USSR	Union of Soviet Socialist Republics
VNG	Verbundnetz Gas AG (Germany)
WACOG	weighted average cost of gas (in the US and UK)
WIEE	Wintershall Erdgas Handelshaus Zug AG, joint venture registered in Switzerland between Wintershall Holding AG in Kassel and the Russian company OAO Gazprom, with a focus on markets east of Germany
WINGAS	joint venture registered in Germany between Wintershall Holding AG in Kassel and the Russian company OAO Gazprom with a focus on the German market
WTI	West Texas Intermediate
WTS	West Texas Sour

Glossary of Terms



Glossary of Terms

Achnacarry agreement	Agreement concluded by the most important international oil companies in 1928 during a meeting in Achnacarry, Scotland, setting pricing mechanisms and establishing a quota system for international crude oil deliveries.
American (option)	Trading term. An option which the holder can exercise at any time up to the expiration date.
Arbitrage	Making use of price differentials between two locations or two points in time.
Arbitrageur	Commercial actor that take offsetting positions in two or more instruments to lock in a profit.
At the money	An option is 'at the money' when the strike price of a call option is very close to the market price.
Backstop technology	Alternative technology to the prevailing energy technology that would become an economically viable substitute, should the finite energy resources be exhausted.
Backwardation	A state in a futures market in which the futures price decreases with later delivery dates.
Basis differentials	The difference in gas prices between two different hubs in North America.
Bid week	The period at the end of the month when pipeline shippers line up their supplies for the following month.
Call (option)	A call option contract gives the holder the right to buy the underlying asset by a certain date for a certain price.
Calorific value	Energy released when the fuel is burned.
Catalytic cracking	Type of refining operation. The catalytic cracking refineries have, in addition to the hydroskimming (see below), vacuum distillation, catalytic cracking and alkylation processes. The catalytic cracking process breaks down the larger, heavier and more complex hydrocarbon molecules into simpler and lighter molecules by heat and the presence of a catalyst, but without adding hydrogen.
Churn	Ratio between traded volumes and volumes at the reference market place physically delivered.

Cost Insurance and Freight (CIF)	Price including the cost of cargo, insurance and transportation to the final destination.
Claw back clause	A clause in some of the long-term UK export contracts to the Continent via the Interconnector, which gives the supplier the right to interrupt the normal contractual flow to take advantage of high UK spot prices.
Clearinghouse	A clearinghouse ensures performance of a contract on an exchange by buying a contract from a seller and selling the contract to a buyer.
Coase theorem	The Coase theorem, attributed to Ronald Coase, states that in the absence of transaction costs all government allocations of property rights are equally efficient, because interested parties will bargain privately to correct any externality.
Coking	Type of refining operation. A coking unit thermally de-composes residues under high temperature and pressure, and produces lighter products (gasoline (petrol), naphtha, gas oil) and petroleum coke.
Commercial	A definition used by the US Commodity Futures Trading Commission. A trader is classified as commercial under its regulations, if the trader is 'commercially' engaged in the business activity hedged by the use of the futures or options markets.
Contango	A state in a futures market in which the futures price increases with later delivery dates.
Convenience yield	Convenience yield is an additional benefit arising from holding physical inventories instead of holding futures contracts.
Cost plus	A pricing approach which is based on covering costs incurred, inclusive of investment, operating and financing costs and risk compensation, plus eventually a premium, regardless of the market value determined by demand.
Crack spread	Trading strategy when a refiner simultaneously buys a long hedge on crude and a short hedge on gasoline (petrol) / heating oil, to lock in the spread.
Crude oil gravity	A measure of the density of the crude oil, usually expressed in degree API.
Dated Brent	Brent crude traded in the spot market. Only Brent crude cargoes with a delivery date of no further than fifteen days are traded in the spot market (see fifteen-day Brent and IPE Brent).
Daisy chain	A series of long and complicated transactions of a forward contract on a cargo-by-cargo basis.

