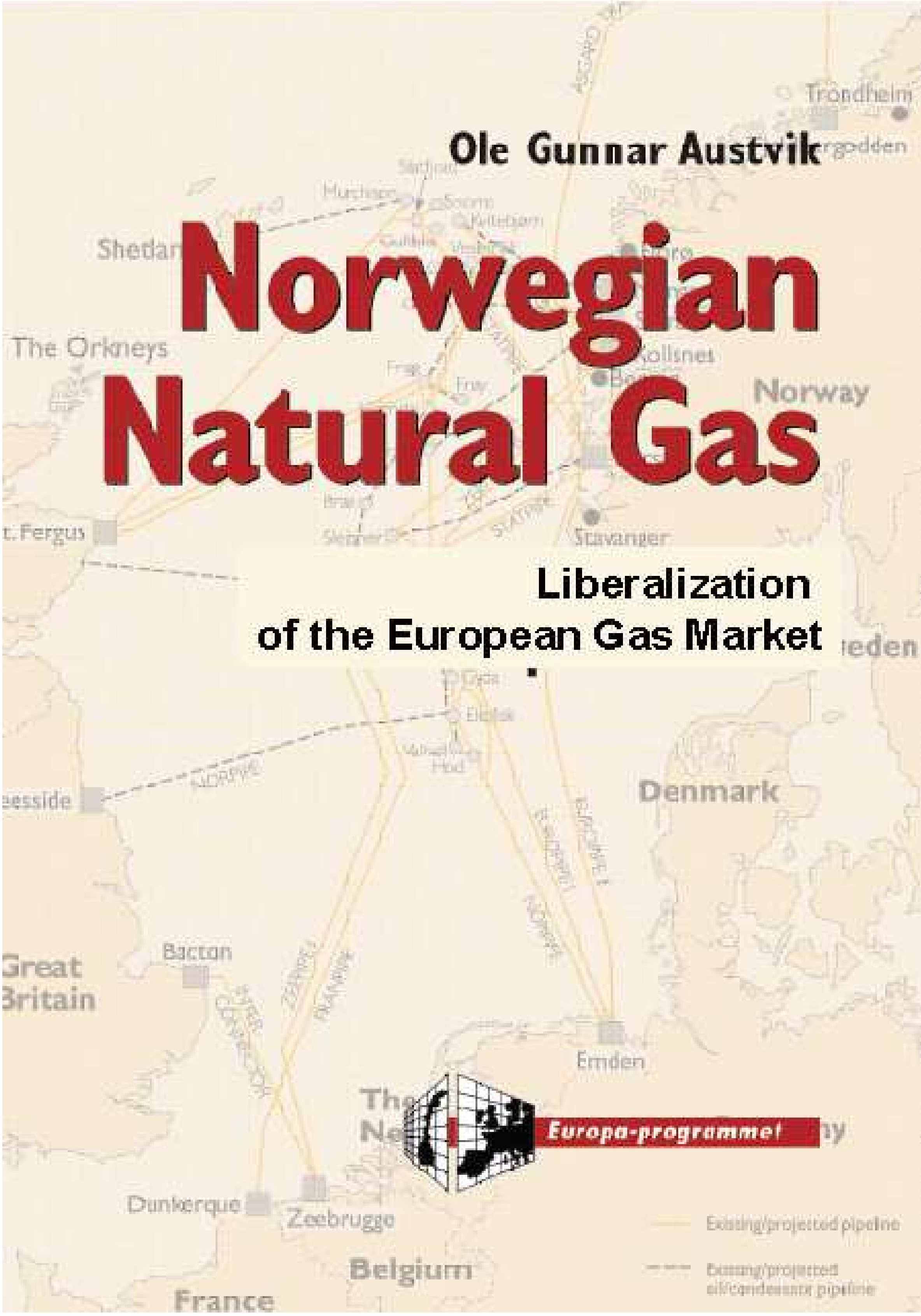
Ole Gunnar Austvik

Norwegian Natural Gas

Liberalization of the European Gas Market



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Ole Gunnar Austvik

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Preface

After having written many articles, reports and edited books about Norwegian natural gas and the development of the European gas market, I have finally got the opportunity to put together a synthesizing manuscript.

The starting point for this book has been the translation, revisjon and updating of a report published in 2000 in Norwegian language ("Norge som storeksportør av gass") under the Europa-programmet project "Norway in the Geopolitics of energy". My thanks still go to those participating in that project, especially Torvild Aakvaag and Vice Admiral Bjørnar Kibsgaard (project leader). This part covers about one third of the volume (Chapters 1, 2, 12 and 13).

The rest of the text is based on research projects, reports and papers I have worked on during the 1990s, most of them unpublished or presented only in "in-house" reports (Chapters 4, 5, 6, 7, 8, 9 and 11). Chapter 10 is however a revised version of an article in a book I edited in 1991. Some conclusions from Chapters 3, 4 and 12 are already presented in journal articles: Sosialøkonomen 1996, Energy Policy 1997 and Internasjonal Politikk 2001.

The book is being published as part of the Europa-programmet´s project "Norway as a European Gas Producer"(2001-2003). I am grateful for the discussions and meetings we have had in the project group. The group consists of project leader Trygve Refvem, and participants Hallvard Bakke, Jon Bingen, Hugo Overgaard and myself. Especially I am grateful for all help from Trygve, who has also worked thoroughly through the manuscript. All responsibility for facts and analysis rests however with the author.

Ingrid Neste has made considerable efforts in making the manuscript ready for print.

During the finalisation of the study Vice Admiral Bjørnar Kibsgaard passed away. This book is dedicated in commemoration of Bjørnar as a valuable colleague and a good friend.

Lillehammer/Oslo, January 2003
Ole Gunnar Austvik
www.oga.no

Project: Norway as a European Gas Producer

This project was started in April 2001 in a situation where the Gas market liberalization project in the EU gathered additional momentum. The idea surfaced that if respecting existing international long term contracts caused delay in the liberalization process, then contract sanctity might be considered as a variable.

This resulted in arguments about inter alia the destination clauses in existing Russian export contracts and the validity of Norwegian gas contracts negotiated under the Gas Negotiation Committee (GFU) structure. In view of long term energy security concerns, however, attitudes currently seem to shift towards the merits of contract sanctity.

While other members of the project team from time to time have indulged in heated arguments about difficult related issues as fairness and long term credibility, Ole Gunnar has always maintained an attitude of analytical distance and neutral observance of the parties and their various interests in an attempt to understand and explain what goes on. His contribution to the project has been vital without compromising his ability to look beyond the conflict of the day.

In this period of fundamental changes in European energy markets, there is definitely a need for more insight. It is my hope that this book may contribute both to a broader understanding of some of the basic concepts and theories that are involved as well as understanding the fundamental forces and processes as manifestations of the basic interests of the many parties which are affected.

The Norwegian Ministry of Foreign Affairs and the Ministry of Petroleum and Energy contributed financially to the project.

Trygve Refvem
Project Leader

Project:
Norway in the Geopolitics of Energy

Norway is the third largest exporter of oil in the world after Saudi Arabia and Russia, and the second largest exporter of natural gas in Europe after Russia. The significance of energy production for the country's economy, directly and indirectly, is increasing. The evaluation of Norway by the surrounding world as an economic, political and diplomatic player is increasingly marked by its role as a producer of energy. In this context, analyses of the situation and a definition of comprehensive strategies are of vital importance for Norway's ability to look after her national interests. Accordingly, Norway's role as a producer of energy has consequences for her diplomacy, including security and defense policies.

Europa-programmet took the initiative in 1996 to focus on these challenges to Norwegian strategy and security policy. The first project report; ”Strategy – Security Policy and the Production of Energy” was published in 1998 (Kibsgaard, Austvik, Orban, Johannessen and Nyhamar). The project ”Norway in the Geopolitics of Energy” was a continuation and expansion of the aforementioned project. The project report was published in 2000 (Kibsgaard, Austvik, Johannessen, Nyhamar, Tanderø and Aakvaag), together with a separate study on natural gas by Ole Gunnar Austvik.

Norwegian Ministry of Defense, Headquarters Defense Command Norway/the Naval Staff and Norsk Hydro ASA contributed financially to the projects..

The late
Bjørnar Kibsgaard
Vice Admiral

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1 Norwegian Challenges in the European Gas Market

Perspective

Norway is becoming an ever-larger exporter of natural gas. Norwegian gas exports is now second largest in Europe, after Russia. It has passed 50 billion cubic meters (BCM) and will increase further to 60-70 BCM in a few years time. Market shares are expected to grow to between 30 and 40 percent in important countries like Germany, France and Belgium. Together with high oil production and high oil prices, the growth in natural gas exports contributes to giving the petroleum sector an increasingly more important role in Norwegian economy.

The petroleum economy is now an image of Norway in the rest of the world. The large petroleum export has increased Norway's international economic and strategic significance and led the country into an exceptional position within the Organization for Economic Cooperation and Development (OECD). In some areas Norway has developed divergent interests relative to importing countries which otherwise are close to her, economically as well as politically. Norway now shares interests with other petroleum exporting countries, as well. These countries are in most cases quite different from Norway in general economic and political affairs.

Thus, Norway's role as a major petroleum exporter is relevant not only for the industry and the economy, but also for her diplomacy, including security and defense policies. This challenge is particularly apparent for the gas sector, as expensive pipelines link buying, transmitting and selling countries tight together. Norway's position as a major European gas exporter gives her strength and opportunities, but it may also weaken the country.

The high gas export is reached at a time when international economic and political integration processes are more comprehensive in depth and scope than ever before. Globally, this is seen most clearly through constantly more comprehensive rules under the World Trade Organization (WTO).

Regionally, the European Union (EU) goes deeper in the integration than the WTO, with major liberalization of markets and harmonization of competitive regulations. The effects of these developments are felt fully in Norway through her open economy, the membership in WTO and the participation in the single market of EU through the European Economic Area (EEA). Furthermore, the European Energy Charter is, inter alia, an attempt to introduce WTO's principles in the energy sector also for non-WTO countries. The processes directly affect the organization of production, transportation and sale of Norwegian gas, the profitability of the activities and Norway's strategies and policies.

It will require considerable political and commercial effort from Norway to reap benefits and avoid problems from the new international order. No other country share Norway's interests fully as a petroleum exporter, either in economic or in political terms. Norway's ability and will to influence the international framework and market rules will be important. The situation poses huge challenges domestically, as well, in creating macroeconomic, social and industrial policies in an optimal and dynamic manner, relevant to the size of the sector and the speed of changes in markets and international affairs.

In developing a petroleum strategy, Norway must allow for it to attract attention from other nations. In the international economy in general, Norway must be considered a price taker. Norway can, in the European gas market, have a greater potential for influencing prices, quantities traded and security-of-supply than in most other markets where she sells her goods and services. The role as a major gas exporter will in itself be a challenge for the thinking in a "small state" which otherwise considers herself to be of limited economical and political significance to others. As a basis for Norway's national and international petroleum polices, in general, and for the gas sector, in particular, it will be important for the country to have an independent understanding and analysis of how economic mechanisms and political actions works, and how domestic and international commercial and political players can influence the development.

Towards A More Liberal Market

The natural gas sector is different from the oil sector in several ways. Clearly the search for and production of oil and gas have many similarities. Natural gas also competes with other energies, not least oil products, in end-user markets. Transportation costs are however far higher for natural gas than for oil. When investments in transmission, storage capacity and distribution have been made, the larger part of transportation costs is determined. Operating costs are usually relatively low compared to capital costs. The degree of utilization of the pipeline does not influence total transportation costs much. A high or low degree of utilization (the 'load factor') affects costs per transported unit directly, but does not affect total costs of transportation much.

Furthermore, for the European market, much gas is found in a relatively small number of large fields far away from consumer areas. While oil can be transported relatively cheap to these areas, transportation costs for natural gas are high and, hence, large-scale operations are important to realize investments in bringing gas to the market. The advantages of large-scale operation and vertical integration imply that few companies operate as gas transporters in any gas market. Often, gas is produced together with oil, and the two must be extracted in an optimal manner over time in order to extract as much of the reserves as possible. Thus, resource management is important for cost effective production over time, as well.

The present liberalization of the European gas market is taking place both due to market growth, new transmission and storage capacities, and political decisions at EU level and in EU countries. Basically a ″perfect″ liberalization of the market entails competition to be established wherever possible (the ″invisible hand″) and regulation of tariffs and prices to be done wherever necessary (introduction of a ″visible hand″). Vertically integrated operations are to become unbundled businesses, either as separate accounting units within a company or by splitting the ownership. However, where joint operation advantages exist, regulation should aim for an optimal, rather than a maximum, split. It is important for the industry to be able to exploit advantages of scale and scope, but authorities (at EU level) will at the same time be concerned with neutralizing undesired effects on prices and market structures, that follows from the fact that companies are often growing very large.

It is difficult to develop regimes, which optimize the advantages of competition and large-scale and joint operations, which are sufficiently flexible to take continuos changes in market sizes and structures into account. A liberalization, which is ″perfect″ according to economic theory, is rarely possible in any gas market. The experiences from the regulation of the American gas market illustrate that public intervention in these markets may create considerable economic inefficiency over time when the decisions are wrong and/or too static (see Chapter 9). Commercial and political conflicts of interest, and the concentration of new gas resources far away outside the EU, make a perfect liberalization of the European markets even more difficult to achieve than it has been in the U.S..

There are different views to whether it is the growth and development of the market or political decisions that are the strongest forces for a more liberal European gas market. EU’s so-called Gas Directive (cf. Chapter 2) introduces a system with third party access (TPA) in the transmission network, but it does not regulate competition between producers or (de facto) the practices of the distribution companies delivering gas to individual businesses and households. The directive does not contains regulations for the pricing of transmission, but presupposes negotiated settlements between the parties, unless individual countries choose to introduce regulated tariffs. It is quite certain that the market will be different than it has been, it will be more pluralistic and ”liberal”. The Gas Directive is a step on the road towards a more liberal market, but represent in itself far from a completely liberalized market system.

It is however important to view the Gas Directive in relation to other development s in the market. Political interventions, like EFTA Surveillance Agency’s (ESA’s) evaluation of the Gas Negotiation Committee’s (Gassforhandlingsutvalget, GFU) functioning (cf. Chapter 2), and any later actions and directives at EU or national levels, are, together with the growth in demand and supply and development of a more extensive transportation network and storage capacity, also important. All the changes must be taken into account when evaluating how liberal the market actually will become and which commercial and political consequences it may lead to for Norway as a major exporter.

Prices, Taxes and Contracts

Any degree or form of liberalization of the market has a potential for affecting prices and profitability to one or more parties in the gas chain. Costs will be lowered as a rule and profit margins will decrease in segments where a successful liberalization takes place, whether it is done through intervention from a regulatory authority or from increased competition. Lower costs and prices one place will in general be an advantage for someone else in the gas chain. EU aims for the consumer to reap this benefit. Who gains and looses with market liberalization for non-renewable European gas is however dependent on how the liberalization processes develop in totality and how authorities and companies act.

One important question is how the balance between production and demand growth develops. This balance has the potential to influence export/import prices to a larger extent and more directly than it has done in the "old" market. In a more liberal market, it could be of great significance for the exporters (Norway, Russia, Algeria and the Netherlands) that the combined growth of natural gas exports do not exceed growth in demand.

At the same time, because natural gas is a non-renewable resource that in Europe is found only in a few places in large quantities, there will, as opposed to many other liberalized markets, exist an economic rent in the market.[1] The existence of a rent contributes to the expectation that the European gas market will remain more politicized than most other international markets. Like oil, natural gas has both a high intrinsic and a high strategic[2] value.[3] The economic rent may in different liberalization scenarios end up with the producing company, the producing country, the transmission or distribution company, or at producers of electricity or large industrial users. Periodically it may end up with the consumers as increased consumer surplus, like the EU expresses the desire to. With an active taxation policy for natural gas in the consumer countries, it may also end up in the treasuries of these countries.

In the question of taxing the use of oil and gas see (Chapter 4),, Norway is in a quite unique and partially conflicting situation with other Western countries. Increased excise taxes on natural gas have the potential of forcing Norway's export prices down. Norway's national economic interests indicate that Norway should argue more strongly internationally for environ-

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[1] *Normal profit* for a business is expressed by its opportunity cost, and will be the minimum profit needed to run the business. *Economic profit* is the profit earned beyond normal profit. *Resource* or *petroleum rent* is an economic profit caused by the non-renewable nature of the resource.

2 Strategic raw materials are here defined as; «Raw materials which are necessary in order to meet military, industrial and essential civilian need in peace, crisis and war: raw materials which do not exist or are not produced/extracted within the borders of the country in sufficient quantities to meet stated needs: raw materials which are important to the surrounding world, and/or to our own economy and through that our security». (Kibsgaard et.al. 1998).

[3] Both the American embargo on the building of the Soviet gas pipeline to Western Europe in 1982 (Chapter 10) and Iraq's attack on Kuwait in 1990 (Austvik, 1993c), were examples of conflicts which were motivated on both economic and strategic effects and the combination of them, regionally and internationally.

mental problems to be solved in a more direct way than consumer countries maximizing the tax on the use petroleum products. This question should become more prominent as the EU countries' tax policy changes from a taxation of labor to a taxation of energy, including not the least, the use of environmentally friendly natural gas (EU, 1997b).

Another important question is the consequences of liberalization on long-term contracts (Chapter 12). Norway has made considerable irreversible investments in production and transmission of natural gas over the past 20-30 years. To safeguard these investments, a number of long-term contracts have been entered into with continental transmission companies with so-called take-or-pay (TOP) clauses. The customers of natural gas (local distribution companies, large industrial users and gas power plants) may in a liberalized market enter into new contracts with gas of another origin than what Norway have already sold to the transmission companies. The transmission companies have purchased the gas from Norway on long-term contracts under the assumption that they will re-sell it to these buyers. By splitting the transportation and sales function of the transmission companies, and if their margins are lowered through competition or regulations, the companies may in a liberalized market be unable to fulfill their obligations towards the exporters. The wholesaler role of the transmission companies may then have to be assumed by the producers through a larger and more diversified contract portfolio directly to buyers to replace the "old gas" under TOP agreements. Alternatively, transmission companies may go bankrupt if they are not freed from or are able to renegotiate their commitments based on force majeure. Such experiences were made in the USA in the 1980s after the Open Access system was introduced and the excess supply of natural gas (the 'gas bubble') that followed, due to the liberalization of the market and the drop in oil prices. Over-supply of gas in the short and medium term may lead to lower investments in new production (particularly large fields) and a lower supply of gas with consequential higher prices in the long-term.

Organization of the Norwegian Petroleum Industry

The other important exporting countries to the European market (Russia, Algeria and the Netherlands) have organized their production, transmission and sale of natural gas in one company (Gazprom, Sonatrach and Gasunie). The arrangements with a governmentally controlled coordination of production through the Gas Supply Committee (Gassforsyningsutvalget, FU), the regulation of transmission on the Norwegian continental shelf and sales through GFU (Chapter 2) has been a looser form of coordination of activities than in the other exporting countries, but has been established for the same reason. The intent has been to have a proper management of resources by optimizing the production of gas over time, exploit economics of scale and scope in and between production and transportation and between simultaneous production of oil and gas in each field. These considerations were then balanced into the sales situation where coordination was also assumed to give a better market position than if several smaller individual volumes were offered independently of each other.

The liberalization processes already challenged the ways Norway organize production, transportation and the sale of gas. One question will be how Norway will and may organize the industry in a new way so that she does not create a form of competition between Norwegian companies that will pressure prices in the market down at the expense of long-term supply. At the same time the organization must be such that companies are allowed to reap advantages of increased competition downstream. Basically, free competition between companies operating on the Norwegian shelf may contribute to a larger supply of natural gas in the market on short and medium term with a pressure towards lower prices, as compared to a situation, which regulate the total supply of gas. The handling of the large natural gas resources managed by the (Norwegian) State's Direct Financial Interest, SDFI (Norwegian: Statens Direkte Økonomiske Engasjement, SDØE) are among the elements which will have to be included in this evaluation.

The period of the very large and long-term natural gas contracts may be waning. The number and variation of contracts may increase considerably in the years to come. The interaction between companies and the public authorities may find a different form than before. The authorities will to a larger extent have to be concerned with the overall framework and rules of the game for entering into natural gas contracts, rather than in the approval of individual contracts. The importance of close dialog and interaction between the industry and the authorities will then not be less important than before, rather the opposite. To defend the large economic interest Norway has in securing the value of both present and future gas contracts, authorities and companies have a need to adapt their way of thinking and acting. At the same time, the EU will to a larger extent have to be concerned about the consequences for the long-term supply of a possible successful market liberalization with lower export/import prices.

Foreign and Security Policy Aspects

As a Western European country, Norway is relatively isolated in her interest in high and stable natural gas prices. The pricing interests are largely shared with export countries, like Russia and Algeria, which politically are further away from the EU countries than Norway, but which are also far away from Norway. This illustrates a new dimension of foreign policy balancing of Norway's particular national interests and considerations as a petroleum producer in the relationship to other Western countries. Oversupply of natural gas in a liberalized market does not serve Norwegian interests. An unfavorable development of the market liberalization and increased natural gas excise taxes, may both work towards lower profits for producers and through that increased uncertainty in connection with long-term investments. If the effects become strong, fields may become unprofitable. As most of the economic profit to the producer goes to the Norwegian treasury, it is a conflict of concern directly for the Norwegian government. It will be of importance for Norway how production in other gas exporting countries develops. Market developments and economic interests will have to be weighed into Norway's traditional foreign and security political relations.

In addition, the large economic and strategic interests tied to the natural gas trade can pull Norway into international conflicts. At the same time, the world has politically changed from bipolarity to multipolarity, with the United States as the only remaining global superpower. As early as 1982 Norwegian gas was dragged into great power politics, when the U.S. tried to embargo the building of new Soviet pipelines to Western Europe, with Norwegian gas as an alternative (Chapter 10). Both due to Norway's size in the market and the geographical localization of the resources, Norway may in the future be involved in economic conflicts of interests and international currents due to the intrinsic value of the gas, and where natural gas deliveries and gas transportation systems are included as important elements in conflicts which mainly are based on other (more general) questions than energy. This means that consumer countries may wish to defend Norwegian oil and gas production in a crisis, even if she herself should not be able, or possibly wish to close down production. This security policy consequence of the petroleum activity makes it necessary to maintain a defense capability sufficient for not loosing control over the Norwegian shelf.

Chapter Contents

This book focuses on these issues important for Norway as a major gas exporter and to the development of a liberalized European market. Chapter 2 explains main features of the European gas market. Natural gas is sold in regional markets with independent pricing structure and particularities. In Europe, this has led to large investments for the producers and long-term contracts. The strong market growth and EU's actions to liberalize the market may change this. The organization of the Norwegian gas production and sale is discussed, as well as the reorganization taking place in 2001.

Pricing mechanisms is discussed in Chapter 3, both in the "old" / existing structure and how a liberalization of the market may change price formation.

The increased importance of energy taxation in EU countries is covered in Chapter 4. Even though natural gas is the most environmentally friendly of the fossil fuels, the use of natural gas may be taxed far harder in the future. The report discusses price effects of such a development.

Chapter 5 discusses whether or not a gas producer, like Norway, necessarily must earn a resource rent. With the use of economic theory for exhaustible resources it is shown how prices to consumers may increase at the same time as prices to producers drop, where the difference is made up by higher gas taxes to the consuming countries.

Transportation of natural gas involves considerable scale advantages and there are often scope advantages from production, storage and sale, as well. Chapter 6 discusses how competition and regulation may influence the functioning and social efficiency of the market, and the concentration of market power.

When companies become large, they may exploit market power, supported by the authorities of their respective countries. Chapter 7 focuses on regulatory challenges for the EU, and how the transporters may change between conflicting and cooperation with the EU.

Chapter 8 focuses on schedules for regulatory regimes. It is shown how multipart tariffs may give the best "second best" results, but that first best result may never be achieved.

The liberalization of the European gas market is not an isolated phenomenon. In the OECD countries, a large number of sectors have been liberalized over the last couple of decades. Chapter 9 discusses the changes in the North

American gas markets (USA and Canada) and in Great Britain, and the relevance these experiences may have for the understanding of the European market.

Chapter 10 discusses the role of natural gas in international affairs. Particular focus is put on the US embargo of Soviet gas in 1982.

Chapter 11 discusses consuming countries supply security for natural gas, natural gas as the environment's best friend and the use of Strategic Gas Reserves (SGRs) to mitigate a crisis, in the same way as the Strategic Petroleum Reserves (SPRs) is assumed to do in the oil market.

Based on these deliberations, Chapter 12 focuses on consequences of a more liberal European gas market for important variables for Norway as an exporter. In particular the effects on prices and taxes, contractual forms and modulation, existing and new long-term contracts, security of supply and environmental concerns are discussed.

The impact on the formulation of a Norwegian gas strategy is discussed in Chapter 13. This applies to the organization of production, transportation and sale of natural gas. It also applies to energy related policies of the EU and of EU countries and strategies of other natural gas exporters, like Russia. Some implications of foreign and security policy character are discussed.

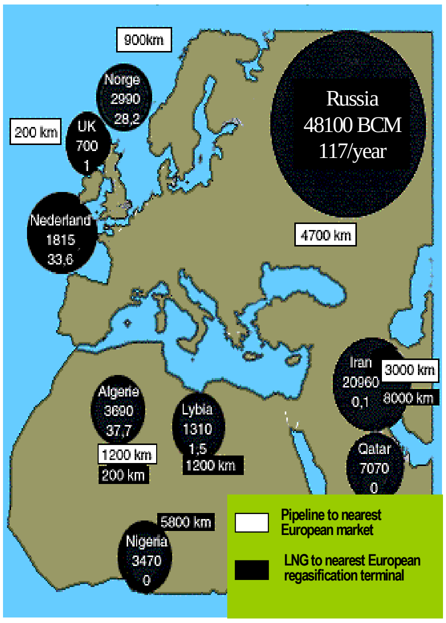
2 Market Developments and Changes

A Regional Market in Strong Growth

Natural gas markets differ from the oil market by the large and irreversible investments that are made in production, storage capacity, pipeline transportation, and among those who use natural gas (Chapter 6). The costly infrastructure makes natural gas less mobile over long distances than oil. There are ”regional” gas markets with pricing mechanisms rather independent from each other around the world. This is different from the oil market where oil is moved relatively cheaply with one global price, when we adjust for transportation costs and varying qualities of the oil. The three most important natural gas markets in the world are:

- The *Asian market*, which up to now mainly has been Liquefied Natural Gas (LNG) imported to Japan, South Korea and Taiwan from countries like Indonesia, Malaysia, Australia and Qatar.
- The *North American market* which mainly is dry gas through the pipeline systems of Canada and the U.S.
- The *European market* which is mainly dry gas in pipeline systems of Europe and Russia, but also some LNG from North Africa.

The huge transportation costs mean that resources, which are possible to sell to the European market today, are limited to distances up to 5000 km from the area of consumption (figure 2.1). EU countries, as the most important gas users, also have a significant domestic production, but this is generally small relative to consumption in individual countries. The exception is the Netherlands, which is the only significant natural gas exporter within the EU. The growth in consumption within the EU is today mainly covered by import from three countries that are not members of the EU: Norway, Algeria and Russia.



Source: Statoil

Figure 2.1: Resources for the European gas market 1995 Reserve size, annual exports and transport distances to the EU

Russia is the world's largest owner of resources and also the largest producer and exporter of natural gas. About one third of the total natural gas resources in the world are located in Western Siberia. A lot of gas is already being sent from this area to Russian and European markets. The Middle East (Iran, Qatar) has large gas reserves, as well. In spite of the shorter distance to Europe than for Siberian gas, there are no sales of gas from the Persian Gulf to Europe as of yet. This is largely due to political conditions and difficult transit routes through Turkey. Also Nigeria might in the future send gas to Europe, and then preferably as LNG. The next exporting country for gas to Europe will however be Libya, which also is closer to Europe. It is particularly political circumstances that have hindered Libya from being an exporter to the European market already.

Even though domestically produced gas has been used in many countries ever since the nineteenth century, the European gas market is not considered to be more than about 40 years old. The trade of natural gas between countries began when the Netherlands started exporting gas from the giant Groningen field in the 1960s. The Soviet Union, Algeria and Norway followed in the 1970s. Infrastructure for production, transportation, storage and use of natural gas has in the last decades developed in line with market growth, and several projects are under development and planning. The European network for transmission of gas is today rather extensive, but it is only in recent years that there in a few geographical are competing pipeline corridors.

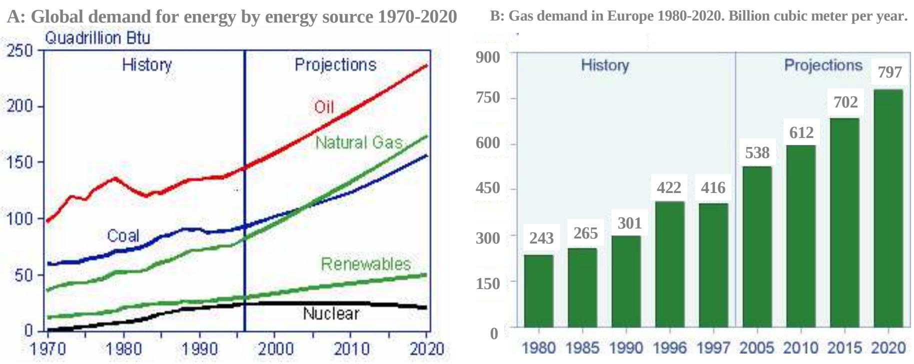


Figure 2.2: Global demand for energy, gas demand in Europe

Sources: Annual Energy Outlook 1998, International Energy Outlook 2000, BPAMOCO Statistical Review 2000

Demand for gas has grown strongly all over the world over the last decades. The growth is larger than for oil and coal. Natural gas therefore accounts for an increasing share of nearly all countries energy balances. Figure 2.2A shows the development in global energy demand for energy by energy source since 1970, and the consensus forecast for the next 20 years. Figure 2.2B shows the development of gas demand in Europe since 1980. Both globally and in Europe, demand for gas is expected to almost double over the next 20 years, which represent a 3-4 percent annual increase.

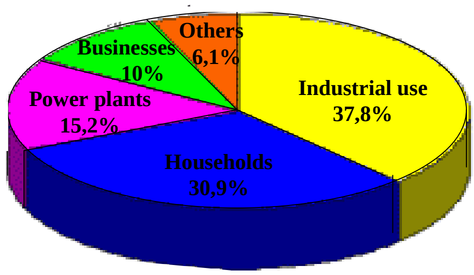


Figure 2.3: Consumption of natural gas in the EU-15 by sector 1997

Source: Eurogas

The largest sectors of natural gas usage in Europe are households, businesses, gas power plants and large industrial users, cf. figure 2.3. In Western Europe, as in the rest of the world, the growth is expected to take place particularly in gas power plants (see also figure 9.1). In Eastern Europe, the growth is expected to also include increased consumption of gas in households and businesses.

If such an enormous growth in demand for gas shall be covered, new gas must come from areas like the Barents Sea, Siberia, Central Asia and the Middle East, in addition to the existing supplying areas. An important question in connection with market liberalization is whether it can be developed in such a way that sufficient volumes can actually reach the market based on long-term commercial criteria among producers.

Huge Investments and Long-term Contracts

In the way the continental European gas market has been working until now, Norwegian gas is sold and resold several times on its way from the drilling hole to the consumers' burner. Norwegian gas exports go through five pipelines to the continent with landfall sites in Emden (Norpipe and Europipe I and II), Zeebrügge (Zeepipe) and Dunkerque (Franpipe), cf. Figure 6.6. In addition there is a pipeline system from the Frigg area to St. Fergus in Scotland. The sale of natural gas to the British is however very small as of now (although expected to increase). On the continent large transmission companies like Ruhrgas, Gasunie, Distrigaz, Gaz de France, SNAM and others, have bought the gas, as illustrated in point A of figure 2.4. The transmission companies have been functioning both as long distance transporters and as wholesalers. They sell the gas to the Local distribution companies (LDC), large industrial users and gas power plants in point B. While the industry and the power plants use the gas themselves, the distribution companies just like the transmission companies also act as transporters and wholesalers, as they sell the gas to individual commercial and private users after having sent it through their local pipeline network.

In order to secure the large and irreversible investments in production and transmission, close ties have developed between producers and pipeline companies and between producer and consumer countries. This has led to large long-term contracts between for instance Norway and the Continental transmission companies. A typical ("old") Norwegian gas contract may last for 20 years, while the contracts between transmission companies and their customers (local distribution companies, large industrial companies and gas power plants) typically are shorter, usually of 1-5 years' duration.

There has been a strong concentration of market power virtually throughout the entire chain of the European gas market. The local distribution companies are usually natural monopolies in their districts. Cooperation, economy of scale and legislation has often made transmission companies monopolists towards the distribution companies, the power plants and the large industrial users. In addition, several transmission companies have in periods cooperated on the purchase and import of natural gas (the "Grand Alliance") and through that gained strong market power towards the exporters (as monopsonists or oligopsonists). At the same time, the sale of gas from producers has been taking place on few hands, through national gas companies like in Russia (Gazprom), Algeria (Sonatrach) or the Netherlands (Gasunie), and the coordinated sale of gas from Norway through GFU. The export side may then also be characterized as an oligopoly. In this way the European gas market could not be characterized as "perfect". Prices and contractual terms have generally been set through negotiations colored by the

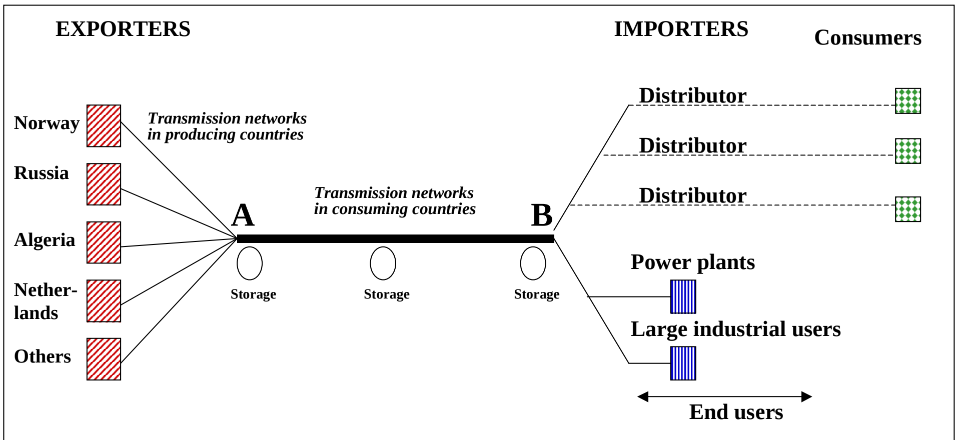


Figure 2.4: European gas from producer to consumer

market power of the parties at different stages throughout the gas chain.

The long-term contracts have strongly contributed to the building of costly production and transport installations on the Norwegian shelf with a reasonable economic security. This is partly due to the take-or-pay (TOP) clauses in the contracts; if the buyers of Norwegian gas (transmission companies) are not able to re-sell it, they still have to pay for (a part of) the contracted volumes. This clause has as far as is known never been applied, however. At the same time, both transmission and distribution companies has profit margins that are associated with low risk. There is reason to believe that they collect high profit margins, as well, partly based on their strong market positions. It has been very profitable to transport gas, on the Norwegian shelf as well as on the continent (cf. Chapter 6). This concentration of market power and profit is not to the benefit either to producers, consumers or overall social surplus. This is an important reason for the EU to intervene into the way the market has been working.

EU Efforts to Liberalize the Market

Market growth and the building of new pipelines and storage facilities has already encouraged competition and direct contacts between various players in the European gas market. Thus, even without political interventions, the European gas market has for some years been on the way to change and become more "liberal". The EU has tried to amplify this development. The Single Act from 1986 and the establishment of the Internal Market from 1993 assumed free movement of labor, capital, goods and services. Obviously, as the European gas market did not satisfy these basic criteria for a common European market, the EU Commission stated that (EUa 1988; 57ff):

> *"National or regional monopolies or virtual monopolies dominate the natural gas transmission and distribution industry in Europe. Primarily for economic and technical reasons (internal) gas producers hold a monopoly over transmission, distribution and, in some cases, imports."*

More specifically, it described the role and position of the transmission companies:

> *"Gas transmission undertakings buy gas from producers under long term (20-25 years) contracts, transmit it and resell it in large quantities to industrial users, power stations and public distributors. Each of these Member States apart from Germany has just one transmission undertaking. Some of them are public-sector undertakings, others are privately owned and the rest are a mixture of the two. The public distribution and transmission undertakings are granted exclusive operating concessions by the national, regional or local authorities."*

The document also addresses constraints on the free movement of natural gas within the Community:

> *"The biggest barriers to the free movement of gas in Europe are government controls on natural gas imports and exports and undertakings holding a monopoly or dominant position enabling them to block movements of natural gas."*

Then the Document expands further on the problem of transportation:

"Transport of gas in the Member States is characterized by the existence of statutory or de facto monopolies in the marketplace. Only in West Germany there are a number of actors but even here there is one dominant transport enterprise. In the UK, a new legal instrument has been introduced in the form of the Common Carriers provisions of the 1986 Gas Act, which require pipeline owners to carry for third parties under certain conditions but as yet no use has been made of these provisions. In the Federal Republic of Germany, there is no legal mechanism outside of competition rules, for the dominant transporters to carry gas for third parties. Italy has, however, provisions that come close to this. In Trentino-Alto Adige and Sicily, legislation provides that, where the transport concessionaire is not the lessee of the gas field itself, the lessee of the field has the right to make use of the pipeline within the limits of available capacity. The conditions for such carriage are to be laid down by the "Assessore" for Industry and Trade.

The presence of dominant or monopoly transmission undertakings in each Member State gives rise to segmentation of the Community market; these undertakings can restrict the through transport of gas and even where no specific legislation exists, can block the import and export of gas."

From these observations, the Document suggests the following priorities to promote the efficiency of the gas grid:

"Decompartmentalization of the natural gas markets; common carriage.

a. The exclusive transmission concessions must be checked to see how to facilitate the free movement of natural gas whilst maintaining a high level of security of supply and economic transmission condition. Transmission or distribution undertakings could be allowed direct access to the resources in question.

b. The prospect of extending direct access to resources to large industrial customers should be considered in the light of the results obtained in connection with point c. (the suggested priorities in the natural gas sector).

The above two points both hold out the possibility of giving third parties access to the grid as against payment of a reasonable charge (the "common carrier system")."

The Commission expressed expectations that a common carrier system can influence the demand for natural gas in Europe. With the amortization of the transportation infrastructure in the Community, gas transportation costs should be reduced and thereby encourage a more flexible approach to natural gas trading. Producers with identified fields for development should be matched with customers that are willing to increase their use of gas at competitive prices.

The "Common Carriage" (CC) system for transportation of gas should have open access for anyone who wished to use it. The transmission companies should collect a "reasonable" tariff covering their expenses and normal profit, but not any economic profit (profit beyond normal profit).

Box 2.1: Concepts of Market Liberalization

Different words have been used to characterize the overall idea of making or mimicking competition in natural gas markets, and these are partly connected with specific understandings of a liberalization process. Among the most important ones are:

Common Carriage, which has been associated with the way excess demand for transportation in relation to pipeline capacity, should be allocated (see Chapter 7). If demand exceeds capacity, the burden should be shared by all shippers according to their nominated volumes on a pro rata basis. In order to give access to new customers, initial volumes could not be used as an allocation device. Therefore, pro rate reductions mean that everybody reduces by the same percentage their throughput according to contracted volumes.

One problem with a pro rata arrangement is that it can lead to gaming between shippers in determining the size of nominated quantities ("over-booking"). Another problem is that it challenges the security of supply for existing customers and contracts. The word origins from the U.S., which have been using this system. The European Commission ultimately rejected this system (EU 1991b).

Deregulation is also a word that origins from the U.S. As will be described in more detail in Chapter 9, the U.S. gas market was regulated at all levels up to 1978. When the market was liberalized, a deregulation took place, in particular among producers. However, pipelines were actually *reregulated*, and the market structure as such changed in a mixture of deregulation, meaning competition, and reregulation, meaning new terms for operating natural monopolies. For many, the word deregulation has remained the term for the entire process.

Third Party Access (TPA) is a more loosely defined concept than common carriage. It defines that gas should not (only) be transported between two parties (usually the producer and the merchant pipeline), but (also) for a third party (usually the customer at the end of the pipeline). As mentioned, the EU proposal did not define specific rules for how regulation should be designed. Rather, it just stated that pipelines should carry gas for others in return for payment. The allocation of access demand, as well as a number of other techno-economic regulatory issues, was not defined within the system.

Open Access (OA) is also a term used in the United States, in a quite similar way as the Commission uses the TPA term. There has been some discussion over possible differences between OA and TPA, but this is not important in our context (Stern 1992: 25-26).

The word *liberalization*, used in this book, could mean the same as the concept of TPA or OA. The important issue is that it involves a process that makes the market work more competitively, by increasing competition or by introducing force or incentives in a regulatory process, in order to reach social goals in a more optimal manner than before. The choice of word is made in order to avoid misunderstandings among those having any specific understanding and interpretations of the other concepts. The IEA (1994) introduces the term "Mandatory Open Access" (MOA) for a liberalization process for much of the same reason.

The CC system was abandoned in 1991. Rather, the EU proposed 3 directives in order to:

a. Make the market more transparent (EU, 1990),

b. Allow the transit of gas between high pressure transmission pipelines (EU, 1991a), and

c. Introduce third party access (TPA) to the transmission Pipelines as well as splitting ("unbundled") the transmission companies' function as both transporters and wholesalers (EU, 1992).

The first two proposals were approved. The TPA directive was postponed following strong resistance from the European gas industry and the European parliament.

Not until December 1997 was the TPA directive (often called the "Gas Directive" – see box 2.2) approved for implementation in August of 2000 (EU, 1998). The directive entails that producers and buyers of natural gas may make direct contracts between each other and have the right to negotiate a transportation agreement with a pipeline company. A corresponding directive for the transportation of electricity preceded the TPA directive (EU, 1997a).

It is likely that the TPA directive is only the first of many directives and political interventions which over time will contribute to the natural gas trade within the EU area to become more liberal than today. I March 2001 the EU signaled the need for speeding up the process (EU, 2001a). However, it is not obvious how far liberalization will, and in which areas and market segments the changes will have the greatest impact for Norway. Norway could both loose and gain depending how the processes develop. In fact, in August 2001 the EU supported Norwegian requirements that pipeline companies on the Continent should open up their services faster, in order for Norwegian sellers to actually reach customers in the market (EU, 2001c).

Box 2.2: The “Gas Directive”

Following many years of negotiation, EU’s directive about third party access (TPA) to the transmission networks (or the pipeline companies) was approved (98/30/EC). The intent of the Gas Directive is to ”establish common rules for access to the market and for the criteria and procedures to be used when licensing the transmission, storage, and distribution of natural gas”. EU’s gas market presently amount for some 110 billion euro per annum.

The directive entails that EU countries over a 10 year period will have to open up for more direct agreements between producers and buyers. 20 percent of the market should be accessible immediately, 28 percent after 5 years and 33 percent after 10 years. All gas power plants may use the arrangement, as well as industrial users above a certain size. In the starting phase, industrial users who may avail themselves of the system must have a consumption of at least 25 million cubic meters per year, at least 15 after 5 years and at least 10 million cubic meters after 10 years.

The greatest difficulty in agreeing on the directive was the stipulation of the minimum shares of each market, which was to be opened in the three phases of the plan. The debate about this lasted almost one year after the Electricity Directive had been approved. France and Belgium wanted to limit the liberalization to include a minimum level of 15 percent of the markets. The intent is assumed to have been to protect the interests of Gaz de France and Distrigaz who both have had nearly 100 percent control over import and transportation in their respective countries. On the other hand, Great Britain and Germany wanted at least 28 percent opening during the first phase of the plan. These countries put forward arguments about the advantages of faster liberalization.

Under the directive, there is access to making new take-or-pay-contracts if national authorities allow it. A number of rules were established for how the Commission might overrule such regulations.

A TPA arrangement should ideally lead to the pipeline companies only operating as transporters. Today, this right to transportation is mainly reserved the owners of the pipelines. The intent of the directive is to create easier and more reasonable access to the main roads of gas for producers and buyers. To a larger extent, these will be able to make agreements directly between themselves, and have the right to *negotiate* for a transport agreement with the transmission networks. The Directive does not however set a procedure for how to solve disagreements, e.g. about which tariff should be applied if negotiations are not successful.

Distribution companies (the local transportation networks) will not be affected by the directive unless national authorities decide so. It does not regulate competition between producers, either. As such, the Directive is a step towards a more liberal European gas market. It is not creating a completely and perfectly liberalized market, but a step on the way. The directive became operational in August 2000.

As Norway participates in the single market through the EEA agreement, the directive will also apply to the Norwegian shelf. Norwegian authorities for long applied for a 5-year extension to find arrangements which satisfies the directive and which at the same time ensures consideration of economics of scope and optimal resource management. In 2001 Norway gave up the resistance and the Directive was implemented in Norwegian law in June 2002.

Organization of Norwegian Gas Production and Sale

Exports of Norwegian gas started in the mid-1970s. The gas has mainly been sold on long-term contracts, but the way this has been done has changed, however. Contracts which were entered into before the Troll agreement in 1986, were so-called field depletion contracts in which the total reserves of the field in question were sold. This included Ekofisk and Frigg gas, which was contracted in the middle of the 1970s, and gas from Statfjord, Heimdal and Gullfaks phase 1, which was contracted in 1981. The Troll agreements and later contracts are volume contracts, where the field of origin for the gas was not specified. GFU, which also was established in 1986, was in charge of the commercial negotiations with the purchasing companies.

The Gas Negotiating Committee (GFU) consisted of the Norwegian companies Statoil (lead) and Norsk Hydro (Saga previously participated). GFU had the responsibility to prepare and carry out all negotiations for sale

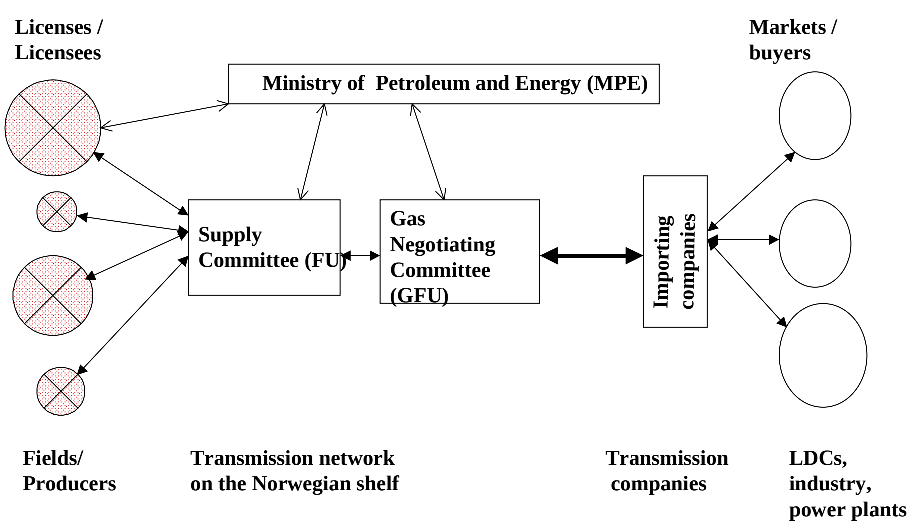


Figure 2.5: Organization of Norwegian Gas Sales Until 2001

of Norwegian gas up to the signing of the contract, no matter which company who owned the gas. In 1993, a Gas Supply Committee was formed ("Forsyningsutvalget", FU), with participation also from foreign companies as an advisory group for the Ministry of Petroleum and Energy (MPE). The FU dealt with questions connected to the development and exploitation of fields and pipelines and allocation of signed contracts to individual fields. It was the responsibility and duty of the authorities to appoint contract and delivery fields to the contracts, as well as approve the commercial agreements (MPE, 1999). The organization of Norwegian sale of gas until 2001 is illustrated in figure 2.5.

When established in 1986, it was argued that a centralized Norwegian gas sale through GFU weakened the one-sidedness of Statoil as the only seller of Norwegian gas. There was also a desire to strengthen the Norwegian negotiation position towards the purchasers, which was arranged as a purchasing monopsony. To avoid having buyers sitting on both sides of the table in a negotiation, foreign companies on the Norwegian shelf were not included in GFU. The opinion was that "free competition" between companies operating on the Norwegian shelf might contribute to a greater supply of gas in the market and a pressure towards lower prices, as the buyer side was heavily concentrated. The later establishment of FU, made Norwegian authorities able to secure scope economies and an optimal exploitation of resources between different fields, and between oil and natural gas production and transmission on the Norwegian shelf.

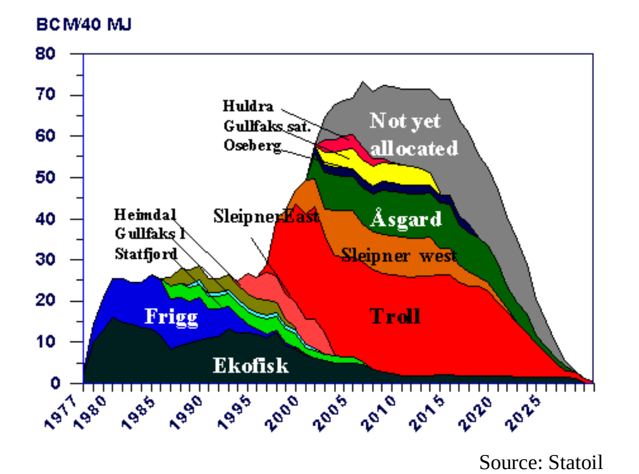


Figure 2.6: Norwegian gas production by field (committed volumes)

In addition to this way of centralized governmentally controlled resource management, production of Norwegian gas takes place on relatively few fields. Up to the mid-1980s, Norwegian gas export mainly consisted of gas from the Frigg and Ekofisk areas (figure 2.6). The Frigg gas with associated fields was sold to British Gas after agreements from 1973 and 1980 and transported through the pipeline system to St. Fergus in Scotland. These deliveries ended in year 2000 when the reserves in the fields were depleted.

From the Ekofisk field the Phillips group sold gas through contracts from 1973 and 1975 to a buyer group consisting of the transmission companies Ruhrgas (Germany), Gasunie (Netherlands), Distrigaz (Belgium) and Gaz de France (France).[4] Through this constellation, purchasing companies gained advantages of scope and market power in their activities. At the same time, each of the companies was a de jure or de facto monopolist in their markets. The constellation of transmission companies as buying wholesalers in the most important markets for Norwegian gas appeared as a buyer monopoly, or import monopsony, towards Norwegian gas exporters.

After the Frigg and Ekofisk contracts, the next large Norwegian agreement was signed in 1981 and included gas from Statfjord, Heimdal and Gullfaks phase 1. The deliveries started in the mid-1980s and are expected to be phased out in a few years. Then came the Troll agreement of 1986. Deliveries of Troll gas started in the mid-1990s and are now growing towards year 2010. These agreements were volume contracts as opposed to the field depletion contracts. Gas from the Troll field will in a few years represent about three-quarters of the total Norwegian gas export. The main part of remaining export will come from ”residual gas” from the Ekofisk area, Sleipner, Oseberg and Åsgard.

In addition to the concentration of Norwegian gas production on a few large fields, there is also concentration on a few companies and owners. The largest gas owner is the State’s Direct Financial Interest (SDFI) which accounts for 30 – 63 percent of the large fields that dominate the sale (Troll, Sleipner, Åsgard and Oseberg) and 40-73 percent of the fields which now largely are being phased out (Gullfaks, Heimdal and Statfjord). In addition, partially state owned Statoil and Norsk Hydro each own 9-20 percent of the larger fields. If we add together the ownership shares of SDFI, Statoil and Norsk Hydro, the three dominate North Sea activities with 53-100 percent of the total. Their combined average share reaches some 70-80 percent for the fields in production, where SDFI alone represents more than 40 percent. If we add a couple of foreign companies like Exxon and Shell, a few ownership interests, with the government as the dominating party, owns more than 90 percent of the Norwegian gas resources. A corresponding concentration of ownership is also found in most important transportation systems from the fields and to the continent, with SDFI as a substantial party in all

[4] In connection with the Troll agreement of 1986, the purchasing monopsony – often called the Grand Alliance – of the 1970s was expanded with two other German companies (BEB and Thyssengas).

pipeline systems build after the system was established in 1986 (MPE, 2000). SDFI had initially no ownership in Statpipe, as this pipeline system was established before the arrangement came into being, but this is now changed in connection with the privatization of Statoil and the establishment of the gas transportation operator Gassco (see below).

Even though field depletion contracts will still exist in the coming decades (particularly Ekofisk), Norwegian exports are now dominated by supply contracts, where fields are not specified. To honor the committed volumes with the purchasing companies, more gas that is not yet allocated to a field will have to be produced over the next 10-15 years (figure 2.7). From a resource point of view, however, it is doubtful that Norwegian gas export will drop as much from about the year 2015 as shown in the figure. New sales will be added which can maintain a volume of 60-70 BCM, possibly also increase it. The figures from the Norwegian Oil Directorate (NPD) illustrate a possible volume of close to 90 BCM up to 2030 and many years beyond that, with a possible increase in the second half of this decade includ-

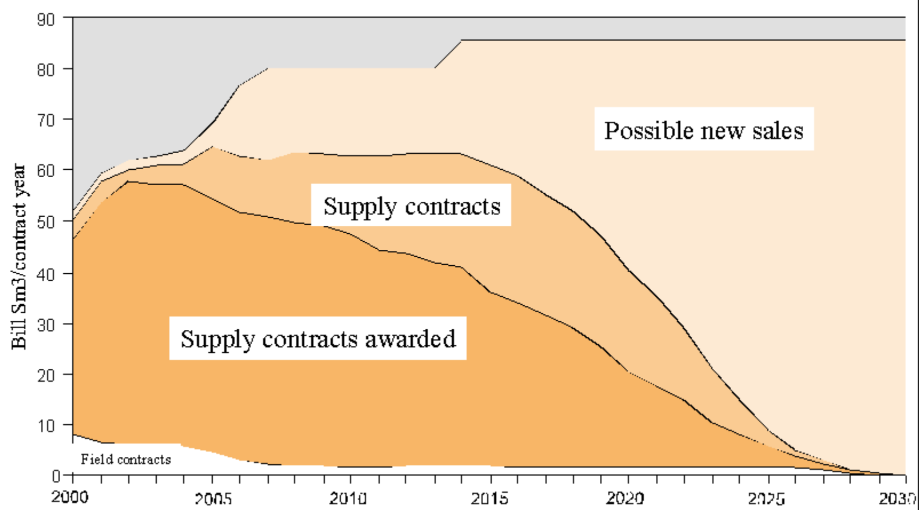


Figure 2.7: Committed and possible new sales of Norwegian gas.
Source: Norwegian Petroleum Directorate annual report 1999

ing the first gas from Northern Norway (Snøhvit). According to present estimated reserves and production levels, Norway can produce gas for more than 40 years onwards. As reserves both in Norway and elsewhere in the world have nearly consistently been underestimated, it is not impossible that Norway may maintain the new production level of 60-70 BCM for fifty to one hundred years into the future. Norway could pass 100 BCM per year for long periods, as well.

The Reorganization in 2001

In 2001 Norwegian oil and gas activities were substantially reorganized. This can be understood as resulting from three processes (Refvem 2002):

Firstly, Statoil expressed a strong desire to be partly privatized. This process started 3-4 years earlier and culminated in a government proposal to the Storting (parliament) of December 2000 proposing to sell up to 20 % of Station's equity to private owners, and list the shares on the stock exchange. As a condition for this part of the privatization, the government proposed to establish two new 100% state companies that would take over tasks previously performed by Statoil. One new company, named Petoro, would manage all direct state ownership rights (SDFI) in oil and gas fields and in pipelines. The other company, named Gassco, would take over operatorships of all gas pipelines on the Norwegian continental shelf and act as an independent pipeline operator (see also Chapter 6). The proposal was adopted by the parliament in April 2001.

Secondly, ESA (EFTA Surveillance Authority) was investigating the legal basis for the GFU. This investigation started in 1996. Saga wanted to sell to Wingas directly. This was blocked by GFU. The authorities followed the advice from the majority - Statoil and Hydro. Wingas complained to German competition authorities that forwarded it to the EU. The process culminated in the spring of 2001 with indications that EU would issue a "Statement of Objections" (SO) relating to proceedings under article 81 of the EC Treaty and article 53 of the EEA agreement, both relating to competition law. Faced with this challenge, the Norwegian government proposed (early June 2001) to abandon the GFU system of gas negotiations as far as sale of gas to the European Community was concerned. Thus, the companies having ownership rights to gas on the Norwegian continental shelf should thereafter set up systems for individual company sales of natural gas. In spite of this change of Norwegian policy, the EU on the 8th of June 2001 nevertheless issued its SO to Statoil and Norsk Hydro (as members of the GFU), and expanded shortly after the objections to cover all gas producing companies on the Norwegian shelf. [5]

[5] Others have also challenged the Norwegian sales and transportation system. The American company Marathon brought suit against Ruhrgas in Houston and Statoil

Thirdly, Norway accepted the "Gas Directive to be implemented in Norwegian law, also for offshore pipelines on the Norwegian shelf. The debate about the directive had been going on for a while, with various proposals for extension of deadline having been discussed. Formally, the Directive passed the Storting in June 2002.

Statoil was partially privatized and listed on the Oslo and New York stock exchanges on 18 June 2001, with 18.2 per cent of the company sold to private shareholders in Norway and abroad. The state thereby owned 81.8 per cent of the company's shares as of January 1, 2002. The Storting has opened for further reductions in the state's shareholding, down to two-thirds.

Partial privatization of Statoil has involved changes in the state's role and decision-making authority towards the company. The provisions of the Public Limited Companies Act apply in full, and the special rules governing state-owned limited companies are no longer relevant. As the majority shareholder, however, the government retains great influence – not least in relation to the company's articles of association (MPE, 2002). The prospectus for Statoil's initial public offering stated that the government has indicated that it – as one of many shareholders – will concentrate on issues relating to the return on capital and dividend, with the emphasis on long-term development of profitable operations and value creation for all the shareholders.

The restructuring of state participation in the petroleum sector included the sale of SDFI assets corresponding to 15 per cent of the portfolio's value to Statoil. The sale of a further 6.5 per cent to companies other than Statoil was completed in March 2002.

Statoil previously provided commercial management for the SDFI. This arrangement reflected Statoil's status as a wholly state-owned limited company, which gave the government opportunities for management and control of the SDFI in accordance with constitutional requirements for managing state property and organizing commercial state operations. The changes in 2001 split Statoil’s role as a company that should be responsible for the Government’s interests in the purchase and transportation of oil and gas

in Stavanger citing unfair transport tariffs on the Norwegian shelf. Marathon owns a share of the Heimdal field, and is dependent on natural gas being sent through the Statpipe system, which maintains high tariffs and accumulates large profits (se also Chapter 6).

and it's role as a commercial company. Two new companies, Petoro and Gassco, were established to take care of this:

Established on 9 May 2001, *Petoro* is organized as a wholly state-owned limited company and based in Stavanger. Due to have about 60 employees, it has three duties (MPE 2002):

- managing the state's interests in partnerships where such interests are held at any given time
- Monitoring Statoil's sale of oil and gas produced for the SDFI (Statoil shall so far continue to sell SDFI/Petoro's oil and gas).
- keeping accounts for the SDFI

The company's operations are confined to the NCS, and it will have no international interests of its own. It will not apply for new production licenses or be awarded operatorships. It cannot sell, swap or buy license interests, but can advice on such transactions. Its duties will be confined to managing the SDFI. Petoro will be financed by appropriations from the government, and will not receive revenues from the SDFI's assets. These assets will be managed on the government's account. As before, income and expenditure relating to the SDFI will be carried on the central government budget.

The government's objective in creating *Gassco* was that (ibid.):

- Gas transportation and treatment facilities will serve all producers and contribute to efficient overall utilization of resources on the NCS
- It shall act neutrally in relation to all users of this infrastructure
- It shall play a key role in further development of the transport systems

Gassco took over as operator on 1 January 2002, and is based at Bygnes in Karmøy local municipality north of Stavanger. The company is, as Petoro, wholly state-owned.

The establishment of Gassco did not change or harmonize gas transportation tariffs on the NCS. The further changes now under discussion include, inter alia, the rebirth of the GasLed idea from the mid-1990s. In that project, the ownership interests of several of the Norwegian transmission companies were to be combined to take care of dry gas transport from the Norwegian shelf to the continent (Statpipe, Zeepipe, NorFra/Franpipe and Europipe II). The companies where valued relative to each other and an application for consent to establish was sent to the Norwegian authorities in the fall of 1995, but was turned down (Elf's annual report 1995 and 1996 and Parliamentary bill no. 15 for 1996-97). Today, a GasLed system should unify, harmonize and possibly lower transportation tariffs, cf. Chapter 6.

Norway's Significance in the Market

In addition to the Troll agreement from 1986 Norway has entered into a number of agreements for sale of natural gas, expanding Norwegian shares in many countries. These include:

- 1986: 1 BCM to Austria (as part of the Troll agreement).
- 1988: Spain (Enagas) and the Netherlands (union of the power producers SEP),
- 1993: Belgium (Distrigaz) and Germany (Verbundnetz Gas in the previous East Germany and to Ruhrgas1993),
- 1994: Germany (Mobil MEEG) and France (Gaz de France),
- 1995: France (Gaz de France), Great Britain (gas from the Frøy field to British buyers)
- 1996: Germany (Ruhrgas),
- 1997: Ireland (gas from the Frøy field), Italy (SNAM) and The Czech Republic (Transgas)
- 1998: Great Britain (winter gas to Alliance Gas, British Gas Trading and Norsk Hydro UK)
- 1999: Poland (polish partners). It is still uncertain whether or not this agreement will be realized.

GFU has also entered into long-term agreements for sale of gas to British National Power. Great Britain will become a net importer of natural gas in the near future, not least due to the new Vesterled connection. Also

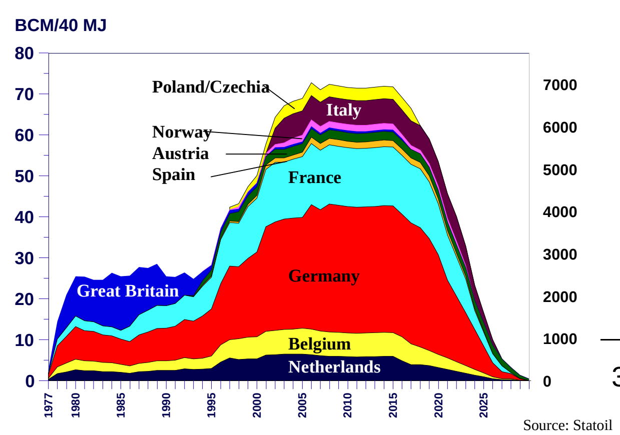


Figure 2.8: Norwegian gas production per country (committed volumes)

Statoil signed a significant contract with the customers in the summer of 2002.

Due to the gas sales in the 1990s, Norwegian gas export of today is more diversified with regard to countries than in the 1970s and the 1980s. It is nevertheless a fact that Germany is the dominant buyer of Norwegian gas by having contracted close to half of the Norwegian supplies for the next ten to twenty years. Nor-wegian dependency on the continental market has increased over the years, par-ticularly in the areas of Northern and Central Europe. Besides Ger-many, France in particular is a con-siderable customer, followed by The Neth-erlands, Belgium and Italy, with smaller vol-umes to Spain and Austria (figure 2.8). The Czech Republic and Poland will gradually also receive significant volumes of Norwegian gas. Sup-plies to Great Britain are now small while they were, relatively speaking, considerable in the 1970s and the 1980s. As discussed above, however, the role of the British market in Norwegian gas exports is about to increase again.

Statoil's expectations for Norwegian market shares in 2005 are shown in figure 2.9. It is assumed that Norwegian shares in the most important markets will increase relativeely strongly. The shares of consumption are here estimated to become 30-40 percent in Germany, France and Belgium. The import shares may reach 40-50 percent in several countries. In other consuming countries, Nor-wegian market shares have a correspondingly strong increase, but at a somewhat lower level. Norway is a large ex-porter of natural gas. However, it is important to remember that Russia is a very much larger producer of natural gas than Norway and is also a larger gas exporter. Norway will reach the level of Russia in some countries, however, making her the second largest gas supplier in Europe.

The use of dry gas (methane) in Norway for electricity production is still not clarified. The government has supported plans to build two gas power plants in Norway. In the debate there have been in particular two opposing points of view:

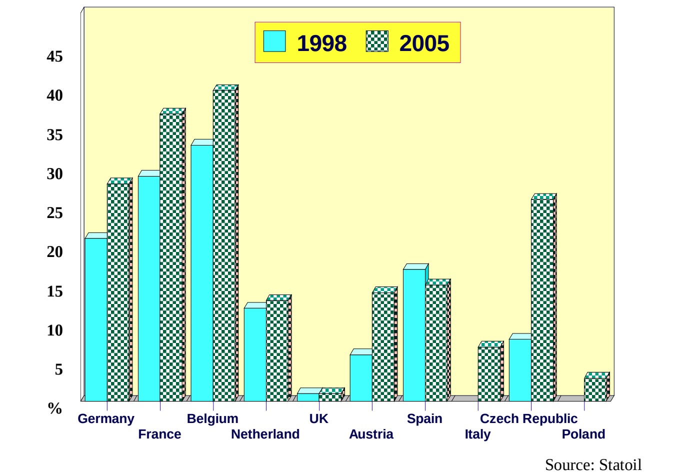


Figure 2.9: Market shares for Norwegian gas based on domestic production and contracted volumes

- Those who emphasizes that as natural gas is the most environmentally friendly of the fossil fuels, Norwegian gas power may replace the more polluting oil and coal power in other countries. The overall CO_2 releases will consequently be lower. New technology amplifies this argument.
- Those who are against gas power put more emphasis on that the local Norwegian CO_2 releases will increase as a consequence of the development and most likely will come in addition to existing power production in other countries, not just as a replacement. Additionally this violates approved Norwegian goals to stabilize the CO_2 releases.

There is already a certain use of natural gas in Norway. At Tjeldbergodden and Kårstø, the associated gas which comes in from the fields into a dry gas part (methane) and various natural gas liquids (NGL). The gas liquids are fractioned into different parts, mainly ethane, butane and propane that are sold in the respective markets. Also at the petrochemical plant at Rafnes in Bamble, NGLs are used as an industrial raw material.

3 Towards More Volatile Prices

Contractual Clauses

Gas contracts in the European natural gas market may vary a lot. Some of the most important provisions included in them are listed below:[6]

- Pricing/Escalation provisions; ensure that prices of gas under contract evolve with normal economic development. Prices for the sale of natural gas in the Western European market are usually positively correlated to other energy prices contained in the contract.
- Most-favored nation; ensures equitable treatment of parties to a given contract and parties to a similar contract of the same region.
- "Take-or-pay" (TOP) clauses; ensures that the volume of gas offered under contract will be purchased or that the seller will get an equivalent amount of cash.
- "Deliver-or-pay" (DOP) clauses; the same as "take or pay", except it is the buyer who benefits.
- Load factor clauses; ensure that a given load factor will be fulfilled by the parties to a contract (see Chapter 6).
- Renegotiation clauses; allows the parties to renegotiate due to changed circumstances not foreseen in entering in the contract.
- Force Majeure; specifies conditions under which a party is not bound to perform according to contract.

This list illustrates that it is not only the price that is important for sellers and buyers of gas, but the entire package of provisions being made. Even if the prices from different suppliers are the same, other non-price provisions might present one seller with a better deal than another. Excluding the discussion of

[6] Davis (1984), page 47-48.

an overall preferential treatment of specific suppliers, we shall here focus on the price provisions.

Even though there is a lack of competition in many segments of the European gas market, natural gas competes with other energy carriers in end user markets. This is an important reason why prices in most existing Norwegian contracts are tied to the prices of the alternative energy sources to the customers, particularly fuel oils. The (gross and net) margins of the transmission and distribution companies are however not tied to end user prices but based on their operational and investment costs and their negotiation strength when buying and selling gas. Their margins are practically independent of the prices in end user markets.

Prices in Today's Market

In Europe, price formulas in contracts have mostly been designed in a way that prices react to changes in other energy prices with a time lag, reflecting the value of gas for end-users. The «value», or consumers' opportunity cost, represents a weighed average of their willingness to pay for gas. Each of these end-users face different alternatives either district heating, fuel oil or coal. In the short run, most of these consumers have no alternative to the fuel they actually use. In the longer run, they can invest in equipment and production facilities that make them able to change, to or from gas. Thus, gas has a market value, determined by its alternatives.

The producer price, or what Norway registers as the export price at the border of the importing countries, emerges as the difference between the above mentioned end user prices, taxes on the use of natural gas and the gross margins of the transportation companies. The contract negotiations between exporters and transmission companies decides how the export price will vary in relation to end user prices and with that which margins will end up with the transport companies. The producer takes the price risk in the market, as his prices are directly connected to the end user prices ("netbacking"). When the end user price of gas is changed, then also the producer prices change according to a formula. Within a given ("old" and long-term) contract, the price to the producer will therefore vary, particularly with the prices of crude oil and excise taxes on fuel oils.

Let us call the price between producers/exporters and purchasing transmission companies p_p, price between transmission companies and the local distribution companies p_t, and the net price distribution companies receive from their customers p_d. This is illustrated in the right bar of figure 3.1. P_d

emerges as the price the consumer pays, p_c, minus taxes on the use of gas, t_{gas}. The gross margin left for the transmission and distribution companies, s_i (where i = t(ransmission share), and d(istribution share)), becomes the difference between the price they sell gas for and the price they buy it for. The price of gas to the end user, p_c, must then be shared between respectively producer (p_p), gross shares to transmission ($s_t = p_t - p_p$) and distribution companies ($s_d = p_d - p_t$), and to end-user excise taxes ($t_{gas} = p_c - p_d$).

$$(i)\ p_c = p_p + s_t + s_d + t_{gas}$$

In the European gas market, the gas contracts have largely been formulated in a way that prices react to changes in prices on alternative energies (with a certain time lag) and, thus, reflect the value of gas for the end user. The price Norway as producer/exporter receives becomes a function of the consumer willingness to pay in the individual markets. Individual consumers have different alternatives to gas. Norway's most important gas contracts are tied to the end user prices of fuel oils, while some other contracts are tied to the price of coal or electricity.

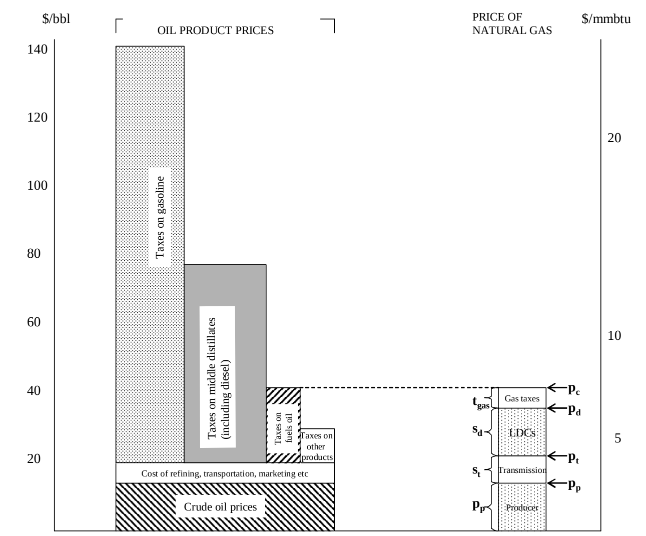


Figure 3.1: Gas prices in Europe and the relationship to oil prices (simplified illustration)

If we simplify contracts to reflect only situations where gas competes with fuel oils, the connection between oil prices and gas prices can be illustrated as in figure 3.1. The left set of bars shows end user prices for oil products. The price of crude oil as well as costs for refining, transportation, marketing, etc. lies as a basis for these prices. The price of crude oil and the costs are illustrated in the figure as if they were equal across different types of crude oil, although this is not strictly accurate. The point here is however that the difference between prices of the various types of products mainly is made up by their different taxation. Gasoline, which has the highest taxation, goes up to 140 USD/barrel calculated as price per barrel of crude oil, using the excise tax rates most EU countries had reached in the 1990s. The end user prices (and the taxes) drop the heavier the products are. For a "representative barrel of Brent crude", calculations in Austvik (1996) arrived at an excise tax on average of 46 USD/barrel and an end user price of about 70 USD/barrel (1994) in OECD-Europe.[7] Chapter 4 will analyze the role of energy taxes in more detail.

The principle of pricing gas equal to the prices of the alternatives is used for prices both between exporters and transmission companies (p_p) and between transmission and distribution companies (p_t). A general pricing formula for gas in the European market can then be formulated as:

$$(ii) \quad p_i = f_i\left(\sum_{j=1}^{n} \alpha_j * p_{ej}\right)$$

Here $p_i = p_c, p_d, p_t, p_p$. The factor α_j expresses which weight energy carrier no. j is given in the price, while p_{ej} is the price on alternative energy carrier no. j. (j=1…n). The function f_i expresses the link between the price of the alternative and gas throughout the gas chain. Below is an example of a price formula concluded in the 1980s (between a transmission and a distribution network in Sweden).

$$(iii) \quad p_d = f\,(0.4 * p_{HFO} + 0.4 * p_{LFO} + 0.2 * p_{GO})$$

In this formula, the “city-gate” price (or price paid by distribution companies to transmission networks, p_d) is a function of the price of heavy fuel oil (p_{HFO}), the price of light fuel oil (p_{LFO}) and the price of gas oil (p_{GO}). The three oil product prices are given a weight of 40, 40 and 20 per cent, respectively, in the formula. Any increase in the price of one of these fuels, will raise the price of gas, as well.

7 Reinch, Considine & MacKay (1994) arrived at about the same results.

Thus, the price of gas depends on the initial price levels of the energy carriers contained in the contract and the escalation mechanism in relation to these prices, or the form of the function, f. A change in the composition and weight of the alternative energies contained in the contract, will also affect gas prices. For example, if light fuel oils have a higher price than heavy fuel oils, and the contract is given a higher weight of light fuel oils, gas prices benefit. Figure 3.2 show that end-user prices on oil products and gas has followed each other closely for the past 20 years. The development for crude oil prices and gas export prices may at the same time be quite different (IEA, quarterly).

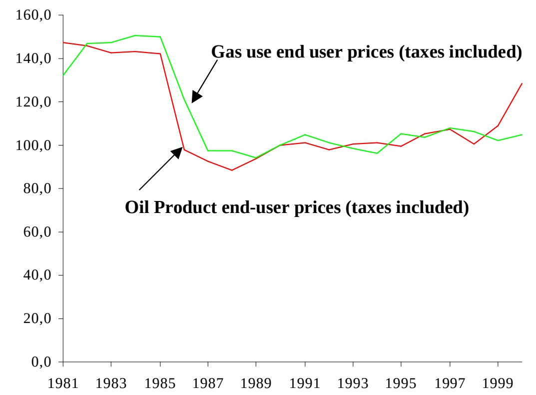


Figure 3.2: Oil and Natural Gas Prices Consumers 1981-1998 OECD-Europe
Index of crude oil and end-user prices (Source: IEA, quarterly)

The initial starting point for the prices in the various levels of the gas chain must necessarily be different, but the way the gas price varies with the price of the energy carriers which are included in the contract may be more similar. This means that the price of gas is influenced by:

- Which energy carriers that is included in the formula (e_j energy carriers, each with the price p_{ej}).
- Weighting of the individual energy carrier (α_j).
- The initial relationship between the price of alternative energy carriers and the gas price, cf. discussion around figure 3.4.
- The escalation mechanisms between changes in prices for the alternative energy carriers and the gas price (the shape of the function f_i).

Contracts that concern the sale of gas to households may relate to other alternatives than for instance gas sold for production of electricity. Generally it has been the case that gas sold to households and commercial activities is better paid than gas sold to large industrial users which in turn are better paid than gas for electricity production, cf. figure 3.3. Increased use of gas in a high price sector, like households, will pressure the average market value upwards. Correspondingly a change of technology in a sector, like the one in power production over the last years, might increase their willingness to pay. The price discrimination between markets makes the producer able to take part of the consumer surplus without disturbing consumption patterns, which would be the case if each group had to pay the same price.

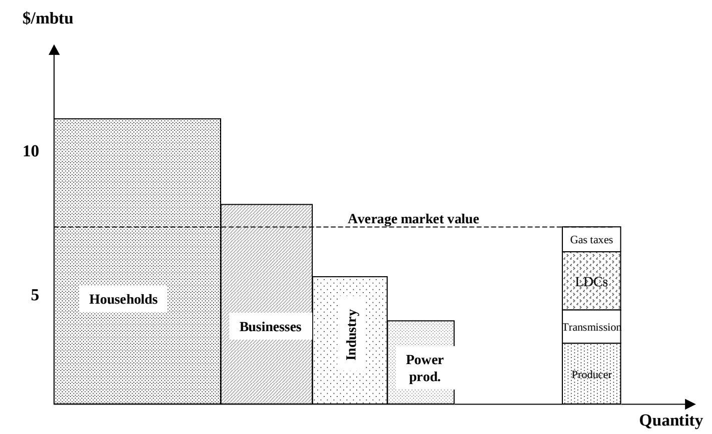


Figure 3.3: The "Market value principle"; price discrimination between sectors

The different prices that emerge cause average export prices per unit of Norwegian gas (p_p) to emerge as a function of the weighed average of the sale prices to the different sectors and countries. The Troll contracts contain clauses to ensure that either buyer or seller can demand renegotiations every 3rd year if market conditions have changed so much that the pricing formulas no longer reflect the competitive position of gas in the market.

A change in the prices on the alternatives to gas, then leads to a change in the price of gas to end users, and to a large extent automatically. As mentioned, it has generally been so that the margins for the transmission and distribution companies (s_i where i= t,d) has been independent of end user prices. For the transmission companies (s_t), their level is mainly determined through the negotiations the companies do with producer and distribution company respectively. For the distribution companies (s_d), they are mainly determined through the above mentioned negotiations with the transmission companies and their relationship to prices on alternative energy carriers (see also discussion in Chapter 6 and 7).

Changes in Gas Prices

Crude oil prices are normally calculated in USD/barrel (price per volume unit of crude oil) while gas prices most often calculated in USD/mmbtu (Million British Termal Units, which is a price per energy content of the gas). The ordinate on respectively left and right side in figure 3.1 indicates the oil price's (per volume unit) relation to the gas prices (per energy content). With a given end user price on oil products, the end user price on gas, p_c, is also determined. P_c is then divided between the various steps in the gas chain for excise taxes, t_{gass}, distribution companies, s_d, transmission companies, s_t, and producer, p_p, respectively. As long as the margins s_d and s_t are nearly constant, the price to producer/exporter, p_p, change due to changes in the competitive relationship to fuel oils, in the following ways:

1) A higher price on crude oil. In our example, this will also raise the price of fuel oils to consumer and through that the end user prices on gas.
2) Higher taxes on fuel oils. In our example, this will also give a higher price on fuel oils to consumer and through that also a higher end user price on gas.
3) Higher taxes on all other oil products than fuel oils will, to the extent it pressures the price of crude oil downwards, tend to create lower end user prices on fuel oils and through that also to lower prices for the gas producer (assuming that refineries, marketing stages, etc., do not increase their margins).
4) If excise taxes are raised on all oil products at the same time, including fuel oils, it is uncertain whether any lower crude oil price which might follow, would be under or over compensated by a higher tax on fuel oils.

Based on these mechanisms, it is often said that the producer assumes the ”price risk” while the transmission companies assumes the ”volume risk”. As price and volume are two sides of market equilibrium, it will over time be the producer who assumes most of the risk in connection with the sale of gas. The pipeline companies are however tied by their TOP agreements with the producers. It might be imagined that the transmission companies get off-take problems sufficiently large that they have to lower their prices to LDCs and other customers when entering into new sales contracts where the TOP clauses come into effect. This might lead to lower sales and/or declining prices for the pipeline companies, i.e. a potential loss. As far as is known, this has not happened yet, but is, like we will discuss later, a possible scenario in a liberalized market (see also discussion in Chapter 12).

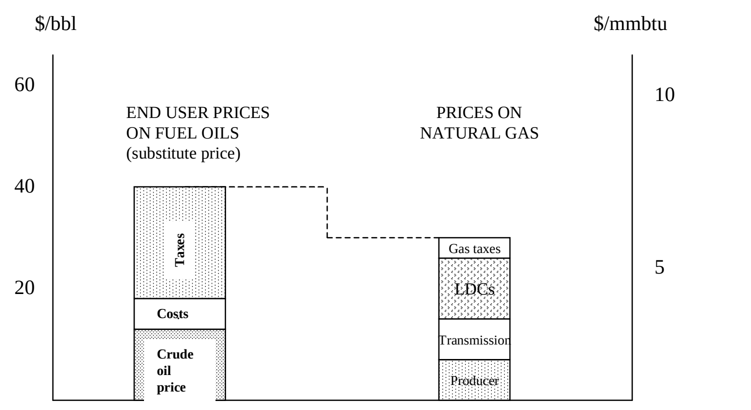


Figure 3.4: Gas prices set lower than substitute prices

In the contracts since 1986, gas prices refer to prices that are somewhat lower than the prices on the substitutes. This refers to the initial connection between the price of gas and the price of the alter-native energy carriers in the discussion of formula (ii) above. This was done in order for the (large) volumes, which were agreed sold, should have the possibility to penetrate the markets where gas competes with other energies. This implied that the producers reduced their prices relative to the par value with the prices on substitutes. In reality, prices paid today for natural gas do not correspond to the prices on oil products, as can be seen from the illustration in figure 3.4.

The gas in the Statfjord agreements from 1981 was originally priced approximately corresponding to the price on substitutes, but the prices were reduced in connection with entering into the Troll agreements in 1986 (Bartsch, 1999:211. See also Chapter 2). If prices were set equal to the price of the substitute, it was assumed that the growth in the market would not be large enough to absorb all the gas that would be produced and contracted. This price reduction was an important cause for Marathon's suit against Statoil and Ruhrgas (Aftenposten, 5. jan 1997).

Price Effects of a Liberalized Market

The price effect of liberalization in the various stages of the gas chain depends on how the market will be liberalized. As a basis for the discussion, it may be useful to first study how a (theoretically) fully liberalized gas market would work, that is: arrangements which the liberalization processes move towards, but which go further than the gas directive.

In a perfect liberalized market, the transport stages (transmission and distribution) would have their profit margins determined by a regulatory authority or by competition. At the same time, producers sell directly to distribution companies, power plants and large industrial users (gas-to-gas competition), as stated in the TPA directive. This implies that the wholesaler role of the transmission companies would be reduced and that they mainly are to function as transporters of gas against a tariff, corresponding to a toll financed road system. In such a market, the margins for the transmission companies would be lower than today (ideally they would only include

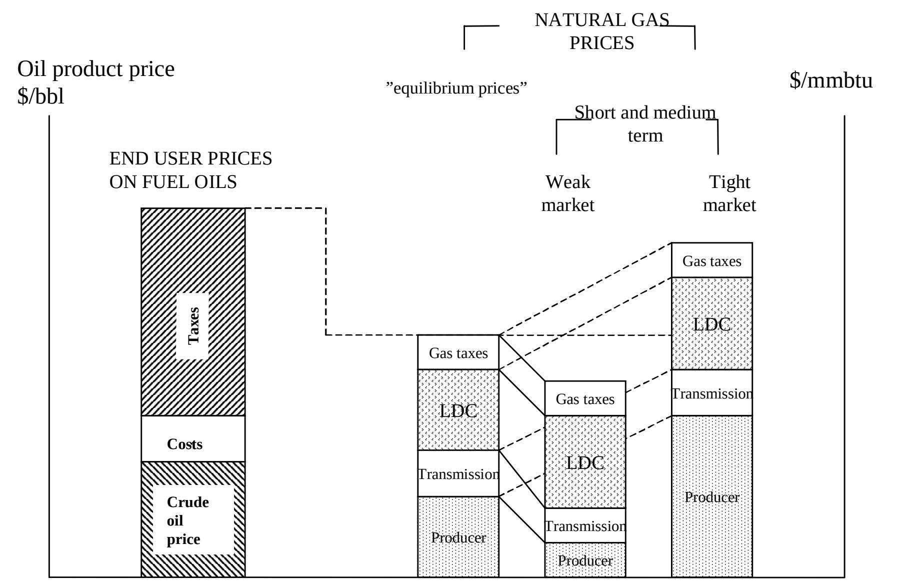


Figure 3.5: Increased price volatility due to liberalization

normal profit). The gross margins will be independent of price changes in the market in a more direct way than under the present market system, as they would not to the same extent be a result of negotiations. The pipeline companies may in a fully liberalized market become more occupied by influencing the regulatory authorities who set the framework for their activities (principal agent situation, see discussion in Chapter 7).

With end user prices determined by competing energy prices, ceteris paribus, the lower margins of the transportation companies go to the producer/exporter. It is however likely that a more liberal gas market also will lead to more short-term contracts for the exporter, including a spot market. The exporter is after all going to take over the contracts that today are handled by the transmission companies as sellers of natural gas. This may lead to larger variations in the gas prices for exporters on short and medium term depending on how tight the gas market is. In periods it may yield both higher and lower prices than the price of the alternatives, cf. figure 3.5. The instability will be perceived as a disadvantage relative to the present situation.

As a liberalized gas market might lead to more unstable prices for producer/exporter, the price to producer might go down if the market is weak (supply surplus), even though the gross margins for transmission and distribution are reduced.[8] This is illustrated by the middle of the three gas bars in figure 3.5, and will be discussed further in Chapter 12. A tight market situation might on the other hand amplify the positive price effect the liberalization effect (seen partially) could have for the producer, as end user prices might then be held higher than the substitute price (demand surplus). It is important to notice that short and medium term in a gas market may be 5-10 years, due to the long time lag between investment decisions and the time when production actually takes place. In addition, short and medium term may be different in a tight and a weak market. A tight market with higher prices to producer, as illustrated in the third gas bar, might lead to a reduced growth in the demand for gas. If the price exceeds the price on substitutes, the demand for gas will decline over time.

The TPA directive, and/or competition between pipelines companies, will lead to transmission company's customers in most cases will obtain lower purchasing prices and through that achieve higher profit, due to increased gas-to-gas competition at the exit of the pipelines. The pressure that transmission companies might receive on the prices to their customers would put

[8] This was the experience in the USA in the years after the gas market was liberalized in the middle of the 1980s ("the gas bubble").

pressure on their margins, as long as they are bound by long-term TOP contracts with Norway and other exporting countries. The transmission companies may then request renegotiation of contracts with the exporters already entered into ("old" gas), based on a force majeure argument about changed market conditions over which they have no control. Both existing contracts and the development of new large gas fields on the Norwegian shelf might then be threatened by the uncertainty with regards to the level of and the stability of the prices. If demand exceeds supply, the volumes might have to be withheld in order to prevent a collective excess supply with a following price drop. A price drop might make the investments unprofitable.

Thus, liberalization may lead to Norwegian sales contracts becoming more pluralistic and short-term. This will in particular apply to new contracts, but it may also be the alternative if the development goes so far that existing contracts are dissolved. It may then become more advantageous for producers to enter into direct contracts with the buyers (customers) than renegotiate the old ones with the transmission companies. Average export price levels may not necessarily be lower than today in a perfectly liberalized market, even though the price to consumers should decline. The assumed lower gross margin for pipeline companies may partly fall to the producers.

The net result of lower transportation costs and lower prices for the buyers of gas depends among other of how the market will be liberalized and how Norway and other exporters manage to reap the advantages and avoid disadvantages of the development. It is after all possible that the transmission companies takes a high profit for exercising the role as wholesaler and balancer of the market in the present market system, a role which Norwegian exporters (and others) might view as valuable to take over. Even though the market became fully liberalized, it would for all players be of vital importance to maintain the highest possible market power against their buyers/sellers, as there would still be an economic rent to be distributed. The players in the market will gain from increased competition in another stage in the gas chain, but usually not on increased competition in the stage they operate in themselves. Many of these issues will be further discussed in Chapter 12.

4 The Important Role of Energy Taxation

Energy Taxes: Higher and Higher

The development in the oil market over the last decade has shown how important energy excise taxes have become. In the 1970s and up to the drop in oil prices in 1985/86, the crude oil producers kept 75-85 percent of the selling price on oil products (gasoline, diesel, fuel oils, etc). The prices were far above the production costs, and gave huge revenues to producing countries. The remaining share went to refining, marketing etc and to the treasuries of the consumer countries. After the drop in oil prices in 1986, the situation is more or less the other way around. Today, crude oil producers receive about 30 percent of the average sales price in OECD countries. The share that consumer taxes take varies between Europe, USA and Japan - on average it accounts for half the selling price. EU countries have the highest taxes, where they represent as much as 70 percent of end-user prices.

Consumers within the EU paid 70-80 $/barrel for a representative barrel of Brent oil in the1990s (1999), taxes included (figure 4.1). While Norway as a producer of crude oil has received 10-20 $/barrel throughout the 1990s, EU countries have received 40-50 $/barrel as net excise tax income. The rest is margins to refining, marketing, transportation and so on (Austvik, 1996b). The EU treasuries now receive corresponding incomes from the sale of oil products as the producing countries did in the 1970s and the 1980s. A country like Italy has for instance for a long time had larger tax income from product taxation than what the Saudi-Arabian state has had from their oil export. The collective high European excise taxes on petroleum has most likely contributed to a downward pressure on crude oil prices (Austvik, 2000a).

As discussed in Chapter 3, taxes on oil products have on the other hand affected Norwegian gas prices positively. Excise taxes on oil products has made export price of natural gas showing a far more stable development than the price of crude oil. The price decline of crude oil is partially countered by increased excise taxes on fuel oils throughout the 1990s. The divergent development for Norway's export prices on crude oil and natural gas respectively, reflect a far more moderate tax level on natural gas than on oil. An increase in fuel oil taxes will as an example, under our assumptions, push the end user price of natural gas upwards without the intermediate stages deriving any benefit from it while the producer price goes up (ref discussion around figure 3.1). If taxes on oil products are held relatively constant, as they have been since the end of the 1990s, the gas price will however mainly vary with the price of crude oil.

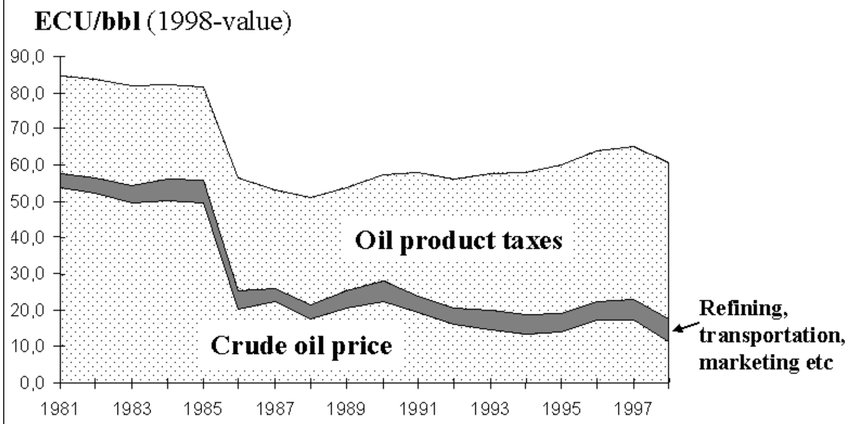


Figure 4.1: Oil price developments for consumer and producer in OECD-Europe 1981-1998.
Source: Austvik 1996 with updated data until 1998

As a share of end user prices to households gas usage taxes were 20-50 percent of end-user prices in 1999, around 20 percent in 1994 versus 15 percent in 1984 (table 4.1). Taxes on gas for electricity production and to the industry are lower and in many countries zero, even though they gradually have increased, as well. Even though natural gas is taxed low, the taxes on polluting coal are even lower in many European countries. Germany has for instance no tax on coal (actually they subsidize the production of coal). This reinforces the impression that energy taxation in consumer countries is not primarily based on environmental considerations, but primarily from fiscal needs.

Table 4.1: Taxes as a percent of end user prices on natural gas and coal in selected OECD countries

	Industry			Households			Production of power			Coal to industry		
	1984	1994	1999	1984	1994	1999	1984	1994	1999	1984	1994	1999
OECD-Europe												
Austria	16.7	16.7	27.7	0.0	n.a.	n.a.	0.0	1.5	n.a.	0.0	6.1	n.a
Belgium	14.5	20.9	21.2[4]	0.0	n.a.	n.a.	0.0	0.0	n.a.	0.0	n.a.	n.a.
Chechia	n.a.	4.8	18.0	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Denmark	18.0	20.0	58.1	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	0.0	25.6	n.a
Finland	1.7	28.0	31.8	n.a.	12.1	n.a	1.7	12.1	16.8	9.6	22.6	59.2
France	15.7	15.7	17.1[1]	0.0	n.a.	n.a	0.0	0.0	n.a.	0.0	0.0	n.a.
Germany	12.3	19.0	18.8[1]	n.a.	17.7	15.3[1]	0.0	14.0	12.7[1]	0.0	0.0	n.a.
Great Britain	0.0	5.7	4.8	0.0	n.a.	n.a.	0.0	0.0	n.a.	0.0	0.0	n.a.
Hungary	n.a.	9.1	10.7	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Italy	13.4	42.6	43.3[1]	0.0	n.a.	n.a	0.0	10.7	11.6	0.0	0.0	n.a.
Nether-lands	16.0	19.1	35.0	0.1	7.8	8.8	0.0	7.5	8.5	0.0	n.a.	n.a.
Spain	1.5	14.3	15.1	1.5	n.a.	n.a.	1.5	n.a.	n.a.	n.a.	n.a.	n.a.
Other OECD countries												
USA[2]	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Canada	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Japan	0.6	2.9	4.8[1]	0.0	n.a.	4.8[1]	0.9	2.9	n.a.	n.a.	2.9	4.8[1]
New Zea-land	8.1	15.0	13.8	n.a.	n.a.	n.a.	11.3	6.4	5.0	1.6	n.a.	n.a.

Source: IEA Energy Prices and Taxes (n.a.: not available). 1999-figures are 2.quarter. 1)1997. 2) Taxes on gas vary between 3 and 6 percent of end user prices in USA (IEA). 3) First quarter 1999. 4)1998.

There are, however, plans to increase natural gas excise taxes considerably. In the spring of 1997, EU advanced a proposed directive that aims to increase taxation on all use of energy to replace taxation on income (EU 1997b). For natural gas, it was said that the minimum taxes would be increased step by step with a whopping 350 percent from 1998 to 2002. This corresponds to what politicians call ”green taxes”.

Environmental Questions and The Kyoto Protocol

That the natural gas taxes are planned to increase this much may be seen as a paradox relative to international environmental policy. The most important reason for global pollution is the production and use of fossil fuels. Coal pollutes the most, then comes oil, while natural gas is the least hostile to the environment. The climate agreement in Kyoto from 1997 commits industrial countries to reducing the total emission of climate gases (including carbon dioxide, methane, nitrous oxide, hydrofluoric carbons, etc.). The reduction shall be 5.2 percent in the year 2012 relative to the level of 1990. This will mean a reduction of 30 percent relative to what the emissions are assumed to be if no actions were implemented. The distribution of these emission reductions is skewed. EU must reduce their emissions by 8 percent, USA with 7 percent and Japan with 6 percent. Norway, Iceland and Australia are the only three countries that may increase their emissions, Norway with 1 percent.

The climate agreement opens up for common implementation of actions. Norway may for instance pay for an action in Poland and have the emission reductions credited the Norwegian climate accounting. Any trade in quotas will come as a supplement to actions in each country (not as full replacement). 149 countries have signed the climate protocol. When at least 55 countries that represent at least 55 percent of the industrialized countries' total emission of climate gases have ratified the agreement, it goes into force. This may however still take several years (if at all).

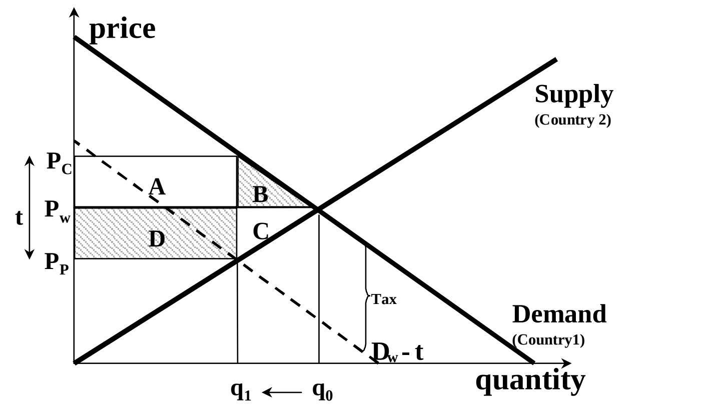
The Kyoto agreement thus opens up for flexibility and differentiation in how the emission targets may be reached, and it should be possible to adapt to with regard to Norwegian emission targets, including for instance building a gas power plant. For Norwegian gas interest, the significance for the consequence of energy taxation in consumer countries may possibly be the most important. The approved limitations on pollution give a basis for among other increased taxation on emission and use of energy. This should point towards believing that natural gas will be relatively less taxed than other energy carriers such as oil and particularly coal. If the taxing structure is changed so that the environmentally friendly natural gas is favored (low taxes on natural gas), it may lead to increased demand and higher prices on gas.

In the proposal for revising the tax system in EU from taxes on labor to taxes on energy from 1997, it was said that the change shall be neutral in the sense that the decline in tax / excise taxes on labor will be equal to the increase in energy excise taxes, so the total tax burden will remain the same. Increasing employment here primarily motivates tax changes, while the environmental effects of the actions are argued as a positive side effect. When the proposed directive suggests that excise taxes on the use of environmentally friendly natural gas shall increase by 350 percent in a few years, it is the same increase as is proposed for polluting coal, and far more than the proposed increase in taxes on oil products. Even though it is uncertain whether the Kyoto protocol will be realized or not, this is in contrast with its goals of reduced pollution.

Price Effects of Consumption Taxes in a Market

Tax policies on oil and gas becomes of particular political interest for the distribution of the economic rent because the principal part of production takes place in other countries than where the consumption takes place. In figure 4.2, this is illustrated by a simplified situation where we assume that all production takes place in different countries than consumption. The equilibrium price in the international market is given by the world market price P_w. A tax, t, is then levied on the consumers in the importing countries. The consumers' willingness to pay remains the same (represented by the demand curve), but through a consumption tax the treasuries of the consumer countries now take a share (t/p) of the price which consumers pay, illustrated by the dotted curve (D_w - t). Consumer price is then pressured upwards to P_C, while the price to producers is pressured downwards to P_P, and amount traded drops from q_0 to q_1.

Areas (A+B) reduce the consumer surplus. Area A is a transfer of surplus from the consumers to the treasuries of the consumer countries. Area B is net welfare loss due to reduced consumption at the higher prices. The excise tax revenue consists of area A+D = t * q_1. Area D becomes a transfer of revenue from the *foreign* producers to the treasuries of the *consumer countries*. Area C is a further loss for the foreign producers due to the lower prices and reduced production. As there is no production of the commodity in the consumer countries, area C does not represent a loss for these. It will in sum be advantageous for the consumer cou-ntries to introduce or increase a tax on consumption if area D is larger than area B, i.e. when the share of tax revenue for the producer countries is larger than the welfare loss of the consumer countries due to the reduced consumption.



Change in:	*World:*	*Importing country:*	*Exporting country:*
Consumer surplus:	- (A+B)	- (A+B)	0
Producer surplus:	- (C+D)	0	- (C+D)
Tax revenues :	+ (A+D)	+ (A+D)	0
Net social surplus:	- (B+C) < 0	- B + D > 0 if D > B)	- (C+D) < 0

Figure 4.2: Price and distributional effects of excise taxes on consumption, when consumers and producers are in different count ries.

The sizes of areas D and B depend on elasticities of supply and demand in both absolute and relative terms. If either demand and/or supply is rather inelastic, there will be little distortion of consumption whether it is the consumer or the producer that pays the tax. However, income distributional effects within the consuming country, may be significant. Whether it is producers or consumers that actually pays the tax depend on which of them is the least price sensitive, or most inelastic. It will always be the side with the relatively most inelastic supply/demand that pay the bulk of the tax. In figure 4.3, four combinations of demand and supply elasticities are provided as illustrations of these effects.

In graph A, supply curve is assumed completely inelastic (vertical) while the demand curve is assumed completely elastic (horizontal). In this case, consumers can switch to another fuel as soon as the price they pay, p_c, exceed p_0, while producers have no choice but to continue to supply, whatever the price is. When imposing a consumption tax, t, producers will pay the entire amount. There will be no change in consumption ($q_0 = q_1$) and area D will be a transfer from producers to consuming countries' treasuries (tax revenue = t^*q_0).

In graph B, demand is still completely elastic while supply, now, is upward sloping. Also in this case, prices to consumers will not be affected by the imposition of the tax, as they can switch to another fuel as soon as $p_c > p_0$. Because elasticity of supply is greater than zero, but less than infinite,

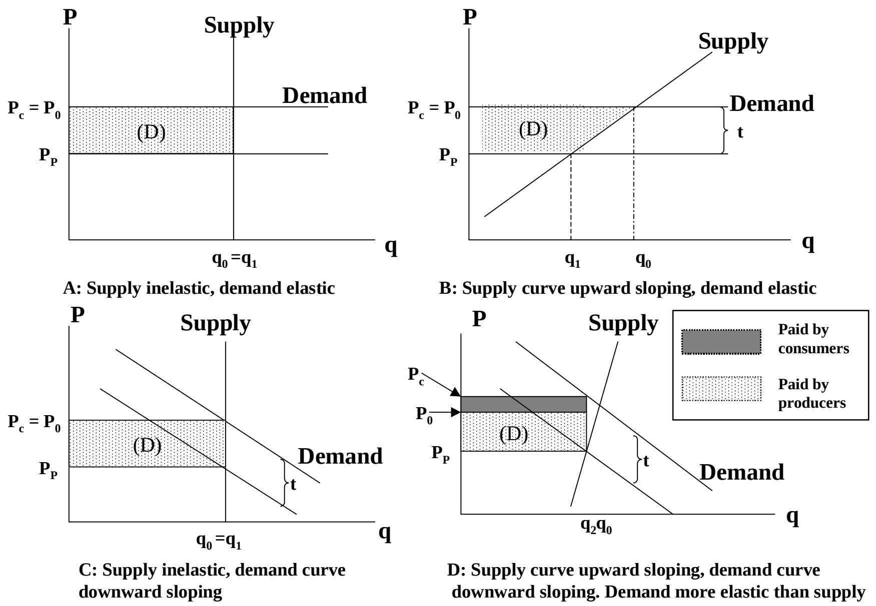


Figure 4.3: Effects of excise taxes on consumption with different supply and demand elasticities

Area D represent a transfer of rent from producers to consuming countries' treasuries, as in graph A. The difference is that, in this case, supply will be reduced to q_1, as consumers switch to other fuel by the amount q_1-q_0. The gain to the treasuries is less than in case A (tax revenue = q_0*t < q_1*t). Producers suffer the loss of reduced volumes in addition to a lower price.

In graph C, demand is downward sloping while supply is, again, completely inelastic. Also in this case, producers pay the entire tax as they are less price sensitive than demand. No reduction in volume takes place (q_0=q_1). Tax revenue will be the same as if demand were completely elastic (graph A) and equal q_0*t.

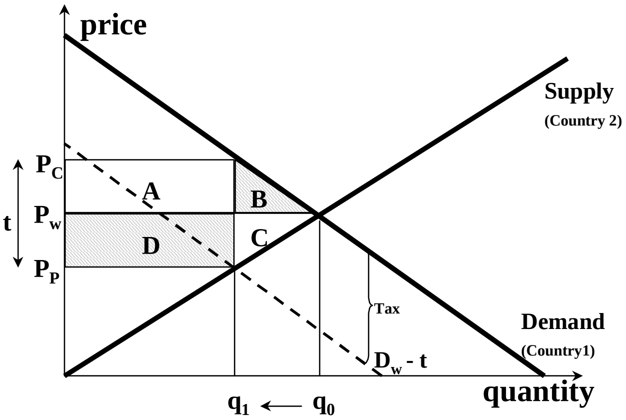
In graph D, demand is downward sloping and supply is upward sloping. This is the equivalent to figure 4.2. However, the graph is drawn in a way that demand is more elastic than supply. In this situation the tax burden is shared between consumers and producers, but most of the tax will be paid by producers because supply is relatively more inelastic than demand. Thus, the more inelastic supply is *compared* to demand, the greater the area D compared to A. That is, the greater the area D, the more of the tax will be paid by foreign producers and it is beneficial to raise taxes for consuming countries.

By introducing (or raising) an excise tax, there will be a transfer of surplus to consuming countries' treasuries. This surplus comes partially from consumers, which represent a transfer of wealth within the consuming country, and partially from producers in other countries. The more elastic the demand, and less elastic the supply, the more certain the consuming countries' governments can be that most of the rent is a transfer from other countries.

As long as there is an economic rent to be gained in the oil industry, one can assume that supply is rather insensitive to price changes, and producers should then, over time, pay the bulk of a tax. Gas consuming countries within the EU have relatively little production compared to consumption, and gas product taxation has thus much the same effect as an import fee. Because producer prices (=import prices for consuming countries) are pressed down, the tax will improve terms of trade for these countries.

The Parallel to Monopolization of the Supply Side

It is, however, important to note the necessity of collective action in raising taxes. A single country may not be large enough to have any impact on prices to producers. In such a case, the tax will all be paid for by consumers and represent a net loss in welfare (parallel to the effect of an import fee under a small country assumption).



Change in:	*World:*	*Importing country:*	*Exporting country:*
Consumer surplus:	**- (A+B)**	**- (A+B)**	**0**
Producer surplus:	**- (C+D)**	**0**	**- (C+D)**
Tax revenues :	**+ (A+D)**	**+ (A+D)**	**0**
Net social surplus:	**- (B+C) < 0**	**- B + D > 0 if D > B)**	**- (C+D) < 0**

Figure 4.2; Price and distributional effects of excise taxes on consumption, when consumers and producers are in different countries.

Similar effects, but with the benefit distributed to producers or producing countries' treasuries, can be achieved by introducing/raising uniform taxes on producers (across producing countries) and by a cartelization of the supply side. In figure 4.4 we consider a situation where producer countries' governments introduces uniform taxes on production (=export) or gathers in a cartel with other producing countries. First, consider all exporters to be price takers at price equal to marginal cost, where they produce output q_0 at world prices p_w. In the case of a cartel, producers' (=exporters') overall profit would be maximized when marginal cost equals marginal revenue. This happens at output q_1 and market (consumer) prices at p_c (the monopoly solution). Total economic profit to producers would equal q_1* (p_c-p_P) = A+D. Some of this economic profit should end up with the producing country's treasury as company tax, royalties etc. If the producing country has a special tax regime for oil and gas activities, such as Norway has, most of the profit should go to the treasury.

The producing country's (-ies') benefit from such an exploitation of market power could also be reached by uniform taxes on output. Producing countries could put a tax t =p_c-p_P, indicated by the curve S+t. Prices to consumers would be the same as if producers restricted output (for example by forming a cartel), and if consuming countries put on a tax on consumption (ref figure 4.2). However, now producing countries governments would collect the rent directly (t^*q_1 = A+D) rather than the consuming countries.

From consumer's point of view, area A is a transfer of surplus to either producers (in the case of a cartel) or producing countries' treasuries (in the case of a tax). Area D is a transfer from producers to producing countries' governments in the case of an excise tax on production. In either case, area B represents a loss in consumer surplus, which should be of no concern for producing countries. Area C, however, is a loss in surplus for producers. The question for the producing country remains whether the benefit of raising prices (area A) is greater than the loss in producer surplus (area C). As long as A>C, there is a net benefit. Producing companies would loose (C+D) in case of a tax. By pushing (gross) export prices to p_c, exporting countries terms-of-trade is improved, as it will deteriorate for consuming countries.

It is important to note that when a tax is levied on all supply *or* demand, the effect on prices and amount traded in the market is the same. The size of the areas D and B depends on supply and demand elasticity, as discussed in figure 4.3. It is always the demand or supply side, which is the least inelastic with regards to price that pays most of the tax. With a relatively less elastic supply side, the producers pay more than half the tax. With a relatively less elastic demand side, the consumers pay more than half the tax. The effect on traded amount is also affected by price elasticity. If either the demand *or* the supply I inelastic, the decline in traded amount will be small and production and consumption is little disturbed. It is only in the cases where *both* demand and supply are elastic, that the traded amount in a market is substantially changed due to a tax.