Dash for gas	The surge in demand for gas driven by its use in power generation in the UK in the 1990s.
Dedicated contract	Contract designating the destination of cargoes.
Density	The ratio of mass over volume expressed in kg/m3.
Derivative	A derivative is defined as a financial instrument whose value derives from the values of underlying assets.
Destination clause	Clause in gas supply contracts which restricts the sale of gas to a specific area for which the gas is destined and priced under a replacement value approach in order to avoid potential arbitrage by the buyer. Often used when the delivery is not at the border of the consumer country and the buyer's transportation costs are compensated by a special rebate element in the price formula.
Downstream	Technical, commercial and regulatory activities linked to the consumption sphere; the dividing line to upstream is usually the point of the first commercial transaction in the chain.
Dual-firing equipment	Equipment capable of using alternatively two different fuels.
Duncan-Lalonde agreement	An agreement negotiated in 1980 between the US and Canada that provided a mutually-acceptable set of pricing rules following the continued rise of gas prices.
End-use priority curtailments	A system in the US in the late 1960s, under which pipelines began to ration supplies to customers when the first evidence of gas shortages appeared.
European (option)	Trading term. An option which the holder can exercise on the expiration date.
Exchange	A market place, where the exchange transactions are organised according to defined rules.
Exchange of futures for physicals	Delivery system at IPE under which Brent contract holders can cancel out a futures contract with a physical spot contract.
Exchange-based pricing	Pricing based on prices determined at an exchange.
Exercise price	The price at which an option holder can buy or sell the contract.
Expiration date	The date on which an option right (or other contractual rights) expires.

Fifteen-day Brent	Brent crude traded in the forward market. It is named after a market practice that only Brent crude cargoes with delivery date of further than fifteen days are traded in the forward market (see dated Brent and IPE Brent).
Flex-fuelled car	A car that can run on ethanol or gasoline (petrol) or a combination of the two.
Flowback system	A system in Canada by which the government as the sole purchaser of Canadian gas for export re-distributed the economic rent from export sales on a pro rata basis to each seller according to his production.
Free on board (FOB)	The seller provides the cargo free of costs at the exporting port, including loading on to the ship and customs clearance; the buyer undertakes the shipping and insurance of the cargo.
Forward	A forward contract is an agreement between two parties to buy or sell an asset at a certain future time for a certain price. Forward contracts most often provide for physical delivery, linked to its particularities, and are traded in the OTC market.
Futures	A futures contract like a forward is an agreement between two parties to buy or sell an asset at a certain future time for a certain price. Futures are distinguished from generic forward contracts in that they contain standardised terms, are traded on formal exchanges, are regulated by overseeing agencies and are guaranteed by clearinghouses. In order to ensure payment, futures have a margin requirement that must be settled daily. A future contract is a financial instrument.
Gas bubble	When the gas market was finally de-regulated in the US, the higher price levels had a stimulating effect on exploration while dampening demand creating a long-term surplus, termed the 'gas bubble'.
Giant field	Oil: more than 500 million barrels recoverable; Gas: more than 3 trillion cubic feet (85 Bcm) recoverable.
Gross calorific value	Energy released when the fuel is burned, inclusive of the condensing heat of the water formed by the combustion.
Gross product worth	The total value of products processed from crude oil.
Heavy crude	Crude oil with gravity under API 22°.
Hedger	A hedger uses futures and other derivatives to reduce the price risk for his physical deliveries that he faces from potential future movements of a market variable.

Henry Hub	A point of the natural gas pipeline system in Erath, Louisiana, owned by Sabine Pipe Line LLC. Spot and futures prices set at Henry Hub are denominated in $/MMbtu and are generally seen to be the primary price set for the North American natural gas market.
Hirschmann-Herfindahl Index	Sum of the square of all market shares; commonly accepted measure of market concentration.
Hotelling rent	Difference between the cost of producing a marginal non-renewable (energy) resource and its value in the market, when production is restricted and the supply and demand curves do not meet.
Hotelling's rule	Hotelling's rule is defining the net price path of an exhaustible resource over time while maximising the overall rent from producing this resource.
Hub	Interconnection of several gas pipelines, eventually in combination with nearby storage facilities.
Hubbert's curve	A bell-shaped curve for production over time of a finite resource like oil or gas; initially proposed by and named after M. King Hubbert in relation to US oil production.
Hydrocracking	Type of refining operation. Hydrocracking is similar to catalytic cracking, but with the use of hydrogen and higher pressure. The hydrocracking process can convert heavy oil (fuel oil components) to lighter and more valuable products (notably naphtha and middle distillate components).
Hydroskimming	Basic type of refining operation in which crude components are separated at atmospheric pressure by heating, condensing and cooling. Hydroskimming refineries are equipped with atmospheric distillation, naphtha reforming and hydrodesulphurisation facilities.
In the money	An option is 'in the money' when the strike price of a call option is lower than the market price.
IPE Brent	Brent crude traded on the International Petroleum Exchange (IPE) in London, a futures market (see dated Brent and fifteen-day Brent).
Light crude	Crude oil with gravity above API 33°.
Long (position)	A party assumes a long position in the futures market when it agrees to buy an underlying asset on a certain specified future date for a certain specified price.