When taxes are introduced, consumers will loose whether it is the producing or consuming country that levies the tax, except in the special nil-effect cases when demand is completely elastic or supply is completely inelastic, ref. figure 4.3a-c. Producing companies will also loose, except in the special nil-effect cases where demand is completely inelastic or supply completely elastic. Thus, both consumers and producing companies have every reason to oppose taxes. Due to producing countries' heavy tax regimes of their petroleum sectors., a fight over the rent in the gas sector, using the tax instrument, will be dominated by the conflicting interests between the treasuries in consuming and producing countries.

Effects of Gas Taxes in the "Old" Market

As far as known, excise taxes on consumption of natural gas are not explicitly taken into account in today's gas contracts. It would also probably be difficult to bind the parliaments of the purchasing countries to not change their excise tax policy in the future. A first effect on an increase in taxes on natural gas consumption might be imagined to be an increase in consumer prices. If the consumers pay for the tax increases through higher prices, it will limit the growth in demand. If the growth in consumption is to be maintained, the prices to the consumer may not be increased and the prices in one or more stages in the gas chain (p_d, p_t and/or p_p) must be reduced.

How renegotiations due to an increase in taxes will affect the distribution of gross margins (and any economic rent) between respectively distribution, transmission and producer stages depends on the negotiation strength between the parties, legal bindings, etc. The margins of the transportation companies seem, as already mentioned, largely determined by negotiations made, where their margins (s_t and s_d) are set independent of end user prices. As long as these companies can argue that the margins are necessary to cover their costs, an increase in taxes will not hurt them. An increase in natural gas consumption taxes must then cause a corresponding decline in producer prices. As far as is known, the (so far relatively moderate) increase in taxes that have taken place, have been passed on to producer/exporter after some time.[9]

[9] ECON (1995, page 6) maintains that "In Continental Europe, import contracts specifically foresee that increased gas taxes compared to oil taxes shall be deducted from import prices..". Such a contractual relationship between taxes and producer prices we have however not been able to have documented/confirmed.

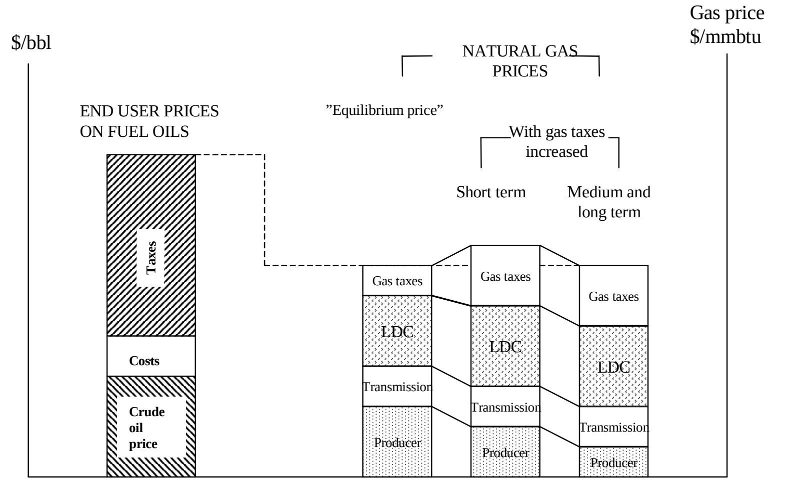


Figure 4.5: Price effects of an increase in excise taxes on gas consumption

In figure 4.5, the end user prices on gas are shown in the first right column, with a direct indexing to end user prices on fuel oils (left bar). The increase in taxes on natural gas may in the "short" term have the effect of higher consumer prices, at the same time as they put pressure on producer prices, while the margins of the transmission and distribution stages are not changed (middle "gas bar"). If the growth in consumption shall be maintained, all of the taxes must be passed on to the producer (third "gas bar"). Under the "old" market system, with sale and re-sale of gas through several stages, all parties in the chain have reasons to object to an increase of gas taxes as long as it *to any extent* may put the profit margins of the transmission and distribution companies under pressure.

Effects of Gas Taxes in a Liberalized Market

Around figure 3.4 we discussed the possibilities that a liberalized gas market would lead to more unstable prices for producer/exporter. We further discussed how a liberalized gas market with increased gas-to-gas competition also might lead to lower prices to producer when the market is weak (excess supply). A continuing excess supply might lead to lasting lower prices to producer. In a period with a tight market we might on the other hand be able to amplify the positive price effect the liberalization effect (seen partially) could have for the producer through lower transportation costs, in that the end user prices might be held higher than the prices before liberalization over shorter periods of time (surplus demand). Eventually they might be kept higher over longer time, but then only at the expense of declining demand.

In figure 4.6, the increased instability in prices due to the liberalization process is abstracted away, as well as the possible price pressure on consumer and producer prices in a situation with surplus supply. Increased competition

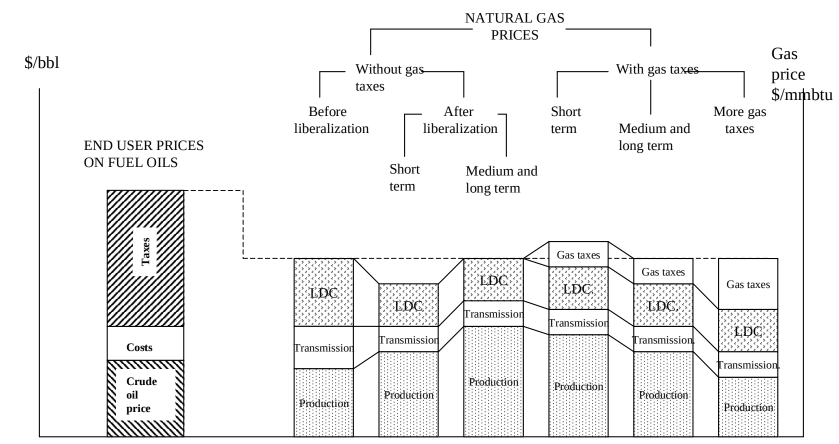


Figure 4.6: Price effects of liberalization AND increased excise taxes on natural gas

between transmission companies, possibly a regulation of transport tariff, will then redistribute parts of these companies' profits to respectively buyers and producers of natural gas. Lower margins for the transporters can in the short-term lead to lower prices to customers and consumers and higher prices to producers at the same time. The situation is illustrated by gas bar no. 2. This will result in increased demand for natural gas. If the growth in demand is to be maintained, the price to the end user must be maintained as well, and most of the economic profit that will be removed from the transporters may be passed on to the producers/exporters (gas bar no. 3).

This effect may make a politically initiated liberalization process unattractive from the consumer countries point of view, not the least since a large and increasing part of the production takes place in other countries than the consumer countries.

A positive effect of liberalization then depends on supply increasing in the same speed as demand. If we abstract the situation to the supply not increasing beyond what is planned, the end user prices must be kept at the same level as before. To prevent a redistribution of economic rent to the advantage of the producers, the consuming countries may increase the taxes on the use of natural gas and capture the released economic rent from the transporters instead of letting the producers have it. The effects of such an increase in taxes is shown in figure 4.5, and transferred to figure 4.6 by gas bar no. 4 (short-term) and no. 5 (long-term). Dependent on the reaction of the producers, the taxes on natural gas may theoretically be increased to the point where the consumer countries do not give any economic rent to the marginal producer at all. (gas bar no .6) As we here face a regional European market, it may be simpler to arrange de facto coordinating actions in the European gas market which has such an effect for producer countries, than in the global oil market.

A tax may then have a corresponding effect as an excise duty for importing countries and pressure producing countries' prices down, like we know it from the theory of an optimal tariff from international trade theory. An active excise tax policy on natural gas may in this way increase the interest among

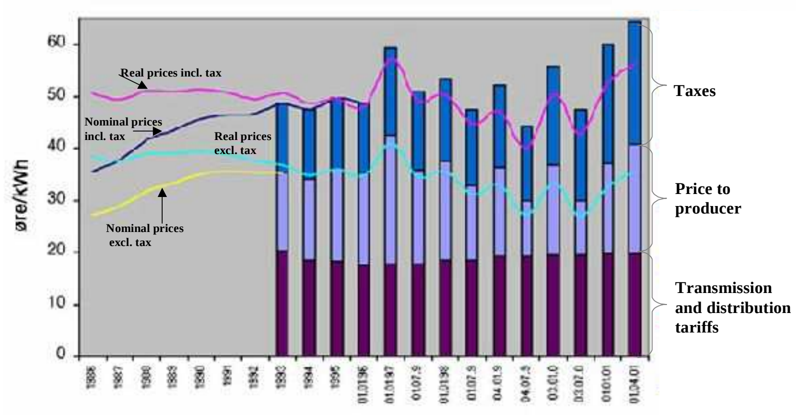


Figure 4.7: Electricity prices to Norwegian households 1986-2000
Source: Kraftmarkedet og prisutvikling, NVE 2002

consumer countries to force a politically led liberalization of the market. On the other hand, the effects depend on supply developments, where the consumer countries do not have the same degree of influence as they have over their own transmission and distribution companies and consumers.

As an example of price and tax effects in a liberalized energy market, figure 4.7 shows electricity prices to Norwegian households 1986-2000. The Norwegian electricity market was liberalized by law in 1990, and is now one of the most liberal electricity market in the world. Transmission and distribution tariffs have been very stable after liberalization. Prices to producers have varied a lot, in line with changes in supply and demand. As the market work more efficiently than before, real producer prices have tended to be lowered during the 1990s. At the same time, production capacity has not changed much in the period, partly due to the low prices. As the balance between demand and supply has become tighter, producer prices have tended to rise over the last couple of years.[10] Excise taxes have been raised several times, and most easily when producer prices were low.

The Future Development of Energy Taxation

The increasing taxes on oil products which has taken place in the OECD area may come to slow down if competing economies elsewhere do not follow the same policy. The challenge is particularly coming from the new economies in Asia, included the giants China and India, which now have far larger economic growth than the OECD area with a corresponding increased energy consumption. Strong competition may develop both in the markets for products and in the market for factor inputs (energy), so that taxes within the OECD area no longer can be increased but must be lowered. This may also happen if the oil price is high over some time. As far as taxes on natural gas in the European gas market is concerned, the large industrial users will face a regional competitive situation for natural gas as an input factor, while they are globally in a competitive situation for oil as an input factor. In product markets, this industry competes globally in the same way, as does industry that uses oil. This may lead to European countries wishing to tax the use of natural gas in the consumer sector harder than gas for industry and the production of electricity.

With the reservations above, the taxes on natural gas may act as revenue generators for the treasuries of consumer countries, like the taxes on oil products do, and in addition transfer economic rent from producer/exporter countries to importing countries. In particular it may for consumer countries become tempting to increase taxes at the time when the bulk of production potential has been developed in the gas exporting countries, and the producing countries have most of the investments as "sunk cost".[11] It will then be

[10] The problems concerning long term investments in production capacity in liberalized energy markets will be discussed further in Chapter 12.

[11] An excise duty may possibly be used to differentiate between different production areas. This however presupposes that WTO / GATT rules or regulations in the European Energy Charter should allow such discrimination in the future.

profitable for the exporting countries to continue to produce even if the selling profits are far less than expected (in worst case, at prices down towards short-term marginal costs).

An increase in gas taxes may seem particularly tempting for the consumer countries in a situation where the oil price is rising or the taxes on oil products are increasing. Italy, for instance, increased the taxes on fuel oils at the end of the 1980s together with a fairly comparable increase in gas taxes. There will be considerations like how large a market share it is desirable for gas to have, and the producing countries' costs for bringing gas to the market that decides the tax ceiling. If there is a perception in the consumer countries that there is already ″enough″ profit for producer because he continues to invest in new capacity at existing prices, there is little reason to give away ″extra″ economic rent by refraining from increasing the taxes on gas consumption.

If, on the other hand, the energy taxes to a larger extent are fixed so that they reflect the individual energy carrier's environmental advantages, taxes on particularly coal should be heavily increased and its subsidies removed. In this situation, natural gas will emerge as the most environmentally friendly among fossil fuels seen from an excise tax perspective. Reduced coal subsidies may result in increased demand for natural gas. The fiscal and regional employment consequences this may have in coal producing countries may make this a demanding and perhaps unlikely change for the energy importing countries of Europe, not the least within the EU.

The consequences for Norway of combined market liberalization and increased taxes on natural gas are complex. Increased market liberalization through more complex market transactions and political decisions is something Norway may to some extent adapt to through increased downstream activities and development of a more diversified contract portfolio. Taxes on oil products, on the other hand, have the positive side effect that they contribute to increasing prices on gas. Taxes on natural gas consumption are, however, not in Norwegian interest, and may become a far more serious threat for Norway's natural gas revenues than market liberalization. Some of the problem lies in the fact that taxes may be increased after the contracts (with their price formulas) have been signed. Norwegian and other producing countries will in the future face a tax risk in addition to an increased price risk. This may make long-term investments more uncertain and lead to fewer investments in large and costly projects. The special structure on the supply side in the European gas market may and should then lead to reticence on the part of the EU in connection with natural gas taxation.

5 Must Producers Earn a Resource Rent?

In petroleum producing countries it has been a prevailing opinion that a resource rent should be earned by petroleum producers due to the commodities' non-renewable nature. An important element in this logic is that the supply of oil and natural gas is limited to relatively few places in the world. As the resources are exploited, the remaining reserves are reduced. What is extracted today cannot be extracted tomorrow. Rationing of the scarce resource takes place through pricing mechanisms. Due to the scarcity the consumers must pay a higher price than the marginal production costs, so that the amounts supplied and demanded become equal. Most producers of oil and gas and not just the ones that produce the cheapest, have therefore until now earned an economic rent.

Especially in the aftermath of the first oil shock in 1973/74, much theory was developed that more or less states this as a fact.[12] There are, however, more factors than resource ownership that affects the distribution of the economic rent. Producer cooperation and wars in the Middle East led to, after the first oil shock in 1973, that a lot of the rent fell to the producer countries. Before 1973 it was mostly international oil companies that gained the most, and partially consumers through a large consumer surplus. The second oil crisis in 1979/80 increased the revenue of the producers further. After the drop in oil prices in 1986, a lot of the rent has fallen to the treasuries of the consumer countries through taxation (particularly in Europe), in some countries again the consumers (as in the USA).

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[12] Salehi-Isfahani (1995) list the research in this area in two categories; those who believe in rising prices due to resource scarcity and those who believe they will rise due to market power on the supply side. Adelman (i.e. 1989) argues, however, that price will decline, due to oversupply of the resource (oil).

Nobody can however claim to have found the right understanding of the behavior of markets for non-renewable resources. Most approaches have shown a rather weak record when confronted with the ability to foresee future price and output developments, as shown in Manne & Schrattenholzer (1987) and Lynch (1992). Economic theory is probably the most widely applied approach for analyzes of price developments and extraction paths for exhaustible resources. How would liberalization and excise taxes influence the distribution of rent in the gas chain within the framework of the theory of exhaustibles.[13]

The User Cost

The underlying assumption in economic theory of exhaustible resources is that producers are rational economic wealth-maximizers. It differs from economic theory of other goods as it explicitly emphasizes the perspective of *time*. For 'normal' goods, marginal costs consist only of the physical costs of labor, capital and input materials. For an exhaustible resource, however, consumption today precludes consumption of the same unit tomorrow. The cost the producer of today imposes on the future, results, in addition, in an opportunity cost (the value of a foregone action).

When resources are scarce, greater current use diminishes future opportunities. The marginal *user cost* is the present value (PV) of the foregone opportunities at the margin. This is opposed to marginal extraction costs; a pure technical economic criteria. Thus, total marginal cost for an exhaustible resource (B) is the sum of the marginal extraction cost (b) and the marginal user cost (u). At time t this can be expressed as:

$$(i)\ \ B_t = b_t + u_t \quad (t = 1,2,....,n)$$

The user cost, also called the *scarcity rent*, is a particular payment to the owner because the resource is exhaustible. Since u_t is the opportunity value of selling the last unit in period t rather than today, the producer should choose to produce at the time the user cost is the highest. If user costs are the same, the condition to be indifferent between producing now, in period 0 (zero), and in the future is:

$$(ii)\ u_o = u_1 = ... = u_n$$

The producer must, however, take into consideration today's value of tomorrow's money. In fact, he could alternatively produced today, invested

[13] The term exhaustible and non-renewable resources are used interchangeably.

the money in something else, and earned the interest this money would yield. Therefore, he has to discount future user costs at a chosen discount rate (*r*). Taken the discount rate into consideration, his indifference-equation can be written as.

$$(iii)^{14} \quad u_o = u_t * e^{-rt}$$

If $u_o < u_t$, the producer could improve wealth by postponing production until sometimes later. The discounted value of his production at time t would be larger than the value of today's production. Vice versa, if $u_o > u_t$, he should rather produce today. The extra price the resource owner gets in the future shall at least be as large as what a chosen interest rate would yield on today's production.

In figure 5.1, two price paths are shown. Both are illustrating the necessary development of the price in order to make the producer indifferent when to produce. If the initial price is p_1, the price has to follow a path higher than if the initial price is lower, for example p_0. But the *rate of increase* in prices has to follow the same exponential path (growth rate) to cover the alternative increase in the value of the money as a result of producing today and put the money into something else that will yield an interest.

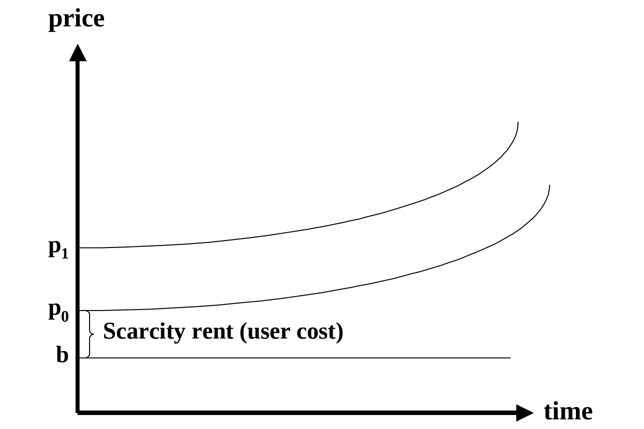

Figure 5.1: Price path of an exhaustible resource

For simplicity reasons, we have assumed constant marginal extraction costs (MC, b_t=b). If marginal cost is increasing over time (MC-curve bends upwards), the scarcity rent diminishes and the sacrifice made by future generations diminishes. The net benefits that would be received by a future

14 e is the irrational number 2.718..

generation if a unit of the resource were saved for them become smaller and smaller as the marginal costs of that resource become ever larger. With increasing marginal extraction costs it will be the difference between the price [p_t] and the per unit extraction cost [b_t] that must raise with the rate of interest:

$$\text{(iv)} \qquad p_o - b_o = [p_t - b_t] * e^{-rt}$$

This is a more generalized way of describing the price path that makes the producer indifferent when to produce. Obviously, higher extraction costs can be compensated by higher prices and vice versa. The main point is that by moving production between periods the resource owner can maximize wealth. The discounted value of the marginal user cost for the last unit produced in any time period should equal the marginal user cost in any other period for the producer to be indifferent when to produce.

The “Hotelling Rule”

The type of optimization problem faced can formally be illustrated as in the following. The owner of the resource wish to maximize the net present value (or net profit) of the resource stock from today until infinity. At time t, his profit Π_t from production q_t can be expressed as:

$$\text{(v)} \quad \Pi_t = p_t(q_t) * q_t - b_t * q_t$$

The producer’s price is described as a function of *q* for it to cover both competitive and monopoly firms. The producer's objective will be to allocate production (*q*) between periods in a way that the net present value of the profit is maximized. He will reach that optimum when the integral of the discounted profit-function is maximized (*T* being the living age of the resource):

$$\text{(vi)} \qquad \int_0^T \Pi_t * e^{-rt} dt$$

Doing this, however, he is subjected to the fact that each extraction reduces remaining reserves (Q_t) equivalently;

$$\text{(vii)}^{15} \qquad q_t = -\dot{Q}_t$$

[15] . denotes the time derivative of the variable.

Thus, if initial reserves are Q_0, then the accumulated output cannot exceed this limit $\sum_{t=1}^{n} qt \leq Q_0$). Obviously, the reserves at time *T*, when resource are fully exploited, cannot be negative). The producer is also subjected not to put any previously produced resource back to the reservoir: $q_t \geq 0$.

Optimal control theory can be used to solve this type of dynamic problem. Optimal control methods are techniques that enable us to maximize a function that is subjected to a set of dynamic conditions expressed as differential equations. Equivalent to the Lagrange multiplier in the non-dynamic case, a Hamiltonian multiplier can be used in the dynamic case. Hamiltonians (*h*) can be thought of as shadow prices. Shadow prices represent the opportunity cost of producing a commodity not traded. In fact, they express the external cost that extraction of the resource bring upon future generations, or the user cost in our terminology.[16] When (*iv*) is maximized subjected to (*v*), the Hamiltonian function can be expressed as:

$$(viii) \quad H(p(q),t,q) = \Pi_t * e^{-rt} + h\,(-q_t)$$

1. order condition will be:

$$(ix) \qquad \frac{dH}{dq} = \frac{d\Pi_t}{dq_t} * e^{-rt} - h = (MR - b) * e^{-rt} - h = 0 \text{ [17]}$$

$$=> \quad (x) \qquad MR = b + h * e^{rt}$$

This result is quite similar to the one in our discussion as expressed through equation (*i*) and (*iii*), where the user cost is the equivalent to the Hamiltonian multiplier. Equation (*x*) simply expresses that, for a wealth-maximizing producer, marginal revenue shall equal total marginal cost (*MR=B*). With the constraint that he is producing a non-renewable resource, he should not only consider the technical marginal cost of production but also the user cost he brings upon future generations. Thus, in optimum, he shall choose a

$$(xi)\ MR_t = b + u_o * e^{rt}$$

[16] For an introduction to the use of control theory see for example Brock (1988).

[17] Setting the derivative of Π with respect to q equal to zero tells us that profit maximum is reached when marginal revenue equal marginal costs. If the producer is a price taker. MR equas price, e.g. price shall equal unit cost.

This is the general condition both for a monopoly and for a price taker. Under competition marginal revenue equals price ($p_t = MR_t$):

$$(xii) \quad p_t = b + u_o * e^{rt}$$

This condition is called the *Hotelling rule* (after Hotelling (1931)), expressing that the (net) price of an exhaustible resource should rise at the rate *r* in order to make the producer indifferent when to produce. The rate of capital gains enjoyed by exploiting the resource must equal the rate of return earned in holding any other asset (e.g. the interest rate). Thus, in the most simplistic competitive case, where price equals marginal costs and extraction costs are assumed constant, the Hotelling rule can be expressed as that the rate of price increase shall equal the interest rate:

$$(xiii) \quad \dot{p}/ p = r$$

Equivalently, for the monopolist that exploits the inelasticity of demand, the rate of increase in marginal revenue shall equal the interest rate.

$$(xiv) \quad \dot{MR}/ MR = r$$

If net prices (or marginal revenues) increases with the rate of interest, the producer will have the same present value of profits in all periods and the same present value of the user cost. The producer will be indifferent between keeping the reserves in the ground and to explore and sell it. Also, in order to be indifferent to buy the right to explore the resource or not, net prices have to rise with the rate of interest to make the investment as profitable as other investments. If prices shall follow an exponential path, either the price itself has to rise and/or the cost of production must fall. With simplified assumptions of zero extraction costs (as i.e. in Gray, 1914), the price must increase with the rate of interest.

The rise in the marginal user cost (scarcity rent) reflects increasing scarcity and the accompanying rise in the opportunity cost of current consumption. In the following example, we assume marginal extraction costs > 0 but constant, b = 1.5 (1.5 dollar per Million BTU, mmbtu), r =0.1 (i.e. 10 per cent p.a.) and u_o = 0.7 (0.5 dollars per Million BTU). The price of gas in year zero is then:

$$(xv) \quad p_o = b + u_o = 1.5 + 0.7 = 2.2 \ (USD/mmbtu)$$

To make the gas producer indifferent when to produce, the price must in the following years be (given constant extraction costs):

$$p_o = b + u_o = b + u_o * (1 + r)^0 = 1.5 + 0.7 = \quad 2.20$$

$$p_1 = b + u_1 = b + u_o * (1 + r)^1 = 1.5 + 0.7 * (1.10)^1 = 2.27$$

$$p_2 = b + u_2 = b + u_o * (1 + r)^2 = 1.5 + 0.7 * (1.10)^2 = 2.35$$

$$p_3 = b + u_3 = b + u_o * (1 + r)^3 = 1.5 + 0.7 * (1.10)^3 = 2.43$$

If the producer expects $p_3 = 2.3$, he should rather extract his gas faster. However, if he expects the $p_3 = 2.6$, he can increase economic wealth by extracting more in period 3 and reducing production in other periods. In marginal terms, his production profile should be scheduled in such a way that the marginal user cost for gas produced in any period is equal.

The Role of a Backstop Technology

If prices rises so much that they reaches consumers' maximum willingness to pay (WTP), consumers will stop using the resource.[18] Thus, if there exists a substitute at a price lower than consumers WTP, extraction will be pushed forward in time and stop earlier than if no substitute product existed. Prices may increase up to the point it reaches the price of the *backstop* technology. A backstop product is a known technology that can serve as a substitute for a product or a resource. The substitute can set the

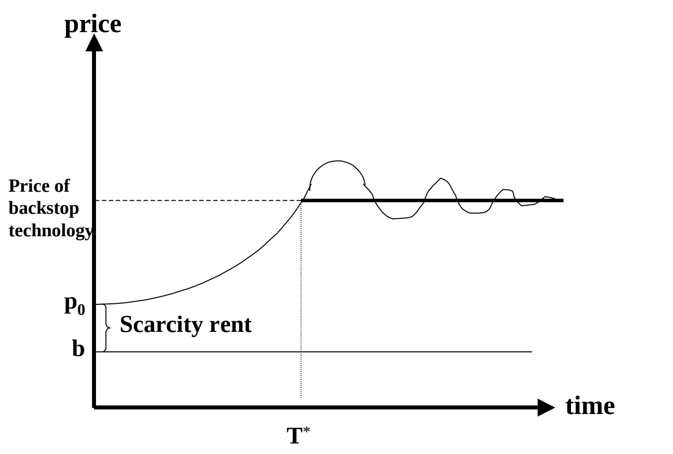

Figure 5.2: Price path with a backstop technology

[18] Willingness to pay is the valuation placed by an individual on a good or service in terms of money. It can be expressed by the inverse demand function: $Q = f(p) \Rightarrow p = g(Q)$. Total willingness to pay is the entire area under the demand curve. WTP is otherwise the same as consumers surplus. Maximum WTP is represented by the price so high that all demand is abolished.

upper limit of the price of the resource. The price profile in a competitive market with a backstop technology is shown in figure 5.2.

The Hotelling model tells us, with the modifications mentioned, that prices would rise with the rate of interest until they reach the price of the backstop fuel. At this price unlimited supplies of the backstop product is made available and the price of the resource will be the same as the price of the substitute. If it takes time to introduce the backstop-fuels (e.g. for technical reasons) the price may pass the backstop price for a while, until sufficient amounts of the alternative fuel(s) have reached the market,. The production profile for an exhaustible resource with a backstop technology is presented in figure 5.3.

The graph illustrates that the extraction of a nonrenewable resource will decrease over time (if the demand curve is stable). This is due to the fact that marginal user costs (or scarcity rents) increases over time. The bowed curve is

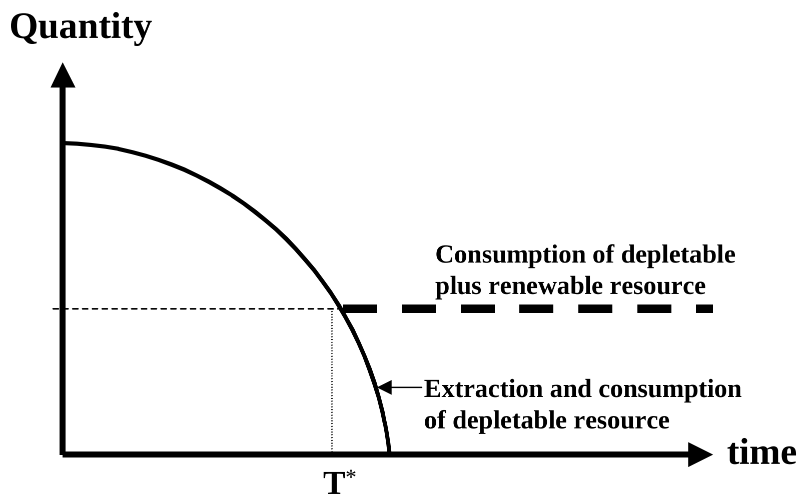

Figure 5.3: Price path under competition versus monopoly

somewhat steeper than if there were no substitute. When the price of the resource reaches the choke price (price of the substitute or the backstop price), consumption of the substitute will start and the extraction of the resource will fall rather rapidly.

The user cost is not observable in any account. But the wealth-maximizing producer must take into account that such a cost exists because of the non-renewability of the resource. *How* he evaluates the future as opposed to today depends on numerous factors. The producer should chose the production profile according to his expectations about future supply and demand conditions. In this consideration, elements as the size of the reserves, prices of alternative energies (backstop fuels), choice of discount rate, reserve size, price elasticity of demand, economic growth in the purchasing countries' economies, technological development and uncertainty are entailed.

Choice of Discount Rate

The *discount rate* influences the *slope* of the price path. A high discount rate make the slope steeper than a low one. An increase in the discount rate imply a larger return on investment and therefore increased production today, a shorter depletion horizon, lower prices and higher extraction. If property rights are public, the discount rate will usually be lower than when they are private. This is due to society's broader view of the economy including multiplier effects of investments and consumption than a private company. The society is usually therefore assumed to give more to future generations than a private enterprise. The private company will use the market interest rate for discounting while the society will use a social discount rate.[19]

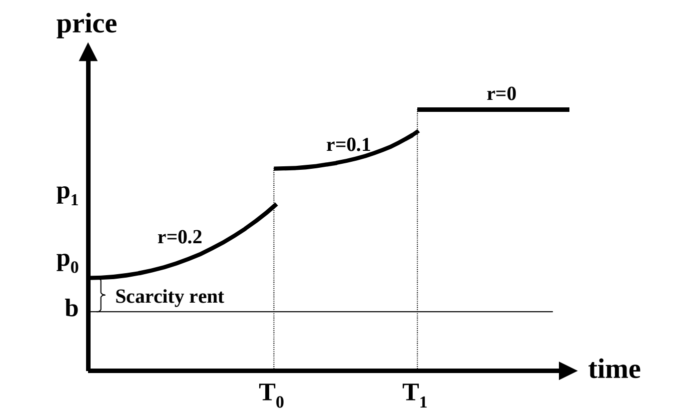

Figure 5.4: Price path with high and low discount rates

[19] Usually representing the rate at which society is willing to trade consumption between different time periods or the society's rate of time preference. In Norway, the market interest rate has generally been in the 10-15 per cent range, while the social discount rate has been calculated to 7 per cent (annually).

In figure 5.4, the producer initially uses a discount rate of 20 per cent and he has a short exploitation horizon. In general it could be private investor's consideration, but it could also be the situation for a nation in an (economic) crisis situation. In a crisis a country could need huge amount of money and revenues in the short term. Thus, "infinity" may in times of crises, change from being perhaps 30 years to 5 years or less. The "wealth-maximizing" process may be considered as how to maximize net present value of the resource over these 5 years. In figure 5.4, at time T_0 the crisis has diminished and the need for government take is reduced. Thus, the country can take on a discount rate of let's say 10 per cent. The effect of a theoretical 0 (zero) discount rate is illustrated in the graph after T_1.[20] Similarly, privatization of nationally owned producing firm would lead to higher discount rates among producers and push production ahead in time. Increased competition among producing firms ("liberalization") would do the same.

Changes in Reserves, Demand Elasticity, Economic Growth and Technology

Similar effects on producers' indifference-paths can be argued for, due to changes in almost any other variable influencing prices. A resource owner that can upgrade *reserves* can produce at today's level at a lower cost for future generations than if reserves are scarcer. Therefore, an increase in reserves will decrease the scarcity premium. Obviously, when reserves are upgraded, more can be produced in total.[21]

In figure 5.5, we have initially a situation with low reserves and the price path stays at a high level up to T*. At T*, reserves are upgraded and prices can follow a lower path in order to exhaust the resource before "infinity" occurs; prices are revised down. But prices should grow with the same *rate* after this reconsideration takes place.

[20] Quite unrealistic, though, with a zero discount rate the country have no present need for revenues at all.

[21] Pindyck (1978) extended Hotelling's model by the effects of additions to the reserves through exploration.

It is usually not easy to determine what are the reserves in a gas field or for a country. It may, however, be helpful to distinguish between 3 different concepts (see for example Tietenberg 1996). *Current* reserves are those that are known to be possible to extract with profit at current prices (and technology). *Potential* reserves are defined as a function of the price people are willing to pay. Thus, the size of the potential reserves is changing with the price of gas. The *endowment* is the natural occurrence of resources in the earth's crust. The third concept is geological rather than economic, and represents the upper limit on the availability of terrestrial reserves. Theoretically, the price of gas can become so high that a resource can be physically depleted. However, in practice, when the price becomes too high, backstop prices will set upper limits for the price of gas and thus how much of the endowment can be extracted. The current and potential reserves set the frames for the economic scarcity of a reserve. The higher the price of gas, the larger the current reserves. The size of the potential reserves depends on the expectations made for the development of the gas price. Adelman (1989;442) claims that because of the difficulties in estimating reserves, reserves of gas cannot be viewed as "a fixed stock to be used up, but an inventory, constantly consumed and replenished by investment." One reason for the uncertainty in determining both current and potential reserves, is technological development. If tomorrow's technology can squeeze out 10 per cent more gas of today's reservoirs (at the same cost as of today), depletion of these additional current reserves will take some 9 years at current production levels.

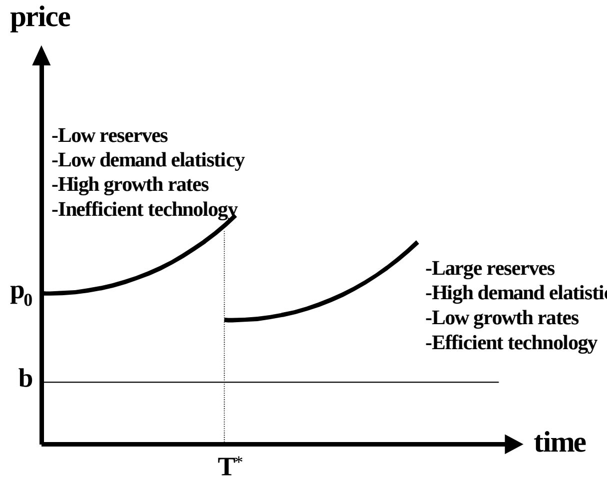

Figure 5.5: Shift in price paths. Change in: reserve base, elasticity of demand, growth rates and technological development

A similar effect as a change in reserves can be observed as a result of a change in expected future (long run) *elasticity of demand*. When demand is rather inelastic, high prices can be sustained and a high price profile is chosen. If long run demand elasticities are revised down, a lower price profile is necessary for the resource to be fully exploited. In the graph above, long run demand is expected to be inelastic up to T* and then revised down.

A decrease in the rate of *economic growth* will also change the price path similarly. Up to T* high economic growth is expected. At T*, expectations changes to a more modest growth level, and, accordingly, the resource is expected to be less scarce in the future. User costs becomes lower and the price must be revised down.

The introduction of a more efficient producers' or consumers' *technology* will also lead to a downward revision of the price path as more efficient technology can extract more (upgrade current reserves) and/or consumers use less for a given level of utility. In the graph above, new technologies are introduced at T*, user costs are lowered and the resource is made less scarce. In order to exhaust the resource, prices must be lowered.

The User Cost and Uncertainty

Obviously, the size of the user cost will vary with future supply and demand. Therefore, today's *perceptions* of the future will be of significant importance for determining the size of the user costs. If supply is sufficiently abundant in the foreseeable future (relative to demand), production today may not preclude production tomorrow. If the producer expects higher prices in the long run, he may restrict supply today in order to sell it at a later point in time. Equivalently, with low discount rates, the growth in the price has to be less than when discount rates are high in order to make it profitable to delay production.

Obviously, how to deal with *uncertainty* in assumption of the future development of a number of factors is a major problem in determining user costs. When uncertainty increases, discount rates becomes higher and production are pushed ahead in time. Uncertainty, in and by itself, shortens the depletion horizon, and gives a steeper price path. Each of the factors we have discussed above involves uncertainties. In addition there is uncertainty concerning the interaction between them. For example, how will a more elastic demand reduce prices or how will these low prices influence growth rates and, subsequently, increase prices?

Analysts have extended Hotelling's model to discuss how uncertainty affect production decisions and price paths. Dasgupta & Heal (1974) considers the role of uncertainty about production techniques of backstop fuels. Hoel (1978, 1980) studies substitute resources, assuming that there is knowledge about the time the substitute is available but not about it's costs. Stultz-Karim & Economides (1989) examines the effect of uncertainty in ultimately recoverable oil reserves and its effect on price paths.

Particularly there is a problem that the market interest rate (for example from a deposit in a bank) is relatively more easily observable than future prices of a commodity. A bank deposit is also more easily shifted from one type of investment to another. The owner of an exhaustible resource have often large fixed costs and may have long-term contracts making it impossible for him to shift to some other type of investment. Transaction rigidities therefore indicate that the Hotelling rule should only be considered to have a possible explanatory power for the market of exhaustibles in the long run when rigidities in production and short and medium term demand inelasticities have time to adjust.

Very simply the producer could, for example, assume that today's population is more important than tomorrow's and choose a high discount rate and produce a lot today. However, if he considers all generations of equal importance, he resides with the problem to determine all other factors influencing the price path. Thus, being a rational wealth-maximizing producer, there are many possible productions and pricing paths depending on assumptions made.

Monopoly vs Competition

Much discussion has been made over the role of cartelization of resource market, especially the role of OPEC. In our discussion of the European gas market it is sometimes discussed, as the supply side is so concentrated around few supplying nations. With a linear demand curve, a monopolist's price will initially be higher than under competition. On the other hand, the higher price encourages conservation measures. Demand for, for example, gas is substantially more elastic over the long than the short term. Therefore, over time, monopoly leads to lower consumption than does competition. The higher prices also initiate production in high cost areas, which in its turn also suppresses prices. Taken together, the monopolist provides less gas to the market and conserves more gas in the ground than a competitive firm. But clearly, he may charge a very high fee (monopoly rent) in order to perform this rationing function. And, due to the higher elasticity of supply in the long run (compared to the short run), he may face loss of market shares as a result of the high prices, as well.

Therefore, as figure 5.6 shows, in the short run the monopoly (with the lowest discount rate) will initially yield a monopoly rent in addition to the scarcity rent. Firms competing with each other have higher dis-count rates, and lower profits. However, after time T^* the competitive price will be *higher* than the monopolist's price. Demand is encouraged by the lower prices, the resource exhausted quicker and the scarcity emanating pushes prices up. The timing of T^* is, however, an intriguing question.

Some modifications can be applied for the market concentration on the supply side. In a *Stackelberg* market, a single producer, or a group of producers, let other countries sell what they wish and they balance demand by

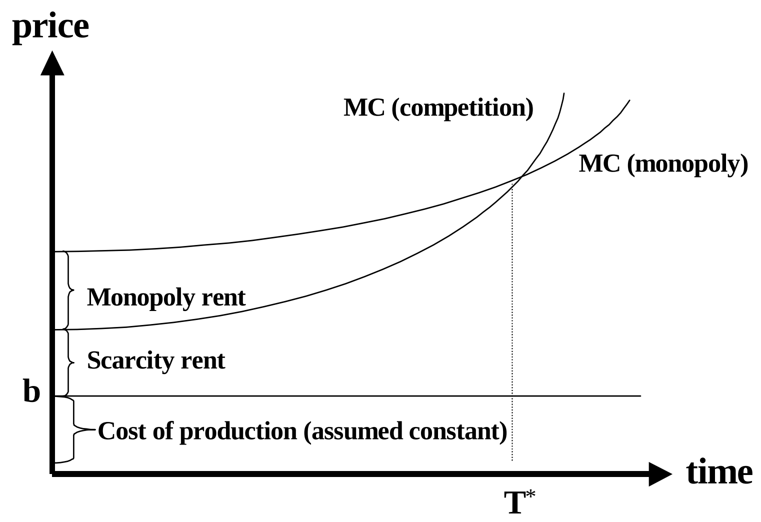

Figure 5.6: Price path under competition versus monopoly

regulating their own production to maintain the monopoly price (they are "swing-producers"). The swing-producers take into account present and future demand, the production of all other suppliers in the market and choose the optimal price path maximizing their wealth over time. All countries, except the swing-producer(s), adjust quantity produced to the prices fixed in the market. The swing-producers behave like monopolists taking into consideration both the degree of inelasticity of demand and the reaction to changes in prices among other producers. Such a partially manipulated market will lead to a price path somewhere between the one resulting from pure competition and monopoly.

A *Nash-Cournot* solution is a modification of the Stackelberg-market. In this market *all* actors are active and a non-cooperative game is established. Thus, also the smaller sellers have expectations about the future price and other elements of the market that is important in order to optimize positions. This type of market generally leads to a higher price path than in the Stackelberg market. But distribution of production and income between producers may be different, to the disadvantage of the swing-producer and to the benefit of the smaller producers.

Saudi Arabia has often been considered such a market leader in the oil market. In the European gas market, the oligopoly on the supply side could possibly be called a Stackelberg situation, with Russia as the market leader. But whether one modification of the theory is better than the other, the question remains whether enough demand remains for swing-producer(s). With high prices, new entrants are attracted to the market and existing producers will be encouraged to increase production, as well. Demand will decrease as consumers will shift to alternative energies and introduce various conservation measures. Thus, the swing-producer must either set high prices and accept declining market shares in the future or lower prices in order to limit entrance of other producers, increase (maintain) demand and expand profits in the future.

Producer Prices May Fall over Time

Most analysts using the theory for non-renewable resources as a basis for understanding markets for non-renewable has concluded that price must rise over time. However, as we have seen, this is only true in *ceteris paribus* cases. *If* reserves are upgraded, demand becomes more price-elastic, economic growth declines and/or technology becomes more efficient, prices should be revised *down*, as illustrated in figure 5.7.

How, then, can this theory be used for understanding price developments for exhaustibles? Probably, in the *aftermath* it can explain why prices rose or fell. But for *predicting* prices, too much is unknown for the analyst to know whether higher or lower prices should be expected. Few, if anyone, can pos-

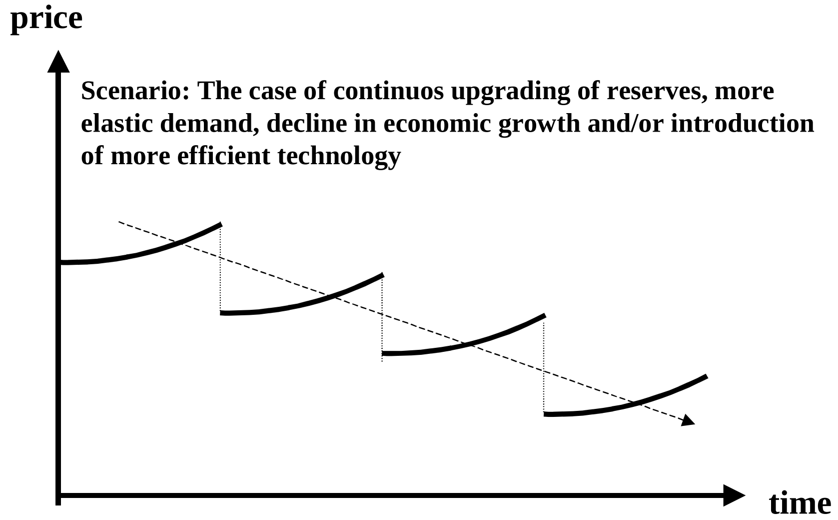

Figure 5.7: Prices may fall in the long run.

sibly know enough about all the factors influencing price paths and their revisions in order to predict the future outcome. The claim that prices necessarily must rise in the future seems to be a too extreme and partial use of the model. Nevertheless, the identification of a backstop price and the technical cost of production will give techno-economic upper and lower limits for how high or low prices can be at a given point of status of the variables influ-encing cost and backstop levels.[22]

Furthermore, producer's inter-temporal consider-ations, being aware that due to the non-renewable nature of the resource extracted, they impose an

[22] See Austvik (1992) for a further modification of this issue. Here, also political variables are included in the discussion of upper and lower limit for the price of oil.

oppor-tunity cost on future generations, may give some sound philosophical background for how a producer rationally should behave *if* the producer can optimize in the long run and possess all information needed, disregarding politics and other considerations.[23]

Consumer Prices May Rise Over Time

Consumers' surplus is maximized in a competitive market if prices are set in the intersection between demand and supply curves. Chapter 4 showed that a monopoly rent could be allocated to producers, by cartelization and output reductions or to producing countries' treasuries, through taxation on producers. Alternatively, consuming countries' treasuries can collect the monopoly rent by taxing end-users. In either case, the effect on *consumers' price path* would be the same.

Could it be that not only the supply and demand side could manipulate the monopoly rent, but also the scarcity rent? Probably, yes. The theory of exhaustibles tells us that when resources become increasingly scarce, consumer prices must become increasingly higher. But it does not guarantee that producers should collect the difference between consumer prices and cost. With active, orchestrated and dynamic taxing policies across producing or consuming countries' governments, the countries' treasuries, leaving no rent (or benefit) to private producers or consumers, respectively may collect the entire rent. For example, active and coordinated consuming countries' taxation (or tariff) policies that continuously increases energy taxes may lead to a situation where no rent is left to producers. Marginal user cost could (in theory) become zero at any point in time. Thus, if excise taxes on end-users are continuously raised, *producers price path* may follow the trend in figure 5.7, while consumer prices increase.

Figure 5.8 illustrates the situation of an initially competitive market with prices at p_0 (no monopoly profit to producers). Prices are expected to increase along the price path H_0 up to the backstop price, as shown earlier. However, at time T* consuming countries introduce an excise tax, t, on end-users. With this tax consumer prices shift to p_1 and producer prices drop to p_2.

[23] For a comprehensive discussion of the theory of exhaustible resources, see Dasgupta & Heal (1979).

In a competitive market environment, where excise taxes on end-users are introduced, consuming countries' treasuries take part of producers' resource rent.[24] If the tax remains at t, consumer prices should rise over time at a slower rate than before the tax, in the same way as the monopolist's price path. Such a price path is illustrated as H_1 while the price path for producers are illustrated as H_2. The distance between H_1 and H_2 equals the constant tax, t. However, if consuming countries rise taxes over time, consumers price path will make shifts upwards until prices reaches the backstop price. This is illustrated as the discrete path H_3. While consumer prices make shifts upwards, producer prices make shifts downwards, as illustrated in the discrete path H_4.

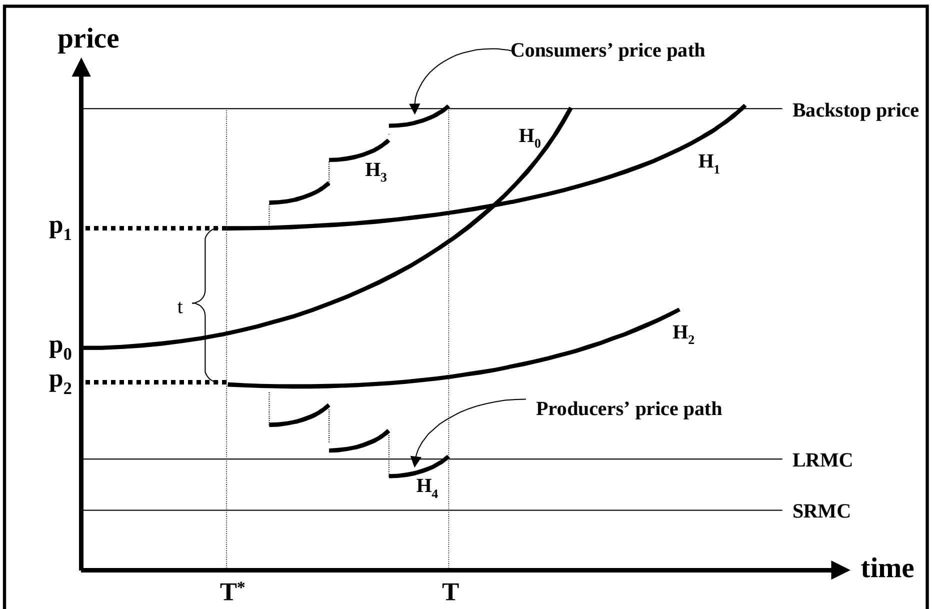

Figure 5.8: Producers' and consumers' price path under competition with an excise tax on consumption

In figure 5.8, both LRMC and SRMC curves are drawn. In the example, producers' prices are pushed below LRMC along H_4. In this case, the producer will continue to produce at existing capacity, but no new investments are made. This will be the case all the way down to SRMC. If prices are pushed

[24] If producers had cartelized the market on beforehand, consuming countries may only have taken part of the monopoly rent.

down only to LRMC, new investments will be made, but no rent will be collected. The shift from H_0 to H_1 represents the same type of effect on consumers as the classical monopolization effect shown in figure 4.4. The difference is only that consuming countries' treasuries get the rent in stead of producers. The practical and political competence and possibilities will contribute to determine where the rent actually ends up and which price paths will be realized.

6 Competition and Regulation of Transmission and Distribution

High Costs of Transportation

Searching for and producing natural gas is quite similar to corresponding oil activities. Gas and oil products also compete in the end user markets as substitutes for each other. This is the main reason why prices on natural gas in the European market largely have been indexed against prices on alternative oil products, particularly fuel oils (cf. Chapter 3). The difference between oil and natural gas markets is particularly linked to transportation costs. Firstly, a given amount of energy in gas form represents a far larger volume than oil does. Secondly, transportation and storage of gas calls for many physical requirements just because it is a gas. These aspects lead to very high sums of investment into transportation arrangements for gas, low flexibility and considerable economics of scale.

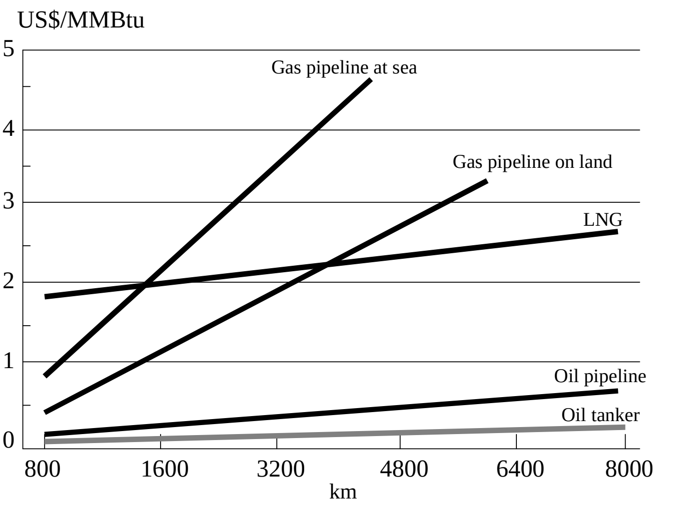

Figure 6.1: Illustrative costs of oil and gas transportation
Source: IEA (1994)

Transportation assumes a much larger part of the costs of bringing gas to the markets than what it costs to bring the oil, and is therefore very important also for price determination throughout the gas chain. The high transportation costs is the main reason why we have regional gas markets in the world, and that the European market can be supplied only from a few areas of production, cf. Chapter 2.

Figure 6.1 is taken from IEA (1994) and illustrates some important differences between oil and natural gas transportation. First and foremost it shows that costs per transported energy unit may be ten times higher or more for natural gas than for oil. That it is more expensive to transport gas sub sea than onshore is maybe no surprise, but it of course also begs some assumptions, among other about how seafloor and water conditions are relative to topography and buildings onshore. Transportation of gas as LNG is considerably more expensive than via pipelines over "short" distances, while it may be cheaper over very long distances (from about 4000 kilometer).

The high transportation costs makes variable costs of operating gas transportation relative to the capital costs considerably lower than for oil transportation. The percentage degree of capacity utilization of a pipeline (the so-called "load factor") does not influence total transportation costs very much. IEA (1994:49) considers operation and maintenance of pipelines, except compressor stations, as fixed costs. They estimate them to represent annually 1 percent of offshore investment costs and 2 percent onshore. The maintenance costs for compressor stations are assessed to be annually 3-6 percent of investment costs at relatively high load factors. Thus, when the investments have been made, also variable costs by and large are given even if transported volume changes. A high or low load factor will therefore influence costs per transported unit strongly, but the total costs, hardly at all. Therefore, transporters of gas are often natural monopolies in the markets they operate.

Natural Monopoly

A natural monopoly is a type of monopoly that exists when it is less costly to satisfy demand with only one company operating in the market than for two or more firms. The monopoly is in this sense 'natural'. However, a one-firm market is not necessarily optimal if the firm abuses it's monopolistic market power and/or allocate inefficiency. Without public intervention, such firms may behave as monopolists without much fear of competitors entering the market, rise prices excessively and serve increasingly more inferior products with inefficient use of resources.

Natural monopolies can arise when there are economies of *scale* and/or *scope* in the production of goods or services. In our discussion of gas transportation we consider the product to be transportation services. Economies of scale exist when it is less costly for one firm to produce a single commodity (or service) than it is for two or more firms. Economies of scope exist when one firm can produce two goods or services at a lower total cost than if independent firms produced each of them.

Economies of Scale

In the very long run, all costs for a firm can be considered variable and fixed costs are zero. In most cases, however, depending on what is considered to be short and long run, some costs are fixed, and total costs of production

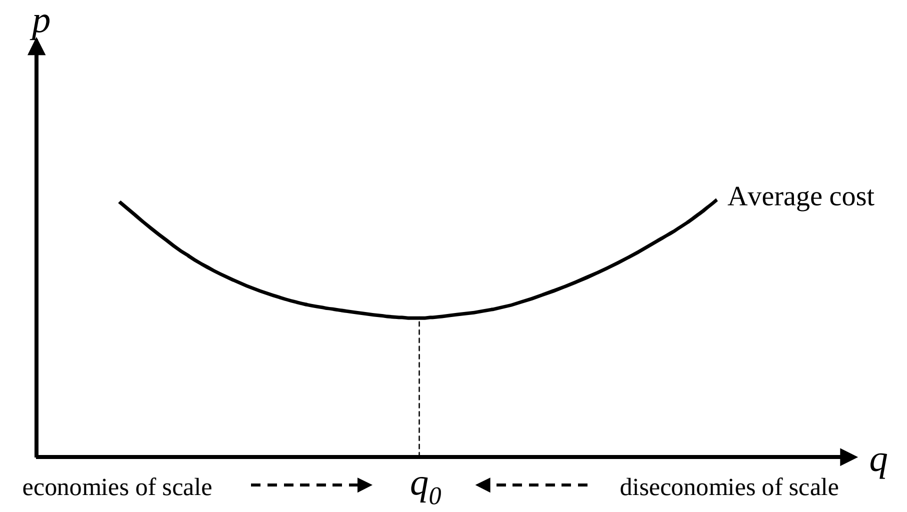

Figure 6.2: Average cost and economies of scale

consist of fixed plus variable costs. Whenever there are fixed costs, average cost must be falling for output levels close to zero and rising with larger quantities of output. Large fixed costs are the most prevalent source of economies of scale. The fixed costs must be incurred no matter how many units of output are produced. In figure 6.2, average costs are falling up to output q_0 and rising thereafter. This plant has economies of scale at $q < q_0$ and diseconomies of scale at $q > q_0$.

This is the general form of an average total cost (ATC) curve. The difference between a plant usually said to be having economies of scale and a competitive firm is that q_0, or cost minimum, occurs at high output levels *compared to market demand*. When there are economies of scale for a sufficient part of the production compared to demand the firm becomes a natural monopoly in producing this product. Thus, for two transmission companies having identical cost functions, one of them can operate as a natural mo-

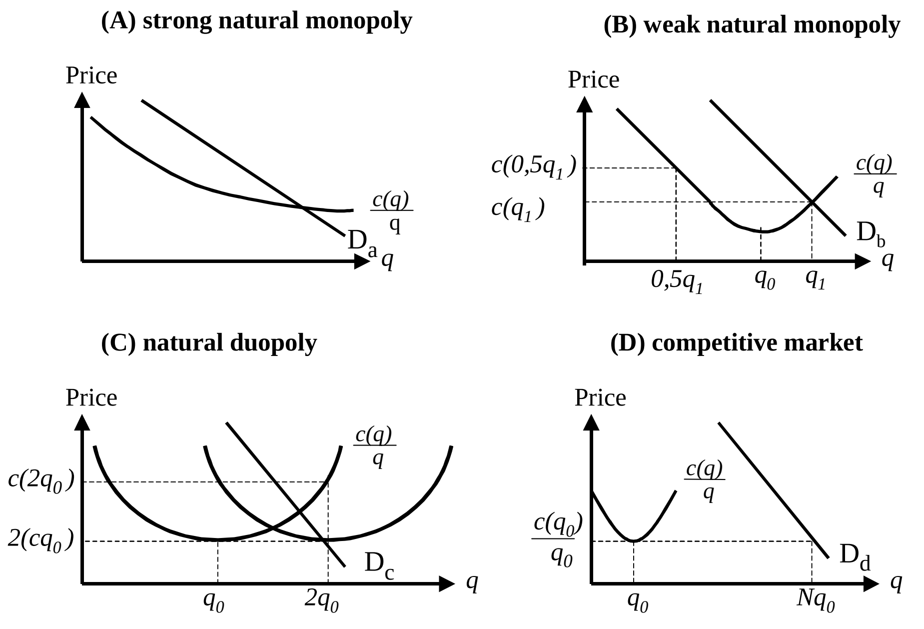

Figure 6.3: Relation of average cost to demand

nopoly, while the other may face some degree of competition. The difference is that demand in the second market is larger than in the first, and large enough so that the economies of scale are exhausted. Figure 6.3 illustrates this in more detail.

Section A shows a situation where average cost decreases over the entire scale of operation to the left of the demand curve, D_a. Let the average cost of producing output q be expressed by the function $c(q)$. Decreasing average costs (AC) can be expressed as:

$$\text{(i)} \quad c(q_i)/q_i > c(q_j)/q_j \quad (\text{where } q_j > q_i)$$

This is the most usual expression for economies of scale and secures that one firm can produce the good at the lowest cost rather than two or more firms. However, this is not a necessary condition for economies of scale to exist.

In section B, the demand curve D_b intersects the average cost curve within the area of diseconomies of scale at $q=q_1>q_0$. Average costs are falling at outputs $q<q_0$, but are increasing for $q>q_0$. Let average cost of producing q_1 be $c(q_1)$. If two firms share the market equally, so that each produces $0.5q_1$, average cost for each will be $c(0.5q_1) > c(q_1)$ (assuming identical cost functions for both firms). An uneven division of the market would give different average costs, but the sum of costs would still be larger than $c(q_1)$ and the firm would operate as a natural monopoly due to economies of scale.

The fact that the firm is a natural monopoly also for outputs $q_0<q<q_1$ is explained by the term *subadditivity.* A cost function is subadditive at q if and only if:

$$(ii) \quad c(\sum_{i=1}^{m} q_i) \leq \sum_{i=1}^{m} c(q_i) \text{ for all quantities of } q_1, q_2, \ldots, q_m \text{ where } \sum_{i=1}^{m} qi = q$$

This condition is necessary and sufficient for costs to be lowest when one firm operate the market. In a more compact form, the condition for subadditivity for output q_1 can be written as:

$$(iii) \quad c(q_1) < c(q) + c(q_1 - q) \text{ for } 0 < q < q_1$$

If q_1 is the largest possible demand in the industry (where the demand curve intersect sthe ATC curve) and inequality (ii) or (iii) holds, then $c(q_1)$ is strictly subadditive and the industry is a natural monopoly. Thus, a cost function can be subadditive even if there are substantial diseconomies of scale at the actual level of output. A firm that has decreasing average costs across the scale is called a *strong* natural monopoly and satisfies function (*i*). If it only satisfies function (ii) or (iii), it is called a *weak* natural monopoly (Berg & Tschirhart, 1988: 24).

If demand compared to cost should be as high as D_c in section C, two companies can produce $2q_0$ at a lower cost than one firm. If one firm should produce all output, it would do so at a higher average cost, as $c(2q_0) > 2*c(q_0)$. The market turns into a natural duopoly (or perhaps oligopoly, if demand is even larger). If demand is really large as compared to the efficient scale of operation, as illustrated by D_d in section D, firms are facing a competitive market. Then, we are back to the situation with a number of firms (N) all producing q_0, as illustrated in figure 1.

Sunk cost is closely related to fixed cost. Sunk cost can be defined as the difference between the ex ante opportunity cost and the value that could be recovered ex post after a commitment to a given project has been made. Thus, the larger part of a project's fixed costs that are sunk cost, the stronger the natural monopoly.

Economies of Scope

Costs can also be saved when one firm is producing more than one product or service. Even though each segment of an industry produces a unique type of output, companies may "bundle" services in order to save cost. When *efficient* bundling of services takes place, within each segment and across the gas chain, it is due to economies of scope. For example, a producer can search for gas, drill and run a gas field. He can also produce oil from the same field. The transmission company can, next to transporting the gas, also function as a broker and wholesaler and offer storage for its customers. Joint production of oil and gas, and transmission services may more efficiently be organized when planned together than independently (served through a market). Similarly, local distribution companies can, besides distributing gas to households and businesses, offer storage, equipment for end-users and advice.

The existence of scope economies indicates that gas companies' bundling services may have competitive advantages over companies operating unbundled. Teece (1990) argues that benefits from joint operation of successive operations may occur if there are:

Informational efficiencies, where one firm may better know the bottle-necks in transportation, producers' opportunities and limitations, customers demand situation etc. than if operations are split to more firms.

Operating efficiencies including pressure controls, rerouting of gas during maintenance work etc. Since gas leaves and enters many stages on the way from producer to end-user, (many of) these operations may better be dealt with under one management rather than many.

Aggregation economies that is achieved if one supplier, better than two, can match demand from different customers. The economic and political costs of failing to supply or purchase are great.

By bringing the decision processes under the management of a single firm or under coordination between firms, greater security and stability of supplies to the market can be provided, when short-term supply disruptions are costly and rapid access to alternative supplies is inhibited or impossible. With one management, or explicit coordination between two or more managements, gas transmission companies may become more credible if they have aggregated customers and suppliers to match changes. By integrating vertically a firm may also avoid opportunistic behavior from parties earlier or later in the gas chain. Centralized managements may handle vertically linked processes more easily than through market transactions. Signing too many contracts may be time-consuming and costly and hamper a firm's ability to produce efficiently. If overall profit is the goal, rather than maximum profit in each segment, one firm may easier give an efficient solution than two or more firms may.

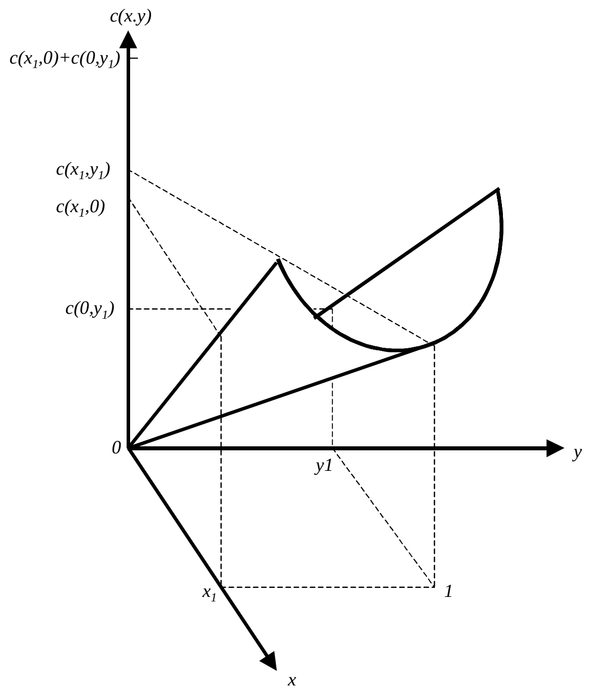

Figure 6.4: Economies of scope

Let's assume that the average unit cost of producing two goods or services, x and y, can be expressed by the function $c(x,y)$. In figure 6.4, $c(x,y)$ is drawn by the U-shaped area showing the cost of production at every combination of x and y. At point 1, quantities x_1 and y_1, are produced at total cost of $c(x_1,y_1)$. If one company produces only x and none of y, the costs for this single product would be $c(x_1,0)$. Similarly, if a company where to produce only y and none of x, it's cost function would be $c(0,y_1)$. The total cost of producing x and y separately would be $c(x_1,0) + c(0,y_1) > c(x_1,y_1)$. Thus, it costs less if x_1 and $y_1$are produced by one company instead of dividing the production between two or more firms. Economies of scope exist if *c(x,y) < c(x,0) + c(0,y)* and minimum costs for combinations of x and y are incurred along the u-shaped curve.

Figure 6.5 illustrates, on the other hand, a situation with *diseconomies of scope*. In this situation, any co-production of x and y will lead to higher costs than if production were separated and executed by independent companies; *c(x,y) > c(x,0) + c(0,y).*

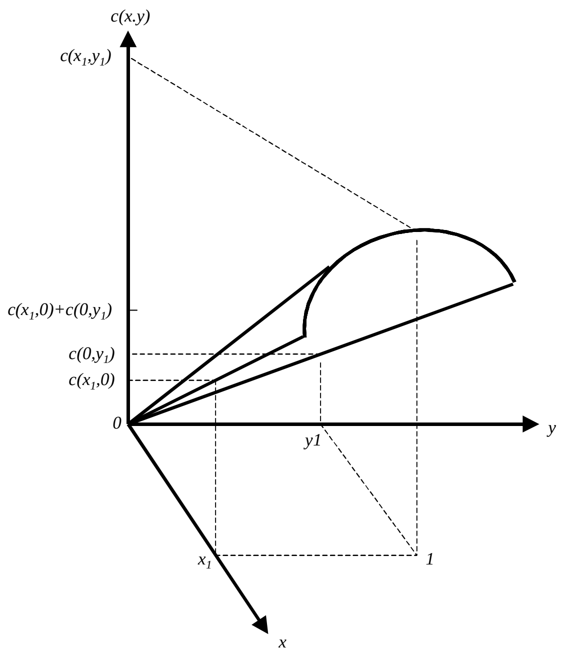

Figure 6.5: Diseconomies of scope

If a natural monopoly bundles services due to scope economics, many combinations of x and y can make it earn an economic profit. A gas producer may i.e. run a normal profit, or even a loss, on a petro-chemical plant, but obtain economic profit in the transmission system they operate. Then, prices are *cross-subsidizing* each other. Equivalently, a transmission company could run a broker- and wholesaler function with normal profits, while the transportation function is run with an economic profit, and vice versa.

Economies or diseconomies of scope may occur with or without economies of scale. Cost may be saved for one firm by producing both services at small volumes, but not at large volumes even if economies of scale are present all the time and vice versa. For the company, the optimal mix of production will also be determined by how economies and diseconomies of scale and scope are distributed compared to demand. This will also determine whether a single plant and/or a firm producing more than one output is a natural monopoly or not.

Limits to Market Power

Private Carriage is transportation where the pipeline buys the gas from the producer for resale to local distribution companies, power plants or large industrial users. This is how the European gas market has been working until now. *Contract Carriage*, on the other hand, is transport of gas owned by others. This is how the market to a larger extent should work in the future.

Being private or contracts carriers, an invoice from the transmission company to shippers (being producers or customers) can incur the cost of transportation, for example as common carriers (see box 2.1), or implicitly as the difference between sales price to customers and the purchase price from producers, as private carriers. With significant economies of scale (and perhaps scope), transmission companies tend to become powerful towards producers as monopsonists, and towards customers as monopolists. As profit maximizers they have the potential of negotiating low prices to the producers/exporters and charge high prices and exploit any possible inelasticity of demand from their customers.

Let the tariff (per unit price of transportation) for a private transmission carrier of natural gas be denoted s_t (see also Chapter 3). The difference between the price it pays for the gas from the producer (p_p) and the price it receives from the distribution company (p_d), is then $s_t = p_d - p_p$, which, disregarding all operational and investment costs and physical losses, equals its profit. A monopsonistic pipeline towards suppliers operating as merchant faces a price function that will increase with quantity (q) purchased from the producer. If the transmission company is the only purchaser, it will bid up the price paid to producers when increasing throughput, expressed as:

$$(iv) \qquad p_p = p_p(q), \text{ where } dp_p(q)/dq = p' > 0$$

On the other hand, being a monopolist towards its customers, the price the transmission company receives from them will decrease with increases in quantity sold:

$$(v) \; p_d = p_d(q), \text{ where } dp_d(q)/dq = d' < 0$$

The pipeline's profit (Π) will be:

$$(vi) \qquad \pi = s_t * q = p_d(q) * q - p_p(q) * q$$

Setting the derivative of (*vi*) with respect to quantity to zero yields:

$$d\,\pi/dq = q * d' + p_d - p_p - q * p' = 0$$

$$(vii) \qquad \Rightarrow \; p_p + q * p' = p_d + q * d'$$

The left side of (*vii*) expresses the marginal cost of buying gas from the producers. The element $q * p'$ tells us how much the price of gas to producers will increase if the pipeline buys an incremental unit. The right side of the equation expresses the marginal revenue of selling one additional unit of gas. The element $q * d'$ tells us how much the price of gas to customers will decrease if it sells one more unit of gas. Not surprisingly, the equation shows that at maximum profit, marginal revenue from selling an additional unit of gas shall equal its marginal cost. The special in this case is that the transmission company, by restricting quantity traded towards producers and distributors, power plants and large industrial users in this optimal manner, can simultaneously exploit inelasticities of demand and supply in order to maximize its own advantage. It is possible, but not likely, that such a situation, that in a stylistic way describes how the present European gas market is working, is socially efficient or maximizing public welfare.

However, several factors determine the transmission companies' market power in addition to scale and scope economies. One such factor is the power of producers and customers, respectively that the transporter meets at its end. By concentrating sellers and customers' power, a counterforce to mitigate pipelines' market power is created. In the European gas market, this has, to some extent, been done at the supply side, which better can be characterized more as oligopolistic than competitive. There are only a few exporting nations, and within each of these nations gas sales have been orchestrated through one body. At the customer's side, however, it is more difficult to concentrate purchasing power. Customers are placed in several consuming countries and there are many LDCs, power plants and industrial users within each of them. Thus, on the customers' side, the European and U.S. gas market is, from an economic point of view, more similar than on the supply side, where in the U.S. there are thousands of producers (see Chapter 9).

It is not only market power which is important for producers. In order to exploit economies of scope, producers have good reasons to integrate wholly or partially with transmission activities. In the Norwegian North Sea, producing firms' in most cases has property rights in offshore pipelines. In Russia and Algeria, it is (so far) done by centralized firm(s) in Moscow and Alger, planning production and transmission to the respective countries' borders. In the Netherlands, Gasunie have bought all gas, transported it to the border and sold it. This product extension contributes in realizing the oligopolistic market structure on the supply side. In the market, the long-term contracts between producers and consuming countries' transmission companies may also be considered as an approach to optimizing the advantages of joint management of transmission and production.

The market power of the transmission companies is also limited if there is an alternative route or method of transportation. Often, the building of another pipeline may incur too high costs to represent any credible threat to the existing one. LNG as an alternative to pipeline transportation, may, in some cases, put a limit on how high pipeline fees can be (intermodal competition). Investment costs for LNG transportation are largely connected with liquefaction of gas (in producing countries) and regasification and storage (in consuming countries). Shipping costs between producing and consuming nations are some 50 % higher than for oil, but represent a much lower share of overall costs in bringing gas from producer to consumers than do gas pipelines. The distance of transportation plays a much smaller role in LNG transportation and there is no technical fixed relationship between producer and customers. "As a result, pipeline transportation costs for onshore distances over 4000 km and offshore distances over 2000 km generally exceed those of LNG where an offshore route of similar length is available" (IEA, 1994: 55). Within the European continent, pipelines often provide the only feasible link to customers. However, gas from he Middle East, Nigeria and the Barents Sea, may prove to be more cost effectively transported to the European market as LNG than through pipelines. The Snøhvit development is for example based on LNG solution, while a development of the Giant Russian Shtokman field can be based on pipeline through the Baltic area, as well. Transporting gas on lorries and trains, is not economically feasible on a larger scale with today's technology.

In end-user markets, competition from other fuels, in particular oil products, but also coal and (nuclear) electricity in district heating, provide a price cap on gas, cf. Chapter 3. To the degree that customers can switch quickly and cheaply between fuels when gas prices change, LDCs monopoly power towards end-users are restricted by this interfuel competition. The prices of alternative energies represent the limit on total market turnover, and on how much rent the various segments of the gas chain can "fight over". Competition from substitute products (in the case of gas: electricity, coal and oil), makes demand more sensitive to price changes and, thus, restrict the degree of market power by sellers, but it usually does not eliminate it.

Taken together, with some modifications, the barriers to entry is significant in pipeline transportation, and transmission companies have great potential of exercising market power both towards producers and customers.

The potential for and benefits of market power, may lead to "over-bundling" of services and over-investment in capacity in order to deter newcomers.[25]

Even without cost-saving advantages in bundling all kind of services, firms may nevertheless profit by doing so due to the benefits of increased market power. For a transmitter, for example, there may be economies of scale in transportation of gas but not necessarily economies of scope in the role as a wholesaler. The broker role may in some cases inhibit elements of economies of scope with the transmission service and in other situations independent firms could do it more efficiently. By having the exclusive rights (natural monopoly) in the transmission function, the pipeline company has the power to prohibit other companies wanting to act as brokers, take over their potential profit and obtain a monopoly in providing merchant services, as well. This will contain the contact between producers and end-users and decrease market efficiency. While the pipeline gains, there may be a net loss for society.

The relationship between dependency and mutual benefit of each other’s activities between producer, pipeline and customer may gain the character of sensitivity and vulnerability for both producer and buyer when large disparities in the market positions arise so market power can be wielded. The vulnerability can be seen as an expression of the parties’ ability to adapt to changes in access to or the tariff, to be paid for transportation in the pipeline, cf. Chapter11. Closing the access or a high tariff may for instance make it unprofitable to produce gas. A producer may become more vulnerable in its dependence on pipelines if there is only one pipeline to the market, than if there are alternative transporters. By being vulnerable, a producer country like Norway may be economically injured and experience a reduced market security by facing a monopsonist in the market. Correspondingly, buyers may have reduced security of supply by facing the transmission company as a monopolist towards the customers. Ex ante a vulnerable dependency on a transmission line make a trade agreement between producer and buyer impossible or unprofitable.

Natural Monopolies in the European Gas Market

The four main supplying countries to the European market (Norway, Russia, Algeria and the Netherlands) compete in selling gas. Often, producers have advantage of large-scale operations. However, even if each gas field

[25] See Broadman (1987) for a discussion of market power in the U.S. natural gas pipeline industry.

may produce most cheaply with one plant, and some of them are very large, there are many independent fields both on- and offshore supplying the European market. In each of the exporting countries, gas sales are done by one body or are orchestrated together (see Chapter 2 and Marbro & Wybrew Bond, 1999). This concentrated sales organization does not represent a by-nature wellhead monopoly across fields due to economies of scale. Producers supplying the European gas market have a greater potential for operating under some degree of competition than the transportation segment. Different fields of production could from a large-scale-benefit point-of-view, compete with each other within and across countries. On the other hand, there may be scope benefits between production, storage and transmission within the exporting countries that gives argument in favor of coordination. The question is whether the scope benefits are so large that bundling services gives the lowest overall costs in providing the services.

The transmission systems, in producing as well as in the consuming countries, inhibit on the other hand, strong elements of a natural monopoly. The purchasing monopsony that transmission networks formed in consuming countries in Europe was created on the basis of by-nature natural monopolies. The position was reinforced through joint negotiations with producers. This by-nature strong position and cartelization towards the producers has been reflected in the fact that the purchasing transmission companies generally attained a monopolistic position towards their customers at the city-gate and towards power plants and large industrial users.

Each of the customers at the end of a transmission line is so small and geographically spread that they usually are unable to construct alternative routes for supply. Power plants and large industrial users are gas consumers themselves. The LDCs are, on the other hand, often natural monopolists in serving local consumers in households and businesses at its exit due to scale economies. In addition, they may have scope benefits in providing equipment for gas use etc. reinforcing their strong position in these end-user markets. Integration between LDCs and pipelines has on the other hand not been a typical feature of the market structure. Probably, this is due to greater dissimilarities between the transmission and retailing business, than between production and transmission. Perhaps, integration between these is restrained by diseconomies of scope, reinforcing the more competitive structure across customers.

Transportation of Gas on the Norwegian Shelf

In line with the development of the Norwegian gas fields, a comprehensive system for transport of gas on and from the Norwegian shelf has been de-

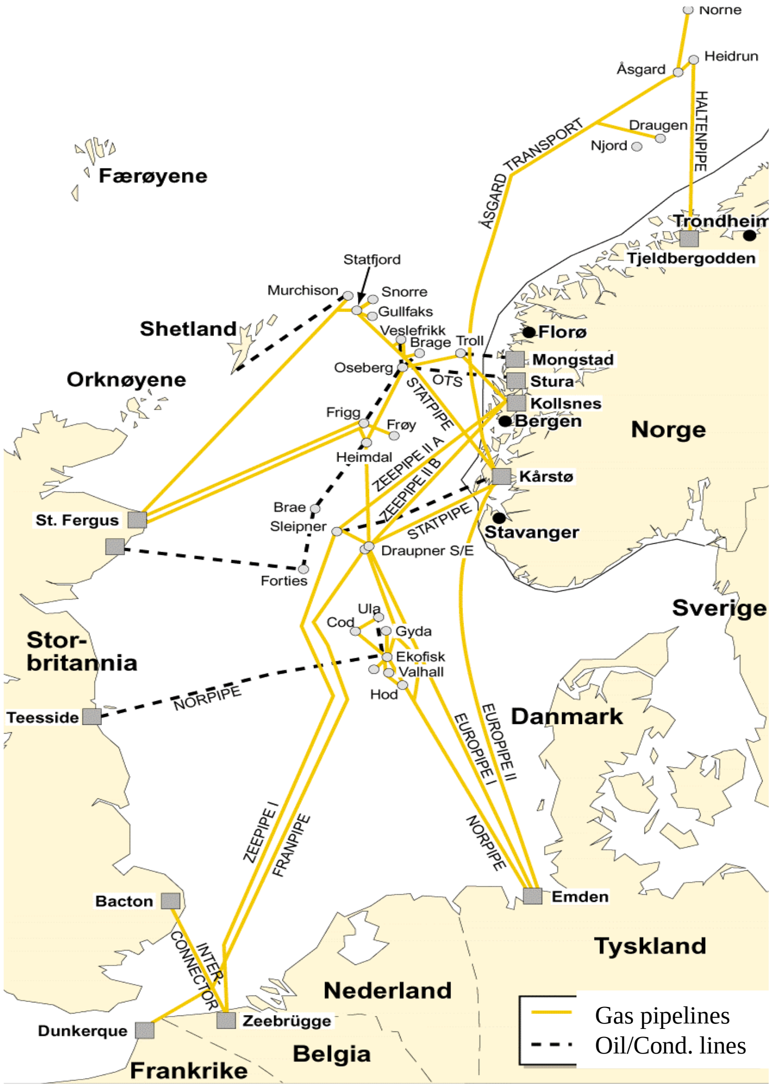

Figure 6.6: Norwegian pipelines in the North Sea
Source: NPD 2002

veloped.[26] When the gas is to be transported from the fields and to a terminal in Norway or abroad, the transportation is organized through separate companies. The first transmission systems were built in the 1970s in order to transport gas respectively from the Frigg area to St. Fergus and from the Ekofisk area (the Norpipe system) to Emden. Throughout the 1980s and the 1990s, a number of new transportation companies have been established as new gas contracts have been signed. Some of most important ones are shown in figure 6.6.

Statpipe was the next large transportation system built, and came on stream in 1985. Statpipe consists of 4 separate parts: transportation from the Statfjord field to Kårstø, the gas treatment plant at Kårstø, transportation from Kårstø to the riser platform Draupner and transportation from Draupner to Emden in Germany. From Ekofisk to Emden the gas runs through the Norpipe system together with the Ekofisk gas or through Europipe I. The Heimdal gas is tied to the system at Draupner. Europipe I (1995) also transports gas from Draupner to Emden, while Europipe II (1999) transports gas to Emden direct from Kårstø. All together there are now three transmission systems for gas from the Norwegian shelf to Germany with a combined capacity of 50 BCM/year: Norpipe (19 BCM/year) and Europipe I (13 BCM/year) and Europipe II (18 BCM/year).

The Zeepipe system, which transports gas to Zeebrügge in Belgium, like Statpipe comprises different parts. Phase 1 (1993) goes from the Sleipner field to Zeebrügge in Belgium and between Sleipner and Draupner with a capacity of 13 BCM/year. Phase II (1996/97) consists of two pipelines from Kollsnes, where the Troll gas is brought on shore, to the Sleipner field and the Draupner platform respectively. This ties Kollsnes to the export system to the continent. Franpipe is the fifth pipeline to the continent and goes from the Draupner platform to Dunkerque in France and was put into operation in 1998 (15 BCM/year). The capacity for delivering gas to the continent through these five pipelines is 78 BCM/year. As contracted supplies as of today is a good 60 BCM/year, there is still excess transport capacity within existing pipelines for further sale of gas. With Interconnector from Bacton to Zeebrügge, which ties Great Britain to the continental market, Norwegian gas can possibly be exported trough the Norwegian and British Frigg pipelines with a total capacity of about 20 BCM through Great Britain to Zeebrügge, as well.

[26] Most "local" systems, which transport gas between different fields within a production area, are counted as a part of the production infrastructure.

In 2000 Statoil took over the operator responsibility from Phillips for the Norpipe pipeline, and the company became operator for all five Norwegian export pipelines to the continent. Statoil also held the operator responsibility for most of the other gas transport companies on the shelf that are organized as separate companies (Haltenpipe, Åsgard transport, Norne gas transportation and Heidrun gas export). The exceptions were the Frigg systems to Great Britain (Total), Oseberg Gas transportation (Norsk Hydro) and Draugen gas export (Norske Shell). With the privatization of Statoil in 2001, Gassco took over this role. The ownership structure in the individual transmission companies is still however, like for the production, dominated by the Norwegian state. For instance, SDFI has shares of 55 percent in Zeepipe, Europipe I and Norne, 60 percent in Europipe II and Franpipe, 46 percent in Åsgard, 51 percent in Oseberg, 65 percent in Heidrun and 58 percent in Draugen. Statoil and Norsk Hydro in addition typically each hold 10-15 percent ownership shares. Norpipe and Statpipe were established before the SDFI arrangement was activated, but there, Statoil has almost corresponding, large ownership shares as SDFI by itself. With the Statoil privatization, SDFI took the majority in both lines.

SDFI, Statoil and Norsk Hydro then owns all together 70-80 percent of the most important transmission systems on and from the Norwegian shelf, just like they do on the production side. The same ownership structures hold for the receiving plants on shore in Norway (Kårstø, Kolsnes, and Tjeldbergodden), and somewhat less in the receiving plants in Emden, Zeebrügge and Dunkerque. In Zeebrügge, Belgian Distrigaz holds 51 percent versus the Zeepipe group with 49 percent and in Dunkerque where Gaz de France holds 35 percent versus Franpipe group with 65 percent.

When the transportation companies on the Norwegian shelf are established as separate companies, this entails that each owner of gas on the Norwegian shelf had to agree with the individual company about conditions for transportation. In most cases, the licensees for the fields are also included as owners in the relevant transport infrastructure, and thus ensure access to transportation for themselves. The question is then how much they must pay the transport company for the service. The tariffs for transport are very different in the individual transport companies (Eik 1983, Austvik 1984) and were not touched by the establishment of Gassco.

Transportation Tariffs as per 2002

In general, Norwegian gas transportation companies base the calculation of their invoices to the users of their systems on a cost-plus principle where expenditures on infrastructure, operational costs, interest payments and profits are important elements:

$$(i)\ R_i = O_i + D_i + I_i + P_i\ .$$

R_i = Total revenue for the transportation company in year i.

O_i = Operational costs in year i.

D_i = Depreciation costs in year i.

I_i = Interest paid in year i.

P_i = Profit in year i.

The tariff as a per unit cost is thus a result of the gross revenue for the

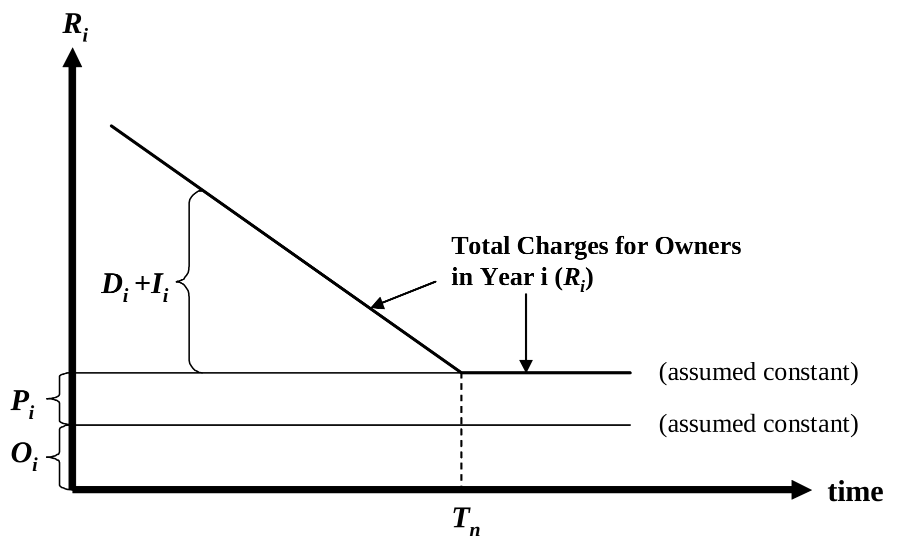

Figure 6.7: Principle for Norpipe Owner Revenues

transportation company divided by quantity transported:

Q_i = Transported quantity in year i.

t_i = Tariff per unit gas transported = R_i/Q_i in year i.

These general principles are however interpreted differently, and most of it is not open information. Only some principles for the Norwegian practice can therefore be discussed here.

One "low-tariff" outcome of handling the different tariff elements is the principle that Norpipe has applied to transportation of gas that is owned by the owners of Norpipe (not 3rd party tariffs). In this, costs for transportation for users will drop in line with depreciation and lower interest payments ($D_i + I_i$). If there are no new investments made in the system, transportation costs will over time include only operating costs and profit to the owners of Norpipe. The profit element is calculated as a percentage of the owners' capital share in the pipeline relative to the total throughput that the owners are responsible for in the pipe. The owners of Norpipe have therefore sometimes been able to transport their own gas very cheaply through the system. In figure 6.7, both the profit and operational elements are, for simplicity, assumed constant. When depreciated at time T_n, only the profit element and operational cost matters for the owner's tariff in this pipeline.

A "high-tariff" outcome has been the Statpipe practice. The Statpipe system is divided into 4 main zones:

- Zone 1: Statfjord – Kårstø (rich gas)
- Zone 2: Kårstø Extraction (separation)
- Zone 3: Kårstø Fractionation
- Zone 4: Kårstø – Ekofisk (dry gas)

A tariff is calculated for each of the zones. In addition to operational costs, Statpipe calculate a capital element to cover depreciation, interest and profit (D + I + P). This element is based on accumulated investments, including capitalized interest payments. 22.7 per cent of this sum gives the annual capital cost element. The basis for the determination of the factor was that depreciation should take place over 15 years and that the investments should yield a profit of 5 percent in real value after taxes. This sum is every year adjusted for 70 per cent of Norwegian consumer price index (CPI). Thus, in a given year Statpipe's total revenue, covering the capital element as well as operational costs, can be written as:

$$(ii)\ R_i = T_i \bullet 0.227 \bullet E + O_i$$

T_i = Accumulated investments, including capitalized interest payments.

E = Escalation factor (70 percent of the increase in the Norwegian CPI).

For a given transported quantity, Statpipe's tariff consequently increases over time (in nominal terms), while Norpipe's tariff drops down to operational costs and a profit margin. Figure 6.8 illustrates for simplicity a situation assuming constant operational costs, no additional investments made and no activated interest payments.

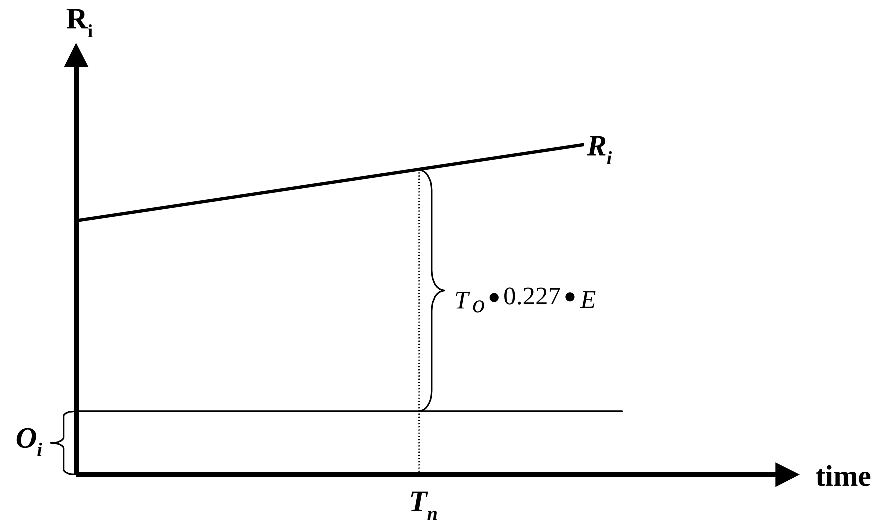

Figure 6.8: Principle of Statpipe Revenues
Assumptions: No additional investments, no activated interest payments, constant inflation in Norway

Under our assumptions, Statpipe's gross revenues will at time T_n be the same as the first year adjusted upwards with 70 % of the Norwegian CPI (in the figure the escalation factor E will be 70 % of the CPI in the period between the first year and year *n*). When additional investments are added and interest payments capitalized, the curve will make (discrete) jumps upwards (a higher gross revenue for Statpipe and a higher tariff). Statpipe then generates a considerable profit for its owners over time. Measured per cubic meter of gas per km the Statpipe tariff becomes many times that of Norpipe's, everything else equal. The other transportation tariff systems have been designed somewhere in-between these two extremes, mostly on Statpipe's principles but at more modest levels.

In most cases, the licensees for the fields were also included as owners in the relevant transport infrastructure, and thus ensured access to transportation for themselves. However, 3rd parties (those who are not owners of the pipeline company in question) have to negotiate a solution. If it concerns "smaller" volumes, i.e. volumes which do not defend the development of a new pipeline, in most cases it leads the pipeline company to exploit its position and demand higher tariffs of these than from its owners. For example, 3rd party tariffs in Norpipe are considerable higher then the owner tariffs. In some cases it will be impossible to develop such "smaller" volumes without a reasonable transportation solution in advance. The transporting company may demand a sum so high from a 3rd party that most of the profit remains with the transporter instead of at the producer. Together with the requirements from EU regulations (such as the "Gas Directive") this inefficient cost structure within gas transportation on the NCS, especially for 3rd parties, gives reason for change.

GasLed

Gassco AS was established in 2001 and is 100% owned by the Norwegian Government, cf. Chapter 2. This new company shall act as an independent operator of gas transport, processing and receiving facilities for all producers of gas. Gassco shall contribute to an efficient use of resources on the Norwegian Continental Shelf, and be neutral in relation to users of the transport system. However, transportation tariffs were not changed, and Gassco in and by itself does therefore not change the economics of Norwegian gas transportation much.

The further changes under consideration include, inter alia, the rebirth of the GasLed idea from the mid-1990s. In that project, the ownership interests of several of the Norwegian transmission companies were to be combined to take care of dry gas transportation from the Norwegian shelf to the Continent (Statpipe, Zeepipe, NorFra/Franpipe and Europipe II). The companies were valued relative to each other and an application for consent to establish was sent to the Norwegian authorities in the fall of 1995, but was turned down. Today, a GasLed (II) system should harmonize and possibly lower transportation tariffs along the same ideas as GasLed I.

The tariff principle was presented with the following formula (MPE September 2002):

$$\text{(iii)}\quad t = \left(K + \frac{I}{Q} + U \right) \bullet E + \frac{O}{Q}$$

Where:

t = tariff per unit for the right to use the inlet, outlet or processing

K = fixed part of the capital element per unit

Q = estimated aggregate reserved capacity in the year in question

I = annual element calculated for investments to maintain the system

U = element calculated for investments linked with extensions of the system

E = escalation factor.

O = anticipated operating costs

- The K-element varies across areas. For gas through the Kårstø terminal the following tariffs are proposed in 2002 NOK:
  - Area A (Statfjord B-Kårstø): K = 5.5 øre/Sm^3. For Brage and other "old" fields: K = 18.0 øre/Sm^3.
  - Area B (Åsgard B – Kårstø): K = 3.5 øre/Sm^3.
  - Area C (Kårstø Terminal): K = 10.0 øre/Sm^3 (extraction) + fractionating, storage, shipping.
  - Area D (Dry Gas Inlets - Continent/UK): Inlet: K = 2 øre/Sm^3. Outlet (- exemptions): K= 12.5 øre/Sm^3 (->2006), 8.5 øre/Sm^3 (2007-2010), 6.0 øre/Sm^3 (2011->)
- The operator (Gassco) shall estimate the Q-element at the beginning of the year.
- The I- and U-elements shall both be determined by the MPE and "be included in the tariffs for the area which necessitates the investment".
  - The I-element "shall be calculated as an annuity within the remaining term of the license so that a "reasonable" return on the investment can be expected.
  - The U-element shall also be calculated as an annuity so that a "reasonable" return on the investment can be expected. How much this will affect the U-element in the tariff to individual users depend on whether or not they triggered the expansion of the system. There is cap on 0.6-0.7 øre/Sm^3 for established users that did not trigger the U investment. "If this U is not sufficient to give the above-mentioned return on the investments in expanding capacity, the Ministry shall determine an [additional

tariff] for the users for whom the expansion was necessary". Thus, the distribution of the total expenditures on I and U on various shippers may be different depending on whether or not they trigger the relevant expansion.

- The MPE can alter the rate of return constrain, cf. the "A-J effect" in Chapter 9, in accordance with the Petroleum Regulations.
- The escalation factor E is set equal to the change in Norwegian CPI.
- The formula is presented as a per unit tariff and will in nominal terms change primarily with the escalation factor. The I-, U- and O-elements will however also change with how much capacity is reserved. The U-element will/may in addition vary with the participation in an expansion of the system. There is not a cap on the tariff on these elements in case load factors decrease.

In figure 6.9 the (nominal) development of the GasLed tariff is shown in principle for areas A, B and C. For simplicity we have assumed constant operational costs, volumes booked and inflation and no investments made in maintenance or expansion of the system.

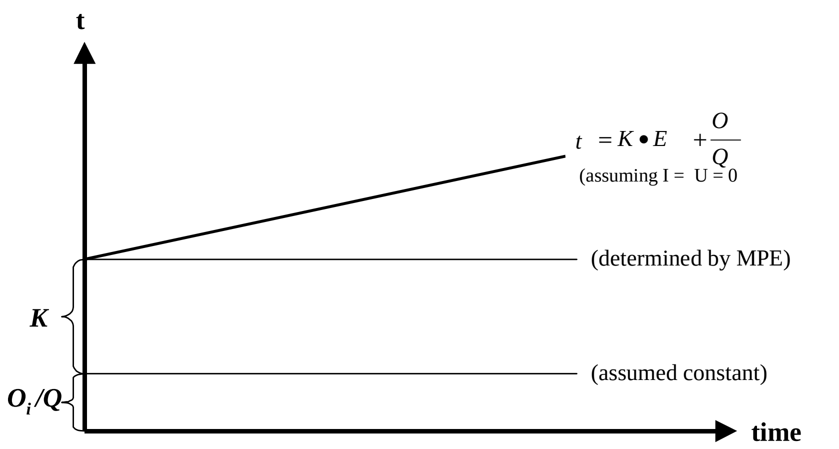

Figure 6.9: Principle of GasLed Tariff Areas A, B, C
Assumptions: Constant operational costs, volumes booked and inflation.
No investments made in maintenance or expansion of the system

If investments are made in maintaining the system (I>0) within one of the areas, the tariff will increase for all although probably not significantly. If investments in expanding the system are made (U>0), the tariff for all within this area will increase, but there is a cap (0.6-0.7 øre/Sm^3) on how much it can increase. The users in need of the expansion will carry the remaining part of the tariff increase. When I- or U-costs are added to initial costs (represented by the K-element), the curve will make (discrete) jumps upwards (a higher tariff).

Statpipe set the K-element implicitly related to a percentage of investment costs (22.7%). Investment costs in Statpipe means accumulated investments and activation of interest payments. In areas A, B and C the K-element is not assumed to change over time, and new investments are not accumulated in the same way as in the Statpipe formula. Nevertheless, the principle for the GasLed tariff for area A, B and C reminds much more of the Statpipe principles than the depreciated Norpipe owner's tariff.

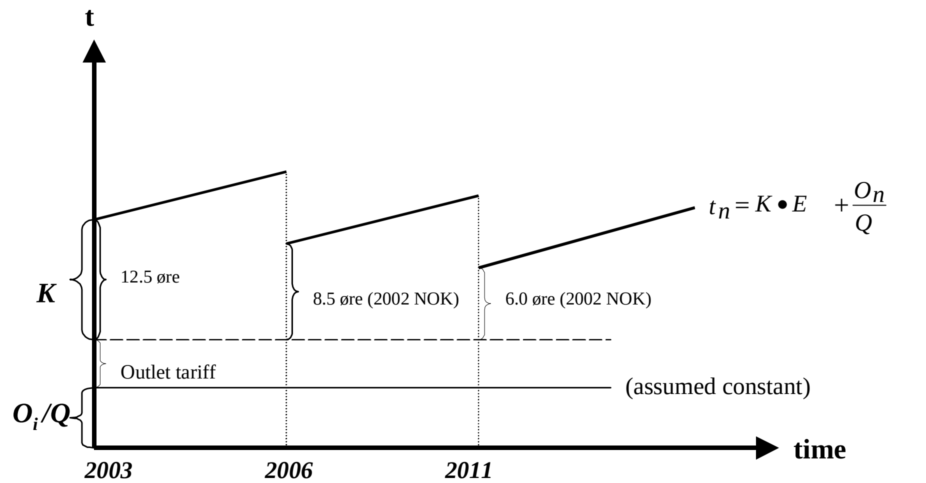

Figure 6.10: Principle of GasLed Tariff Area D

Assumptions: Constant operational costs, volumes booked and inflation.
No investments made in maintenance or expansion of the system

At the same time, the escalation factor E is 1:1 compared to the Norwegian CPI in the GasLed system as opposed to 0.7:1 in the Statpipe system. GasLed Tariff should then, everything else equal, increase more rapidly than do Statpipe tariffs.

In figure 6.10, the (nominal) development of the GasLed tariff is shown in principle for area D. Again, we have assumed constant operational costs, volumes booked and inflation and no investments made in maintenance or expansion of the system. The difference from the tariffs for areas A, B and C is that the K-element is adjusted down in 2006 and 2010. Thus, area D tariffs have elements that remind of the Norpipe owner's tariff. In nominal terms the tariff for area D may over time fall or rise (or remain stable as a special outcome) depending on the Norwegian rate of inflation.

The general picture is that tariffs in the rich gas systems (areas A, B and C) probably will be maintained. In the dry gas systems (Area D), tariffs may in periods be lower.

7 Regulatory Challenges

Maximizing Social Welfare

The problem for policy makers wanting to liberalize natural gas markets is that it's concentrated structure may also be the socially most efficient one. Because of scale economies, more firms operating in the market may incur higher transportation costs unless the market grows sufficiently in each geographic segment. This argument goes for product extension through vertical (or horizontal) integration and the exploitation of economies of scope, as well. Thus, the challenge for governments is to intervene in a way that preserve a market structure that have the potential to minimize cost, and at the same time change its behavior in order to avoid possible lax cost control and exploitation of market power.

One important question is how large the benefits of vertical integration and coordination are. The existence of scope advantages indicates that liberalization of the market should open for the possibility to bundle services in competition with provision of unbundled services. The smaller the market and fewer the number of players, the less cost arguments seem to be in favor of unbundling operations. If operations are unbundled and there exist economies of scope, the gain from increased competition should be weighed against the losses of less efficient operations of each firm. Thus, with the growth in the European market, gradually more arguments support the idea of unbundling.

The significant scale economy in trunk pipelines, sunk investments and capital immobility, possible economies of scope in vertical integration and companies' bundling of services influences vertical and horizontal ownership relations and contractual terms in the European gas market. In specific segments of the markets, these relationships may promote efficient investments and pricing without public interference, but the strong concentration of market power indicates that this is rather the exception than the rule. Possibly high and rigid prices paid for transportation may lead to underinvestment in production, as an overly large part of the market price ultimately paid for natural gas is accrued in the transportation sector rather than by producers. Similarly, high or rigid prices to distribution companies may lead them to exploit their strong position towards consumers (over time restrained by the price of the alternatives to gas), making consumption of natural gas sub-optimal. Gas is fairly non-polluting and, thus, inhibits a positive externality for the environment relative to the use of other fossil fuels. The view from the EU (See Chapter 2) is that a too rigid market structure may be harmful for the economies involved both from an environmental, efficiency and security-of-supply point of view.

The transmission systems are integrated parts of the gas market that should balance in competing demand for transportation services, optimal resource management and risk evaluations. From a social point of view, it is important that the economies of scale and scope is exploited, but at the same time that market inequities caused by extensive pipeline concentration and excessive bundling by transmission companies are neutralized. An optimal gas grid should enhance security of supply for consumers as well as security of demand for producers. The system should secure flexibility both in a static and dynamic sense. Statically, by creating a variety of arrangements suiting each actor. Dynamically, by permitting arrangements to evolve gradually based upon market trends rather than through radical change every few years. These goals are sometimes complementary and sometimes conflicting. Ideally, the grid should barely figure into the producers' production decisions and the consumers' choice of energies.

A regulatory regime that aims at optimizing the transporters' behavior should look for arrangements that do not primarily place this judgement upon public policy makers. If one could find self-regulative arrangements, the chances that the system contains the necessary dynamics when market conditions alter are better. This is also important in order to impose minimal administrative costs. Even if a possible regulation may yield a socially efficient outcome, the costs of the enforcement process need to be subtracted from the benefits achieved by regulation, and compared to the costs of operating the existing system, in order to appraise the net social benefits. In the U.S., conditions under which gas could be produced and transported have repeatedly led to undesired results. After some time, some of the regulations was removed and new regulations introduced, but only after having incurred considerable judicial and regulatory costs, loss of efficiency and social welfare (See Chapter 9).

An additional argument in favor of self-regulative arrangements is that the regulator over time need not necessarily seek to maximize social wealth only. A regulatory agency may begin its existence with public interest in mind, but end up as an agency to protect producers and/or pipeline companies. The persons employed in the regulatory agency may be influenced by his or hers career opportunities, political motives, self-assertion, power, etc. The regulated companies can gain control over the regulator and trap or capture the regulator to act in their interest and influence the goals that the regulator sets and the way he/she seeks to attain them. Such "capturing" can be encouraged by the movement of personnel between regulatory agencies and the firms, which may increase the desire for cooperation and making close ties between them.

Regulatory policy that involves transfer of huge sums from a large group to a small group is often lobbied for more easily by members of the small group. The small group has a lot at stake per capita, and easier to organize than a large group. Therefore, small groups are usually more successful in satisfying their demands towards public policy makers than large and often more diffuse groups. With huge interests at stake, producers, consumers, pipelines and distribution networks have good reasons to vociferously pursue their interests. Some countries and companies may be better off by exploiting a possible monopoly power in the market, even if it is not a zero-sum game in total. Usually consumers are associated with large groups and companies with small groups. Stiegler (1971) argues that public regulation therefore often leads to producer-protectionist results. Each party may also be too small to influence the situation and therefore does not consider the optimal situation even if they would be better off if it prevailed, and may stick to an existing sub-optimal situation.

Maximizing social welfare may, therefore, be an intriguing challenge. How to avoid inefficient bundling in the natural gas industry and keep, or even create, efficient bundling and exploitation of economies of scale and scope? How to prevent firms from taking unacceptable advantage of a possible strong positions in segments of the market? The correct answers to these questions will easily be viewed differently by competing parties, and these groups may pressure regulators. In order to design an efficient and welfare-maximizing way of regulating the market one needs a closer identification of the actual goal of the regulation.

Microeconomic theory is often used for this purpose, i.e. that the ideal situation exists in the market when price equals marginal cost (corrected for externalities). In perfectly competitive markets, there should be no need for public intervention (the *first best* solution). If one market failure arises, such as the existence of a cartel or of pollution, marginal social cost no longer equal marginal social benefit. In order to correct for this market failure, government should intervene to restore the first-best situation, where social benefits equal social costs. A first-best economy operates under conditions of social efficiency (Pareto optimality) and the policies introduced correct the market distortions that occur.

Box 7.1: Social costs and benefits

Private cost to an individual person or a firm is measured at market prices. In many cases, private cost approximate the opportunity costs (the value of a foregone action) of employing inputs to an activity or production process. Private efficiency is attained when marginal benefits equals marginal costs.

Social cost reflects all costs incurred by a society in producing a good or a service, or the opportunity costs to the society of the resources which it uses. Thus, social costs equal private cost plus externalities of production (costs borne by people or firms other than the producer).

Social benefit equals private benefit plus externalities in consumption (benefits from production (or consumption) experienced by people or firms other than the producer (or the consumer))..

In most cases there is a divergence between private and social costs and benefits of a (production) activity.

However, in the real world, this is rarely possible. In a *second-best* economy, compromises between theoretical first-best solutions and the real market are adopted. The application of a second-best policy means to minimize the distortionary effects of the market. Policy measures, other than nationalization, generally aims at second-best solutions. In fact, one could argue that nationalization also is a second-best solution (at best), as it over time often does not satisfy social efficiency goals even if it's intended to do so.

Of course, effective public intervention needs to consider political, psychological, cultural, practical and other issues, in addition to the knowledge of economics. Seeking to practice a pure economic model within the real world, i.e. in constructing tariffs for gas transportation, may lead to other results than what should be expected. Economics may first of all give insight into the processes around and the purpose of regulation, describing important forces operating towards optimality. By understanding these forces, the regulator can use this insight together with other aspects to be taken into consideration, to improve welfare and market efficiency and move towards optimality, although not necessarily reaching it.

Laissez-faire, Nationalization or Regulation?

To illustrate the situation we will start with a strong simplification of the position of a transmission company. Figure 7.1 considers a strong natural monopoly, due to economies of scale, with low (and constant) marginal costs compared to fixed costs. The position and shape of the demand curve (assumed linear and falling) determines which output-price combinations that are possible in this market. We will discuss three possible outcomes. In point A, the firm acts as a monopolist choosing a high price/low output combination. In point B, the firm acts as a 'cost-plus' company where price is set equal to average cost. In point C, the firm produces an output so large that price must equal marginal cost in order to make consumers absorb the entire output.

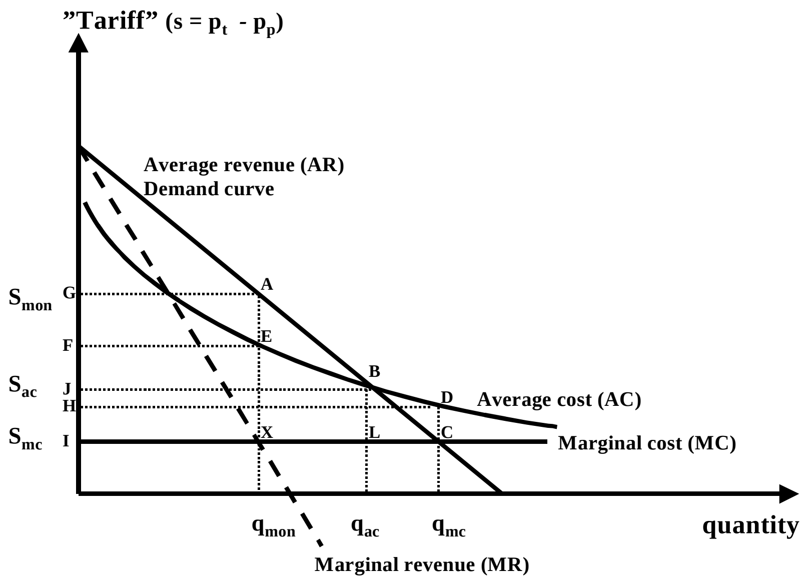

Figure 7.1: Decreasing average costs in a natural gas pipeline

Point A: A monopolist would choose to produce where marginal revenue equals marginal cost, which happens at point X. The production (or the amount of transported gas) will be q_{mon}. For this quantity, consumers are willing to pay the price, or tariff, denoted earlier as the share to transmission company, s_{mon}. The company's economic profit will be GAEF, which results from the difference between market price and average costs at output q_{mon}. If the company increase production beyond this point, marginal cost would be higher than marginal revenue and it would loose money on the margin.