Long-term contract	A contractual relationship between two parties beyond a single transaction with a minimum duration usually of at least one year up to 20 years and longer. While single parts of a long term contract, like pricing provisions, may be changed over time under the rules of the contract, the contractual relationship between the parties will remain for the term of the contract.
Majors	Major oil companies, usually the Seven Sisters.
Marginal cost	Either the incremental costs to produce an extra unit or the costs of producing from a marginal production site.
Marker crude	Dominant price-setting oil grade.
Market place	Used in this book as the place where market transactions take place.
Maturity	See 'Expiration date'.
Medium crude	Crude oil with gravity between API 22° and API 33°.
Minimum-pay contracts	Long-term contracts with minimum-pay obligations.
National Balancing Point	A notional point on the UK gas grid, where gas can be sold and purchased without paying an entry or exit fee for the gas.
Netback pricing	Replacement value of gas minus the costs of bringing it from the netback point to the customer with the off-take characteristics the customer requires.
Neutral point	During the time period when the two-base pricing formula (see below) was used (1947-1971), a point to which transportation costs of oil from the Persian Gulf and from the US Mexican Gulf were equal.
Non-commercial	A definition used by the US Commodity Futures Trading Commission. A trader who is not classified as commercial is called non-commercial, see 'Commercial'.
Norm price	In the Norwegian petroleum tax system norm prices may be used for the calculation of taxable incomes instead of actual incomes from sales.
Norm Price Board	An independent panel in Norway which determines the norm price based on Brent prices and the sales reports by companies operating in the Norwegian sector.
Nota de Pous	The note presented to the Dutch parliament in 1962 by the then Minister of Economic Affairs of the Netherlands, de Pous, establishing the main principles of the Dutch gas policy.

NYMEX Access	24-hour electronic trading system at the New York Mercantile Exchange.
NYMEX Strip price	The average of future prices, usually over the following 12 months.
Official selling price	The price that was regularly established by OPEC member states for their delivery contracts from the 1970s until the mid-1980s.
Oil derivatives	Oil-related financial instruments.
Oil grade	Oil of a defined quality.
One-base pricing	A pricing formula (1928-1947) according to which the international price of oil at any delivery point worldwide outside the US was calculated as the price FOB Mexican Gulf plus cost of (factual or virtual) freight from the Mexican Gulf to the point of delivery.
OPEC basket price	A reference price made up of 11 grades produced by OPEC member-states: Saharan Blend (Algeria), Minas (Indonesia), Iran Heavy (Islamic Republic of Iran), Basra Light (Iraq), Kuwait Export (Kuwait), Es Sider (Libya), Bonny Light (Nigeria), Qatar Marine (Qatar), Arab Light (Saudi Arabia), Murban (UAE) and BCF 17 (Venezuela).
Options (call or put)	An option contract gives the holder the right to buy or sell the underlying asset by a certain date for a certain price.
Organisation of Petroleum-exporting Countries (OPEC)	OPEC was established by major developing oil producing countries in 1960 and is aimed at increasing their export revenues through collective efforts.
Out of the money	The option is 'out of the money' when the strike price of a call option is higher than the market price.
Outcry	Open trading floor at an exchange.
Over-the-counter (OTC)	An OTC transaction is a bilateral transaction outside an organised exchange.
Peak oil theory	Approach, which claims that the production of oil is approaching or will reach soon its peak.
Phillips Supreme Court decision	The US Supreme Court's decision of 1954 that effectively imposed wellhead price controls on gas moving in interstate – but not in intrastate – commerce.
Possible reserves	Estimated quantities of oil or gas which are inferred by geological and engineering data.