Point C: If output increases beyond q_{mon}, this would be more optimal from a social point of view. The willingness to pay is larger than the marginal cost all the way up to point C. Thus, point C is considered to be the socially most efficient way of production. The problem is that the price for transmission at point C, $s_{t\text{-}mc}$ is below average cost and the company looses money unless someone is willing to pay the deficit. The loss is represented by area HDCI, which is the difference between the market price and average costs times output q_{mc}. The net advantage for society in moving production and prices from point A to point C is represented by area ACX.

Point B: If the company should break even, price must equal average cost. At point B an output of q_{ac} is produced at price s_{ac}, and the company earns normal profit but no economic profit. This point is also more optimal for society than the monopoly solution in point A. The gain for consumers (GABJ) is obviously larger than the loss for the producers (GAEF). Society's net gain equals area ABLX, while the deadweight loss is BCL compared to the first-best solution in C. Point B is a second-best-solution from a social point of view as compared to point C.

Historically, *nationalization* (point C) has been widely applied in Europe after Word War II. Under nationalization, the government replaces the market by providing the service or good itself. When nationalized, the governmental owned company, usually, sets price equal to marginal cost. As long as average costs often exceed marginal cost for natural monopolies, public budgets must transfer funds to the firm to cover the deficit (HDCI). However, marginal cost pricing is a necessary, but not sufficient, criterion for maximizing social welfare, as it ignores the question of the 'best' or 'fairest' distribution of income. It may be possible to reach a higher level of welfare with an 'inefficient' way of production than with an efficient one. This could happen if the income distribution is 'sufficiently wrong' or if it is difficult to reach the most efficient way of producing. Then, it could be better to look for second-best solutions for how the goods or service should be provided.

Regulation (point B) is such a second-best solution and has been the American way of intervening into such markets. Public regulation may be made through force, or by incentives, inducing the firm to act in its self-interest, which at the same time is compatible with social goals. Under regulation, the goal is to make the firm decrease price/tariff, increase output and to produce this output efficiently at minimum cost. The firm must earn normal profits on its investments in order to remain in business, but no economic profit. However, this simple goal is not that simple to reach.

There are many techniques for such regulations (Chapter 8). Each of them is at best second-best solution from a social point of view, but they are usually better than leaving the firm unregulated, or nationalized. As long as regulators shall 'repair' misallocation of resources caused by imperfect markets, the system of regulated (private) enterprises may easily end up with outcomes that are either overdetermined or have too many degrees of freedom to yield the desired results. We will discuss regulation as a second-best approach below.

Often *laws* about market structure and firms behavior are parts of a liberalization of a market. Laws may prohibit or regulate the behavior of firms that are imposing external costs. For example, a firm can be banned or restricted from performing polluting activities. In the case of monopolies and oligopolies, laws can be used to change the structure of the industry or the behavior of the firms within it. When affecting market structure, laws can make mergers (horizontal integration) illegal. Even though there may be a large number of firms in the market, one or a few may control the major part of it and, thus, behave as monopolist/oligopolists. Thus, market concentration can be measured in terms of how many firms control a certain market share. The government could make a merger illegal if the degree of concentration rises above a certain amount. If firms already control more than this percentage, they could be split into smaller firms. Whether this is efficient or not, depend on cost structure of the activity compared to size of market and the behavior of the firm. Competition laws in the EU, therefore, studies the actual performance of the firms rather than market share to assess whether or not, for example, a merger should be considered illegal.

Taxes and subsidies are often favored by economists to repair for market imperfections. These are used both to improve social efficiency and to redistribute income. To improve efficiency, taxes can be used to reduce the social costs of (negative) externalities, monopoly power, imperfect knowledge and irrational behavior. In some simplistic cases, taxes can be used to achieve first-best solutions. However, because it usually is infeasible to use different tax and subsidy rates towards different firms, and because the government lack detailed knowledge about markets, taxes and subsidies seldom achieves more than second-best solutions.

Regulation as a "Second-best" Approach

The varying degree of large scale and scope advantages in various segments of the European gas market makes it difficult to find an optimal liberalization portfolio of competition, regulation and unbundling . If one first selects a given portfolio of measures, it is furthermore technically difficult to find regulating mechanisms that do not create new weaknesses in the market. We will mention some of them here:

a) The first question will be what a reasonable tariff really is. After the discussion above, it can be defined as one that covers the average costs in the systems (point B in figure 7.1). The only profit then included is normal profit, or the alternative cost of running the operation and which is calculated into the cost curves together with the other costs. A normal profit is the profit investors would have had if they had invested in something else, corrected for risk.

It is, however, hard to determine the average costs in such a natural monopoly because it will drop with increasing degree of utilization, due to large capital costs and relatively low variable costs. A pipeline, which uses half its capacity, will for instance have considerably higher average tariffs than a pipeline with full use of capacity. There is also a question about how costs are to be distributed between users. The simplest way is to demand the same rate from all gas owners. But, one might also imagine discrimination between customers with high and low elasticity of demand (conditional on season and/or industry), so that the total revenue for the pipeline company on the average corresponds to the costs of the system (so-called ″Ramsey″ or ″peak-load″ price determination, see Chapter 8).

b) Another question is how to distribute a possible excess demand beyond pipeline capacity. Who will then get gas transportation and who will be pushed out, when demand is so great that the existing pipeline network cannot cover it? A pro rate system distributes remaining capacity in proportion to contracted quantity. Existing customers' volume is reduced in order to make space for new customers. The disadvantage of this system is among other that the volumes are not then distributed according to economic criteria of efficiency. It may further lead to a speculative determination of contracted volumes.

Another way is to prioritize the customers. Under such an arrangement, high priority customers may be schools, hospitals and small companies, while large industrial users and electric power plants have lower priority. A third way is differentiated contracting of the service. By paying a somewhat higher tariff, the customer may buy a fixed service instead of an interruptible one at a lower tariff, i.e. interruptible services are replaced by gas with fixed service contracts. The amount of fixed allotment contracts may then not exceed pipeline capacity.

Independent of how the distribution of excess demand is chosen, it must also be determined who will decide how large the actual capacity is. If it resides with the pipeline company, it may downgrade capacity in order to exploit demand inelasticity and again exercise monopoly power against the shippers.

c) A third question is how to price new transport capacity. The question about building new capacity comes up when there is excess demand relative to capacity. We have already discussed some ways in which to distribute such an excess demand. At some point demand will however be great "enough" for extending capacity by the criterion chosen. If the pipeline company on average is to maintain a tariff covering the costs in existing network, such an average price will normally not cover the costs of building a new pipeline. A new pipeline implies an investment with newer and more expensive capital relative to the existing pipeline. The average cost for the new pipeline will exceed the old one.

One way to solve this problem is to include, or "roll-in", the costs of the new pipeline in the tariffs for all transport. A new average cost, which covers both the old and the new pipeline, will then be established. The price that is paid by such an arrangement will not reflect the actual costs in every pipeline. Some costs will exceed and some will be below the average tariff. Another way is to evaluate every pipeline project independently. In this case the new pipeline will operate with higher costs than the old one, and the users of the new pipeline will have to pay a higher tariff than the users of the existing one. Even if the latter system in principle meets the demand for economic efficiency more satisfactorily (a new pipeline will not be built before the customers are willing to pay for its full costs), the prior system gives the pipeline companies reason to expand capacity faster.

d) A fourth question is how large the capacity actually should be. A new, large gas contract may justify a new pipeline project by itself. A marginal contract will not be able to do so. On the other hand, many marginal contracts combined will be able to. Corrected for uncertainty, a new pipeline project should give a positive present value at a suitable discount rate. With society often having low discount rates relative to the private sector, a project may be profitable to realize for society while it is not profitable for the private sector. If a new pipeline is subsidized, the quantity requirements are lowered and the construction is correspondingly pushed earlier in time. This may be right from a social view and is also an argument for some degree of public involvement in the sector (cf. the discussion of the Canadian gas market later). A system where the pipeline companies may roll-in the costs of a new pipeline in the existing pipeline system might on the other hand lead to over-investment in transmission systems.

e) A fifth aspect is how good or bad the alternatives to regulation is. In parts of the market, there may already be enough competition for the market to operate so well that the costs of a regulatory regime will be higher than its benefits. Perhaps, competition and unbundling could be a better alternative on certain distances. In particular, alternative pipelines with new owners within geographic areas of strategic importance might be better if regulation and the resistance against them turn out to be too costly. Competition has the advantage that one does not have to have the same degree of control and follow-up of the myriad of details which is necessary under a regulated system.

Competitive encouragement as a means to increase efficiency will only be useful if demand for transportation is large. It will be the position of the demand curve relative to cost curves that determines whether economics of scale affects the market structure in a way that this is possible or not. If the demand relative to a company's cost curves are like illustrated by curve E_1 in figure 7.2, the company will not be able to exploit its economics of scale fully, corresponding to the demand curve in figure 7.1. If it for instance were to produce at cost minimum (X_A), demand would not absorb production unless the price is lower than the company's average costs, which would lead to the company operating at a loss. In this market situation, the company consequentially becomes a (strong) natural monopoly.

If the demand curve relative to the company's cost curves are positioned as illustrated by E_2, the company will be able to produce more optimally, and there may be room for another company with the same production technology. The market would in such a situation operate under an oligopoly (as the figure is drawn, it might become a duopoly). If the demand curve is as far to the right in the diagram as illustrated by E_3, however, it is possible that the company operates in close to free competition, with room for many companies. In this situation, in the long-term all companies will (theoretically) produce at cost minimum. The larger the market, usually the fewer companies may operate with strong market power. One point of international trade in general is that by making larger markets it increases competition between companies and contributes to companies exploiting their economics of scale. A company, which may be a natural monopoly in an autarchic national market (E1), will in international competition be a part of an oligopoly (E_2) or in free competition with the companies of other countries (E_3).[27]

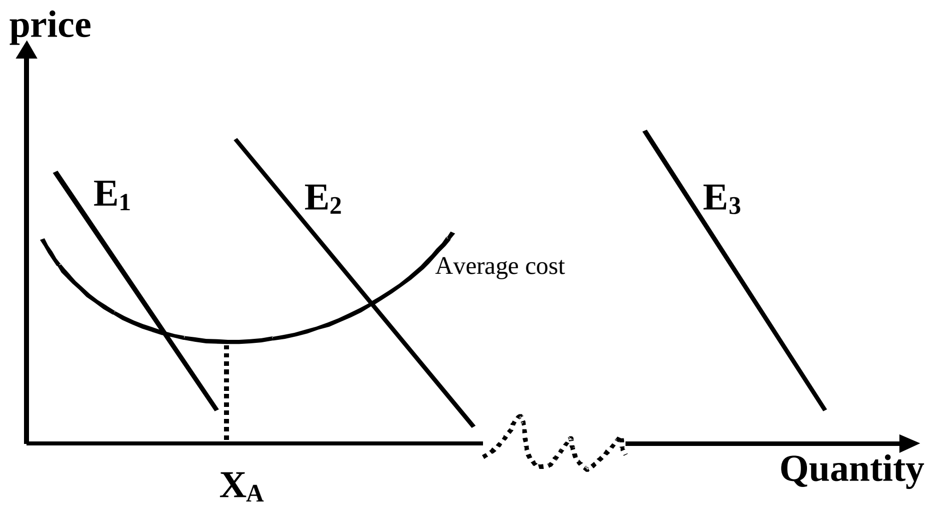

Figure 7.2: Economies of scale, market size and competition

f) In market theory, the property rights of an industry is often considered as given. On this basis the forces that determine price and quantity are discussed. But a pipeline company acts as a monopsonist (as gas buyer) and monopolist (as gas seller) because its owners are intent on maximizing the profits of the pipeline company. By changing the property rights to owners that have other goals than maximizing profits of the pipeline company different results can be attained. If the owner has social efficiency as a goal, profit maximization may not be the best. Alternative property rights structures may be government ownership, or that distributors and/or producers owns the transmission companies with a share which is so small that they do not want their profit to accumulate in the transmission sector.

27 Hogan (1987) discusses the demarcation between competition and regulation of the natural gas industry more closely.

g) A seventh aspect is that market conditions change over time. A politically controlled liberalization process must contain a dynamics in order to change optimally over time (Stern, 1998). Strong economic interests in companies that are included in the process further works to mobilize strong resistance against changes that affect their profits (see later in this Chapter). The development in the American gas market is an example of this (Chapter 9).

h) European gas trade is international, where there may be conflicts of interest between EU countries, but particularly between EU countries and the exporting countries on the outside about the distribution of economic rent in the market. Among the conditions that may influence rent distribution, there are changes of market rules (such as the Gas Directive) and energy tax policies (see Chapter 2 and 4). The fact that the European gas market is international, even if the EU were to develop into some sort of a federal state, means that it may be expected to remain even more politicized than the international oil market.

Conflict and Cooperation in European Gas Regulations

The argument behind various forms for public intervention in the operation of private natural monopoly transport utilities is that if they are allowed to behave as profit maximizers, without constraints, consumers and overall economic efficiency will suffer. By intervening into their functioning, governments wish to repair for market failures created by dominating enterprises. Inefficient operation and possible opportunistic behavior among monopolistic firms, together with externalities in the use of gas as an important source of energy, the environment, concerns over economic activity, rent distribution, reduced dependency on Middle East oil and lack of information throughout the gas chain, have justified government intervention. We shall discuss some possible the regulatory schedules in Chapter 8.

Many EU member countries have now established regulatory procedures and authorities for their gas industries. In a few years we may even face a regulatory body on the European level.[28] In this process, questions to be discussed here are: Will gas transporters be better off by going into conflict with the regulator and try to halt or stop the process? Or is it better to

[28] In the efforts in creating a liberalized European gas market, and improvements of the so-called "Gas directive" (EU 1998), the EU Commission state that "All the respondents on this issue pleaded for strongly independent regulatory authorities, with some arguing for a European regulatory body" (EU 2001a).

cooperate and try to "trap" the relevant authority in order to make him/her do the regulations in a way they want?

Conflict with the Regulator

Generally, transmission companies and LDCs will receive lower margins when regulated as compared to an unregulated situation. The drop in profit will be distributed to producers, customers, and final consumers or to producing or consuming countries' treasuries through taxation depending on *how* the system is liberalized. Even though transmission companies' and LDCs' margins are rather stable both under the "old" system and in a liberalized one, their economic profit will be lost or, at least, reduced. In a partially liberalized market, competition between transporters may be established, at least on some distances, which could make more variations in throughput. In a liberalized market system, transporters may face lower margins and/or increased volatility and risk regarding volume. Thus, they have every reason to oppose almost any type of liberalization.

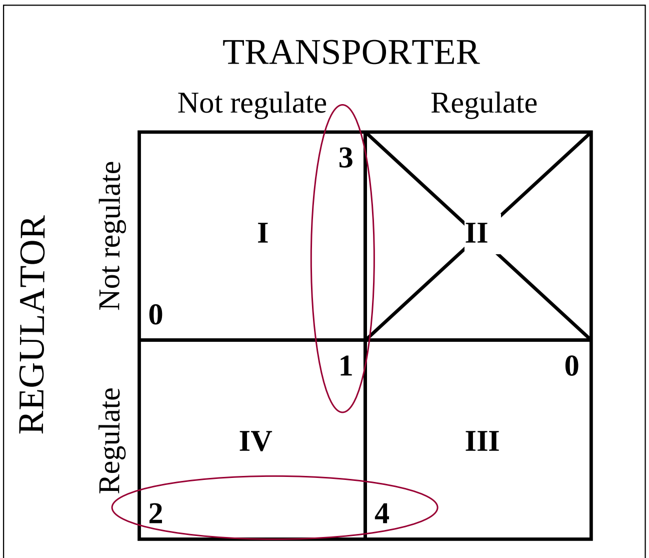

Figure 7.3: Regulation through force

Let's first consider the interest of the regulator (for example represented by the EU Commission) in a liberalization process simplified to a desire to unconditionally take away the transporters' economic profit and give it to consumers. The interest of the transporter is assumed unconditionally to maintain as much profit as possible. Thus, the interests of the regulator and the consumers are assumed identical but conflicting. Under the assumption set up, the game is not zero-sum for society, as regulation is assumed to yield a greater surplus for consumers than the loss incurred on transporters. This binary situation (the choice between regulation and no regulation) is illustrated in figure 7.3.

Both the regulator and the (potentially) regulated can chose between favoring a process that introduce regulation and a process where no regulation takes place. The outcome for the transporter is depicted in the upper right corner in each cell, and the outcome for the regulator is depicted in the lower left. Best possible outcome for each party is value 3 and worst possible outcome value 0 (zero). All utility is considered ordinal, which means that each party may rank the outcomes, but do not know how much better or worse it is compared to another outcome.[29]

If the regulator does not regulate, consumers get no extra surplus, which represents their and the regulator's worst possible outcome, equal to the value 0 (zero). At the same time, no regulatory initiative is the best possible outcome for the transporter, achieving maximum profit, with the value of 3, as depicted in cell I. On the other extreme, if the market should be perfectly liberalized, and the transporter fully accepts the regulator's terms for operations on a normal profit basis, consumers' surplus is maximized. This outcome would be the worst possible for transporters, value 0 (zero), but the best possible for the regulator, value 3. The outcome when both parties favor regulation is depicted in cell III.

If the transporter opposes regulation and the regulator nevertheless choses to regulate, the outcome for the regulator (and consumers) must be assumed to be less than if the transporters just accept new terms for operation. Now, transporters fight against intervention, making as much difficulties as possible for the regulator, and tries to postpone and destroy regulator's initiatives. In spite of this resistance, the regulatory efforts can be expected to yield a better outcome for consumers than no regulation at all, but less than if the transporter adheres. This outcome for the regulator is depicted with the value 2 in cell IV. At the same time, transporters will gain compared to a strategy just following regulator's desires, but less than if no regulation was introduced, depicted with the value 1. Cell II represents a situation where transporters want to be regulated and the regulator doesn't and are, under our assumptions, considered an impossible combination of strategies.

[29] Under cardinal utility, utility can be measured and it is possible to say how much better or worse one outcome is compared to another.

Even if the outcome for each depends on the choice of the other, both the transporter and the regulator have dominant strategies independent of the other's choice. The transporter will gain 0 (nothing) if regulation is supported, and 3 or 1 if regulation is opposed. Thus, opposing regulation will be a dominant strategy for the transporter. The regulator will gain 0 (nothing) if it does not regulate and 2 or 3 if it does. Thus, favoring regulation will be a dominant strategy for the regulator. Outcome from cell I (status quo) will result if regulator does *not* have the ability to force regulation on transporters without their acceptance. Outcome from cell IV will result if it can do so. This is a situation of direct confrontation between the parties. The relative political strength of the regulator and the transporters will be the main variable in determining the final outcome.

Cooperation with the Regulator

Let's now assume that the transporter knows that it cannot prevent regulation to be introduced. Now, the option "not regulate" does not exist anymore. Then, the question arises for the transporter whether it is best served by continuing to make a maximum amount of difficulties for the regulator or if it is better to make an interplay with the authorities in order to design a regulatory regime that is favorable. This is known as a principal/agent problem, in which the agent tries to take control of his/hers principal and traps the regulator to act according to it's desires (Binmore 1992: 526-530).

In this situation, when the transporter continues to resist and the regulator nevertheless intervene, the outcome are the same as in the previous game, as depicted in cell IV in figure 7.4. The transporter knows that the best result he can expect by opposing a new system is of value 1 (cell IV), because the regulator certainly will now introduce regulation (cell I will not be possible). However, by participating in the regulatory process, in stead of only opposing it, the transporter might succeed in achieving a value at least as high as when opposing regulation, even though it will still be lower than if no regulation is introduced, set to value 2 in cell III. By doing this, the outcome for the regulator (consumers) may simultaneously be reduced to less than if the transporter only adheres to regulator initiatives set to value 1. At the same time, when transporters participate in the regulatory process, better solutions can be found than if the regulator shall figure out all details and the outcome for consumers *may* not necessarily be reduced compared to cell IV, value closer to 2.

In this situation, regulator's dominant strategy will still be to regulate, as regulation would yield a better outcome for consumers no matter what the transporter does (2 or 1). The transporter, however, will change strategy towards collaboration, because it knows that regulation cannot be avoided. By participating in the formulation of regulatory mechanisms the situation can be improved (value 2 in cell III) compared to opposing it (value 1 in cell IV). However, if the transporter considers that the regulator will not get such authority, or it can be prevented by some means, it will still choose to oppose any intervention, as shown in cell I in figure 7.3.

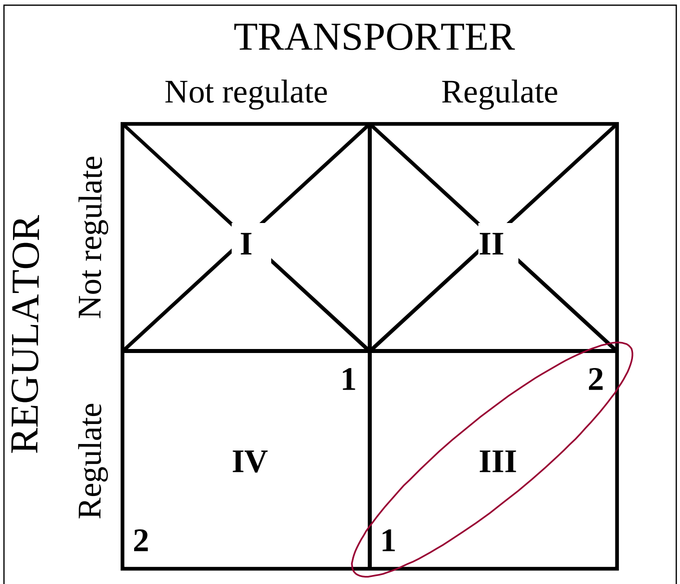

Figure 7.4: Regulation through interplay

Pay-off-matrixes for Transporters and the Regulator

Transporters may have diverging views on the possibility of introducing a strong (enough) regulatory authority in Europe. However, the greater the number of transporters that think the regulator (will) get such an authority, the more of these transporters will start to influence regulatory design and, accordingly, increasingly set the premises for each transporter resisting. Thus, in the beginning, transporters would form coalitions in order to prevent "too many" others to participate in regulatory processes. In this multifirm dilemma, there may be a critical mass of firms (weighed with their quantity transported, sunk capital, strategic significance, political influence etc) that are needed to do so.

If we, for simplicity reasons consider transporters acting as one firm towards the regulatory authority, the game-theoretic results from this regulatory process can be illustrated in a “Schelling-diagram" (Schelling, 1978), as shown in figure 7.5. On the vertical axis to the left, the utility for the transporter, U(T), is measured (by its profit) while on the vertical axis to the right utility for the regulator, U(R), is measured (by consumers' surplus). The horizontal axis between the two vertical axes measures the "level of liberalization". To the left, at point A, no liberalization is introduced; to the right at point B, the market is completely and perfectly liberalized. This is an unmeasurable continuum, but can be thought of as the number of regulatory initiatives; the more liberalized, the more interventions by government must take place such as increased competition and introduction of increasingly more regulatory details.

Maximum utility for the transporter is achieved if no regulation is introduced, as illustrated in point C. In this situation, minimum utility for the regulator is attained, as illustrated in point A. If regulation is established, and the transporter just follows passively regulator's initiatives, maximum utility for consumers is achieved, illustrated in point D. In this situation, minimum utility for the transporter is achieved, as illustrated in point B. Thus, the utility possibility curve goes from C to B for the transporters and from A to D for the regulator when the market is increasingly more liberalized. The curves' down- and upward directions illustrate that more (and efficient) regulation takes increasingly more profit from the transporters and gives it to consumers. Maximum regulatory utility (point D) is drawn as greater than the maximum utility for transporters (point C).

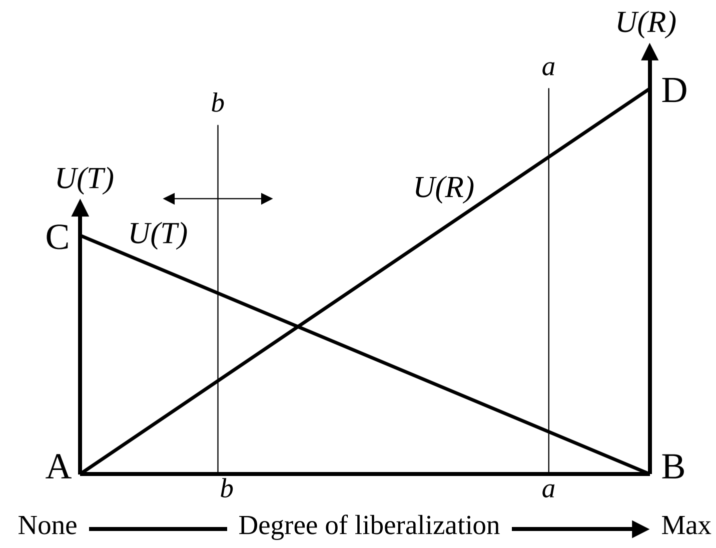

Figure 7.5: Pay-off matrix for a regulatory process

Point D is higher on the right axis than point C is on the left axis, because the gain for consumers should be greater than the loss for producers under regulation.

The outcomes in figure 7.5 can be traced back to the games illustrated in figures 1 and 2. In figure 1, point C (value 3 for transporter) and point A (value 0 for regulator) represents cell I, where no regulation takes place. Cell III is represented by point D (value 3 for regulator) and point B (value 0 for transporter). Cell IV yields outcomes somewhere between C and B for transporters (value 1) and A and D for consumers (value 2). By opposing regulation, the transporter may succeed in either preventing it from being established, or to maintain some of it's profit. This will simultaneously reduce the effect for consumers and is illustrated by the vertical line *aa*. Thus, under our assumptions, the line *aa* represent the worst outcome for transporters (value 1) when conflict with the regulator is chosen, and the best possible outcome for consumers (value 2).

If the transporter knows that regulation will be established, it may start to interact with the regulator to design the system in a best possible manner for themselves, as discussed under figure 7.4. By doing so, transporter's utility will at least measure value 1. If it really succeeds in capturing the regulator, real profit may be increased almost back to a monopoly level (point C). The vertical line *bb* illustrates a situation where the transporter has managed to regain most of its profit, but not all, through this interplay. Transporter's outcome is somewhere between 1 and 3, or value 2, while regulator's outcome simultaneously is reduced from value 2 to 1.

If the transporters could influence regulation in a way that also improves efficiency, and not only their own profit, as compared to a situation with no interplay with the regulator, there may be Pareto improvements in the process. This may happen because regulator's insight into the industry's complexity may be limited and partly be depending on transporter's information. Such examples can be found in the U.S. regulatory history, where regulator has made inadequate decisions for the industry with huge losses in efficiency and resulting stop-and-go-policies. In this case, the utility curve for the transporter will not be a straight line. In figure 7.6, *U(T)* is dropping when some regulation is introduced. When the transporter starts to interact with the regulator in the formulation of new governmental interventions, with a number of market interventions from the regulator it manages to maintain its profit without reducing the benefit for the regulator/consumers.

This is due to the fact that it can suggest arrangements that are more efficient than the regulator could do itself. Overall surplus in the market is increased compared to the more static first strategy. At some level of liberalization, illustrated by the line *cc*, transporters may start to suffer again, regulatory interventions are so comprehensive that transporter's utility curve drops more steeply down to point B. The transporter would loose so much by passing cc, that it starts to oppose regulation again. In this situation, it is possible that the best point for the regulator could never be reached, because he lacks the ability to liberalize the market perfectly in an efficient manner and, thus, needs the collaboration from the transporter. By trying to move the transporter all the way to point B, the outcome for consumers may be worse than if stopped at *cc*. Thus, utility for regulator may drop if more regulation is introduced. The two ways the utility curves are drawn are just examples on their many possible natures. They may be bowed in various ways or even be discrete.

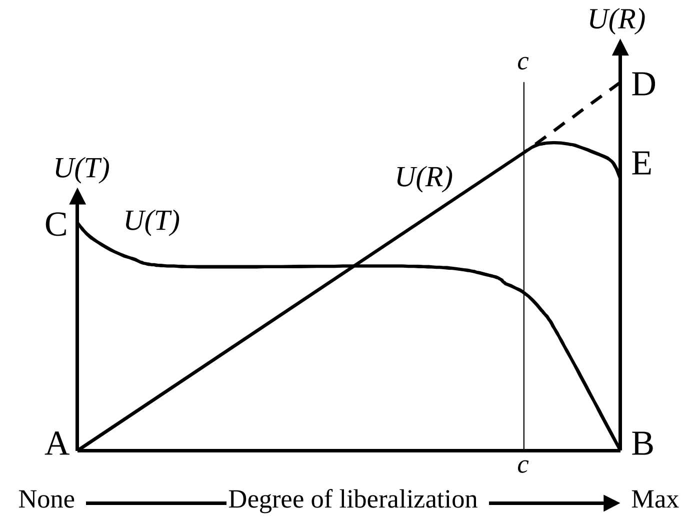

Figure 7.6: Pay-off matrix if the pipeline can improve regulatory efficiency

Conflict or Cooperation?

In a market for a strategic and non-renewable commodity as natural gas is, regulatory authorities will easily remain an arena of politically oriented interest groups in conjunction with market mechanisms and firms operating more or less under competition, within and across borders.

The most important information we can get about transporter strategy from this analysis, independent of the shape of the utility curves, is that it depends heavily on whether a regulatory authority gets the power and have the ability to liberalize the market or not. The transporters should adopt a dual strategy opposing any initiatives taken by authorities on market intervention and simultaneously prepare for interplay in designing optimal regulatory regimes, if or when they come.

Transporters will be best served if they succeed in delaying or destroying political decisions giving such power to regulatory authorities, pointing out the complexity of regulations, security issues, risk or any other arguments that work. But when or if a decision about actual regulation is made, nevertheless, transporters should shift partly to a collaborative strategy. The regulator should, on its side, try to penetrate a possible collaboration between transporters by starting to design regulatory regimes with only one or a few of them. If a critical mass of transporters cooperates, the rest must follow, as well.

In the dynamics of this decision making process, the strategies may shift from conflict to elements of cooperation, and back. When and how the parties should or would collaborate and when they confront each other, depends on the shape of the curves. The shape depends on market complexity, competence among each party, ability to intervene etc. If one accepts that it is difficult to reach a fully and perfectly liberalized market, one should rather discuss what would be the optimal degree and form for regulation, not only in the sense of economic efficiency, but also in terms of political feasibility (*cc*).

8 Schedules for Regulatory Regimes

The idea of regulating transporters' terms of operations is that if the market itself does not produce optimal outcomes, then it can be mimicked to do so through regulatory and other public instruments. The first-best solution could be a subsidized (publicly owned) enterprise that set tariffs according to marginal costs, as discussed in Chapter 7. This has been the tradition in many European countries in the aftermath of WW2. Due to lack of innovative pressure on and x-inefficiency in these companies, this solution is today viewed as inferior to the system of regulating independent (privately owned) firms. When the European gas market becomes liberalized, part of the process in many countries is to (partially) privatize the transport utilities. Privatized or not, in a liberalized market, the transport utilities should face an independent authority that overviews their operations not only in technical, but also in economic terms.

Under regulation, a "visible hand" is introduced to correct the imperfect market's "invisible hand". By regulating the framework and conditions for how firms may operate, public authorities seek to achieve what is considered optimal for the society. The incentives and disincentives given for pricing and production should create mechanisms leading to an efficient allocation of resources and "acceptable" distribution of income. As part of intervening into firms' behavior, regulation may be introduced to direct the firm to behave in certain ways. The framework and regulatory mechanisms for the market must then be constructed in a way that companies voluntarily produce an amount at a price that gives maximal profits and simultaneously satisfies social goals. The regulations should lead to consistency between the company's desire to maximize profits and the society's desire for maximizing welfare, as in a perfectly competitive market. This is the core of regulatory economics.

Rate-of-Return (ROR) Regulation - the "A-J-Effect"

Averch-Johnson (1962) is considered one of the most influential investigations into regulations' effects on firm's behavior. They showed that a regulation of return on capital not necessarily mitigate the aspects of monopoly control that the regulation addresses. They even concluded that such regulation could make the situation worse.

Consider a monopolist producing a single output q and using two factors of production, labor (L) and capital (K). The (market) price of capital and labor is denoted r and w, respectively. Let $q = q(L,K)$ denote the (neo-classical) production function, and the price of q as the inverse demand function $p = p(q)$. The firm's (economic) profit (π) will be:

$$(i)\ \pi = p(q) * q(L,K) - w*L - r*K$$

Unregulated, the firms will choose its capital-labor ratio in a way that costs be minimized. This happens when the marginal rate of substitution between the two inputs q'_K/q'_L, are equal to the ratio of input prices, r/w. When regulated, assume that the regulator allows a rate of return on capital equal to m. Return on capital is defined as net revenues, which is gross revenues ($p*q$) minus costs of labor ($w*L$) and other possible non-capital input factors (here: zero) divided on amount of capital invested (K). The firm is otherwise unconstrained and can choose its price/tariff, level of output and input as long as profit does not exceed this "fair" rate. The rate of return constraint can be expressed as:

$$(ii)\quad m \geq \frac{p(q) * q(L,K) - w * L}{K}$$

The behavior of the firm will vary a lot with the chosen level of m. If the regulator sets $m < r$, the firm will make more profit by closing down the business and selling it's capital than by continuing it's service (assuming no sunk cost and that it legally can do so).

If $m = r$, the firm makes zero economic profit which yields an indeterminate situation. The firm would earn the same profit per unit whether it increases or decreases output, whether it uses resources efficiently or inefficiently, or whether the input mix is optimal or not. The firm would, in fact, make the same money if it closed down and sold off it's capital (assuming no sunk cost). Thus, as the firm can choose many different outcomes, a ROR regulation that set $r = m$ cannot be relied upon as a device to make it act in any particular way.

If the regulator set $m \geq r^{mon}$, where r^{mon} is the return of an unregulated firm, the constraint is higher than what it possibly could make in the market. This will not change its behavior. In such a case there is essentially no regulation.

If the regulator set $r^{mon} > m > r$, the rate of return is higher than the cost of capital but less than it would earn as unregulated monopolist, the firm will still earn an economic profit on it's investment. If we subtract the (market) price of capital from both sides of inequality (ii) and rearrange:

$$m - r \geq (p^*q - w^*L) / K - r$$

$$m - r \geq (p^*q - w^*L - r^*K) / K$$

$$m - r \geq \pi / K$$

$$=> \quad (iii) \quad \pi \leq (m - r) / K$$

The maximum economic profit the firm can earn on it's investment is $(m - r) / K$.[30] The problem with this approach is that the firm is allowed to increase it's (economic) profit by increasing it's amount of capital. The rate of return (with an economic profit up to $(m-r)$) will remain the same with a higher capital base, but in absolute terms profit becomes higher.

The discussion above showed that the only way the regulator can set the rate of return constraint is by letting $r^{mon} > m > r$. Whether it is feasible or not for the firm to earn an economic profit on its investment under the constraint of an allowed profit ceiling depends on its technology and demand for service. Some combinations of K and L could exactly yield a rate of return $r = m$. If the firm can manage to find this set of K and L combinations, it chooses the one among them that uses the greatest amount of capital. This gives the highest absolute profit. If the capital stock is not increased, feasible profit will be lower $(\pi < (m-r)K)$, and thus, inferior to the cost minimizing point with the maximum use of capital. Other cost minimizing combinations of K and L, yields the same economic profit but on a smaller amount of capital, and thus, less total profit.

In essence, the A-J analysis shows that the firm adopts an inefficient production plan, as it's marginal rate of transformation between capital and labor exceeds it's cost-minimizing level when the regulator set $m > r$:

$$(iv) \quad q'_K / q'_L < r/w$$

This implies that it over-invests and accumulates capital in order to relax the rate of return constraint. This is called the *A-J effect*. The regulated uses more capital than the unregulated; $(K/L)_{reg} > (K/L)_{mon}$, which will be an inefficient

[30] If m = 0.12 (12 per cent), and r = 0.09 (9 per cent), the company's economic profit should not exceed 3 per cent.

way of production. Thus, the output produced by the regulated firm can efficiently be produced with less capital and more labor at a lower cost.

Some modifications have been proposed to this type of regulation (Train, 1991: 20-67, 94-113 and Berg & Tschirhart, 1989: 324-333). Rather than constraining the rate-of-return on capital, a constraint can be put on the return on output, revenue or cost. These modifications may induce the firm to behave more optimal than when return on capital is regulated.

Regulating return on output: In this case, the firm is allowed to make a profit on each unit of output. Now, the firm will expand output as long as consumers' willingness to pay is above total production cost (including allowed profit). If allowed return on output is set sufficiently low, the firm may end up close to where price equals average cost, or the second best solution in figure 7.1 (point B).

Regulating return on revenue: If the firm is allowed to make a certain profit on each unit of revenue, the firm will expand output in the same way as under a return-on-output regulation as long as marginal revenue is positive. When marginal revenue becomes negative, expanded output decreases revenue. Thus, the firm will produce at the point where total revenue is greatest, or when MR=0. Therefore, a return-on-revenue regulation will only approach the second-best-solution if MR≥0 to this point. In figure 7.1 the volume produced will be quite far from the volumes representing point B.

Regulating return on cost: If the firm is allowed to make a certain profit on each unit of cost, it increases its allowed profit by increasing its cost. Maximum cost is accrued when output is maximized. However, increasing output, decreases revenues when MR < 0. Therefore, when MR < 0 the firm wishes to increase cost rather than output. The firm start to waste at this point of output. In the same way as under return-on-revenue regulation, although of a different reason, a return-on-cost regulation will only approach the second-best-solution if MR≥ 0.

Thus, regulating either the return on capital, revenue or cost yields inefficiencies by the firms' behavior. Regulation of return on each unit of output that is produced is the one form of regulation that has the greatest chance of achieving a solution that in some sense may optimize social welfare, disregarding the problem of actually setting this rate with weak insight in firms cost curves.

Price Discrimination – "Ramsey Pricing"

Under the regulations discussed above, we assumed that the firm charges the same price to all its customers. Price discrimination is, on the other hand, a situation where the firm charges prices for each unit of output equivalent to consumers' willingness to pay (WTP). Such price discrimination can be performed towards different type of customers, at different levels of output, seasons etc.

A firm that can charge prices equal to each consumer's WTP performs a perfect price discrimination. By doing so, the firm receives an extra profit that is represented by the entire area under the demand curve and above the price equal to consumer's surplus. Referring to figure 7.1, a firm can expand output beyond q_{ac} under price discrimination, as long as p≥MC, because it's fixed costs are covered by already charging higher prices to customers with a high WTP (to the left of point B). Under price discrimination, as the firm increases output it has to decrease price all the way *on the margin*, but it does not have to lower the price taken from customers that are willing to pay a higher price. The firm wishes to sell more units as long as the price it receives from selling extra units exceeds the extra costs incurred by producing this unit (the marginal cost) without reducing the price for volumes already sold.

In figure 8.1, let's first assume that all customers buying the volume q_1 are charged the same price p_1. If output is expanded from q_1 to q_2, without price discrimination, price must be reduced for all customers from p_1 to p_2. Gain in total revenue due to higher volumes is represented by the area DEFG and the loss in revenue due to lower prices is represented by the area ABCD. If DEFG > ABCD, there is a net gain and MR>0. Otherwise there will be a loss of revenue due to increased production. Let's then assume that increasing output from q_1 to q_2 do not lower prices customers are willing to pay for q_1 only. In this case, when the firms take one price p_1 for volumes q_1, and another price p_2 for volume q_2-q_1, the loss in revenues ABCD equals zero. Net gain will now be DEFG.

Either selling for the same price or under price discrimination, the firm sells an extra unit of output as long as its marginal revenue is above its marginal cost. When the firm must charge the same price to all customers, this happens where MR=MC (< AR as in point X in figure 7.1). Under perfect price discrimination, the firm chooses optimal output where p = MC = MR = AR, as in point C in figure 7.1. Thus, under perfect price discrimination, the demand curve becomes the marginal revenue curve. Under perfect price discrimination, the firm extracts all surpluses and none is left to consumers.

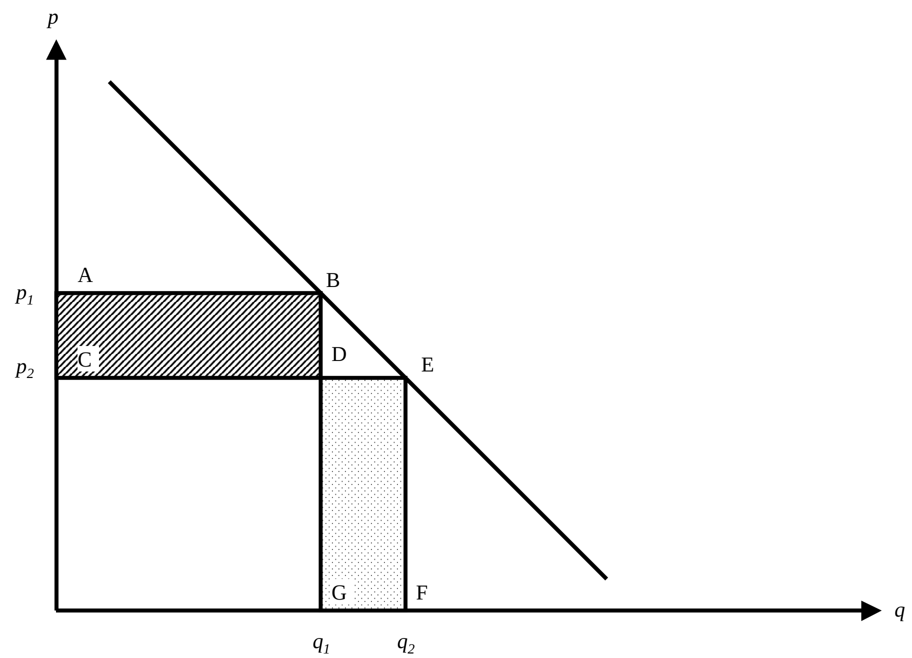

Figure 8.1: Effects of quantity changes on price and revenue

Price discrimination could bring the firm to the first best solution rather than to the second best solution and allows the firm to produce more output than under a regulatory mechanism that requires the same price for all outputs. The social success of such discrimination depend, inter alia, whether customers with a low WTP are able to resell their volumes to customers with a higher WTP. Normally, the pipeline itself can prevent this when unregulated. When regulated, the regulator must establish and enforce rules against such resale.

If prices on average shall equal average cost (firm breaks even) and prices are set differently to customers, the firm must deviate from marginal cost pricing (at least) for parts of it's sale. This should be done in a way that harms overall welfare as little as possible. At *Ramsey pricing*[31], prices are raised more

[31] After Ramsey (1927). Ramsey showed how governments could set tax rates for various goods and at the same time disturb consumers' surplus as little as possible. Baumol and Bradford (1970) uses this principle for setting second-best pricing for multiproduct natural monopolies.

in markets with less elastic demand than in market were demand is more elastic, in inverse proportion to the values of each market's demand elasticity ("inverse elasticity rule"). This way of discriminating minimizes the welfare losses when prices are increased beyond marginal cost.

Under Ramsey pricing, output should be reduced from the point where p=MC by the same proportion in *each* market. The higher prices obtained by these even output reductions and uneven price reactions, reduces the firm's loss compared to a situation where prices are increased similarly in all markets until the (common) price equal marginal cost. Output should continuously be reduced proportionately until the firm eventually breaks even. More revenue can be obtained with less reduction of output (and less disruption in consumption patterns) if prices are raised more in markets with inelastic demand. In this way, total surplus is reduced as little as possible, and the firm can break even without being subsidized by the government.

In figure 8.2, the product is sold in two markets, market 1 and market 2. At p=MC, each market wants to consume equal amounts, q^*, of the product (marginal cost is assumed constant). The only difference between the markets is that demand in market 1 is more inelastic than demand in market 2. If output is reduced by the same amount in each market, down to q^{**}, price in market 1 increases to p_1 while price in market 2 increases to p_2, where $p_1 > p_2$.

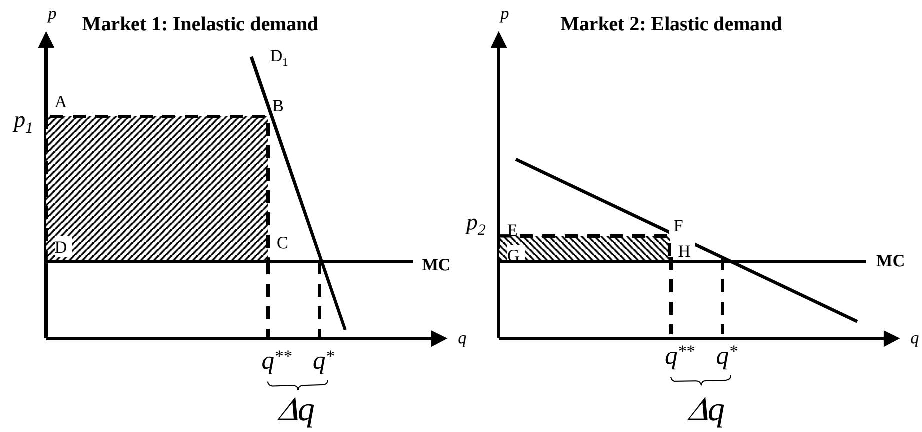

Figure 8.2: Price changes depend on price elasticities; Ramsey pricing

By doing this, market 1 contributes with a profit to the firm represented by area ABCD and market 2 to a profit represented by area EFGH. Total profit contribution from the two markets would be ABCD + EFGH = $(p_1\text{-}MC)$ + $(p_2\text{-}$

MC) * q^{**}. Output should be reduced in this way until total profit contribution from the two markets makes the firm brake even.

In a more general form, denoting the sale of *q* in the two markets as q_1 and q_2, the Ramsey rule tells that the relative quantity change shall be the same in each market in order to make consumers behave very much as they would have without the price increase:

$$(v)\ \Delta q_1/q_1 = \Delta q_2/q_2.$$

(*v*) is the "inverse elasticity rule" in volume terms. Expressed in price terms, prices should be raised inversely related to elasticity of demand in each market:

$$(vi)\ \ (p_1\text{-}MC)/p_1) * \varepsilon_1 = ((p_2\text{-}MC)/p_2) * \varepsilon_2$$

where ε_i is the price elasticity of demand in market i (i=1,2): $\varepsilon_i = dq_i/dp_i * p_i/q_i$.

Ramsey pricing is already applied in the European gas market, for example when p*eak-load pricing* formulas are used. Under this system, the price that consumers pay varies, in order for the firm to cover average costs, including normal profit. This principle would set prices higher when demand in general is more inelastic (especially in winter months). Under this type of price setting, parts of consumers' surplus are transferred to transmission companies when demand is inelastic and from transmission companies when demand is more elastic. Such pricing satisfy efficiency considerations quite well, as they distort consumption patterns as little as possible, and much less than if the same price were charges in both periods (for example in winter and summer).

Subsidizing to Marginal Cost Pricing

If a regulator possesses all information on cost and demand curves, he could simply require prices to be set at marginal cost and give the firm a subsidy, equal to area HDCI in figure 7.1, in order to let it make a normal profit. Together with nationalization, this has been an important principle for how natural monopolies have been dealt with in many European countries after WW2. However, the regulator rarely has all this information. The company has also incentives to misreport costs in order to increase profits. If reported correctly, incurred cost may not be minimum cost of production, for example due to inefficiencies or sub-optimal capacity choice. Thus, making the firm produce in the firs-best-option is not an easy challenge. Our question here is whether it possible to design some subsidizing mechanisms that induces the firm to produce at marginal cost without a public ownership and regulator's knowledge of the pos-ition and shape of cost curves?

Let's assume that the regulator knows that the firm will not charge prices higher than p_a in figure 8.3. This price could for example be the monopolistic price of an unregulated natural mon-opoly. The regulator sub-sidizes the firm for the portion of consumer surplus between p_a and the price the firm actually charges. Thus, the lower price the firm charges, the higher the subsidy. If the firm sets prices equal to $p_b = MC$, the firm maximizes the transfer of subsidy and at the same time behaves in an optimal manner.

Loeb and Magat (1979) showed that, in general, if the regulator subsidizes the firm by the entire consumer surplus (CS) generated at the price existing in the market, the firm would choose to produce at p=MC. In order to do this, the regulator must have information on the demand curve and the firm's price, and no information on cost is needed. Firm's profit would equal total social surplus, or the sum of producers' (PS) and consumers' surplus. Because this surplus is the greatest when p=MC, the firm maximizes profit (the sum of PS and the subsidy = CS) at this point.

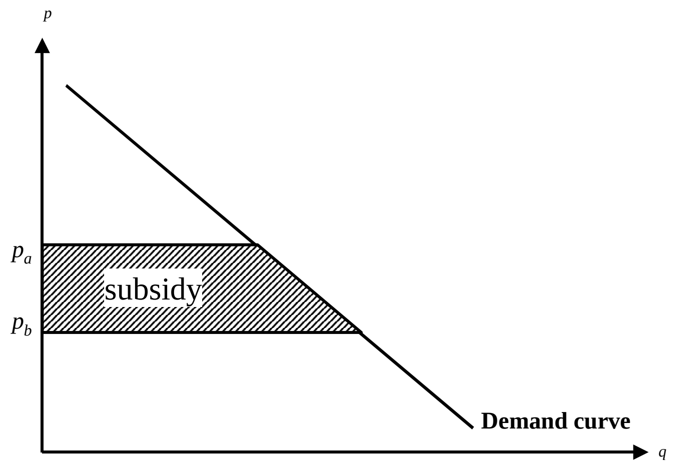

Figure 8.3: Subsidizing firm to marginal cost pricing

This will be true even if many products exist. By setting all prices equal to marginal cost, profit is maximized in all markets and market segments when receiving such a subsidy. Any decrease in cost results in an increase in profits and firms have an incentive to produce efficiently. As the government pays the subsidy, consumers' surplus is also maximized by this rule, if we disregard that the funding for the subsidy must be collected from many (but not necessarily all) of these consumers.

Such a transfer from the public to the firm may be considered inequitable. One way of reducing it, but maintaining the main principle, is to subsidize only a portion of CS. As the firm could never charge prices higher than p_a in figure 8.3, it could not receive the CS accrued above p_a. By subsidizing only the portion accrued below p_a, the same result is obtained as if transfers should equal the entire area under the demand curve. This type of transfer should cost less for the public, and thus, be of a less intolerable size from equitability considerations. If we refer these results to figure 7.1, unsubsidized profit for p_{mon}(=p_a in figure 8.3) is represented by area GAEF. Subsidy when p_{mc} (=p_b in figure 8.3) is represented by the area GACI > GAEF.

By moving p (=p_a in figure 8.3) down from p_{mon} along the demand curve, the firm's economic profit will decrease as will total subsidy. The difficulty is to set p sufficiently high, but not higher than what is necessary, in order to make the firm brake even. But the inequality GACI > GAEF holds all the way until the firm earns only normal profit. At this point, the subsidy will equal the firm’s loss when producing at prices equal to marginal cost. Train (1991: 182-190) discusses some regulatory mechanisms that have been proposed in order to find these optimal prices. He suggests a multiperiod marginal cost approach, where prices, revenues and expenditures in one period determine the subsidy of the firm in the next period with or without full information about the position and shape of the demand curve.[32] Another alternative is to use multipart tariffs.

Multipart Tariffs

A multipart tariff consists of several billing components. There are two main types of multipart tariffs: access/usage tariffs and block rates.

Access/usage tariffs consist of an access charge, which is a fixed fee for having the right to use a system, and a usage charge, which is a per-unit tariff for actually using it. For example, telephone companies often use access/usage tariffs, billing one fee for access to the network, and one (per unit) fee for each call made. This system makes consumers’ marginal cost for each call constant, but their average cost (the average price for consumption of telephone use over a period) declines with the number of calls.

Block rate tariffs changes when total level of consumption reaches certain *thresholds*. For example, electricity companies often charges one price for consumption of a certain number of kilowatt-hours and another charge

[32] See also Sappington and Sibley (1988) and Vogelsang and Finsinger (1979).

(higher or lower) for additional kilowatt-hours. This system makes consumers' marginal cost of using electricity change with the level of consumption, while the average cost (the average price for using one kilowatt hour) is the weighed average of the price of all units consumed and may increase or decrease depending on the tariff structure.

Access / Usage Tariffs – "the Coase Argument"

Coase (1946) argued that the first-best solution for a natural monopoly (price equal marginal cost) could be reached if demand for usage is fixed and an access/usage pricing system is used. The access fee should be set to cover the natural monopoly's fixed costs and the usage fee to cover marginal cost of usage. In this situation, the aggregated access fees are considered a transfer of funds from consumers to producers as if the firm received a subsidy from government. The access fee will not affect consumption of service as long as the access fee covers fixed costs. The firm will benefit by supplying more output as long as price is equal to or higher than marginal cost. When demand for access is fixed and the fixed cost are covered by the "subsidy", the firm will gain by reducing usage fees down to marginal cost of production. Up to this point consumer's willingness to pay is greater than the firm's marginal cost of providing the service. Any other price will incur a loss and, accordingly, the firm will serve in an efficient manner.

However, demand for access is not always fixed, but may vary with the access charge. When demand for access is price-sensitive, any rise in the access fee will, to some extent, lower demand for access. Low access charges may, for example, increase the number of households installing pipes and equipment for use of gas. In a situation with price-sensitive access demand, the access fee influences demand for access and indirectly the demand for usage. The access fee can no longer be considered only to be a transfer from customers to the firm.

Consider the access and the usage of the firm's services as two different goods with separate but interrelated demand, each with a separate marginal cost. For example, there is one demand for installing a new pipe and equipment into a house and another for the actual use of gas when equipment is already installed. With price-sensitive demand for access, optimality can be reached if access fees are set equal to marginal cost of access and usage fees equal to marginal cost of usage. The problem is that with access fees set at marginal cost of access a loss is often incurred to the firm, as average cost of access if often higher than it's marginal cost.

If the firm runs a loss, somehow access must be reduced in order to rise access fees for the firm to brake even. From an efficiency point of view, the reduction in access should be allocated in a way that consumption pattern is distorted as little as possible. Ramsey access and usage fees for the two goods may achieve this. Each customer or group of customers should then reduce consumption by the same proportion, and prices raised for each of them according to their inverse price elasticity of demand. If demand for access is totally inelastic (zero), then the Ramsey rule applied in this situation reduces to the result presented by Coase. This may be true if access fees are relatively low. If not, access fees should be raised to whatever level is necessary for the firm to break even and usage charges reduced to cover usage (marginal) costs of usage. This will generate a second-best solution, as Ramsey pricing does in general.[33]

Figure 8.4 depicts a situation where consumers take into consideration both the access and usage charge. Let's assume that the usage fee is fixed equal to p_{usage} and that the line AE, given that the customer has access to the system, represents the demand curve for usage. The area ADF then represents consumers' surplus. If the usage fee is raised, consumers' surplus is reduced accordingly. At some level of the usage fee, consumer surplus is not greater than the access fee anymore. This is assumed to happen at p^*, where the area ABC the size of the access fee. At usage fees $p_{usage} < p^*$, the consumer will demand usage dep-ending only on the usage fee, independently of the access fee.

[33] In a situation when usage demand is fixed, but not access demand, the access fee should be set equal to the marginal cost of access, while the usage fee is set sufficiently high in order to make the firm break even. That is, natural monopolies that do not use access fees, but only usage fees, can do so only if usage demand is less elastic than access demand. However, this is very rarely the case for a natural monopoly as fixed compared to variable costs are usually very high.

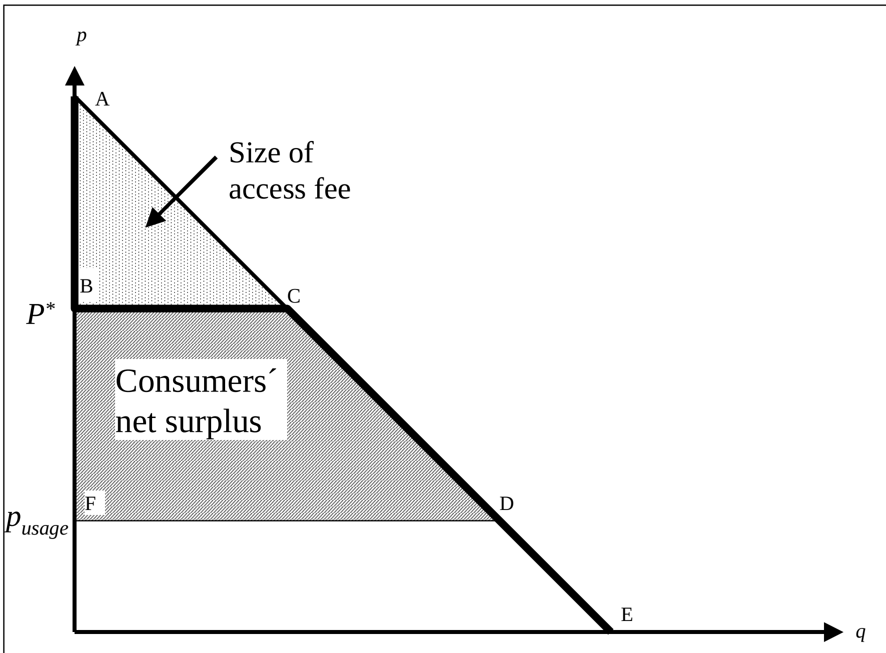

Figure 8.4: Ex ante and ex post demand curves

Obviously, ex ante, the size of the access fee must be taken into consumer's consideration as well. Consumers know that the surplus they get will be the consumers surplus generated at the usage fee charged minus the access fee (ADF-ABC). Therefore, at $p_{usage} > p^*$, the consumer will choose not to acquire access. In this case the benefit of usage will be less than the cost of getting access. If $p_{usage} < p^*$, consumers get a net surplus equal to area BCDF. The lower the usage fees the greater the surplus. This means that the consumer will have no demand for service at usage fees above p^*. Therefore, ex ante, the kinked line ABCE represents demand for service. Ex post, when the customer has paid the access fee, the line AE will be the demand curve. If consumers net surplus is sufficiently large, which happens when (relative) changes in access and usage fees within 'reason' does not induce consumers to forego service, access demand can be considered fixed. Then access fees can be raised to the point where fixed costs are covered (the Coase result). However, demand for access is fixed only if the surplus from usage is so much greater than the access fee, that "relevant" changes in access *and* usage fees does not imply that consumers forego service.

Block Rates

The term 'block' rates have arisen from the particular form of its graphical presentation, as the pricing algorithm looks like series of blocks. Consumption of service under each of the prices is called a 'block'. In a declining block rate tariff, as shown in figure 8.4, price (*p*) for each unit consumed declines with the level of consumption (*q*). In the figure the following rates exist:

$$p_1 \text{ for } 0 < q < q_1$$

$$p_2 \text{ for } q_1 \leq q < q_2$$

$$p_3 \text{ for } q_2 \leq q$$

In this case, there exists three blocks: $0 < q < q_1$, $q_1 \leq q < q_2$ and $q_2 \leq q$. The price the consumer pays for an additional unit of consumption is called the *marginal price* and the prices that applies for lower levels of consumption the *inframarginal price*. In figure 8.5, a customer that consumes $q_1<q<q_2$ faces a marginal price of $p=p_2$ and an inframarginal price of $p=p_1>p_2$. At consumption $q>q_2$, the marginal price would have been $p=p_3<p_2$ and two inframarginal prices would exist, p_1 and p_2.

Block rates can, of course, also be 'inverted', as opposed to declining. Inverted block rates consist of blocks with higher, instead of declining, prices with higher level of consumption. Beyond the first block marginal price is below average price under declining block rates and above average price under inverted block rates. Usage charges under a system with access/usage tariffs can, of course, also consist of block rates, making a combination of the two pricing systems possible.

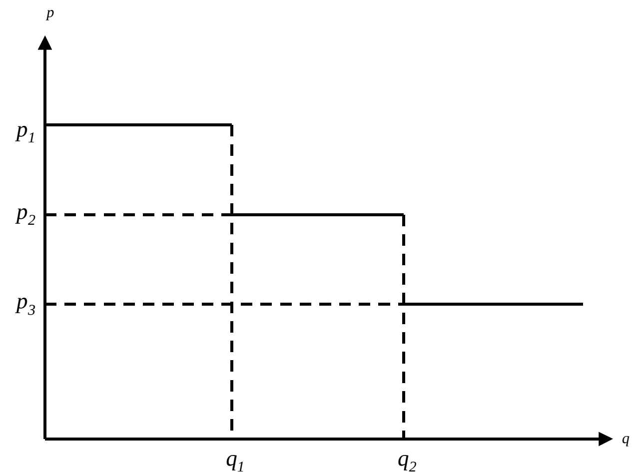

Figure 8.5: Declining block rate tariff

With a block-tariff system the question arises how to determine the optimal threshold(s) and price(s) in each block. Optimality is reached when consumers' surplus is the greatest given that the firm should break even. This may sometimes yield a first-best outcome and sometimes a second-best outcome.

Let p_1 in figure 8.6 represent the (uniform) price before a block-tariff system is introduced. This yields consumption of q_1. Marginal cost (MC) is assumed constant. Then the uniform system is replaced by a two-block tariff system, which set the threshold for consumption at which tariff changes equal to q_1 and the price for the second block to $p_2<p_1$ above marginal cost. With this two-block pricing system, the price for output up to q_1 is maintained.

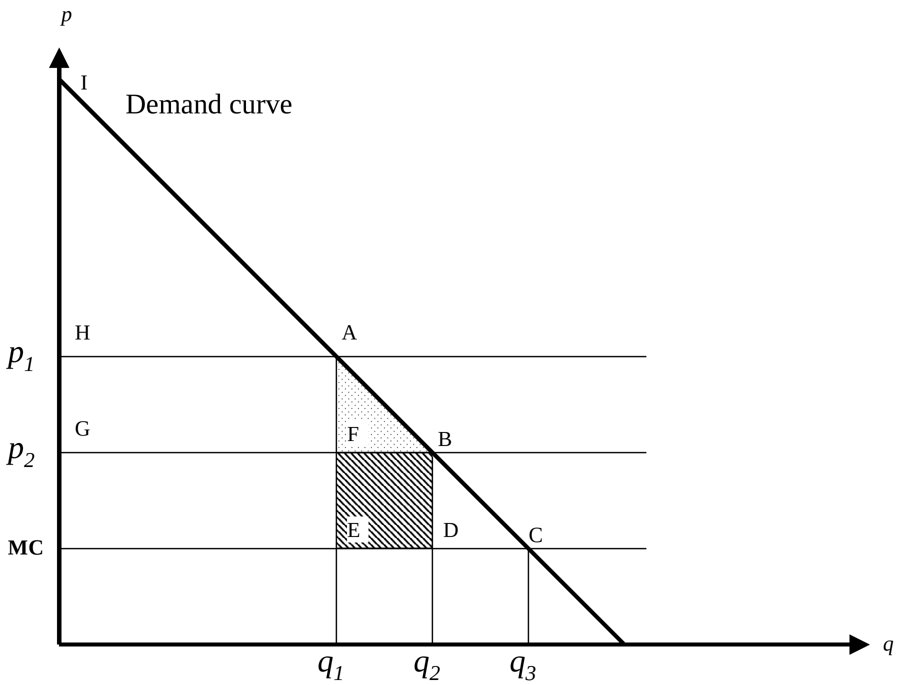

Figure 8.6: Pareto dominating two-block tariff system

By increasing consumption up to q_2 at the lower price p_2, consumers get an extra surplus of ABF and the firm an extra profit of FBDE. No party is worse off compared to the system with a uniform price, in fact in our example both consumers and the firm is better off. Thus, such a block-tariff system is Pareto dominating the uniform tariff system.

If this is the situation for a single customer consuming more than q_1, the area FGHA can be considered similar to an access fee under an access/usage tariff system. The usage tariff will be equal to p_2 for all quantities demanded, as the "access fee" FGHA must be paid "first" in order to consume more than q_1. The consumer faces the same total bill under both systems. The bill under a block rate tariff system will be $q_1*p_1 + (q_2-q_1)*p_2$. The bill under an access/usage tariff system will be $q_1*(p_1-p_2) + q_2 * p_2$. Producers face the same marginal price (p_2) under both systems and receive the same total revenue as consumers pay the same total amount.[34]

By replacing a "one-block" tariff (or a uniform price) by a two-block tariff, the deadweight loss is reduced from ACE to DCB. It is easy to see from the figure that introducing a third block at outputs with a threshold $q_2<q<q_3$ at any price $MC<p<p_2$, reduces the deadweight loss further to the benefit of consumers' surplus and firm's profit. Thus, surplus is improved by increasing the number of blocks, and, in principle, until the first-best outcome is reached ($p=MC$ for the last unit). If number of blocks are N, an optimal N+1 tariff provides greater surplus than the optimal N block tariff as long as the tariff of block number N is greater than marginal cost of service.

At a given $q=q_1$, the optimal prices for each block, p_1 and p_2, should be set in a way that it distort consumption as little as possible (given that the firm shall break even). One good is considered the output within one block. By using the inverse elasticity rule of Ramsey pricing, the price is raised more for the good with the lower elasticity. For consumers in the second block, the inframarginal price in block one does not affect their consumption. At increasingly higher quantities of output, however, in particular in the second block, demand becomes more price sensitive. Thus, prices in the first block should be higher than in the second if consumer surplus should be distorted as little as possible. This is the reason why the optimal block-rate tariff usually consists of declining blocks, rather than inverted block-rates with prices rising at each successive threshold.[35]

[34] This is true if there is no (positive or negative) externalities or transactions costs and the consumer knows its demand. However, if these assumptions do not hold, there is a difference between them as consumers could in certain situations desire access without having any charged usage.

[35] However, from an equity consideration, inverted block rates may be preferable. Inverted block rates are lower for smaller quantities of output. Consumers face the lowest rates at low levels of consumption. This benefits low-income consumers, while declining rates benefit larger and high-income consumers.

In the example above, the threshold was set in a way that consumers demand exactly q_1 at price p_1. Under a uniform price system this will be the customer's demand. The introduction of a declining block rate tariff will be to the benefit for each consumer, as it makes it possible to consume more. The two-block system will increase consumption to q_2, and surplus is increased by the area AFB in figure 8.6.

Now, assume that the threshold for block 1 is set higher than q_1 ($q_1<q=q^*<q_2$), as shown in figure 8.7. Because the first block is larger than consumer's will-ingness to pay, there is a loss of consuming more than q_1 as illustrated by the area AJK. The gain by increasing consum-ption to q_2 is reduced from AFB to KLB. If KBL>AJK it is a net gain of continue con-suming q_2 at the new threshold $q=q^*$. However, the closer q^* approaches q_2, the smaller the gain and eventually it becomes a net loss.

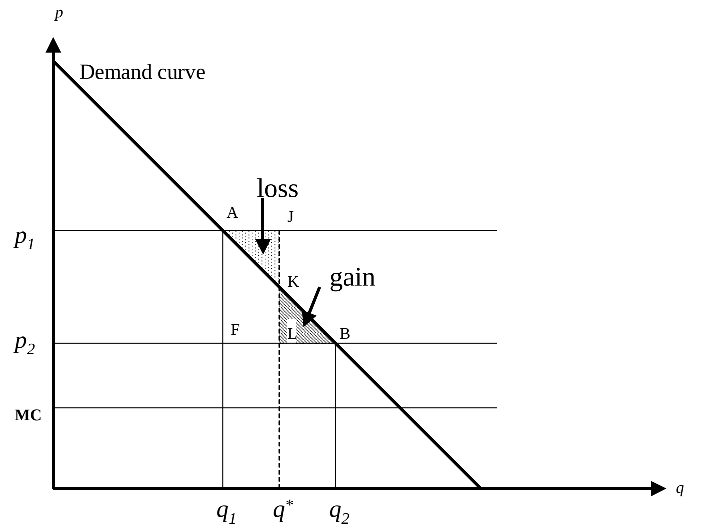

Figure 8.7: Loss and gains by determining the block threshold

As long as consumers continue to consume in the second block, their elasticity of demand is zero in the first block. The inverse elasticity rule suggests that the price in the second block should be set equal to firm's marginal cost and the price in the first block sufficiently high for revenues to cover total cost. By using Ramsey pricing to determine p_2 and p_1, where p_2=MC and $(p_1\text{-}MC)*q_1$ equal the revenues needed for the firm to brake even (mainly fixed costs), first best optimality can be achieved.

Thus, the optimal threshold in a two-block tariff system depends on which price-output combination make the firm break even. A reduction in the threshold gives more consumption in the second block, which benefits consumers, but simultaneously less revenue to the firm (assuming p_1 constant). Usually a reduction in the threshold will also increase the number of customers. At the optimal threshold, the gains and losses for consumers and firms are equal when the threshold is changed in either direction. Even if this is rather unprecise from a practical perspective, it may nevertheless give some assistance in determining the threshold.

Determining Optimal Capacity

In the long run, all costs for the firm can be considered variable. However, in periods from when an investment decision is made until a pipeline actually operates, capacity must be considered fixed. Ex post, capacity is determined by the investment done in a pipeline. Ex ante, capacity can be adjusted. The question is how to determine the size of capacity.

Corrected for uncertainty, a new pipeline project should give a positive net present value of the investment at an appropriate discount rate. One way of considering this investment is in terms of flow of expenditures, rather than as a one-time payment. This flow of expenditures may include mortgage payments on the loans taken to finance the project and varies in particular with the repayment period and the interest rate.[36]

The annual flow of expenditures *per unit of capacity* (*a*) represents the cost of increasing capacity from K to K+1, at all capacity uses at a given capacity. The short run marginal cost (SRMC) for output $q \leq K$ is denoted *b*. Both *a* and *b* are assumed constant of reasons of simplicity. Then, long run marginal cost

36 With societies' lower discount rates compared to the private ones, caused by a usually longer time perspective and an overall view on the gas business and the economy, a project may viable for the society but not for the private company. On the other hand, governments are normally risk averse, i.e. the numerical cost of the possibility of losing one dollar is often viewed as larger than the benefit of gaining one. Private businesses may be more risk neutral (the numerical cost of the possibility of losing one dollar equals the benefit of one). Some may even be risk lovers (the numerical cost of losing one dollar is smaller than the benefit of gaining one). If private industries are less risk averse than governments, they may tend to invest sooner than governments. The assessment of the uncertainty, at a given discount rate, will depend on factors as the resources at hand, market possibilities, the presence of alternative energies, time horizon etc. The advantages of the government's longer and more general view, may be of particular importance for huge and strategically important pipelines due to reasons of security of supply, overall economic considerations et.c.

(LRMC) of producing one output is the sum of the costs of expanding capacity by one unit and the cost of producing it at this capacity; LRMC=$a+b$ as shown in figure 8.8.

At output q_1, consumers are willing to pay the price p_1. Their WTP exceed both variable and average fixed costs. The difference between price p_1 and SRMC is p_1-b and represent the amount consumers are willing to pay more than variable cost for capacity to be expanded in order to get one additional unit of output.

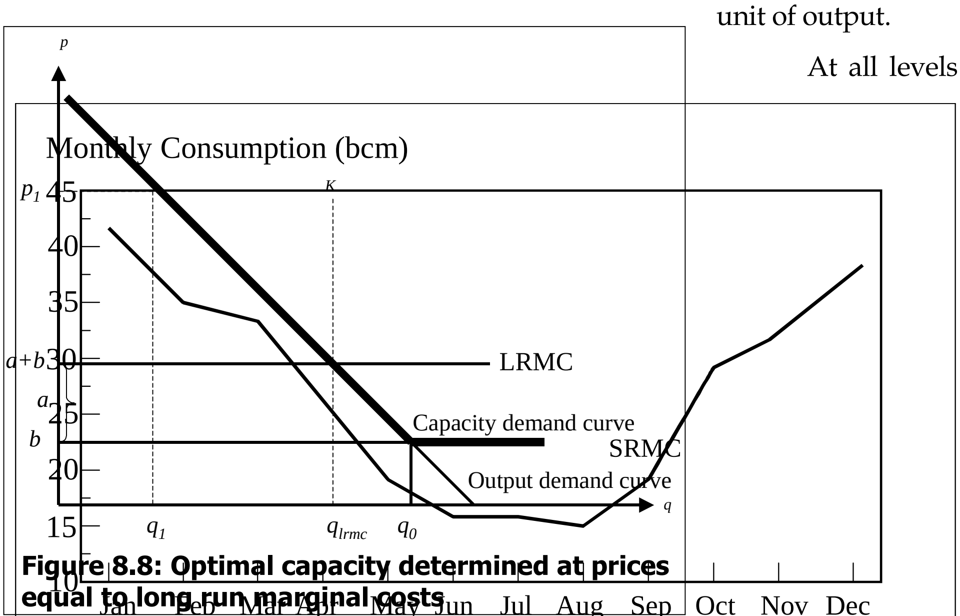

Figure 8.8: Optimal capacity determined at prices equal to long run marginal costs

Figure 8.9: Seasonal consumption of natural gas in OECD-Europe.
Source: (IEA (1994), page 35

At all levels of output $q<q_0$ (where q_0 is the amount demanded at $p=b$), consumers are willing to pay for additional capacity. Thus, the demand curve for capacity is the bolded line in figure 8.8 with a kink at $q=q_0$. Demand for extra capacity at $q \geq q_0$ equals zero. However at $q_{lrmc}<q<q_0$ prices do not cover more than a part of a pipelines' fixed cost. Only if consumers' WTP for extra capacity exceed the cost of building extra capacity, it contributes with a net surplus. The optimal level of capacity and capital investment is where the demand curve intersects the LRMC-curve at $K=q_{lrmc}$ (where q_{lrmc} is the amount demanded at $p=a+b$).

Social optimum is achieved if prices are set equal to marginal cost of production (at given production capacity). In figure 8.8, short run marginal cost is constant equal to *b* for outputs $q \leq K$. If demand exceed *K* at $p=b$, no more output can be provided (in the short run), and marginal cost increases infinitely. Thus, the (short run) marginal cost curve for providing *q* is horizontal for $0<q\leq K$ and kinked at $q=q_{lrmc}$ to a vertical position for $q>K$ at a given capacity (see figure 8.11). Using a marginal cost pricing principle in this situation yields prices at or above b depending on where the demand curve intersect the (short run) marginal cost curve (*b*).

A problem in determining demand is that it varies over the year. Figure 8.9 shows a typical pattern over seasons for the consumption of natural gas in Europe. Consumption in summer months is only one-third of winter peak consumption.

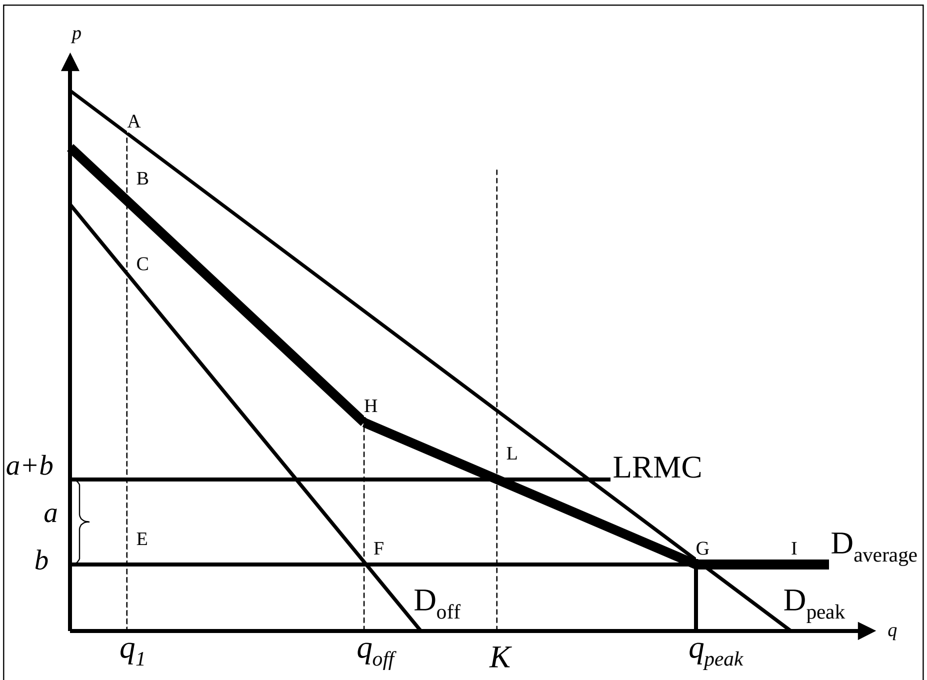

Figure 8.10: Optimal capacity with two period demand

Let's denote the cost of adding capacity *a* in *each* period (summer and winter). Customers in high and low demand periods are considered of equal importance. Thus, total cost over both periods is *2a*. If consumers' WTP for capacity on average over high and low demand periods exceed the cost per period, or a, capacity should be added. That is $WTP_{summer} + WTP_{winter} \geq 2a$.

Combinations of high and low demand situations (peak and off-peak periods) with consumers' average WTP greater than the cost of adding capacity can exist if one or both of them are willing to pay more than the cost of increasing capacity. In figure 8.10 we have drawn one off-peak demand curve (D_{off}) and one peak demand curve (D_{peak}) as one possible combination of the two. q_{off} is the amount off-peak consumers are demanding and q_{peak} is the amount peak consumers are willing to consume at price $p=b$ (SRMC). We assume that the two "groups" of customers consume only in their respective periods and each of them is willing to pay for additional capacity as long as $q<q_{off}$ for off-peak consumers and $q<q_{peak}$ for peak consumers.

As the two groups of consumers are weighed equal, the average willingness to pay can be determined in the middle between peak and off-peak demand curves. For example at output q_1, off-peak consumers are willing to pay CE and peak consumers AE for additional outputs, where AE>CE. The average willingness to pay will be in the middle between CE and AE, which is BE (where AB=BC). Thus, B is one point on a new curve showing average demand over the two periods.

Up to q_{off}, off-peak consumers are willing to pay for extra capacity while peak consumers are willing to pay for additional capacity up to q_{peak}. At output levels $q_{off}<q<q_{peak}$, off-peak consumers are not willing to pay for adding new capacity to the system. Thus, demand for new off-peak capacity is zero a $q>q_{off}$ and off-peak consumers' demand curve will be a curve kinked at F, running through the points CFI. Capacity demand for peak consumers (AG) will be zero at $q>q_{peak}$ and will be kinked at G, running through point AGI. The

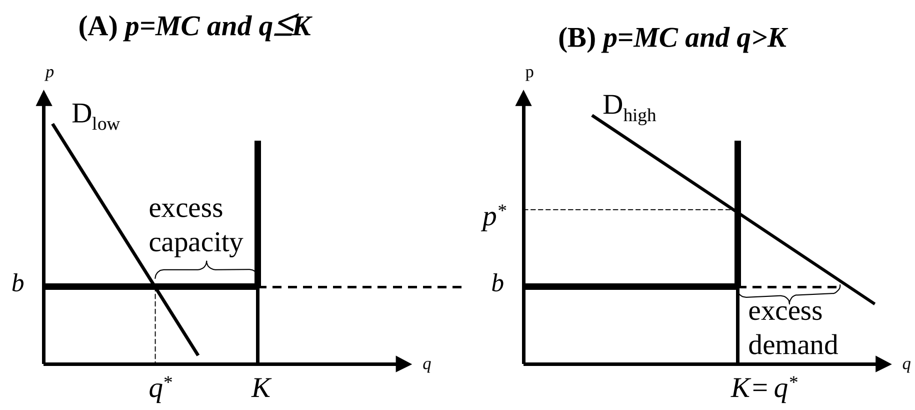

Figure 8.11: Optimal marginal cost pricing at high and low demand

average demand curve can be drawn in the middle between these two kinked curves, shown as $D_{average}$ running through points BHGI. The distance between this new curve and *b*, expresses consumers' average WTP for extra capacity. Optimal capacity is determined where average willingness to pay in the two periods equal long run marginal cost, equivalent to the one-period example above. This happens at point L, with capacity K at LRMC prices *a+b*. At point L, average willingness to pay for extra capacity equals the cost of adding it.

Pricing in Peak and Off-Peak Periods – “Riordan Regulation”

A situation of high and low demand (peak and off-peak demand) compared to capacity is shown in figure 8.11. Marginal cost curves at fixed capacity (*K*) is shown as kinked bold lines. Graph A shows a situation with low demand ($\leq K$) and graph B a situation with high demand ($>K$), both at prices equal to short run marginal cost (*b*).

In graph A, quantity $q^*<K$ is demanded at $p=b$. There is no way capacity K-q^* can be used as long as consumers' WTP < SRMC at these levels of output. In graph B, quantity demanded at $p=b$ is greater than capacity, which is impossible in the short run. In this situation, somehow $q=K$ must be rationed among consumers. Economist usually argue that the most efficient way of rationing is to raise prices high enough to exhaust demand, that is setting $p=p^*>b$. Other methods of rationing may lead to a situation where a consumer that is willing to pay a price above marginal cost (at $q\leq K$) may not get the product. A consumer that is not willing to pay such a price, for example by queing, a draw, use of force or size, may get it. Thus, if demand for transportation in winter months exceeds capacity and is lower than capacity during summer months, transportation tariffs should be higher during winter than in summer.

However, the firm obviously looses money in summer months with such a pricing principle, as it earns no profit to contribute to investment costs. On the other hand, in winter months the firm makes a profit $(p^*-b)*q^*$. On total, it will not be possible from this information to determine whether the firm runs a loss or a surplus. There are mainly two ways the firm can cover the difference between total revenues and total costs. Government can give the amount to the firm as subsidy or an access charge can be added without affecting the usage charge. The access charge can be evenly distributed on consumers if demand is fixed (the Coase result) or be allocated by resorting to Ramsey prices, depending on the degree of price responsiveness to access charges.

Riordan (1984) discusses how such fixed capacity pricing can be achieved through a regulatory mechanism. The idea is that the firm receives a subsidy from the government or charges an access fee that amounts to the fixed costs of capacity minus the amount prices exceed marginal cost times capacity. In order to do this, the regulator need to know the price charged in the market, the actual capacity of the firm and it's variable and fixed costs, but he does not need information about the demand curve. The information needed is usually accessible, at least as an approximation, even in natural gas markets.

In figure 8.12 the two situations with demand ≤*K* (graph A) and demand >*K* (graph B) is redrawn. In graph A, the price for service is set at *p=b* and the firm receives a subsidy/access fee to cover fixed costs, amounting to *a*K*. If the

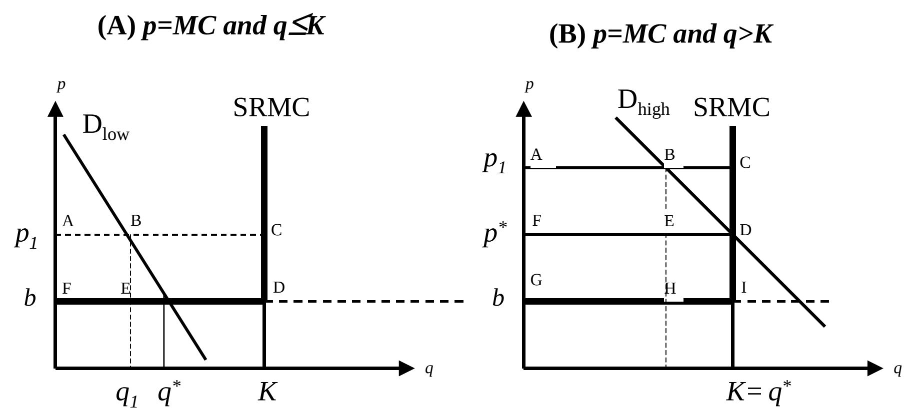

Figure 8.12: Optimal behavior under Riordan regulation

firm attempts to raise the price from *b* to p_1, his (economic) profit would increase with the area ABEF = $(p_1\text{-}b)*q_1$. But, an amount equal to the price increase *times capacity* is withdrawn from his subsidy/access fee, represented by area ACDF = $(p_1\text{-}b)*K$. Obviously, ACDF>ABEF, and the firm suffers a loss by increasing price beyond b. The main point is that while the price increase raises profit on the basis of actual output, the subsidy/access fee is reduced on the basis of capacity.

In graph B, prices are set equal to p^*, equal to marginal cost at the given demand and capacity $K=q^*$. The firm earns a profit over variable costs equal to area FDIG to cover fixed costs. If the subsidy/access fee is set equal to it's fixed cost minus the area FDIG the firm breaks even. If prices are raised from p^* to p_1, it's profit would increase by the area ABEF-EDIH. The subsidy/access fee will be reduced with the area ACDF. Again, because the subsidy/access fee is calculated on the basis of capacity, while profit is calculated on the basis of actual output, net profit suffer a loss. The firm must choose between earning either normal profit or less than normal profit.

Obviously, in "low demand periods", a p=SRMC-principle could yield $p \geq b$ as well as in high demand periods and vise versa. In general, over both the high and low demand periods (over the year) the firms profit will, when a subsidy/access fee = S is included, be:

$$(vii)\ \pi = (p_{low}-b)*q_{low} - a*K + S_{low} + (p_{high}-b)*q_{high} - a*K + S_{high}$$

The footscripts 'high' and 'low' indicate that the values of the variables refer to high and low demand periods, for example winter and summer. $a*K$, represent the (flow of) capacity costs over each period. For simplicity reasons we have assumed that the year is divided into two equal parts, such that K is half-of-the year per unit fixed cost. The size of the subsidy/access fee in each period must equal:

$$(viii)\quad S_i = a*k - (p_i-b)*K \text{ at } p_i \geq b, \text{ where } i = high, low$$

Substituting (*viii*) into (*vii*) and rearranging yields a profit expressed as:

$$(ix)\qquad \pi = \sum_{i=high}^{low} (p_i - b)(q_i - K)$$

Pricing at p_i=b and producing an amount of output equal to capacity (q_i=K) yields zero (economic) profit. Because the firm must set $p_i \geq b$ (to cover variable costs) and $q_i \leq K$ (output cannot exceed capacity), the term (p_i-b) is greater or equal to zero and the term (q_i-K) less or equal to zero. If the firm sets $p_i>b$, which it is allowed to do, and output is below capacity ($q_i<K$), profit will be negative. As long as actual output must be lower than capacity at $p>b$, the firm will loose money by raising prices above marginal cost. In all other situation the firm will make normal profit. Riordan argues that these mechanisms induce the firm to price service in all markets and periods equal to its marginal cost, and thus the first best solution can be achieved.

One problem using such a pricing principle is that LRMC for a new pipeline is often above the average cost of the existing pipeline. One way of covering the costs of new construction is to roll them into the charge for all transportation services. A new average cost level would be established including costs in both old and new pipelines. This may involve new subsidy/access charges in old pipelines when capacity is expanded. The price paid for transportation will under this arrangement not reflect the true costs in each pipeline, as some costs will lie above and some below the average tariff. Another way is to consider each pipeline project separately. Under this arrangement, the newer pipeline will operate with higher costs and the users will have to pay a higher tariff using this pipeline as opposed to using the old ones.

A tariff structure that sets different rates for each pipeline meets the efficiency criterion that prices should equal marginal costs better than when the costs of a new pipeline is rolled into the charges for all transportation services. However, such a price structure may lead to competition between different shippers attempting to gain access to the oldest, and thus the cheapest, pipeline. Market structure and the ability to bundle services will influence the evolution of this allocation. But even if new and old gas are reallocated between pipelines, the marginal quantities will still have to pay the new pipeline's higher marginal cost which serves to equilibrate the market for transmission services over time.

By giving subsidies or regulating the access fee, Riordan suggests that the regulator can induce the firm to install the optimal level of capacity, as well. Because the firm will be indifferent to which capacity level to choose, as long as it earns no more than normal profit in any situation, he suggests that the regulator should actually know the level of capacity by his/hers own evaluation. Then, by subsidizing or regulating the access charges according to which capacity level is optimal, the firm will actually choose this level. Any other choices will result in less than normal profit.

The problem of excess demand allocation has been particularly debated within the natural gas industry. The Ramsey pricing principle may cause intolerable distribution of income, as the most needing pay the most. One alternative has been to use a pro rata system. In this system all customers shall be allocated access in proportion to the volume of their shipment. Existing customers' volume is reduced in order to allow incremental customers' access. In the U.S., which has been using this system, downstream customers can choose between buying a good bundled - both the gas and it's transportation fee - from a pipeline or paying the unbundled transportation charge. All shippers according to their nominated volumes share the burden of excess demand.[37] A problem with this approach is that an allocation on the size of volume need not be economically efficient, which can lead to gaming to determine the size of the nominated quantities.

Another alternative has been to take "high-priority" customers before those with "low-priority". In the United States, FERC defines "high" and "low" priority. Schools, hospitals and small commercial users have high priority, while large industrial direct users have low priority. Of course, other priority rankings are possible, such as first-come first-served, bidding and auctioning etc.[38]

In the U.S., an arrangement that is called mandatory contract carriage has been considered. Under this schedule, a customer can contract for "firm" transportation service and get a higher priority than "interruptible" service. Interruptible service can be delayed in order to fulfill firm transportation commitments.[39]

Alternatives to Regulation

Public Ownership / Changing Property Rights

An unregulated transmission company is behaving monopolistically because its owner has an interest in maximizing profit. By changing it's property rights, the new owners may have other goals. If the owner has, for example, overall efficiency in society, or maximum profit in the distribution or production sector, as a goal, profit maximum in the pipeline may not be in the owners' interest.

One way to change property rights is to socialize the firm by changing its ownership from private to public. In Europe, this has, until recently, been a quite usual way of approaching the problem for a wide range of branches, such as coal, electricity, railroads, post, telecommunication, defense industries, steel, shipbuilding, buses, airports, water and gas. The idea has been that the problems of monopoly power, externalities, inequality etc. can be dealt with

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[37] In order to give access to new customers, the initial volumes cannot be used as an allocation device. Such a pro rata system is used in a Common Carriage arrangement (as in the U.S.).

[38] See e.g. Hogan (1989).

[39] Broadman (1987) discusses alternative ways of allocating excess demand in more depth.

directly if such companies are run with social welfare as goal rather than private profit.

Nationalization has been argued for both on ideological grounds and because of the market failures natural monopolies create. In Europe, labor parties have mostly favored nationalization, advocating that ownership of means of production; distribution and exchange should be common. The early advocates of nationalization in the 1930s and 1940s hoped that the old class antagonism between workers and owners of businesses should be broken down. Nationalization should be one means of rectifying the injustice in income distribution between consumers and producers and across classes, when huge firms exploit their monopoly power. However, there has been considerable debate through the twentieth century on how much of a nation's industry should be under public ownership and how much should be managed trough market mechanisms (as the "Austrian school"). As we have discussed, "untouched" natural monopolies often do create inefficiencies in markets, restrain economic growth and lead to an unfair distribution of rent, between producers and consumers and throughout the gas chain. The question arises whether nationalization is superior to regulation or whether some other means should be used to correct deficiencies.

One major argument for the privatization of publicly owned enterprises over the past 20 years has been their relatively poor economic performance. Obviously, that these run a deficit, and not with a profit, is a non-valid argument. The nationalized industry *should* in many cases run a loss if prices are set equal to marginal costs and average costs are falling, as discussed for example in figure 7.1). Therefore, the assessments of nationalized industries should rather be done on the basis of its costs and quality of service than on it's profit. Because such comparisons are rather difficult[40], especially for natural monopolies without competitors, it will not be possible to observe such differences with certainty before they become rather significant.

Another argument in favor of privatization has been that private firms will be more exposed to market forces than the publicly owned ones one. Privatization should improve efficiency, reduce costs, and improve quality and lead to greater responsiveness to the wishes of the consumer. However, if a publicly owned firm is privatized in a non-competitive market a private monopolist should not have much more reason to behave more efficiently

[40] See for example Meyer(1975).

than the public one.[41] Thus, in most such cases, privatization must be followed by some sort of regulation should efficiency be improved. Ownership may be only one determinant for the efficiency in an industry, while the degree of competition is another. Also public enterprises can be more efficient if they face competition.

Whether publicly or privately owned and run, transporters in the (non-competitive) European gas market must be followed closely by public authorities, which under whatever approach will need independent competence and power to decide on a number of issues that arises. The nationalized industry may show lax efforts to improve if government always is ready to increase subsidies when they run larger deficits. A private industry can do the same if regulations are not followed in an optimal manner. Tough hands are often needed both on the amount and the way subsidies are given and how regulations are enforced, including incentive-type regulations. Thus, the government's attitude, competence and political standing may in many situations be as important as the principles that it adheres to.

Market Forces versus Regulation

Competitive markets should ensure entry of new firms on equal terms as the incumbent firm. Firms should have costless exit; if a firm wants to leave business it could sell all it's capital minus depreciation costs. The latter is rarely the case in the gas industry. For example, the ex ante opportunity cost of an investment minus the investment's value ex post are considerable in pipelines (the "sunk" costs). Usually the pipes laid cannot be sold for any other purposes than for transportation of gas if a company should terminate operations.

With large sunk costs and economies of scale it is sometimes impossible to build another pipeline. If, nevertheless, another company should make the required investments, i.e. in an alternative pipeline, the outcome is uncertain. If demand is constant and the incumbent firm operates as a strong natural monopoly (average cost are downward sloping over the entire range of outputs) a new firm could not take a share of the market and produce at a lower cost. However, if the incumbent firm operates as a weak natural monopoly (where diseconomies exists, but not sufficient to make the industry a natural duopoly), prices could be forced down, and the new-comer, possibly both, will loose money. Thus, competition may be impossible or, if more

[41] The main exception is perhaps that the private firm would not have to frequently adjust their targets for political reasons.

pipelines enter the market, be destructive for both the old line and the newcomer.

The idea of regulating transporters' terms of operations is that if the market itself does not produce optimal outcomes, then it can be mimicked to do so through regulatory and other public instruments. However, no single theory of regulation and regulatory behavior seems fully to explain the behavior of regulated firms or lead to first-best outcomes. For this, the issue is far more complex than the partial and highly stylized models we have studied. The alternative theories are not mutually exclusive and may be used in combination. Cost curves may change over time as do demand. The regulatory instruments may include price regulation, profit constraints and subsidies. As long as regulators shall 'repair' misallocation of resources with such a wide range of instruments, the system may easily end up with outcomes that are either overdetermined or have too many degrees of freedom to yield desired results. In a market for a strategic and non-renewable commodity as natural gas, regulatory authorities will easily remain an arena of politically oriented interest groups in conjunction with market mechanisms and firms operating more or less under competition, within and across borders. US governments have repeatedly has changed the way of intervening in the market, policy makers should by humble towards the task and take an approach that accept some inefficiencies in the market in order to avoid the creation of new (and perhaps more serious) ones.

From the outset, the non-competitive structure of the European gas industry indicates that today some parties have significantly more power than others in contract negotiations. The investment risks and economies of scope in vertical integration between many of these parties lead to an ex post situation, which is relatively inflexible in facing of altering market conditions. On the other hand, the bundling of services, directly or through long-term contracts, provides assurances for the companies with massive sunk investment in production, storage, pipelines and LDCs. If unbundling should take place, the efficient access to transportation requires a dynamic attitude from the regulator. The arrangements should include a variety that suites each actor and segment of the market. These arrangements should be permitted to evolve gradually based upon market trends rather than radical change. In doing this, policy makers must evaluate the development of market demand in each segment of the market, horizontally and vertically, and how firms will respond to these changes.

9 Experiences from North America and Great Britain

The liberalization of the European gas market is not an isolated phenomenon. In the OECD countries, a large number of sectors have been liberalized over the last couple of decades. USA and Canada were the first to liberalize their gas markets in the 1980s, followed by Great Britain. Australia and New Zealand have also privatized large parts of the industry and increased competition. We will in this section look more closely at other countries' experiences in liberalization of gas markets, particularly the development in the United States that has the longest experience with this type of market organization. To the extent one can gain experience from other countries, it is important to realize that no two markets are exactly alike. It is not possible to understand one market fully by studying another. There will however also be some common features that may be useful to study across markets.

The United States

Most gas in the U.S.is located in Texas and Louisiana; the two states produce more than 70 percent of the United States' natural gas. If neighboring states Oklahoma, Kansas and New Mexico are added, the figure rises to more than 90 percent. From the producing areas in the Southwest a comprehensive gas grid has developed to serve consuming areas in the east, north and west. The United States' total consumption in 2000 was approximately 590 BCM (more than 20 trillion cubic feet), making this market 50 per cent bigger than the European market (excluding Russia), today the biggest in the world. Canadian production is about 30 percent of U.S. production, but the U.S. is an important importer from Canada. In 2000, the Canadians exported some 102 BCM to the United States. As figure 9.1 shows, growth in US demand for gas is expected to outpace growth in production over the next two decades. The need for imports will increase, both from Canada and other sources. The main drive in demand is growth in gas fired power plants, as it is in the rest of the world.

The history of the North American gas market is much longer than that of Europe. Gas has, in fact, been used since the first half of the nineteenth century. From the mid-1920s trade expanded, as consuming areas with no gas themselves were connected to the production areas on a larger scale. The pipelines bought the gas at the wellhead at low prices and sold it at the city gates to the local distribution companies at significant markups. They sometimes also refused to service customers if they sought some control over the rates charged. Until 1938, the courts could not deal with the excessive pricing practices on the grounds that state authorities had no jurisdiction over commerce between the states (inter-state trade), only over trade within their own state (intra-state trade).

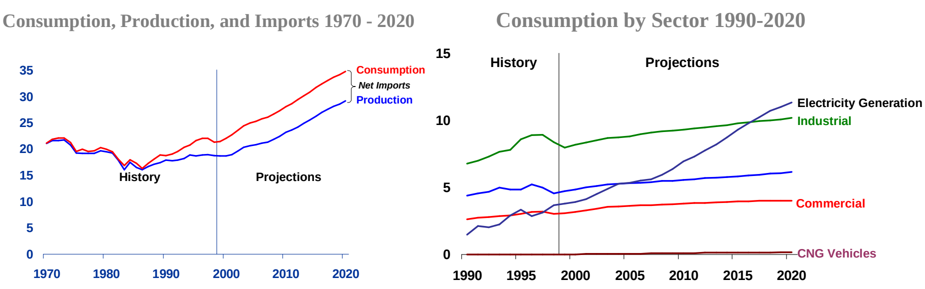

Figure 9.1: U.S. Natural Gas Consumption, production and imports. Trillion cubic feet.

Source: Natural gas markets; Status and outlook, EIA January 24, 2001

The Natural Gas Act (NGA), passed unanimously by Congress in 1938, created the Federal Power Commission (FPC) to control inter-state commerce in natural gas. The FPC set the rate of return for gas through inter-state lines for resale to local distribution companies (city gate prices), known as "private carriage" (see Chapter 6), at a "just and reasonable" level. It was specified that the conditions they offered one company would have to be offered to others on a non-discriminatory basis. While the FPC could approve that pipelines could transport gas owned by others, or "contract carriage", the NGA did not prescribe that they *should* exclusively do so. The pipelines were not obliged to provide transmission access to all customers on a common carrier basis even if this was a "clear intention of Congress in framing the NGA" (Broadman, 1987:127). Furthermore, pipelines were still free to negotiate sale prices directly with large end-users.

The setting of "reasonable" rates of return for the pipelines was largely a result of bargaining between the companies involved and the Commission

(Davies, 1984: Ch.4). This situation seems to have limited the extreme profit taking by the pipelines, but may, nevertheless, have produced rates that were well above the rates of return on equity for alternative investments (normal profit).

The FPC was a regulatory agency, and as such it had the rights to amend its regulations in accordance with the NGA. The amendments made were, however, subject to appeal by any party to a U.S. court, which could block them. Thus, the discussions between the Congress, the courts, the FPC and the industry over the extent of FPC jurisdiction remained controversial for more than 15 years after the NGA was passed. Finally, in 1954, the Supreme Court, in the Phillips Decision, stated that the FPC had jurisdiction over "the rates of all wholesalers of natural gas in interstate commerce whether by a pipeline company or not and whether occurring before, during, or after transmission by an interstate pipeline company" (Phillips Petroleum Co. vs. the State of Wisconsin, 347 U.S. 672 (1954). The Phillips decision extended FPC jurisdiction further to the wellhead, also to set producers wellhead prices on gas. However, still, it regulated only the interstate trade, leaving intra-state gas free of federal control of wellhead and pipeline prices.

The main economic problem that gradually became apparent, was that prices set at the wellhead were based upon costs in fields in production or even in decline ("old gas"). It did not take account of the marginal cost of the discovery and production of new developments ("new gas") which was higher than for old gas. However, as energy markets remained reasonably stable for the following 15 years after the Phillips-decision, the arrangements established gas prices for interstate trade close to the prices determined in the non-regulated intra-state gas market. During this period, large reserves were added as a result of findings of associated gas together with major oil discoveries. Also the pipeline grid expanded substantially.

Increased demand for gas, and, in particular, the quadrupling of oil prices in 1973-74 raised gas prices substantially in intra-state markets. However, as prices in the intra-state market could respond to the increased demand and prices in the inter-state could not, the two-tier price system gave incentives to producers to dedicate their supplies to the intra-state market. This created shortages in inter-state trade. These shortages of supply forced a number of gas consumers to shift to alternative and more expensive fuels. For example, the third-ranked natural gas producing state, Oklahoma, was a major supplier of inter-state pipelines before the oil shock. But in the period 1972-77 more than 85 percent of newly discovered gas was dedicated to the intra-state market at higher prices (Davies 1984; 83).

This untenable situation was addressed when the FPC was replaced by the Economic Regulatory Administration (ERA) and the Federal Energy Regulatory Commission (FERC) in 1978. FERC should handle most cases involving the U.S. natural gas industry, and the ERA the jurisdiction over natural gas imports. These responsibilities were defined in the Natural Gas Policy Act (NGPA), which began the "deregulation" of the American gas industry.

The NGPA brought intra- and inter-state markets under the same regulations and thus established a single national market. This stimulated natural gas exploration and development. The NGPA deregulation also reduced the need for pipelines to obtain regulatory approval for contract carriage. In 1983, under Special Market Programs (SMPs), pipelines were allowed to devise discount prices for "direct sales" to *industrial* end users. In many industrial markets this led to market clearing prices, which in the 1980s dropped significantly below those of alternative fuels. Prices dropped due to oversupply of gas in the market due to higher energy prices after the tripling of oil prices in 1979-81. The high prices provided incentives for conservation and along with the economic crisis following the oil shock, demand for gas dropped. The SMPs regained customers who had switched away from gas during the 1970s.

The SMP arrangements also forced pipelines to engage in a greater amount of contract carriage, increasing the share of contract carriage in inter-state gas trade from 24 percent in 1978 to some 37 percent in 1984. However, the increased contract carriage was mainly on behalf of other pipelines (84 percent of the growth). Thus, the interconnection between pipelines developed on a "sounder" economic basis as a result of the SMP arrangements. Still, however, private carriage, where pipelines bought gas at the wellhead and sold it at the city-gate, dominated the transmission sector.

In 1985, the volume transported for others through the inter-state system represented some 50 percent of the total. However, many of the LDCs that were able to obtain cheap gas contracts with producers, could still be denied access to the pipelines. Because SMPs discriminated against *residential* users, the courts and FERC terminated the arrangement in October 1985. Under Order 436 they stipulated that a pipeline company providing a contract carriage service to one customer must do so to others on a non-discriminatory, "open access" basis. Furthermore, if a pipeline wants to engage in contract carriage, all of their customers can, over some years, completely transfer their private carriage to contract carriage service.

However, due to the oversupply in the market (the "gas-bubble"), many pipelines suffered from take-or-pay contracts with producers. On this basis, the Appeals Court found that a take-or-pay policy in Order 436 was inadequate. In response to this decision, FERC issued Order 500 in 1987. By this decision open access pipelines are allowed to share 50 percent of their take-or-pay costs with their customers.[42] Many pipelines applied for such certification and the number of contract carriage transactions increased.

The terms set for providing contract services have been determined by allocating fixed and variable costs, respectively, to customers by a two-part tariff (access/usage tariff). The demand charge represents the maximum daily volume of gas that a pipeline customer is entitled to purchase at any time during the year. The commodity charge represents the actual volume of gas purchased. All variable costs are incorporated into the commodity charge, but different rate-designs are used to allocate fixed costs. The volumetric method, where the commodity charge reflects all fixed costs, lies at one extreme, while the other is the fixed-variable method, where all fixed costs are incorporated in the demand charge. In most situations, FERC has employed an intermediate rate design. See Chapter 3.5.4 about multi-part tariffs for further discussion.

FERC also has jurisdiction over abandonment - the termination of a pipeline's statutory service. A pipeline cannot, in most cases, terminate a service to a customer until it is approved by FERC even if the contract has expired. Exceptions can be made if a pipeline receives a blanket authorization for contract carriage and on "off-system" sales if they do not harm on-system customers and are on an interruptible basis or inter-pipeline contracts.

But new regulations caused new problems. The pipeline could still refuse to sell gas even if it was obliged to provide transportation service if they had excess capacity. Therefore, the customer in many cases did not have the choice to substitute contract carriage for private carriage. That decision still resided to some extent with pipeline companies. The entry and exit requirements in and out of contracts posed in addition institutional barriers to inter-pipeline competition. At the same time, however, competition between pipelines increased and reduced some of the regulatory needs.

Lower oil prices, gas-to-gas competition and excess supply in the market led to dropping gas prices in the second half of the 1980s. From 1984 to 1991

[42] In between these orders, order 451 was issued, allowing renegotiation of old gas contracts to reflect current market situation. However, order 451 was never implemented.

producer prices dropped from 2,69 $/tcf to 1,58 $/tcf (tcf = thousand cubic feet), ref. figure 9.2. The weak market and the free access to transmission also led to an increase in the number of short-term agreements and spot contracts that gradually replaced many of the long-term contracts. The wishes of producers and consumers to sell and buy gas were reflected in the market faster, and the division between the transportation and the broker function became more clear-cut. Gas could now be bought from entirely new producers in new areas. Available capacity in, and open access to transmission, combined with large quantities of gas being offered, made short-term and spot contracts dominant in the market.

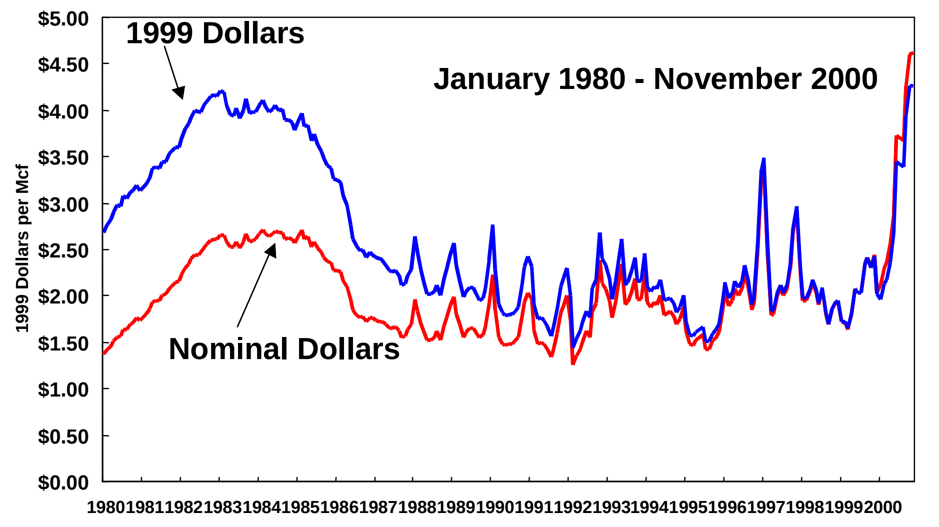

Figure 9.2: U.S. average wellhead prices 1980-2000

Source: Natural gas markets; Status and outlook, EIA January 24, 2001

With the liberalization new players also emerged in the market. Marketers started to buy gas for re-sale, and brokers began to arrange trade between parties. A market for futures contracts was also established in 1990. The marketers began to compete with the transmission company broker function when the pipeline network capacity became accessible. But during the top of winter demand, the transmission companies were assured access to the pipeline system, but not the marketers, a fact, which weakened their competitive position. In 1991 contract carriage reached 82 percent of the total market. Order 636 in 1992 was intended to further the future competitive ability by requiring that independent companies should separately arrange transportation and storage.