Posted price	The price established in concession agreements between host states and IOCs for taxation purposes.
Price escalation clause	Formula by which the gas price is calculated as a function of other parameters, like prices of alternative fuels or inflation indicators.
Principal-agent theory	Addresses the special pattern of decision making between the principal who owns the resources and the agent producing them.
Probable reserves	Estimated quantities of oil or gas which are indicated by geological and engineering data; a sub-set of 'possible reserves'.
Proved reserves	Proved reserves are those quantities of oil or gas which, through analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations.
Put (option)	A put option contract gives the holder the right to sell the underlying asset by a certain date for a certain price.
Rent	The difference between price and cost, and / or between cost and marginal cost.
Replacement value	Concept of pricing gas at the value of its replacement fuels taking into account differences in efficiency and costs of using the replacement fuel.
Reporting agency	A reporting agency issues a publication which lists price records on the OTC market.
Resource rent	For an individual resource owner, the sum of the Ricardian rent and Hotelling rent.
Ricardian rent	Differential rent, the difference between the production costs of a marginal unit and a unit produced at more favourable cost and / or a rent stemming from the costs resulting from the distance to the market. The Ricardian approach recognises that resources become more difficult and costly to exploit, without looking at the overall limitations of a particular resource.
S-curve	A formula linking gas prices to those of oil. The S-curve uses price ceilings and bottoms and allows to soften oil price shocks when setting the gas price. Is is introduced in some LNG contracts in the Pacific.
Seasonality	Seasonal pattern of prices due to seasonal weather changes (and, consequently, energy demand).

Self-contracting	Under a self-contracting scheme, one or more partners in a venture (or their marketing affiliates) sign a sale and purchase agreement with the venture and assume the marketing risk for the contracted volumes.
Seven Sisters	Informal name of a group of international oil companies, which until the 1970s had almost full control of internationally-traded oil, operating on the basis of the 1928 Achnacarry agreement. The group initially included: Exxon (Standard Oil of New Jersey), Mobil, Gulf, Texaco, Standard oil of California (SOCAL) from the US, British Petroleum from the UK and Royal Dutch / Shell from the UK / the Netherlands.
Sherman Anti-trust Act of 1890	US act which made monopoly illegal; it was on the basis of this act that in 1911 Rockefeller's Standard Oil Company was split up.
Ship-or-pay	A pipeline transport contract under which the shipper has to pay for booked capacity regardless of it being used or not.
Short (position)	When a party agrees to sell an underlying asset on a certain future date for a certain specified price, the position it assumes is called short.
Sour	Crude oil with a high sulphur content (more than 1.5%).
Speculator	Commercial actor who takes on risks to gain profits in the market. A speculator does not use the market in connection with the production, processing, marketing or handling of a product.
Spot	A spot contract is an agreement to buy or sell an asset for immediate delivery.
Spread trading	Transactions which do not take place in absolute price terms but in terms of the price differential between the benchmark crude oil and other crude oil, or between products.
Squeezed	Situation on a market when no-one is willing to lend a futures contract.
Strike price	See 'Exercise price'.
Super-giant field	Oil: more than 1 billion barrels recoverable; Gas: more than 30 trillion cubic feet (850 Bcm) recoverable.
Swaps	In financial terms, the exchange of one security for another; for energy also used when exchanging equivalent volumes of energy of two deliveries of different origin between two delivery points and /or two delivery times
Sweet	Crude oil with a low sulphur content (less than 0.5%).

Swing	A provision in supply contracts allowing the buyer to vary the amount of gas to be taken.
Take-or-pay	Obligation of a buyer to pay for a certain volume of gas irrespective of whether it is taken or not.
Third-party access (TPA)	The possible use by a third party of a pipeline for transportation and / or distribution purpose while paying a charge for such use to the owner / operator. TPA can be negotiated or mandatory.
Transaction cost theory	Transaction cost theory suggests that the mix of instruments: (i) market places, (ii) long-term contracts and (iii) vertical integration, will tend towards a minimum of overall transaction costs, reflecting technical, market, legal and regulatory developments.
Transfer prices	In this report: prices used for taxation and internal accounting of cross-border transactions within international companies and within vertically-integrated structures.
Transmed	Pipeline bringing Algerian natural gas to Italy.
Two-base pricing	Pricing formula (1947-1971) according to which the international price of oil at any delivery point worldwide outside the US was calculated as the price FOB Mexican Gulf plus the cost of (factual or virtual) freight to the point of delivery: (a) from the Mexican Gulf – for the delivery points located to the west of the neutral point, and (b) from the Persian Gulf – for the delivery points located to the east of the neutral point.
Unbundling	Separation of production, transportation and distribution functions in a vertically-integrated company. Usually three types of unbundling are identified: ownership, operational and financial.
Upstream	Technical, commercial and regulatory activities linked to the production sphere; the dividing line to downstream is usually the point of the first commercial transaction in the chain.
Volatility (of price)	Price variability calculated mathematically on the basis of a set of historical data of price movements.
Webb-Pomerene law	A law passed in the US in 1918 under which American companies were allowed to act abroad irrespective of the anti-trust law in the domestic US market.



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