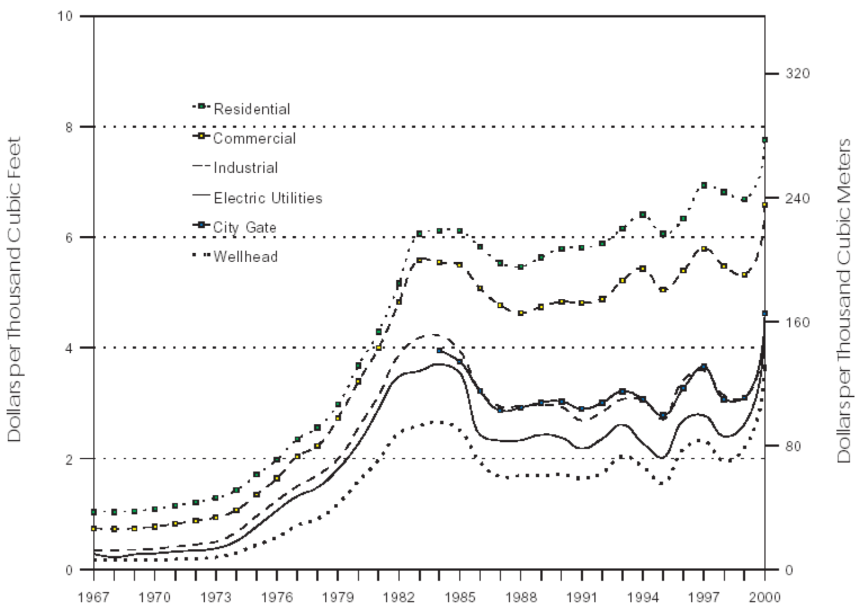

Figure 9.3: Average natural gas prices to U.S. consumers 1967-2000
Source: Historical Natural Gas Annual, EIA 2002

Figure 9.3 shows the price development for the period 1967-2000 to the various market segments. As illustrated in figure 3.2 there is varying willingness to pay for gas in the individual sectors. This is reflected in higher prices to households and companies rather that industrial users and power plants. In the American market, the difference between the prices in the different sectors was however considerably less before the liberalization than it was afterwards. In total the prices on gas followed the development in crude oil prices up till the early 1980s. In the middle of the 1980s, a significantly larger difference developed between the price of gas sold through distribution companies and gas sold to industry and power plants. When the oil price dropped in 1985/86, the market at the same time was liberalized. Both factors contributed towards a lower price on gas in all segments. There are different opinions about which of the factors was the most important for this price decline. In particular the prices on gas to industry and power plants dropped.

Already in 1991, prices to households and companies was however again at the same level as before the price drop in 1986, while the prices to industry and power plants seems to be stabilized at a lower level than previously. "The bubble" gradually disappeared in the 1990s due to the lower prices. The production decreased and the demand increased. This lead to more long-term contracts again being signed and the prices have gradually increased.[43] The ″newly established″ difference between prices to the individual segments has remained, but prices to households and companies became (nominally) higher than before the price drop, while the prices to industry and power plants in 1997 approached the same level. Compared with the price on oil products in the American gas market (including American excise tax), the price of gas has dropped far less and was again on the rise toward the end of the 1990s even though the price of crude oil was declining (the figure does not show the development after the oil price increase in 1999/2000). This is parallel to the development in Europe. In Europe the more stable gas prices are however due to higher excise taxes on oil products (see Chapter 3 and 4) while it in the United States seems difficult to explain in any other way than a tighter gas market.

Canada

In Canada, most of the gas reserves lie in the western part of the country. The province Alberta alone is thought to have about 60 percent of these reserves. Most of the population lives in the east, however. The gas network in Canada was therefore primarily built in order to transport gas from west to east. In addition, a north-south network ties Canada and the United States together.

When they were established, the four large Canadian transmission companies received support from the province or federally so that they could exploit the considerable economics of scale, which exists in gas trans-

43 Towards the end of the 1980s, occasional or 30-day contracts dominated the gas market, and represented nearly 75 percent of the total gas sales. Early in the 1990s 50 percent of the gas sales were less than one year contracts, 35 percent on a 30-day basis and the rest on contracts of longer than 30 days but less than one year (Saga, 1993). Historically, long term contracts have not been as important in the USA as in Europe.

portation (see Chapter 5). This contrasts with the American gas industry that developed from private companies. The long distances made the Canadian pipelines few and large. There has then not been much competition between transmission companies in Canada, where there is usually one or some times two transmission companies covering a single transport route.

Alberta began to regulate producer prices, inter-provincial transport and export prices in 1949, and other production provinces followed suit. In 1958 the National Energy Board (NEB) was established to regulate the construction and operation of inter-provincial and international pipelines, gas export and excise taxes and tariffs on pipeline companies under their area of authority. Up to 1970, both inland and export prices were left to negotiations between buyer and seller. NEB however set limits for how much could be exported and started regulating prices. In 1973 the industry was totally regulated by NEB.

When the lack of gas occurred in the inter-state market in the USA in the 1970s, the demand for Canadian gas rose. At this time, Canada attempted to export gas at prices corresponding to the level of oil prices, while prices of inland gas still was regulated. In the beginning of the 1980s the high international oil and gas prices, and decline in the American economy, led to reduced demand for Canadian gas. The Canadian export nose-dived with about 40 percent in a short time. Some transmission companies, especially TransCanada, suffered from large take-or-pay obligations like in the USA.

The Western Accord, signed by NEB and the provinces in 1985, forced all international and inter-provincial pipelines to become ″Open access″ transporters on a non-discriminating basis (″contract carriage″). Furthermore, the price of gas in the inter-provincial trade was to be decided by buyer-seller negotiations. The export prices remained flexible, but they were not to be lower than the inland prices.

The Western Accord specified that the broker function of the transmission companies ought to be transferred to a separate unit (unbundling). When demand exceeded supply, the capacity was distributed according to how terminable the contracts were in descending order from irrevocable to terminable agreements. Within each group of contracts, the capacity was distributed on a ″pro rata″ basis (see Chapter 5). The tariffs were all of fixed-variable type, where all fixed costs were put into the “demand charge” part. Take-or-pay costs could not be included in the transport tariffs. According to American terminology, the Western Accord made the transmission companies to ″common carriers″.

Great Britain

Up to the mid 1980s, the state owned company British Gas (BG) had close to complete control of the entire gas chain, having exclusive rights over transmission, distribution and retailing of gas. BG was also a sizeable producer, in addition to aggregating and purchasing all production (from a large number of producers) on the British Continental shelf. The market was divided into a "tariff market" (mainly the residential and commercial market) and a "contract market" (mainly industrial customers).

The Oil and Gas Enterprise Act of 1982 allowed for sales of gas to end-users by others than the BG, but these had no access to the BG gas grid. In 1986, British Gas was privatized and the Gas Act created an Office of Gas Supply (OFGAS). The Act defined the terms on which parties could transport gas through the BG grid, but new actors did not enter the market to any significant degree. The Monopolies and Mergers Commission (MMC) stated in 1988 that the BG did not provide adequate information of cost on third party transportation and that it was able to discriminate between customers because of it's market dominance. BG was requested to publish more information about their charges, how they were calculated and unbundle the operations of transportation and marketing/purchasing. Furthermore, in 1990, OFGAS initiated a 20 to 40 per cent reduction in transportation tariffs.

The liberalization of the production of electricity became particularly important. In 1989 the ”Central Electricity Generating Board” (CEGB) was privatized and divided in two. The company National Power was to take care of local distribution through the regional electricity company, while the power generation (not nuclear power) was to be handled by the company PowerGen. The transmission company, National Grid, was to ensure that supply and demand was kept in balance at all times through a so-called ”pool”. While British Gas at first was only privatized, without any significant changes in the market stemming from it, the electricity industry was split into production, transmission, distribution and sale from the start.

Through the liberalization of the electricity industry, power manufactures began to build combined-cycle turbines that used gas as an input factor. As long as British Gas no longer had a purchasing monopoly on produced gas, the gas producers could sell to this new part of the power industry where they could also gain higher prices. At the same time, producers began selling directly to large industrial users, where they could undercut the regulated prices of British Gas.

Into the 1990s, relatively short-term agreements between producers and buyers were developed, and the spot market that was created through this also began to affect the long-term prices. In 1996 the International Petroleum Exchange (IPE) published a forward contract, and trade in gas futures contracts began. Many marketers and electricity producers now purchased gas directly from producers. But BG's competitors maintained that the market still did not function with a satisfactory degree of competition. MMC recommended in 1993 that BG's transport and broker functions should be completely separated by 1997, that the threshold for monopoly supply to tariff customers should be reduced, and the feedback rate when calculating the prices of the transmission companies should correspond to 6.5 to 7.7 percent on new investments.

British gas demerged into Centrica in 1997. Centrica plc became the trading name for British gas in the UK, while BG plc continued outside Great Britain. In 1998, all of the British gas industry was opened for competition, and British gas spun off its transmission and distribution activities (Transco). BG plc maintained ownership of Transco. Transco demerged from the BG Group in 2000 and became part of the Lattice Group plc.

In 1993, the plans also started for the building of the Interconnector between Bacton and Zeebrügge, which was to tie the continental and the British markets together. The first gas was sent through the system in October 1998. Through Interconnector, the liberalization of the British market will also influence the development elsewhere in Europe, where the gas can be sent through the system both to and from Great Britain. Zeebrügge may develop into a significant hub for buying and selling of gas, not least the short-term agreements. At the same time, the connection between the British and the continental markets may contribute to converging prices in the two markets.

Relevance for the Continental European Market

In the discussion of the EU Commission's ideas on a more liberalized European gas market, it is important to keep it within the context of the Western European market structure. The most striking *difference* between today's European and U.S. gas markets is that in Europe, there is strong concentration around few firms at most levels and segments of the market, while in the U.S. there are thousand of producers and a well developed market infrastructure. While the typical pipeline in Europe faces oligopoly and oligopsony at its entrance and exit, the typical U.S. pipeline faces something closer to competition at each end. In the U.S., because of the competitive structure at the end of the pipelines, the transmission companies' market power may be even stronger than in Europe. On the other hand, a more comprehensive U.S. grid indicates more interpipe competition.

In Europe international trade of gas has been negotiated bilaterally, as between U.S. States before 1938. The role of the EU Commission in intervening in (parts of) the market may parallel the U.S. federal government's role in regulating the inter-state trade at that time. However, it is interesting to observe that even more than *50 years* after the first regulations passed Congress in 1938, the U.S. gas market still suffered from undesired inequities. The wishes of the Congress were not always enough to make the market conform to its desires. Repeated regulations and deregulations have often lead to undesired results with dramatic stop-and-go policies following.

These experiences indicate that regulations should be made with a consciousness of the market framework and mechanisms and how these may *evolve*. Placing a lot of this judgement on policymakers and lawyers, may create inefficiencies in Europe, as it has in the U.S.. If it is possible to find self-regulatory mechanisms, the damages on the economies made by misjudgments and inefficiencies created may be reduced.

It is also worth observing that the choice of *doing nothing* probably has been considered the worst possible solution in the U.S. Few suggested that the situation that existed before the NGA was implemented in 1938 was better than the more or less regulated situations after. Correspondingly, it is not likely that we in Europe may face any significant reversal of the liberalization processes which the Gas Directive has helped initiate.

This far, a *supra-national* regulator, corresponding to the federal FERC in the United States, is not found in Europe. European gas trade is still international. This is both due to the EU being mainly a confederation and not a federation like the US, and that a lot of gas will be imported from areas outside EU's area of authority. The most important "outside country" in this context is Russia, even if the EU can affect the Norwegian sale of gas through the EEA agreement. North African gas is also outside the jurisdiction of the EU. In the USA, only smaller parts of the consumption are imported. The absence of a possibility to regulate the entire market limits the possibilities for a full liberalization of the European market. The fact that the trade passes through national states outside and inside the union, with all their differences, underline the problems of handling divergent economic interests in Europe.

One important experience from the USA is that a more liberal market led to larger and more price variations even though competing energies and production costs over time limit these variations. It is however important to note that the drop in American prices at the end of the 1980s was caused both by lower oil prices and a surplus of gas. Correspondingly the American gas prices rose in the 1990s, due to a better balance between supply and demand. A liberalized European gas market must also be assumed to lead to higher prices when it is tight and lower prices when there is a lot of unused capacity, that is, a somewhat more independent pricing of gas than in today's market (Chapter 3).

Another experience is the larger variations in contractual terms. The faster and stronger the market responds to a change in supply and demand, the faster the portfolio of long-term, short-term and spot contracts changes. To what extent this leads to a desire to re-negotiate existing (long-term take-or-pay) contracts in Europe, depends on how much the existing contract portfolio resembles the portfolio a given liberalized market would give. Both producers, transmission companies, LDCs, large industrial consumers and power plants may demand renegotiations of existing contracts if the portfolio differs a lot, and enter into new contracts where they are most advantageous, if possible. In a tight market, producers may achieve better prices by signing contracts directly with the customers, while the customers may obtain lower prices directly from producers in a weak market.[44] As long as pipeline companies are able to sell the amounts of gas they have contracted at present prices, it is unlikely that demands for renegotiations will arise. The problems may occur if producers enter the market and directly competes for existing customers. In this case the pipeline companies might wish to renegotiate contracts with producers through the TOP problems they may get.

[44] Hagen (1994) discusses the similarities and differences between the European and the American gas markets in more detail.

10 Norwegian Gas in International Affairs

Energy and Politics

Scarcity of oil and gas will continue to characterize international energy markets, either in an economic, physical or political sense, over shorter or longer time. With a constantly increasing Norwegian petroleum production, it is likely that the international community closely will observe petroleum developments in Norway. Apart from security policy, petroleum issues may be the most central single factor in Norwegian foreign policy, simply because the outside world defines it so.

As natural gas is a non-renewable resource which requires development of long-term, costly and immovable transport capacity, Norwegian gas production creates a dependency with strategic and security consequences for Norway. The size of the natural gas exports makes Norway a strategic player in a market of vital interest for the energy supplies to Europe. The economic development and national security of the receiving countries depend on secure supplies of energy at stable prices on an acceptable level.

Norwegian gas strategy, therefore, must be conscious that the superpower USA, the EU and great European purchasing countries like Germany, France, the UK and Italy, as well as competitors Russia and Algeria, among others, will be interested in its content. International attention towards Norwegian oil and gas policy must be expected to increase as the production volumes increase (also) for natural gas and energy markets become tighter. Norway has through this gained increased significance for both other producing countries and for countries which buy oil and gas, also in peacetime.

As an example of how Norwegian petroleum policy may be influenced from the outside world, this Chapter will analyze the case when Norwegian energy policy first became an explicit element in a larger political game. In order to prevent Western European countries from completing a notable gas contract with the Soviet Union in 1982, the U.S. introduced a ban on all American exports to firms supporting the project. Also the U.S. boycotted European firms supplying equipment. The Americans claimed that if Western Europe became too dependent on Soviet gas, one might come under pressure in a future political crisis if the Soviets turned off the taps to stop the energy supply. The U.S. urged Norway to increase her gas exports as a substitute for Soviet gas.

Norway, on the other hand, maintained that gas production could not be increased as quickly as desired. This was due to the long time lags between the making of a field development decision until actual production can take place. The Norwegians also wanted, in case a development should be accelerated, a "price premium" to justify an act that otherwise would have been different.

To analyze this situation we must try to understand the underlying motives of the conflict. Was the argument regarding the risk of supply disruption the sole American concern? Also it is a question whether or not the US strategy was a realistic one. Was the policy acceptable or possible to buyers and sellers in the market? Furthermore, it is interesting to discuss whether or not Norway played her cards right when responding to the American requests. Could she have gained by some other strategy? And finally, we pose the question if anything can be learned if Norwegian petroleum again should be linked with international conflict.

Soviet Gas Export and American Interests in 1982

The background for the conflict in the early eighties was that the Soviet Union planned to construct a pipeline with a capacity of 40 billion cubic meters (BCM) per year. The pipeline was to transport gas from the Urengoy field on the Yamal peninsula in Western Siberia to Western Europe. Yamal is about 4000 km from Western Europe, with permafrost and difficult weather conditions. In Western economies the project would probably not have paid off at the time. But since it would bring the Soviet Union considerable revenues in convertible currency, while the expenditures were paid for in roubles, the project was assessed as profitable from a Soviet point of view.

The purchasing countries were West Germany, France and Italy. At one stage, the Netherlands and Belgium too were about to buy Soviet gas. While the initial volume was set to 40 BCM, it was later reduced to 25-30 BCM. This represented a Soviet share of 30% of the German and French and 40% of the Italians' gas import.

The Carter Administration was skeptical to such a gas agreement already in the late 70's. The view was that Western Europe would become to dependant on energy supplies from the Soviet Union. Assistant Secretary of Defense in the Reagan Administration, Richard Perle, made the arguments more clear in November 1981 ("Defense" February 1982) as a threat to Western security. *First*, the exports gave the Soviets vast revenues in hard currency. This enabled them to import technology for military use. It would also release civilian resources, which in its turn could be used for military purposes. *Secondly*, Perle thought the project would result in the formation of economic bonds between Western Europe and the Soviet Union. This could widen Soviet influence on U.S. allies, and could, over time, contribute to a Soviet desired division between the U.S. and Western Europe. *Thirdly*, in a crisis the Soviet Union could disrupt the gas supplies to injure the West. A *fourth* argument, which was put forward later, implied that parts of the equipment delivered for the construction of the pipeline itself could be used for military purposes. Thus, the fear of a supply disruption was only one of several U.S. arguments to stop the Soviet gas supplies.

The Soviet Union was, as Russia still is, very dependent on energy exports to earn convertible currency. In 1970, the country earned $ 444 million from its energy exports, which represented 18.3% of its hard currency revenues. In 1980 these revenues amounted to $ 14.7 billion, or 62.3% of hard currency revenues (Jentleson, 1986). In 1986 the energy share of Soviet hard currency exports had increased to 80% (Austvik, 1987b). Other products of interest to Western countries have not been and are still not many. Consequently, for the Soviets, the gas export deal became an important target in improving foreign trade balances.

Thus, if the U.S. should influence the Soviet economic situation, the gas agreement became an attractive target. Besides, the Soviet Union was in great need of Western technology in its energy production. Therefore, the technology transfer through the shipment of equipment for the pipeline construction had a double economic significance. New technology could make the Soviet Union more efficient. This strengthened the Reagan administration's conviction that the pipeline had to be stopped: an economic strong Soviet Union would be more dangerous than a weak one.

The American policy was to a large extent a result of the relationship between the superpowers after the Soviet invasion of Afghanistan in 1980. The U.S. assumed that the Soviet Union would face a difficult economic situation, with a deficit in foreign trade and lack of hard currency. Not only limiting the access to Western technology and credits, but also by curtailing Soviet trade with the West as such could worsen this situation. An autarchic state usually exploits its resources less efficiently than a trading state.

As both an economic and a military superpower it seemed logical for the Americans to link economics with politics in order to promote their interests. This is in particular valid vis-à-vis an opponent which more or less exclusively was a military superpower and was regarded as rather under-developed in economic terms.

Therefore, the Polish state of emergency in 1981 became a convenient reason for the American measures. The Polish situation gave the U.S. a concrete reason for introducing sanctions against the pipeline. "The Evil Empire", as Reagan called the Soviet Union in his first presidential term, had to be punished for the treatment of Poland.

Economic Pressure as a Foreign Policy Instrument

The use of economic pressure to change other countries' policies is not unknown. The United Nations undertook economic sanctions against Rhodesia and South Africa with rather limited success. The U.S. undertook grain embargoes against the Soviet Union, also with limited achievements. The first time international economic sanctions were undertaken in an effective manner (with a substantial majority of countries participating) was evidenced the UN sanctions against Iraq after the invasion of Kuwait in 1990. However, in general, sanctions have proved rather ineffective in obtaining political goals (Allison & Cornesale, 1988).. This has mainly been due to three factors:

- Individuals, businessmen and others who have to endure the burdens of an economic boycott are not willing to do so. This was for example expressed by American farmers who put pressure on President Reagan to cancel the grain embargo imposed on the Soviet Union by the Carter Administration in 1978.
- Countries representing alternative sources for the boycotted country have refused to cooperate. This may be due to diverging views as to the purpose of the penalty. Or they find that an undue share of the burden by the sanctions falls on them. During the grain embargo in the late seventies, Argentina did not only allow sales to the Soviet Union, but twisted the export to some extent away from her former markets to the Soviet Union (Mastandano, 1985).
- It has not always been easy to predict the reaction of the country subjected to economic pressure. It may be milder, but can also get harder. Besides,

countries depend on trade in varying degree. This puts limits (as well as it creates potentials) as to what may be achieved through a boycott.

Here, I shall distinguish between three ways of using economic pressure to reach political goals: economic warfare, tactical linkage and strategic embargo.

Economic Warfare

Economic warfare implies, in short, to weaken another country's military potential by hurting its economy. This presupposes linkages between the country's trade and economic development as well as between its economy and the military. Improved technology, a better-qualified labor force and a more sophisticated civilian sector will strengthen the military beyond the effect of the imported goods as such.

Such a strategy does not necessarily have to be applied to all goods. In principle, it may be selective by picking those indispensable to the penalized country, while of less economic importance to the sanctioning part. One must find goods where demand in the target country is very inelastic, where the costs of indigenous production are unreasonably high and where it is (made) impossible to retrieve from other contractors.

Highly developed technological equipment will very often be such an objective. Apart from being important for the military, technology is also a bottleneck for economic development. Because the gas contracts represent significant Soviet income in hard currency, they will also be a suitable goal under a policy of economic warfare.

Tactical Linkage

Tactical linkage is a systematic combination of economic and political/military elements aimed at influencing the policies of the target country, rather than weakening its military capability through a weakening of the economy. If trade can impair the opponent's benefit from the military apparatus, even when this is still being built up, the net result regarding own security may well be positive. A country's security is not only dependant on the military capability of its opponent, but also on the costs involved for the opponent of using this capability.

In such a strategy the trade policy will be adjusted according to how content one is with the policy of the opponent. The trade may be extended if this policy is seen as positive and reduced if not. The adversary will then actually be inhibited in his actions in the sense that a political action may imply a loss of an important trade agreement. If the contract is sufficiently extensive and important the dominant country may gain political influence in the target country through the economic dependence which have arisen and the personal ties that have been established. An economic interdependence has been developed which reduces the interest in waging war against each other.[45] The influence will, however, in varying degree go both ways, positively as well as negatively.

The reason why the U.S. embargo of 1982 usually is not regarded as a linkage policy is that it was linked with Soviet policy at large, rather than with any singular aspect of it. And it aimed at reducing trade and relations, rather than increasing them.

Strategic Embargo

By a strategic embargo the concern of the sanctioning country is not to weaken the opponent economically. It merely wishes to strike goods that can be of direct military use. The prohibition of contraband in wartime is the most typical example of a strategic embargo.

During a strategic embargo, export of goods that reduce economic bottlenecks in the target country is allowed as long it doesn't affect military ones. Raw materials have historically often been such goods, while technology may be more predominant today. As long as equipment for the gas turbines is of no military relevance, a boycott of the Soviet gas supplies will not be included in such a strategy. Limitation of technology export under the Consultation Group Coordinating Committee in COCOM[46], however, must be characterized as a part of a strategic embargo.

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[45] This is an important reason why another war between France and Germany seems quite unlikely today. Both countries will have more to loose than to gain by destructing the other. Before this economic (and political) interdependence was established, these two countries have fought wars regularly over centuries. Such a linkage philosophy is also a major element in the German "Ost-Politik" from the sixties. Making east and west economic interdependent, the blocks would gradually converge.

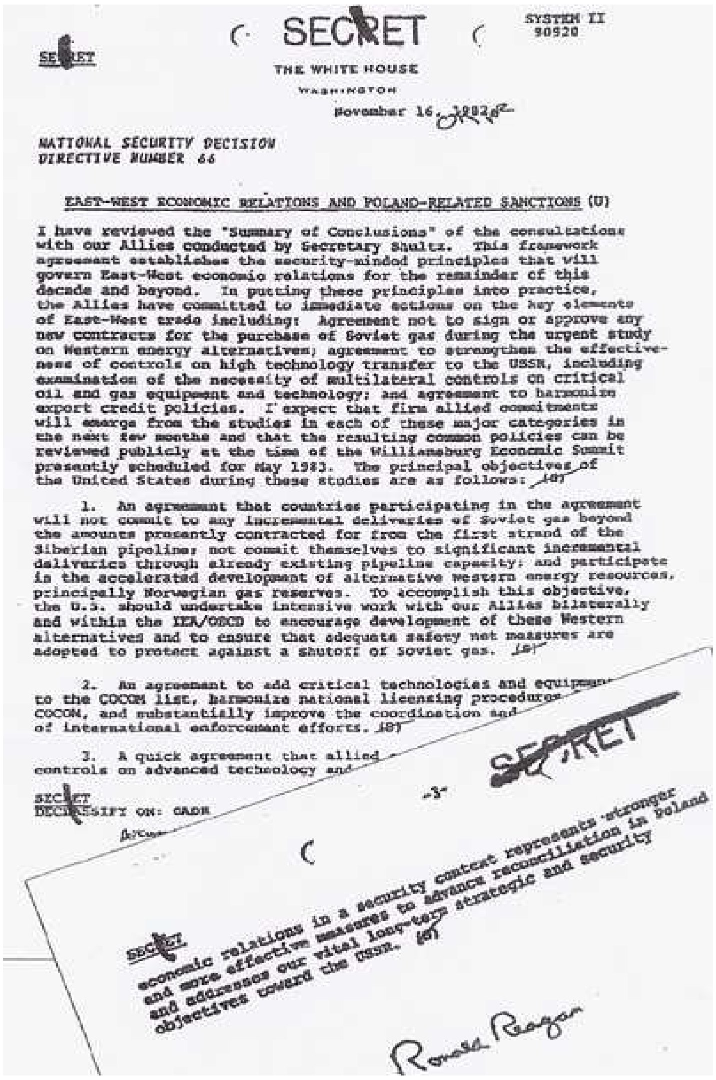
46 The Coordinating Committee for Multilateral Export Controls (COCOM) consisted of representatives from all NATO countries (except Iceland) that, between 1949 and 1994, coordinated policies restricting exports of products of potential strategic value to the former Soviet Union and certain other countries. Created in 1949, the committee not only reviewed military technology transfer for potential embargo but also tried to anticipate the end use of products manufactured for civilian purposes, such as computers and transistors. For reasons including the disintegration of

Why Did the US Boycott Fail?

In 1982, a delegation under the auspices of the U.S. State Department went to induce the Western Europeans not to buy Soviet gas. Western Europe should rather choose alternatives to meet their increasing energy demand. The arguments in favor of such diversion were close to our notion of economic warfare, even though the whole range of arguments was actually used (cf. Perle's list): An economically strong Soviet Union is more dangerous than a weak one. The U.S. compensation package contained two main components: American coal (Jentleson, 1986: 185-187) and Norwegian gas (see President Reagan's letter in figure 10.1) were presented as alternatives to Soviet gas.

The proposal concerning American coal was somewhat vague as the capacity needed for such an export was not obtainable in the U.S. at the time. Besides, coal entails an environmental problem and may be seen as inferior to gas as a source of energy. Complete solutions as to transportation across the Atlantic were also omitted.

the Soviet Union and the goal of assisting economic and political reform in Russia and the Newly Independent States, the COCOM partners agreed in 1993 to end the Cold War regime effective March 31, 1994, and to work toward a new arrangement to enhance transparency and restraint in exporting conventional weapons and sophisticated technologies to countries whose behaviour is cause for serious concern and to regions of potential instability. The successor regime to COCOM is the Wassenaar Arrangement on Export Controls for Conventional Arms and Dual-Use Goods and Technologies, which began operations in September 1996 and is headquartered in Vienna, Austria. (Source: US Department of State, International Information Programs, 2002).



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November 16, 1982

NATIONAL SECURITY DECISION
DIRECTIVE NUMBER 66

EAST-WEST ECONOMIC RELATIONS AND POLAND-RELATED SANCTIONS (U)

I have reviewed the "Summary of Conclusions" of the consultations with our Allies conducted by Secretary Shultz. This framework agreement establishes the security-minded principles that will govern East-West economic relations for the remainder of this decade and beyond. In putting these principles into practice, the Allies have committed to immediate actions on the key elements of East-West trade including: Agreement not to sign or approve any new contracts for the purchase of Soviet gas during the urgent study on Western energy alternatives; agreement to strengthen the effectiveness of controls on high technology transfer to the USSR, including examination of the necessity of multilateral controls on critical oil and gas equipment and technology; and agreement to harmonize export credit policies. I expect that firm allied commitments will emerge from the studies in each of these major categories in the next few months and that the resulting common policies can be reviewed publicly at the time of the Williamsburg Economic Summit presently scheduled for May 1983. The principal objectives of the United States during these studies are as follows: (S)

1. An agreement that countries participating in the agreement will not commit to any incremental deliveries of Soviet gas beyond the amounts presently contracted for from the first strand of the Siberian pipeline; not commit themselves to significant incremental deliveries through already existing pipeline capacity; and participate in the accelerated development of alternative Western energy resources, principally Norwegian gas reserves. To accomplish this objective, the U.S. should undertake intensive work with our Allies bilaterally and within the IEA/OECD to encourage development of these Western alternatives and to ensure that adequate safety net measures are adopted to protect against a shutoff of Soviet gas. (S)

2. An agreement to add critical technologies and equipment to the COCOM list, harmonize national licensing procedures COCOM, and substantially improve the coordination and of international enforcement efforts. (S)

3. A quick agreement that allied controls on advanced techoology and

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economic relations in a security context represents stronger and more effective measures to advance reconciliation in Poland and addresses our vital long-term strategic and security objectives toward the USSR. (S)

Ronald Reagan

Figure 10.1: Letter from President Reagan Source: Lerøen 1996:79

The proposal of Norwegian gas implied problems the Americans obviously had not been aware of. Jentleson (1986) claims that the Americans found that the Norwegian government lacked the will to increase production above existing plans. But for Norway it was technically impossible to increase production as fast and as much as desired.

Apart from putting forward these rather unrealistic alternatives, the U.S. failed to include a proposal of compensation for the loss of export contracts for equipment to the pipeline. The basic conditions of a "just" burden sharing when a boycott is introduced were consequently broken in the proposal.

In addition to the differing economic interests in the burden sharing, there was a political divergence between Western Europe and the U.S. on the desirability of an embargo, as well. First, Western Europe had, partly with strong internal opposition, just been deploying Pershing and Cruise missiles. This complicated an acceptance of another Western initiative against the Soviet Union.

Secondly, most countries thought the gas supplies would result in a lesser degree of dependence than what was maintained by the U.S.. Much of the risk of such a dependence could be counteracted by enlarging storage facilities for gas, increasing the flexibility of the national distribution systems and securing the supply of Dutch and Norwegian gas in the long term. Even though the Western European countries did not reject the possibility of a Soviet stop in supply in a worst case scenario, they did not see themselves as vulnerable as the Americans did.

A third divergence occurred as the Europeans thought the Americans overestimated the strategic Soviet advantages of the agreement. It was argued that the Soviets would benefit from high technology import, i.e. the importance of a strategic embargo. The views, however, differed as to what degree hard currency incomes would increase Soviet military capability. There was, in other words, no consensus on the effect of economic warfare.[47]

When the supplies of compressors and other equipment commenced at the end of August 1982, President Reagan banned all American export to those firms that supplied the project. Despite the ban, however, supplies of the European equipment continued. When President Reagan, the same fall, increased U.S. grain exports to the Soviet Union, the European countries became even less willing to break the contracts.

[47] The Western European Governments acted rather similarly despite different ideological make-up. The EC protested against unacceptable interference in sovereign decisions in member countries. Margaret Thatcher used British economic interests as an argument to pursue with the supplies of the equipment. The Western European joint reactions may have improved their positions at the expense of the U.S..

The tension was eased on November 13, 1982, as the U.S. terminated the sanctions. No European return services were agreed upon, but it was settled (Jentleson, 1986) that Western Europe should close no further gas contracts with the Soviet Union until a) The International Energy Agency (IEA) had completed a study on the danger of becoming (too) dependent on Soviet gas; b) the OECD had concluded a study on the effects of export credits to the Soviet Union; c) a COCOM agreement was reached on limitation of high tech export to the Soviet Union and d) a NATO study of the significance of trade in general between the WP and NATO countries was completed.

The gas volumes were reduced as compared to the original 40 BCM per year. The U.S. claimed that this was a result of the pressure put on the Western European countries. The countries themselves declared that the market situation had led to this reduction. Decreasing oil prices and weaker economic growth were the main reasons, and most central suppliers of gas to the Western European market had to reduce their quantities according to the expectations. Commercially there was no reason to consider Soviet supplies more insecure than for example Middle East supplies or Norwegian gas supplies. From an energy policy view, the absence of Soviet gas supplies would imply less diversification between different suppliers and weaken European security of supply. In addition, a boycott could provoke the Soviets and, thus, weaken the security political situation rather than strengthening it.

Though the joint economic warfare against the Soviet Union failed, an agreement was reached on revising and updating the COCOM rules, in other words; on a strategic embargo. The U.S. wanted a somewhat longer list of commodities on the COCOM-list than her allies did, while these accepted a more consistent enforcement of the rules and control with Soviet agents involved in technological espionage in Western countries. Western European and U.S. economic interests diverged to some extent, as more trade with data equipment took place between Western and Eastern European countries than between the U.S. and Eastern Europe. In June 1984, however, an agreement was signed imposing a strategic embargo on the Soviet Union through the COCOM rules.

Norwegian Reactions and Strategy

Norway expressed, in response to the American initiative, that it would be impossible to accelerate production, for instance from the Troll field, sufficiently to make Norwegian gas a real substitute for Soviet gas in the short and medium run. Even though the U.S. appeared to have difficulties in accepting this, the reaction seems correct enough. It does take a long time to develop a gas field in the North Sea, often as much as 5-10 years.

Furthermore, Norway stated that if production was to be accelerated compared to existing plans in the long term, Norway should get an additional price to justify the increase. There would be no reason for Norway to increase gas production if profit was not increased as compared to existing expectations. By this strategy, Norway put forward wishes for a higher price than her competitors for security policy reasons. This line was pursued until the fall of the Willoch government in 1986, without any gas contracts of significance having been signed. When the Harlem Brundtland government adopted a form of market pricing in 1986, the Troll negotiations were eventually speeded up.[48]

Views may diverge about what should be the aim of Norwegian strategy in 1982. Even though higher prices in new contracts was one option, implicitly a volume increase, Norwegian interests would also have been promoted through price guarantees, securing access to the markets and flexibility in the contracts, to mention a few. Actually, the Gas Committee established at the time was concerned that the Norwegian negotiating position was threatened.[49]

Should the goal be limited to desire for more profits by new gas sales compared to previously expected profits, it is vital to have an opinion of how the market functions. An increased price may be obtained by being preferred to competing exporters. But is it possible to be preferred to other exporters in terms of price? If the answer is yes, one has to establish whether this is a result of commercial calculation only or, as in this case, whether it can be made on political grounds as well. Or can higher prices only be achieved when prices in the market in general are increasing? If so, is there anything Norway can do to make this happen? And is it desirable?

If the objective is modified from aiming at higher prices to promoting Norwegian gas interests in general, an increase in volume could also be a goal in and by itself. An increased volume will be important, partly because production and transmission of gas is an industry with obvious elements of

[48] Another important reason for the lack of new contracts was a weak market development in the first half of the eighties. In the second half demand increased again.

[49] This Committee consisted of Deputy Energy Secretary Hans Henrik Ramm, Statoil Head Arve Johnsen, Saga Head Asbjørn Larsen, Director Trygve Refvem from Norsk Hydro and Director Tore Sandvold from MPE. The Committee was later expanded with Deputy Foreign Secretary Thorbjørn Frøysnes.

economies of scale. A large production usually implies lower costs per unit than a smaller one. But will volumes increase primarily due to a growing total market where all exporters increase their export? If so, is there anything that can be done in order do expand consumption of natural gas in Europe? Or is it so, that Norway had the potential for enlarging her market shares at Soviet expense when parts of the central framework of the market changed in 1982?

A totally different objective could have been to improve Norway's economic and political relations with the outside world in general. As a significant exporter of petroleum in a strongly politicized market, this is, of course, a relevant aspect to be considered in an overall strategy. The importance of considering such aspects was clearly demonstrated in connection with the signing of the Troll agreement. In order to accept this commercial agreement the French government required an improvement in a series of fields in the Franco-Norwegian relations. An important aspect of such type of national linkages is that parts of the deal cannot be negotiated on the commercial level only, but directly involves governmental bodies and politicians.

The purpose of the discussion above is to point out that the choice of objective and strategy has to be made according to how prices and volumes are formed endogenously in the market and the exogenous factors influencing the market. This equilibrium is very hard to find. But it is, in one way or another, being created by techno-economic barriers, structures of production, transmission and distribution, diversification wishes on commercial, competitive and security grounds, as well as by overall economic and political assessments. Equilibrium can be changed over time, as capacity is being increased, management capability (political and commercial) enhanced, political and commercial positions changed, demand and overarching political structures develop, new pipelines constructed, etceteras.

On the basis of these observations, additional questions may be posed. Did the situation in 1982 per se alter the functioning of the market or the strategies of the actors, in such a way that Norway's situation as a gas exporter was significantly improved? Could the situation be used to influence and improve the frameworks or the functioning of the market in the interest of Norway? Clearly, a "free market" in a microeconomic sense does not exist anywhere. And the case discussed demonstrates that in the European gas market, political overtones are more pronounced than in most other markets. There may be no real long run development of the market based on pure economics. Politics may well, from time to another, overthrow any of the expectations based on purely economic analyses. Therefore, perhaps Norway should more actively play her own "cards" into the formulation of the outcome?

Gold Dust Parity?

At the time the U.S. put forward the wish for increased Norwegian gas sales to substitute Soviet gas, oil prices, and consequently gas prices in Western Europe, were high. In the market there were expectations that new large gas contracts would be signed at high prices. The Statfjord contract of 1980/81, which till then represented the highest prices of natural gas in Europe, underlined these expectations. The U.S. pressure on the purchasing countries to buy Norwegian instead of Soviet gas was added to this favorable market situation. In the early 80's the prospects for Norwegian gas trade seemed bright, both in a commercial as well as in a political perspective.

The breakthrough came through the Gelsenberg deal and the later Statfjord/Gullfaks/Heimdal contract. James Allcock, at the time Purchasing Director in British Gas disapproved the Norwegian high price demands so much that he asked whether or not “gold dust parity” would be the next claim (Refvem 2002). Algerian Sonatrach tried to pursue the same principles without much success. After the rejection of the Sleipner deal the Norwegian negotiating position was weakened, as the UK no longer could be considered a market for Norwegian gas. Earlier British gas was a competitor to the “Grand Alliance” of purchasing companies on the Continent (cf. Chapter 2). Thus, for the Troll gas, the only alternative to sell it to the Continent was to delay production. The final terms for the Troll contracts in 1986 were a decisive step back from the price premium policy, where at the same time, also the high prices for Statfjord gas were adjusted down.

The Norwegian "price premium" policy mainly rested on the ground that prices, first, certainly must cover all expenses attached to the development of fields and pipelines. Secondly, gas production was put up against crude oil production. If gas production was less profitable than oil production, there would be no reason for Norway to increase sales, at least not in such a degree that would have been necessary if Soviet gas should be replaced. Consequently, the reason for the Norwegian price demand had its basis in production economic considerations.[50]

[50] The "price premium policy" for gas contributed to the formulation of a Norwegian "oil option policy". In short, the latter formulated that if the higher gas prices were not accepted, oil fields would rather be developed and the gas will remain in the

In Norway, much attention was paid to the U.S. argument that the Soviets, in a crisis, could turn off the tap. But, as outlined above, the disruption scenario was only one of the American arguments for halting the supplies. Even though Western Europe had considered the risk of a supply disruption, it was only one part of their overall risk assessment. For them, in an overall evaluation, it was desirable and beneficial to pursue the import deal with the Soviets. In a crisis, common Western security and/or American interests would eventually be jeopardized, not only the interests of individual European consuming countries. Thus, the Norwegian price premium policy can not be defended as well from a market point of view as it can be argued from a production point of view.

It was the *American*, and not Western European governments, that wanted the Soviets to sell as little gas as possible. A price premium on Norwegian gas should, consequently, be invoiced to the U.S. or, for instance, NATO. Whether it would be possible to make the U.S. pay such a premium is doubtful, when regarding American administrations' previous reluctance to cover the expenses of others when economic sanctions against the Soviet Union are imposed (cf. the grain embargo and the reaction of American farmers). It also seems most unlikely that NATO, as an organization, could agree upon such an arrangement, when taking the conflicting interests across the Atlantic into account. The conclusion is that it would be difficult to achieve a price premium, whether paid by the consuming countries, the U.S. and /or NATO.

Of course, security against disruption in energy supplies is vital to all importers. To reduce the chances for being pressured economically and to suffer under a supply disruption/reduction, whether for technical or political reasons, most countries want to reduce their dependence on oil imports (and, thus, supplies from the volatile Gulf region) and increase the use of alternative energy sources. Such a philosophy of risk aversion is to be found in all international trade and division of labor. There must be a mutual trust to make the international system work, which is only partially the case.

Each importing country must have an opinion about the costs of maintaining high self-sufficiency (if gas is produced domestically) vs the (short-term) benefits of basing much consumption on (basically cheaper) imports with the risk of a supply disruption. Similarly, the (short-term) benefits of relying on few energy carriers and suppliers in the import balance

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ground. This policy contributed to the doubling of Norwegian oil production in the period 1986-90.

must be gauged against the risk and costs involved in such one-sided reliance if it is possible to (more costly) diversify imports.

This security-of-supply situation is different for Western European countries when assessing the sensitivity to imported gas as opposed to imported oil. The infrastructure in the European gas market makes the rigid physical linkages between countries important for security. For oil dependence, the price of oil, for most countries, is the variable to be concerned with. Oil can, in a crises (in peace time), still be imported from any producing country, but at an unacceptable high price involving unemployment, inflation and possibly recession. Gas, on the other hand, cannot be imported from another country if pipelines or LNG terminals are not built. In the short and medium term, a one-sided dependence on one single exporter makes an importer vulnerable to economic exploitation, as well.[51]

The probability of a disruption and the damage it may cause must be large enough to offset the costs in non-disruption periods to diversify more than (short-term) economic considerations dictate. Faced with the disruption scenario as a motive, the Soviet Union benefited by the Western European perception of the situation.

In fact, the argument of supply disruption could be turned *against* Norway. In a scenario where one supposes that the Soviets would turn off the tap, in an extreme state of tension between East and West, they will also lose their currency revenues. What if they, instead, could reduce Norwegian supplies? Then they would reduce the supply of energy to Western Europe at the same time as they (most likely) maintained their currency incomes. Western Europe would then be even more dependent on the Soviet supplies. Possibly, the likelihood that the Soviets should turn off their own taps is such a dramatic scenario that the political climate could make such a pressure on Norway likely, too. This clearly demonstrates that the evaluation of risk as to a supply disruption must be put into a wider context in order to prove meaningful.

Could Alternative Strategies Been More Successful?

[51] This is the situation for some East European countries and former Soviet republics throughout the nineties, being one-sided reliant on Soviet gas supplies. Many of these countries are even one-sided physically dependent on Soviet oil supplies, with no access to the sea and costly development of oil pipelines.

To illustrate some alternative strategies to the price premium policy, I will mention some options below which possibly would fit better with the way the market works combined with how the interests were positioned in the conflict at the time.

- With the huge costs of developing Norwegian fields, it would have been important to Norway if she was guaranteed a certain price for a long period of time. Such a price guarantee would perhaps have been obtainable in a good market situation, as in 1982-85, simply because it *sseemed* improbable that it would ever be effective. In a weak market with low prices, such a guarantee would function as a price premium. In a situation as in the latter half of the eighties and beyond, with low prices, Norway could have profited considerably from such an arrangement. Various marginal improvements of normal contracts at that time could (from Norway's point of view) have been implemented as well. Most likely, signing the Troll contract in this period would have resulted in better contractual conditions than in 1986, when it was actually signed.
- The preference for one exporter may also be expressed through more favorable take-or-pay clauses than what other exporters get (see Chapter 2). This can also be done through more favorable force majeure conditions or, generally, by giving one seller more security against variations in quantity demanded than other suppliers, or that compensation systems favor particular sellers.
- The transmission companies (the pipelines) for gas are the third actor in the market, in addition to seller (producer) and purchaser (distribution companies, large industrial consumers and gas power plants). In the case of the Austro-Norwegian gas agreement of 1986 Norway witnessed how the pipeline company (here: Ruhrgas) for a long time was able to impede the fulfillment of the contract. Perhaps, a more reliable access to the continental pipeline systems, at a reasonable tariff, should have been contemplated as an element of the negotiations in order to improve the conditions of future Norwegian gas sales.

A weakening of the Western European gas market was observed during the eighties. Seeing this in retrospect, the unexpected "support" that Norway received from the U.S. regarding purchase of Norwegian gas, could have been used to improve positions in one or more of the ways mentioned above, rather than pursuing the price premium policy.

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June 9, 1995

The Honorable Ronald Reagan
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Los Angeles, California 90067

Dear Mr. President:

Recently, the Norwegian government announced the completion of the giant Troll field in the North Sea. This project was the centerpiece of your efforts to find alternatives to Soviet gas almost fifteen years ago. While Bill Clark, Cap Weinberger and your NSC staff of which I was a part were criticized for our pipeline sanctions, the reality of our vision is vividly shown in the enclosed picture of the Troll offshore rig. I realize that this was only a small part of your many foreign policy achievements, but many believe today -- as witnessed by the new book, Victory -- that your efforts to find alternatives to Soviet gas was one of the major contributors to the rapid economic decline of the former Soviet Union.

It also shows that the United States continues to have close friends in Norway -- a nation which today is the world's second largest oil exporter (after Saudi Arabia); a nation which has the economic might and technological ability to develop Europe's largest gas field, Troll; and a nation which stood by you during our European nuclear missile deployment in the early 1980s.

Our theme for the Williamsburg Economic Summit was "Ronald Reagan's vision is becoming a reality." We had it right!

With deepest respect,

William F. Martin

William F. Martin

Enclosure

Figure 10.2: Letter From Energy Secretary Martin
Source: Lerøen 1996: 84

Even though the American demand for an increase in Norwegian gas supplies failed in the short and medium term, President Reagan's Energy Secretary William Martin's letter to (1995) him indicates that they perceive politics to be successful (figure 10.2). The letter presents the large increases in Norwegian gas production in the 1990s and beyond as a result of the American demands from the 1980s.

Can a Similar Situation occur Again?

The fact that Norway was driven into the discussion of the Siberian gas pipeline illustrates that the content of Norwegian energy policy already then was important to international politics. Just as the Americans were engaged in preventing exorbitant Soviet hard currency incomes, the Soviets were correspondingly eager to get such revenues. To the Soviets, Norway was an economic competitor as a gas seller. At least, in many situations, Norway could be perceived as limiting Soviet chances of gaining hard currencies. Even if the two countries had and have common interests in terms of prices, they still are competitors as to volume. Consequently, Norwegian gas strategy will be of major economic and strategic significance, also to Russia, partly independent of the overall political development.

A similar situation of joint and conflicting interests that Norway faces towards Russia in the European gas market is to be found within OPEC. In the global oil market, all oil producing states share the interest that the public good, the oil price (within certain limits and in varying degree) should be at a higher level than most consuming countries want and that the market should be as large as possible.

OPEC member states have conflicting interests as to who is to pay to keep such high prices if they are not a result of a genuinely tight market, and production reductions are necessary in order to realize these prices. This is demonstrated in the recurring discussions on production and quota sharing within the organization. All OPEC countries wish to urge other producers to reduce output and keep prices up, as that is the least cost approach to maintain their own price goals. The Iraqi invasion of Kuwait is maybe the most extreme expression of an "influence" of one producing country towards another (Austvik, 1993c).

Norway is an increasingly more significant oil producer. By this, Norway has an impact on the welfare of other oil producers. Norwegian production contributes in keeping oil prices at a lower level than it otherwise would have been. This proved to inhibit the potential for conflict, when Norwegian interplay with OPEC, introduced already in 1986 was introduced as a result of pressure (Austvik, 1989). Such type of pressure has occurred again in the late 1990s, in line with increasing Norwegian oil exports, market conditions and international relations. Correspondingly, Norwegian gas exports are politically and economically important to both importers (principally EU countries) and exporters (mainly Russia and Algeria) of gas.

Norwegian international petroleum strategy, consequently, has to be molded in the awareness that large states and petroleum exporting and importing countries in general, in many situations, indeed are preoccupied with its content. As an energy exporter, Norway has no overall joint interests with any other country, even though such interests exist within singular areas. Therefore, "the policy packages" that Norway will compose in the energy area, have to be defined by Norwegian national interests and must be flexible in relation to the status of the market and the political situation.

In a tight energy market and/or tense political situation, the energy importing countries will give preference to supply security and a moderate price development. Norway could be put under pressure to increase Norwegian supplies and to moderate prices, which may, to some extent, be in Norwegian self-interest. In a weak market and/or in a situation of détente, however, Norwegian supply possibilities and the price development for gas may be threatened. A subsequent pressure may occur from other exporters towards production limitations and coordinated actions to stabilize the prices. In such a situation this too may be in Norwegian self-interest. Norwegian interests will therefore, as an energy exporting western industrialized country, be found somewhere "in between" those of the sheer energy importing and sheer energy exporting countries.

Of course, this discussion does not mean that Norway should adapt to all pressure coming from other countries in various situations. Norway should independently assess any requirement coming from other countries on a national interest basis. But the discussion indicates that Norway's interest partners, in the energy field, may change, depending on the state of the market and political situation.

As to credibility, Norway is therefore facing somewhat different problems in her international energy policy than in, for instance, in her security policy. In the energy area the conditions change rapidly and, some times, dramatically, in a closely integrated interaction of economics, politics and even purely military movements. The formulation of Norwegian international petroleum strategy should therefore be rather flexible. Her national interests indicate that it is the dynamics and the independence of the policy that may be the decisive factor whether a given policy is to prove successful or not. There is no such thing as an "entirely free market" in international economics or relations, where politics and economics are closely intertwined.

11 Strategic Gas Reserves and EU Security-of-Supply

Import Dependency in the European Gas Market

All consuming countries are concerned about securing energy supplies, paying a "reasonably" low and stable price and acquiring the best technology to use it. Even though it has been of less concern, producing countries have similar interest in secure purchasers and stable prices, but at a "reasonably" high level. Consuming and producing countries, being either risk averse or wanting to increase their influence at the expense of others, have developed comprehensive policies towards energy security issues. The International Energy Agency (IEA) is an institution that particularly has concentrated on international energy security from a consuming country point of view since 1974. The Organization of Oil Exporting Countries (OPEC) has concentrated on defending oil exporting member countries' interests since 1960. Any similar organization does not exist on behalf of gas exporting countries.

After World War II, energy security has been particularly focussed in the context of the oil shocks in 1973/74 and 1979/81. Also in the Gulf-war in 1990/91 energy was at the top of the agenda. In the European gas market, energy security was put on top of the agenda when the U.S. introduced the ban on exports to firms supporting the completion of the notable gas contract with former Soviet Union (cf. Chapter 10).

Energy security is back on the agenda. Prime reasons are tighter energy markets in general, and a tighter oil market and a volatile Middle East in particular. As demand for gas is rapidly growing, the European market for natural gas may become tight, as well. In a liberalized European market, prices may react more directly to whether or not there will be sufficient supplies to meet this demand growth (cf. Chapter 3). Thus, it is of significant interest how a potential disruption of supply from one source, being Norway, Algeria or Russia, or other, caused either by nature, military, political or economic reasons, could be dealt with among consuming European countries, as addressed in EU *2002).

In this Chapter we shall make an attempt to distinguish a country's "normal" dependence on imports of a commodity from sensitivity and vulnerability dependence. We will then discuss how the risk for disruptions in supplies may be viewed as an externality in imports and, thus, consumption of gas. The model presented demonstrates how environmental externalities as a result of increased domestic production can be evaluated together with the security-of-supply problem. Finally, it is discussed how gas reserves can be used as a means in an emergency situation.

When is Import Dependency a Problem?

Dependency for a consuming country can be defined as a situation where it does not possess the capacity to produce 100 per cent of it's own needs (Hogan & Mossavar-Rahmani, 1987:8). According to this definition, most countries are dependent on imports of a whole range of commodities. Dependency is thus a normal state of affairs. A country can be sensitive, vulnerable or neither in it's dependency of the commodity when it's *price* or *availability* changes. This will be a function of the magnitude and duration of the change, the country's ability to adjust to the changed environment and the importance of the commodity in the economy. Obviously, changes in the supplies of gas are more important for most countries than changes in the supplies of, for example, widgets.

Sensitivity dependence is measured by the degree of responsiveness within an existing policy framework. It may reflect the difficulty to change policy within a short time and/or bindings to domestic or international rules. *Vulnerability dependence*, on the other hand, is a measure of the ability to adjust to changes in the availability or price of a commodity on which the country depends. Thus, vulnerability is represented by the costs caused by external price shocks even *after* policies have been altered. In economic terms, vulnerability can be represented by the potential for significant losses of output or welfare. Sensitivity dependence, on the other hand, does not need to induce a welfare loss in the long run when circumstances change. As dependency on imports is a normal state of the economy, government policies should aim at eliminating or reducing sensitivity and vulnerability.

The costs of the dependency on imports of a commodity are measured both by increased expenditures on imports as well as the costly effects of changes on societies and governments due to more difficult access to the commodity. The change in policy will depend on political will, governmental ability, resource capabilities as well as international rules. A sensitivity dependence occurs in "the short run or when normative constraints are high and international rules are binding". A vulnerability dependence occurs when "normative constraints are low, and international rules are not considered binding" (Keohane & Nye, 1977). Thus, a country's vulnerability dependence can be significantly different from it's sensitivity dependence, and potentially much more costly.

A country can become more sensitive or vulnerable in a given state of dependency if the commodity originates from one powerful state as opposed to if it is multilaterally dependent. It will also depend on whether the supplying nations are antagonistic or friendly in their relations to the purchasing country. Foreign politics will therefore be an important instrument for reducing sensitivity and vulnerability dependency in addition to the domestic measures.

It is important to notice that sensitivity or vulnerability dependence can occur even if a country does not import gas from any "risky" source at all. If the price of imports from 'secure' sources varies with the insecure sources the problem for countries importing from "secure" sources still persists. During a disruption anyone can normally purchase the gas or energy they want (unless it comes to an armed conflict). The problem is that the disruption may lead to so much higher energy prices that serious damages are brought on to the countries' economies. Parts of demand will switch to oil, coal or electricity and press these prices up, as well. Thus, the security of supply issue for gas consuming countries is a question both of the pure physical access to gas, the economic cost due to rising energy prices during a crises and the political pressure that can be brought on them by parties controlling supply.

In the following discussion, the security problem is related to the magnitude of imports. The quality of this measurement for sensitivity and/or vulnerability dependence can be modified. If two countries import the same amount of gas and one of them has the option to shift to alternative energies or increase domestic production and the other not, the first country is less vulnerable than the other. The speed of the adjustment of demand and supply is important in determining the degree of sensitivity/vulnerability in the short and the long term, respectively. If a country changes from being inelastic in it's demand for imports in both the short and long term; to inelastic in the short and elastic in the long term, the country's dependence on imports may change from vulnerable to sensitive.

Security of Supply of European Gas

Let us assume that a gas consuming country also have some domestic production, as illustrated in figure 11.1. For simplicity, we just call this the "EU market". Long run supply curve for EU domestic production is represented by the upward sloping curve $S_{EU}^{long\ run}$. Domestic short run supply is assumed much more inelastic, as illustrated by the vertical line $S_{EU}^{short\ run}$. This is because it takes time for producers to adjust to a new price environment.

Demand for gas is illustrated by the downward sloping curve D_{EU}. The price of gas is assumed to be set in the European market equal to p_1, determined by traded vol-umes between the huge producing (outside the area) and consuming (within the area) regions. For simplicity, we assume that the EU is a price taker and not able to influence market prices. "Domestic" EU production is q_{EU}^{prod} and consumption is q_{EU}^{cons}. Quantity imported re-presents the difference $q_{EU}^{import} = q_{EU}^{cons} - q_{EU}^{prod}$. The curves are drawn linear for simplicity reasons.

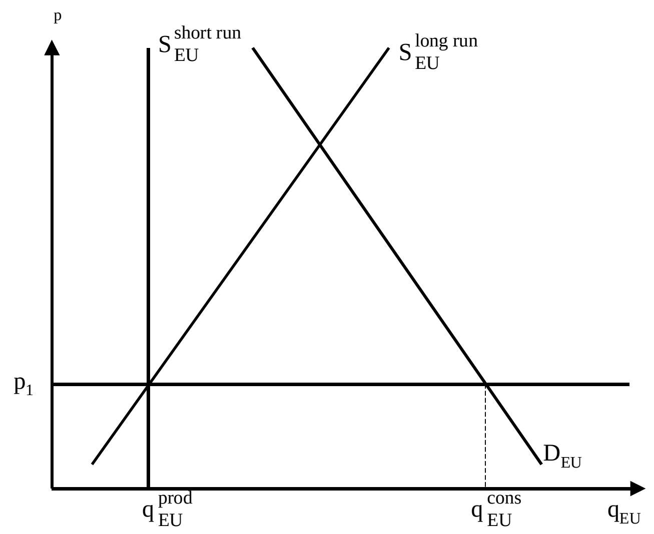

Figure 11.1: Production, Import and Consumption of Gas in the EU

If a disruption occurs (some import is no longer available), the price for gas moves from p_1 to p_2 as illustrated in figure 11.2. The loss in consumer surplus of this price shock will be the area ADEG. Because of rigidities in the expansion of domestic production, EU suppliers will not be able to immediately increase production to C along their long-run supply curve. In the short run they will produce the same as before, q_{EU}^{prod-1}, but at the higher price p_2, represented by point B rather than point F. They gain the area ABFG as a result of the increased prices. If they had been able to move to C, they would have gained ACFG, which is BCF greater than ABFG.

The area BDEF represents the net (short run) loss to society. DEJ is deadweight loss for consumers, and BDJF transfer of wealth from domestic consumers to foreign producers. In the longer run, if the new price level is sustained, domestic producers will adjust to C. Thus, the area BCF is benefit for foreign producers in the short run and for domestic producers in the longer run. In the long run foreign producers gain (only) CDEO, while CFO will be higher costs due to higher (and inefficient) domestic EU production. Therefore, a price shock causes larger economic damage in the short than in the long run. Consumers lose the area ADEG both in the short and long run.

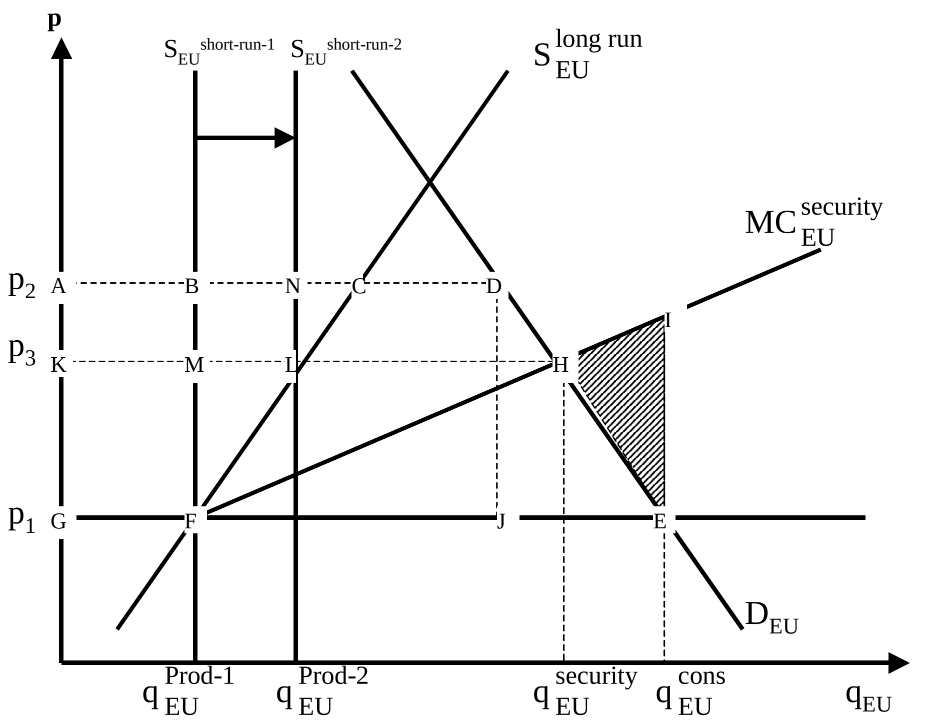

Figure 11.2: The problem of security of supply

Let us now assume that the imported quantity q_{EU}^{import} is viewed as a security problem, because of the losses in consumers' surplus in case of a disruption. We assume that the problem is increasing in magnitude as quantity imported is increasing. One way to interpret the security problem connected with imported gas is that individual consumers, by buying gas and making investments and behavioral adjustments with the expectations that gas shall continue to flow at current prices, are imposing an externality to the society. They do not take into account the costs of increased stockpiling of various energies to counterbalance short run disruptions, the development and maintenance of emergency plans, domestic economic, political and external diplomatic efforts and possible military movements to secure supplies. Each of the consumers are too small to influence the overall outcome, and is better served by maximizing their own utility disregarding the externalities they cause.[52]

The social cost they impose on society is illustrated by the upward sloping marginal cost curve $MC_{EU}^{security}$ in figure 11.2. As imports grow, the costs to society are increasing in order to minimize the likelihood of severe disruptions and to deal with the disruptions if they occur. EU welfare could be improved by changing consumption and domestic production decisions to reflect the total costs of gas imports, not just the private costs in market transactions.

With these external costs included, consumption should have been $q_{EU}^{security}$, represented by point H where marginal *social* costs equal marginal benefits. In point E, which the market realizes, marginal benefits equal marginal *private* costs. At all consumption above $q_{EU}^{security}$, marginal social costs *exceed* marginal benefits. Thus, the loss for overall EU economies by consuming q_{EU}^{cons} instead of $q_{EU}^{security}$, is represented by the shaded triangle HIE.

If the price before the crisis occurs, by some means, is set to p_3, consumers would lower demand from q_{EU}^{cons} to $q_{EU}^{security}$ and domestic producers would raise production from q_{EU}^{prod-1} to q_{EU}^{prod-2} after some time. The market has in fact realized a too high consumption and too low domestic production. The damage, if a disruption occurs, is reduced to an acceptable level at an acceptable cost by realizing consumption and import levels represented by point H in stead of point E before it occurs.

To realize price p_3 is however an intriguing question. However, a release of stocks of gas could have some of the same effects. A stock release of quantity (q_{EU}^{prod-2} - q_{EU}^{prod-1}) would be equivalent to a shift in the short run supply curve from $S_{EU}^{short\ run-1}$ to $S_{EU}^{short\ run-2}$. The question is, however, whether stocks

[52] See Schelling (1978) for numerous examples on how rational behavior at the microlevel can lead to an irrational macro outcome. "The Tragedy of the Commons" is one methaphor on this type of problems.

can be large enough to cover this gap over the time period needed to increase domestic production. A stock release can only serve as a relief for a shorter period of time. The loss for society will be larger if EU relies *only* on stock policies to take care of the security problem without any adjustments in the magnitude of imports in case of long-lasting supply disruptions.

The Environmental Benefits of Natural Gas

However, increased gas import is not followed only by *negative* externalities. Gas consumption also has an environmental advantage over oil, and even more over coal. This environmental advantage indicates that gas consumption should be *increased* compared to a level resulting from free market operations. This argument is reinforced by another security of supply aspect; in order to reduce dependency on (Middle East) oil; gas consumption must be increased.

Let's assume that the marginal social benefits of increasing gas consumption also are increasing with quantity consumed, as illustrated by the demand curve $D_{EU}^{environment}$ in figure 11.3. Now, consumption in point E, found where the private willingness to pay ($D_{EU}^{private}$) equals price, represents a loss in social surplus. At consumption in E, social willingness to pay, p_4 is much higher than the private willingness to pay p_1. At p_1, consumption should increase from $q_{EU}^{private}$ in point E, to q_{EU}^{social} in point P. The net losses for society by not capturing the environmental benefits of gas is represented by the area OPE.

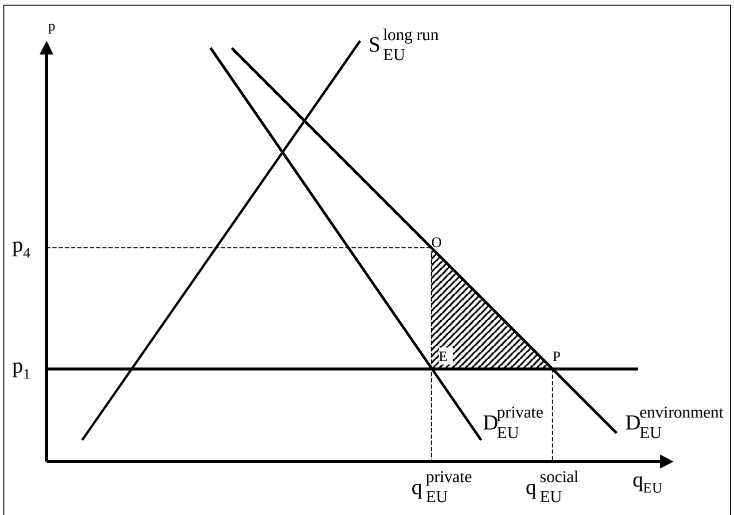

Figure 11.3: The environmental issue

Thus, the optimal price of gas should be lower than p_1 when environmental concerns (and also import dependency on *oil*) are taken into consideration. This is in contrast with the fact that the optimal price of gas should be higher than p_1 when import dependency on gas are considered. In figure 11.4, the private and social costs of security of supply and the benefit of the environment are taken together. For society, the optimal point of consumption and import will be where the marginal social cost (MSC) equals the marginal social benefits (MSB) of consumption; $MC_{EU}^{security} = D_{EU}^{environment}$ equal to $MSC_{EU}^{social} = MSB_{EU}^{social}$ at point Q, realized in the market by price p_5 at quantity q_0. Whether gas consumption should be increased, maintained or decreased as compared to a situation where these externalities are disregarded is actually not possible to say without detailed information on the type and degree of security problems and environmental advantages.

The problem of import dependency and the advantages for environment pull in opposing directions. While security considerations indicate higher price of gas, environmental interests indicate a lower price. Then, which policies would be suitable to reach optimality (point Q)?

Obviously, if $q_0=q_{EU}^{private}$, nothing should be done. In this case, points Q and R are the same. If $q_0<q_{EU}^{private}$ a net positive tax could be introduced. In this case, the costs of increasing consumption in case of a disruption are considered greater than the benefits of improved environment. If $q_0>q_{EU}^{private}$ there should be a net subsidy to consumers in order to give fair attribute to this advantage (e.g. through lower excise taxes on gas as *compared* to on other

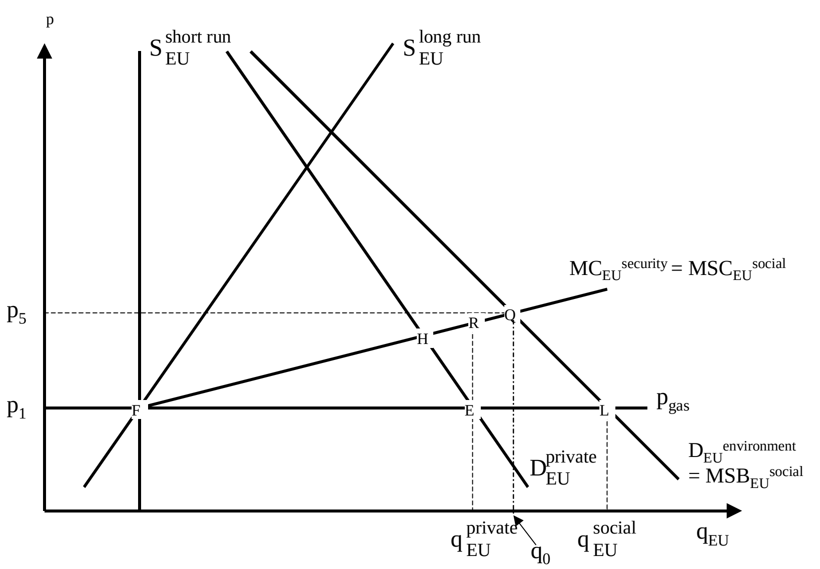

Figure 11.4: Joint assesment of security and environmental concerns

energies, cf. Chapter 4). This is much the situation in the EU-countries today.

The security problem can be considered along two dimensions. First, to reduce the general level of dependency on imported gas. Second, at any given level of imports, to reduce the damage by a possible disruption in supply. Conservation and switching policies between energy carriers could be one contribution in improving energy security as part of a policy to increase consumption. Such policies would turn the $MC_{EU}^{security}$ curve around point F closer to the horizontal line represented by p_1 in figure 11.4. Conservation and installation of equipment that rather easily can switch between fuels would make demand for gas more elastic and reduce the losses in consumers' surplus if a disruption occurs.

Strategic Gas Reserves (SGR)

Most businesses trading and/or refining commodities need inventories to meet temporary fluctuations in production and sales. The size of the inventory depends on ordered quantity and variations in supply and demand. In low-demand periods inventory is built up, and it is drawn down when demand is high. Increased variations in demand and/or supply as well as increased uncertainty increase the need for stocks.

In a liberalized European gas market, prices will fluctuate more strongly and often. Then, in addition to '*normal stocks*', mentioned above, a firm can also build inventory for *speculative* purposes. This is not done from a need to fulfill delivery obligations, but to make profit on speculating on changes in price of gas. Speculative inventory behavior implies that firms should build stocks when prices are rising, and sell when they are beginning to fall, corrected for the administrative and capital costs of keeping the stock. A speculative stockholder should build inventory when the difference between expected future prices and current prices exceeds the costs of storage.

The third types of stocks introduced here could be of a *strategic* kind, similar to the Strategic Petroleum Reserves (SPRs) for oil, owned by consuming countries' governments. Strategic stocks would be an additional source of supply in case of a crisis, which would dampen the rise in prices in the case of a disruption (shift in the short run domestic supply curve $S_{EU}^{short\ run-1}$ to $S_{EU}^{short\ run-2}$ in figure 11.2). Total stocks (S) can then be expressed as the sum of 'normal' private stocks (S_n); speculative private stocks (S_s) and the governmental owned strategic stocks (S_g).

$$(i) \quad S = S_n + S_s + S_g$$

The effect of using strategic stocks on prices is first of all to dampen an immediate shock. For SPRs (oil), Hubbard & Weiner (1982) and Austvik (1989b) divide the effect of a stock release in four. The sum of these four effects gives the net result of a strategic stock release.

- The *direct effect* reduces demand for producers output, and thus the magnitude of the spot (or short term) price changes. The mitigation of short-term price change may also reflect some mitigation of the future prices.
- The *feedback effect* represents the reduced cutback in consumption caused by a lower price than the market would have yielded without a stock release. Obviously, the feedback effect works against the direct effect.
- The *international interaction effect* depends on how foreign stocks react to strategic stock releases. If all countries cooperate, the strategic stocks in all countries are released simultaneously. This serves to magnify the effect. If not, competition implies that as some countries' stocks are built down, other countries' stocks may be built up, due to speculative purposes. This also serves to mitigate the direct effect.
- The *domestic production*s effect. Keeping down the prices implies reduced increase in domestic gas production compared to no intervention if high prices persist over a longer period of time.

As indicated, there may be a relationship between strategic and private (normal and speculative) stocks. Consider a situation where prices rise rapidly and the government starts to draw on strategic reserves. The drawdown increases supply in the market and tends to dampen spot prices as well as the price volatility. Less price increase and volatility serves to lower both normal and speculative stocks. Thus, normal and speculative stocks will both increase less than with no strategic stock release. Thus, strategic stock releases serve to reduce private inventory accumulation and tend to lower total stocks more than just the reduction in the strategic stocks themselves. Similarly, when these stocks are built, the partial effect on both private normal and speculative stocks is that they will be increased as well, because strategic stock build-up increases demand and, thus, prices. Therefore, strategic stock build up tends to increase total stocks more than just the build-up itself:

$$\text{(ii)} \qquad \frac{dS}{dS_g} = \frac{\overset{+}{dS_s}}{dS_g} + \frac{\overset{+}{dS_n}}{dS_g} + 1 > 1$$

However, the reduced volatility in prices due to strategic stock releases does not necessarily manage to stabilize them totally. Therefore, when prices are increasing, speculative stocks may be built at the same time as strategic stocks are released. It may thus look like they absorb strategic stock releases because the net effect on prices is that they still are increasing. Furthermore, normal stocks will also increase at the same time, as strategic stocks are released, but less than with no intervention.

If we assume the shock is big enough so both normal and speculative stocks are built in a crisis even if strategic stocks are released and that they, thus, worsen the crisis, the question is whether the government can keep companies from making spot-market purchases in such a situation. Obviously, governmental interest in overall stability may in such a situation conflict with the companies' need for increased inventory to fulfill obligations as well as their speculative interests.

If a country becomes sensitive or vulnerable in its imports of gas; the imports (and consumption) have an added cost which is not reflected in the market place. As shown, a 'free' market generally results in too much dependence on imports. Self-sufficiency is, however, inefficient and the private costs of increasing domestic production to achieve self-sufficiency exceed social benefits. An embargo or a major disaster is not a certain event, it may not even occur. Thus, some imports are desirable. The optimal amount of imports will depend on the likelihood for a crisis to happen, the intensity and duration of the crisis and the ability to make policies to counteract the potential damages. The slope and shape of the marginal social cost curve for import dependency reflects this.

A liberalized European gas market should increase flexibility compared to today's market in a way that customers, in principle, can buy gas from any source. If a disruption occurs in one place, another source can replace the disrupted gas more easily than today. This indicates that the $MS_{EU}^{security}$-curve can be lowered under liberalization (turned downwards around F), indicating an improvement in security-of-supply. Furthermore, perfect liberalization would lower consumer prices and increase consumption, which would benefit the environment. These benefits must be weighed against the disadvantages caused by increased dependency on gas resources, much of them in remote, physical, economic and/or political difficult areas. As we will discuss in Chapter 12, large investments in gas production and transmission facilities may be delayed and, hence, increase the problem of secure supplies in the long run.

Stocks, Conservation and Switching Policies

A successful strategic stock policy could improve the situation enough to take care of the externality posed on society for security of supply reasons. A shift in the short run supply curve in figure 11.2 from $S_{EU}^{short\ run\text{-}1}$ to $S_{EU}^{short\ run\text{-}2}$ would reduce imports by the same amount. Increased flexibility for switching and conservation would further improve the situation by making demand for marginal gas more elastic during a crisis. With switching flexibility, the demand curve would make a shift to the left during a disruption and reduce imports further.

The use of stocks and conservation policies during a crisis in the European gas market could influence market prices both on gas and other competing energies. In figure 11.5, the market supply is con-sidered inelastic in the short run (S_0) due to capacity re-straints in pro-duction and pipe-lines. Demand is drawn in D_0 with initial market price p_0. If some gas falls out of the market, supply is reduced from S_0 to S_1 and prices are shooting up to p_1. Flexibility in switching makes it possible to shift demand curve to the left to D_1 with a following price decrease to p_2. The release of strategic stocks would push total market supply to the right as illustrated in S_2 with the prices dropping to p_3. By a combination of these to policies during a crisis, the problem caused by the disruption is significantly reduced. This a typical IEA procedure in an oil market disruption.

The question still remains, however, whether stocks can be built

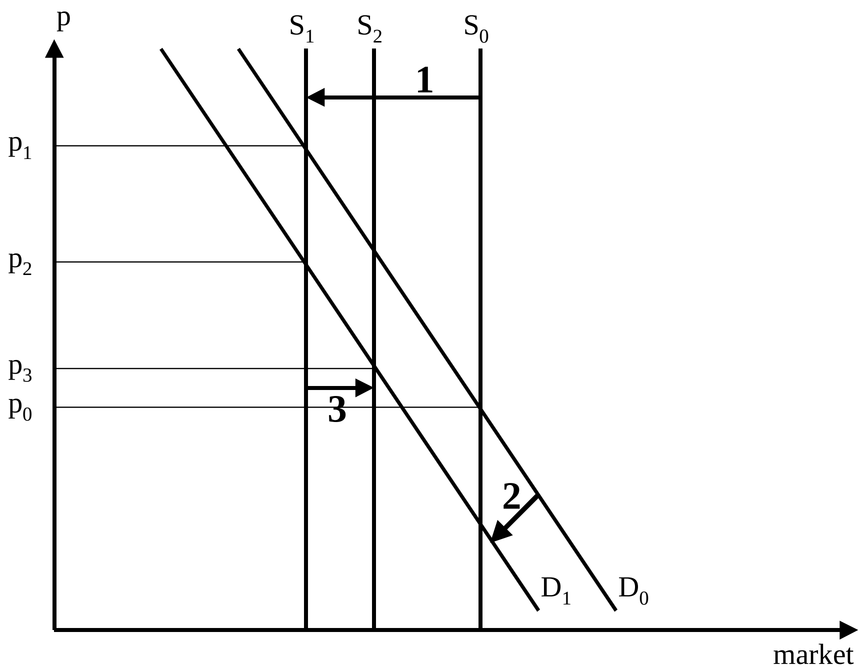

Figure 11.5: Effects on market prices on gas of a flexible demand and use of strategic stock during a major disruption

sufficiently large as compared to a possible disruption. In this context, the Groningen field, and perhaps other smaller domestic fields could be used for the purpose.

The security issue in today's gas market is that, with it's rather rigid structure, consuming countries could perceive the physical dependence on gas resources from a specific area to be a problem. In a liberalized market, where gas, at least theoretically, should flow freely across Europe, the price risk may become an additional concern. As the removed institutional barriers for trade reduce the volume risk, the security of supply risk in the gas market may be more like in the oil market, where excessive pricing and ensuing stop-and-go policies is the major concern.

12 Effects of a Liberalized European Gas Market

New Liberalism: The Interaction Between Visible and Invisible Hands

Liberal ideas were for a long time thought of as a creation of the nineteenth century. Mostly, it has been connected with a limited role of government and a high degree of individual sovereignty. As a response to mercantilism, dominating between the sixteenth and late eighteenth centuries, liberalists emphasized that individual right of private property and exchange of goods and services best served societies. Markets should be free and exploit the gains from trade. During the period of industrialization, a liberal economic system contributed to significant economic growth, but also concentrated capital accumulation and social injustice. Thus, from early twentieth century, liberalism was mostly not considered proper as an economic system to achieve social goals.

After World War II, however, a position that for some time was called "left-liberal"[53], tried to reconcile the values of individual freedom with social justice and a more egalitarian distribution of income. According to this perception, the government should let markets work if they satisfy social goals. To use Adam Smith's term, the *invisible hand* (the market) is the best way to satisfy efficiency criteria and promote economic growth. However, if markets are non-competitive, either by nature or cartelization, often a *visible hand* (a public authority or a regulator) must intervene in order to secure social goals, such as the provision of important goods and services, to avoid excessive pricing practices etc..

[53] A loose term denoting a certain spectrum of attitudes among Western intellectuals. These argued that "the two sets of values -those associated with liberal doctrine of rights and freedom, and those associated with socialist ideas of equitable distribution and social justice - are ultimately derived from a single universalist intuition, concerning the equal value for each individual." (Scruton, 1982: 261).

Such a public authority can either regulate the framework for and rules of operation for firms in the market, in order to promote competition, and/or directly intervene into the behavior of single firms if markets are by nature non-competitive. Regulations of single firms should encourage (or force) them to provide an amount of a good or service at a price that gives maximum profits and *simultaneously* satisfies social goals. In Chapter 8 we discussed some schedules for regulatory regimes. If the results from competitive markets achieved either by actual competition or by public regulations, brings about unacceptable injustice or inequality between persons, groups or regions, governments should intervene to correct this by redistributing income through taxes and subsidies, partnership schemes with the industry, and so on.

Thus, the "new" type of liberalism is rather another type of a *mixed economy* concept, as most European countries have adhered to since World War II, than a rebirth of the nineteenth century's laissez-faire economics. However, as opposed to, for example, conventional social democratic economic models, new economic liberalism emphasizes the benefits of competition as an instrument to reach social goals rather than that governments should run businesses. The goals themselves, however, need not be entirely changed, although perhaps modified.

For the functioning of natural gas markets, the most crucial element is the cost of, and access to, transportation, cf. Chapter 6. Cost of gas transportation is often characterized by strong elements of scale and scope economies, making transporting firms natural monopolies in the markets in which they operate. This situation exists within other types of communication as well, such as roads, harbors, airports, railways, mail services, telecommunications and public transport, within water- and electricity supplies, health services, education, cable-TV, garbage collection etc.. Often, when this type of firms provides an essential good for the society at large, they are called public utilities.

In Europe, many public utilities operating as natural monopolies were nationalized in the aftermath of World War II. Under nationalization, the management of a single firm should take care of both private and social goals, cf. Chapter 7. However, these monopolies were gradually accused of being slow to upgrade technology, service and productivity. Being monopolists by nature (but sometimes only by law) they were considered bottlenecks in the development of each nation's competitiveness. Probably, the most frequently used argument explaining these firms' inefficient use of resources, has been the lack of competition.

Liberalization of a market represents a departure from the "one management" approach. However, the particular aspect of by-nature non-competitive markets, such as major parts of the European gas market, is that the goals of competition cannot be achieved only by removal of trade barriers. If the most efficient operation of a market is done by one, or only a few, firms, these must be *made to behave* in a way that improves efficiency. In fact, an increase in the number of actors in such markets, *per se*, may increase cost, and, thus, represent a waste of resources. Usually, but not necessarily, state owned firms are privatized (even though the government may hold a significant share or, or control over, the ownership), the operation of vertically integrated services are separated ("unbundled"), competition is established when possible and regulation introduced when necessary (when competition does not work).

In the case of natural gas, the U.S. and Canada liberalized their markets in the mid 1980s. Later, gas markets in the U.K., and then Australia and New Zealand, followed. Now, in the European natural gas industry, both market growth and infrastructural developments, as well as political decision making, forcing competition on to firms, is now creating a more competitive environment.

In order to analyze these issues in relation to Norway as a major natural gas exporter we have studied the development of EU energy policies, price effects of liberalism, energy taxation, the economics of non-renewable (exhaustible) resources and regulatory economics as well as foreign policy issues concerning security-of-supply issues. The complexity and inter-disciplinary insights needed to analyze the European gas market makes it even more complex than analyses of the global oil market. In the European gas market, the problem of choosing the right in-depth level and correct parameters and discipline to apply, becomes particularly apparent and challenging. For most analysts and policy makers, it seems to be an overwhelming task to describe exactly how a liberalized European gas market works, how it should be organized and will develop. In this analysis of the political economy of European gas, we will nevertheless try to shed some light on the causes and effects of what may happen.

The Analysis of the Market

We will in the following base the discussion on the fact that the European gas market will become more liberal than it has been. At the same time it is highly likely that the market can not become “perfectly and fully” liberalized. It will not be possible to say with certainty either how far the liberalization processes will go, or fully how they will develop. Neither will it be possible to say exactly how nations and companies will adapt to the changes, and through that influence which effects and consequences the processes will have for Norway as an exporter. Norwegian companies and authorities must to a large extent accept increased uncertainty as an integrated part of the basis for decision-making processes. All actors must develop their strategies in a way that is robust not only for the changes which are ”most desirable” or ”most likely”, but also for those which today seem unlikely, but which are not impossible, and even extreme, outcomes in a positive or negative direction.

Even though it will be impossible to predict the development with any accuracy, it will be possible to bring out particular features, which the liberalization processes bring about. Various models and mechanisms can be combined through multidisciplinary integration in order to increase the understanding for how the market works, rather than to give alternative exact prognoses under economic or political science theories and methods. This means that we integrate disciplines and factors by translating the consequences of changes in technological and political factors on prices and market development and strategic type of the players. Alternatively, we could for instance have used a purely economic analysis of the problem. In periods of stability, such approaches may have considerable explanatory power. Their periodic success at the same time contributes to making them dangerous. As they often are based on assumptions that the future will be similar to today, they rarely take into account the possibility for larger and more fundamental changes in markets and behavior of firms and policy makers. If we get used to the models being right for a while, the limitations under which they were established, may easily be forgotten. These prognoses typically use as a basis one growth pattern or another in the demand for gas, certain changes in supply, certain policy traits from the EU, and so on.

We try to study what future outcomes depend on and then, often, end up with an indication of what cannot happen rather than what will be the approximate development. In one dimension we have a lower ambition level than more deterministic models. However, given specific conditions, a uni-disciplinary analysis can be understood and interpreted within the framework of our analysis, as one possible scenario. In another dimension, we have a higher ambition level. As we are pulling several types of explanatory variables together, we should give a greater understanding of the relationships in the strongly politicized European gas market, even if on a more aggregated level.

The focus will be on the consequences of liberalization of the European natural gas market in the following main areas:

- Prices and excise taxes.
- Contractual forms and modulation
- Consequences for long-term contracts, “old” and “new” gas, respectively.
- Security of supply.
- Environment and environmental policy.

This discussion will form the basis for the analysis of strategic options and consequences for Norway as a major natural gas exporter in Chapter 13.

What is a Perfectly Liberalized Market?

Even if we have already argued that a fully liberalized European gas market is neither possible nor likely, we will analytically make such an extreme solution the starting point for the discussion of various modified trends of development. We have already taken the starting point that a perfect liberalization of the market involves establishing competition wherever possible and public regulation of tariffs and prices to be carried out wherever necessary. We base this extreme scenario on the following, more specified conditions:

a) Third Party Access (TPA) is introduced on all transmission lines in Europe, also on offshore pipelines on the Norwegian shelf, and to storage capacity. Large end-users receive TPA also to the distribution network. The transmission companies must divide transportation and storage from sale of gas, accounting-wise or by reorganization, through unbundling. Gas sale from transmission companies may still take place, but now through separated marketing companies or sales units. Local distribution companies are regulated so that they serve supply households and small business customers at regulated prices and tariffs. The transmission companies are not obliged to supply local distribution companies, gas power plants or the industry. These agreements must be made commercial, so that producers and marketing companies will offer this fixed service against payment.

b) The Norwegian Gas Negotiation Committee (Gassforhandlingsutvalget, GFU) and the Supply CommitteeForsyningsutvalget, FU) are eliminated, cf. Chapters 2 and 6. Transportation of gas on the Norwegian Shelf is regulated following the same principles as in the EU. License holders on North Sea gas fields are allowed to sell their own gas. Similarly on the continent, all import and export monopolies are abolished. Local distribution companies and large end-users through this gain the right to buy gas directly from producer or license holder. In Russia, Gazprom is privatized so that also foreign companies get access to Russian gas resources and the right to selling gas. A state owned transportation company will operate the pipeline network by the same principles as in the EU area. Investments in pipelines and development of gas fields in Russia are based on Western commercial principles. The same applies for Algeria and future suppliers of gas.

c) A regulatory authority at the EU level introduces rules for how to allocate limited pipeline capacity. The agency also regulates transport and storage tariffs wherever competition is not considered to work properly. The principle for regulations is that tariffs shall cover long term marginal costs for transportation companies and storage facilities. As long as there is free capacity in the transmission network, it shall be available for both firm and interruptible contracts and be made public. Short-term transportation needs (”interruptible service”) must yield for long-term contracts if demand for transport capacity is higher than what is actually available. Other arrangements may also be considered. Transportation contracts may be transferable, so that an owner of transportation capacity may sell or lease it for shorter or longer periods. The regulating authority decides on tariff structure, including depreciation periods, choice of discount rate, pricing of new pipeline capacity, and other regulatory issues, as discussed in Chapter 8.

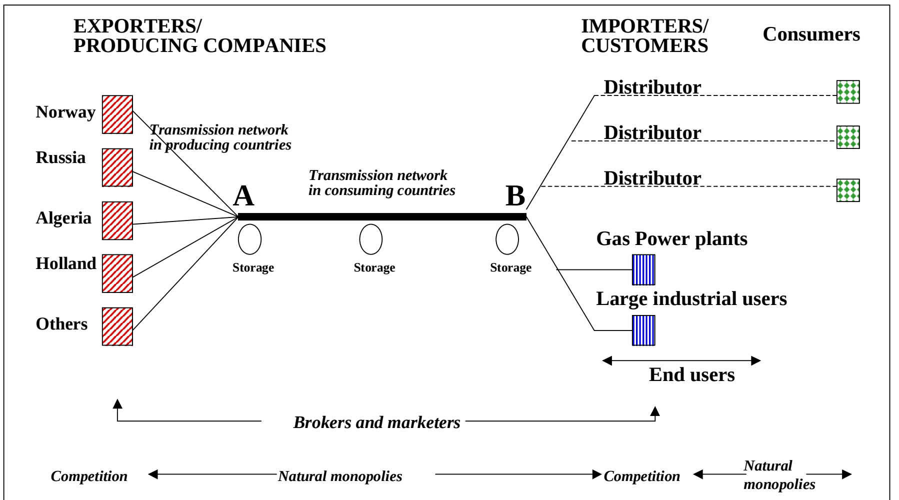

Figure 12.1: European Gas in a Liberalized Market

In such a new organization of the market, the market power of the transmission companies is eliminated, and buyers and sellers of gas can trade gas directly. They use the pipelines only as transporters, corresponding to a toll financed road system. The old structure, where an oligopoly of sellers at point A meets a monopsony of buyers in point B in figure 12.1, is replaced by a structure where many sellers in each producing country meet many buyers at point B.

Prices and Excise Taxes

In a perfectly functioning liberalized market, the economic profit (the resource rent for producers and the monopoly rent for transporters) will in principle disappear in all stages. EU's assumption (EU 1998) is that the users of gas will be the ones to reap the benefits of liberalization through lower prices, as has happened in most other markets which have been liberalized.

The assumption that the economic profit will disappear in such a market may be correct for the *transmission and distribution companies*, as the lack of competition is assumed replaced by an efficient regulatory regime. They have in today's system and will in a liberalized system have relatively stable margins. Margins will however be lower in a liberalized system. If there are several competing transmission systems, they may in addition have increased uncertainty about what volumes they will transport. Their income may vary more which further aggravates their position.

The transmission companies therefore have every reason to oppose the implementation of any liberalization of the market. However, when regulation is seen as impossible to avoid, they will seek to "trap" the regulator in such a way that as much of the profit as possible actually remains with themselves (a "principal – agent" situation). Their strategy will then include elements of both conflict and cooperation with the authority(ies) and forces in the market, which might push a liberalization process forward, as discussed in Chapter 7.

The customers' (local distribution companies, power plants and large industrial users) possibilities to buy gas from several sellers/producers will improve in a liberalized market. It will mainly be their bargaining position in relation to the producers that will determine whether they may obtain cheaper gas than before. Through the larger number of sellers they will be facing, most likely their bargaining position will be strengthened in relation to the monopoly (through the transmission companies), which they often face today. This means as a starting point that prices may become lower for the customers. Depending on how the supply develops, buyers may however still end up with prices approaching the prices paid today. This is determined by the balance between supply and demand and is thus directly linked to prices to producer.

As for the customers, market development and competing sources of energy will contribute to deciding the price *producers* will get in the market. At the same time, the introduction of TPA and the elimination of the import monopsony strengthen the bargaining position of the producers. The lower margins in transportation may end up with the producer as well as the customer. The establishment of gas-to-gas competition at the customer level (point B in figure 12.1), will tend towards reducing prices to the producer. If there is free competition between all small and large producers of gas, each of them will sell gas as long as it is profitable, just like they do in other markets with free competition. Production decisions which have been made on commercial criteria for the individual producer lead to each of them increasing production and sales up to the short-run marginal costs (which may be very low), leading to an increased total supply of gas. When prices are contractually disconnected from the prices of the alternatives, it may in the short and medium term lead to an increased total supply of gas with a following drop in prices. At the same time, it will lead to a quicker rise in demand, which will consume the surplus supply faster than if the prices did not drop.

The existing balance between producer supply and buyer demand will therefore be reflected more clearly in their prices, which may fluctuate to a greater extent than what has been the case. The question is how long a surplus supply based on increased competition between producers may exist. Short-term contracts may in this context hardly form the foundation for in-

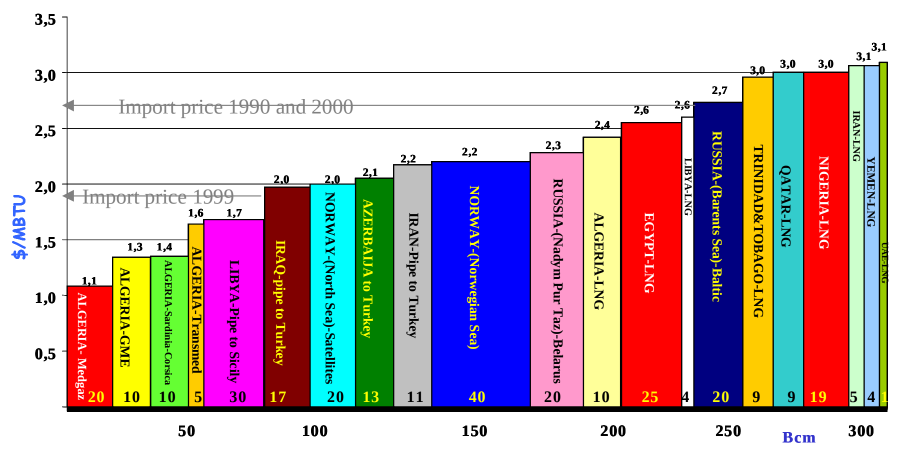

Figure 12.2: Gas Supply Cost Curve for EU-15 to 2020
Additional volumes - excluding producer country's royalty.
Source: OME 2001, IEA quarterly.

vestments in infrastructure and large development projects for the producers. This will increase the uncertainty about the development of large projects that require very long-term investments. The price volatility and price drop may then lower the long-term supply of gas, as discussed in Chapter 5. The reduction of the supply of gas in the long term will increase volatility over time, and, ceteris paribus, tend to create higher prices to producers in the long-term. In this context, long-term may easily be 5-10 years or longer, and corresponds to the situation in the American gas market as discussed in Chapter 9.

Increased supply of gas in the long run may, given today's price level, mainly come from regions that already are suppliers to the European continent. In order for new regions to enter the arena, pipeline investments are required which probably will demand gas prices higher than today's level. This primarily applies to fields remote from the European market (the Barents Sea, Central Asia, and Middle East, Nigeria). Figure 12.2 illustrates a long-run marginal cost curve for gas to the European gas market. Today, the price at EU's borders is some 2.7 $/mbtu, which cover the costs of all production within the EU, Algerian, Norwegian and Russian gas which already is on the market. But only in 1999 the price of gas was below 2 $/mmbtu, excluding many of the projects from being realized. The shape of such a curve can obviously be further analyzed and discussed, but it is clear that low and unstable prices, which are advantageous for consumers in the short-term, may cause problems for the supply of gas in the long-term.

Thus, supply of gas from large new supplier countries may thus be delayed through liberalization, as well as the development of large new fields from existing supplier countries. On the other hand, as gas is a non-renewable resource which is found only in a few places (potentially) accessible for the European market, prices may over time increase towards prices on alternatives and in periods also above the alternative price when gas production from existing/developed areas (including satellite fields) levels out. This indicates that the short and medium term effect of liberalization will be lower prices and the long run effect higher prices.

However, price developments also depend on taxation of gas usage in consuming countries. Excise taxes may be determined independently of the liberalization processes, but also be part of them. As we discussed in Chapters 4 and 5, excise taxes on gas consumption may pressure producer prices down. Today, as prices are set lower than the prices on alternatives, gas taxes may also increase consumer prices and thus slow down growth in demand.

Clearly consuming countries are well served with low gas prices, and they are not interested in giving producers any profit beyond what is necessary. At the same time, producers must have short and long-term profits that give them reason to invest in new, large long-term projects. If consumer countries desire a high growth in gas demand, lower prices for the consumer and low taxation will be advantageous in the short and medium term. In the long-term, this may then however lead to higher prices, like we have seen in the USA throughout the 1990s, cf. figures 9.2 and 9.3.

In figure 12.3 a situation is illustrated where producer prices are dropping at time T^1 due to liberalization and/or a higher excise tax (cf. figure 5.6). The figure illustrates a situation when the price drops below long run marginal costs (LRMC) for large and remote fields. The lower prices lead to higher

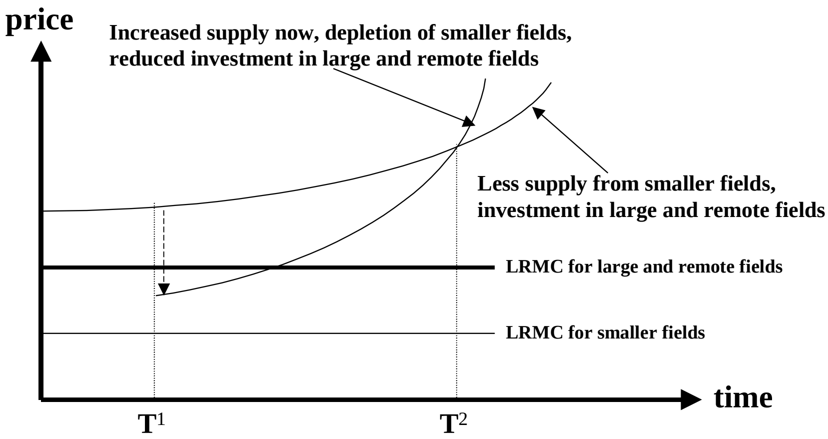

Figure 12.3: Two Possible Price Paths for Natural Gas as an Exhaustible Resource for the European Market.
Illustrated long run marginal costs (LRMC) for large and smaller fields (assumed constant).

consumption and absorption of existing capacity as well as the smaller and marginal field that will be developed due to their easier market access. As the price will be lower than the cost of developing large and remote fields, new supplies from these fields will not be realized. Thus, in the long run, at time T^2, prices become higher than if prices had not dropped at T^1. In our discussion of natural gas as a non-renewable resource in Chapter 5, we focused on a parallel situation in the discussion of figure 5.6 when a monopoly would yield a lower long run price than competition.

Thus, in a long run perspective, consuming countries may wish lower producer prices only after most large investments have been made. Preferably, consuming nations would be served by differentiated gas excise taxes adjusted to the long run marginal costs of each producing area. This could be solved through differentiated import duties, as well, but be in violation of the free trade regimes which are now established both in Europe and globally. Regardless of how consumer countries will balance these requirements, the developments point towards producers assuming not only an increased price risk, but also the political risk of taxation and the uncertainty connected to political decisions in other countries.

Norwegian gas export may therefore, through the development in prices and excise taxes, be sensitive or even vulnerable (cf. Chapter 11) to these changes in the short and medium term. If liberalization takes a very unfortunate form for her, with competition established between exporters and less competition downstream with a resulting aggressive tax policy in the EU area, the outcome may have a dramatic impact for Norwegian revenues and long-term investments already made. The worst case situation is a (perhaps theoretical) scenario where the prices drop or are pressured down after most of the Norwegian infrastructure has been developed. Norway will then have to produce even at prices down towards the short run marginal costs (SRMC), without recovering even all investment costs.

Contractual Forms and Modulation

In a liberalized market, a spot market and other markets for short-term contracts will be developed. The proportion of shot term trade depends on market conditions. In a market characterized with excess supply, spot trading can be expected to account for a relatively large part of total gas trade, as periodically seen in the American market. In a tighter market, customers can be expected to be more cautious about buying gas on short term.

As a rule, spot sale will depend on either free capacity in the transmission system and at the producers, or that gas storages have been filled so much that short-term demand can be met. Such short-term demand may be dealt with by a wholesaler (e.g. as today) or it might be handled under separate contracts. It seems likely that there is a potential demand for gas if the supply of such gas can be made more flexible. At the same time, some purchasers who now only make long-term contracts (because they have to) will sign up for short-term contacts for some of its volume. The spot market may become larger than just the additional demand created by a more dynamic supply. The greater the possibilities for spot sale, the larger the market.

A TPA arrangement should open up for “short term gas”. With a continued oligopoly at the producer side however it can be imagined that the volume of the spot market is limited if it leads to a more restricted supply than competition does. In a system where there is free competition between producers it is difficult to imagine a cooperation good enough to avoid the development of a spot market, and such competition would obviously be illegal.

Gas purchasers may in a liberalized system in principle buy directly from producer or license holder in a field, but this is unlikely for smaller buyers. It is more natural to assume that market centers (so called ”hubs”) grows up in places like Zeebrügge or Emden where several buyers and sellers meet through pipelines and/or LNG-terminals. Aggregation, modulation and storage may be better taken care of in such a place than at each individual producer. One may for instance imagine a system where the producers are responsible for the transportation of gas to the center where purchases and sales take place, while the customers (distribution companies, large end users or electricity producers) take responsibility for transportation from the center.

The complexity of these transactions may lead to a need for brokers and sales companies to take care of them. These may have knowledge about up-and-downstream circumstances which smaller customers can not posess themselves, knowledge about special niche markets not held by larger customers either, and which they are willing to pay for. In addition to the statistical publication of prices, costs, etc., brokers may lead to increased market transparency. Changes taking place in one part of the gas chain will then affect all parts of the gas chain much faster than today.

Increased volatility due to liberalization requires greater dynamics in producer decision processes. We will have a larger quantity of contracts with more customer types and sizes. More smaller and short-term contracts and expectations for the long-term market development may become a barometer for how long long-term contracts actually will be, as we have seen for periods of time in the oil market. It will be significant for producers if they organize production, transportation and sales operations to exploit these changes.

Consequences for Long-Term Contracts

Long-term and large contracts have been a precondition for the large investments in the gas fields in the North Sea, as well as for the development of Siberian and Algerian gas. There is the question about what will happen to the contracts already entered into ("old gas") in a liberalized market.. There is also the question about which incentives there will be for new long-term contracts.

"Old" Contracts

Today's long-term contracts "assure" a market and a price for Norwegian gas according to specific guidelines (Chapter 2). The exporter assumes the price risk through these arrangements, but prices are tied to the development of consumer prices of competing energy sources, which in practice has given Norway a high degree of price stability (more than in the market for crude oil). Actually, the taxation policy for oil products has caused gas prices to be more stable than crude oil prices, f. Chapter 4. A liberalized market system threatens this stability and may lead to transmission companies requiring renegotiations or cancellation of TOP-agreements entered into.

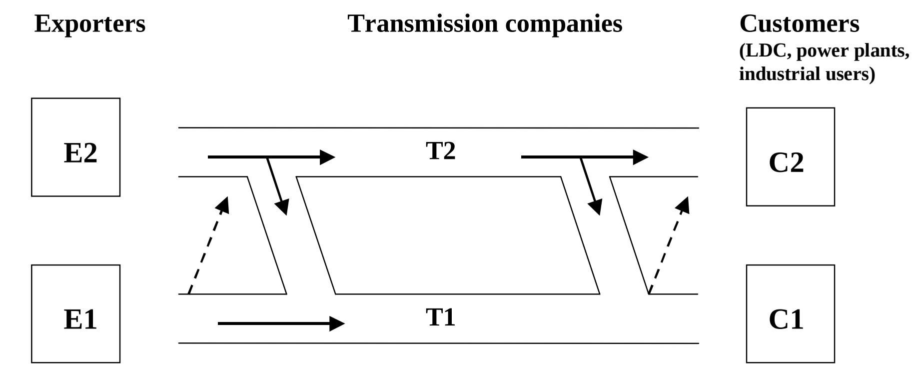

Figure 12.4: When a New Transmission Company Enters the Market

Competition, perhaps regulation of their tariffs, will reduce their profit margins at the same time as market pressure may lead to lower prices on the gas they sell at the end of the pipeline, thereby making them unable to meet existing contracts with the producers.

Even when there is no regulation, but a competing pipeline is built, existing contracts may be threatened. Assume in figure 12.4 that exporter E1 sells gas to transmission company T1 in a long-term contract for 20 years. T1 resells the gas to customer C1 in a more short-term contract that for practical purposes are renewed every 1-5 years. Then a new pipeline T2 is built, and a competing transmission company is established. If a new exporter E2, now signs a new contract with customer C1, who was previously tied to a contract with E1 via T1, through the new pipeline T2, then T1 looses a volume and T1 will have to cover his costs with a lower transported volume. If the transmission company operates with falling average costs, the lower volume will lead to costs per transported unit increasing, cf. Chapter 6. If exporter E2 transports gas through T1 and replaces an old contract held by E1, the transaction costs should on the other hand only have significance for T1.

Even if the new seller E2 makes a contract with a new customer, C2, who is not already buying gas (for instance because demand for gas is increasing), and transports this gas via the new transmission company T2, the profits of

T1 are affected. In order to become the best transport alternative, T2 will have to lower its transport tariffs (or gross margins) relative to T1, something that will be advantageous for exporter E2 and buyer C2. The new competitive situation leads to a pressure towards T1 also lowering its tariffs, as more and more contracts will otherwise be placed via T2's net. At the same time it will become more difficult for T1 to sell gas on his more short-term contracts based on terms for old gas, as the prices to the customer will be pressured down.

The new situation with many suppliers will create incentives for the customers to renegotiate the existing contracts with the transmission companies, and in any case make new contracts on better terms when the old run out. As these contracts are shorter (1-5 years) than the long-term TOP contracts (20 years) with the producers, the transmission company may be left with large volumes of gas they are not able to resell at conditions expected. This was an experience among American transmission companies at the end of the 1980s, as well.

With a sufficiently high market growth, T2 on his side will be able to calculate when a new project is profitable on a given (sufficiently long) planning horizon and challenge the existing monopoly T1. A decrease in tariffs will lead to both lower prices to customers and higher prices to producers, and through that to increased supply and trade of gas. If the growth is strong enough, T2 will also gradually fill up with gas. If the growth is not large enough, T2 will be able to compete with T1, so that T1 must demand renegotiations of its TOP clauses with its producers. If E1 continues to sell gas through T1 to C1, and prices to E1 drop, the producer will assume all disadvantages by the new market structure, but not the advantages of lower transmission costs through T2. This will pressure E1 to also transport gas through T2 and sell gas under new (and better) terms to both C1 and C2. If these processes go on long enough, exporters may also come to the point where they require long-term contracts to be dissolved, as they no longer reflect prices they could have obtained in the market with lower transportation tariffs through T2. Of course, when either the transmission company or the producer will require such concellations of existing contracts depend not only on market conditions, but also on financial strength, expectations of future developments and jura.

It is not obvious how tariff structures will be affected in such an oligopoly of transmission companies. Neither T1 nor T2 will have an interest in reducing each other's tariffs too much through competition, and a game between the two will start. At some point in time T1 will profit from changing strategy from being opposed to a changed market situation to participate in influencing the forming of it. Cooperation with T2 would then be the best for both T1 and T2. A competition authority will have as its obvious task to make sure that T1 and T2 do not start to collaborate. However, T1 and T2 will also begin to work towards capturing the acts of the authorities/regulators to serve their interests, as discussed in Chapter 6.

A development of infrastructure in the market, for instance in Germany, indicates that there may come a situation when a company like Ruhrgas (T1) may wish to renegotiate old contracts with among other Norwegian exporters. If this is to be carried out with the only content that prices and other contractual conditions shall reflect the new competitive position the transmission company is facing, Norwegian gas prices will have to be adjusted down. Norwegian exporters might then be better served by accepting the new competitive situation and start to sell at better prices via T2 (Wingas), maybe also before T1 presents renegotiating requirements. The further restructuring of the German natural gas industry through E.on's purchase of Ruhrgas may on the other hand be considered an example of an attempt to increase concentration of market power across the German natural gas industry. The processes of conflicts and cooperation between the transmission industry and public authorities (here: German and EU) have already started.

The effects of the present Gas Directive (box 2.2) on existing TOP contracts and the construction of new transportation capacity does not have to be as dramatic as outlined above. In a situation with gradual development of transportation capacity and several TPA contracts, renegotiations of prices may take place as agreed (as under the Troll agreement). Gradually Norway's alternative of selling gas directly to customers will be built into the pricing, in addition to changes in the end user markets, and thus gradually reduce the margins in the transmission network to the advantage of producers and/or buyers. The part of the directive that states how fast and how much the market should be opened is an expression of this attempt.

Incentives for New, Long-Term Contracts

For new contracts, both buyers and sellers of gas may desire long-term agreements because this makes planning easier. Still there will be long periods where buyers desire shorter agreements than sellers and vice versa. In a period with low prices, the buyers will wish to enter into short-term contracts. If they think that prices will increase, they will try to close long-term contracts at these low prices. Sellers may during periods of high prices hope for further price increases and desire short-term contracts. If they think that prices will start to decline, they will try to land long-term contracts with high prices. With a spot market for gas, customers will have alternatives to how long term contracts they want to enter into. A customer who exclusively bases himself on long-term contracts may not capitalize on low gas prices in the spot market. A broker, for example as a subsidiary of a transmission company, will have problems to enter into contracts of today's length with the increased market volatility and uncertainty.

The TOP contracts of today give high security of supply under normal conditions, but rather low security under force majeure situations like the breakout of war, strike, technical problems, etc. The struggle between the Ukraine and Russia about transit agreements at the beginning of the 1990s when deliveries to Western Europe dropped by 50 % in a week, is one example. The problems were of short duration and the individual end users could not notice anything at all, as gas storages were drawn and demand was lower than normal for the time of year. Under a TPA regime the customers will have access to several suppliers, even though they may be facing only one transmission company, something which in itself leads to a higher security of supply. This weakens the argument that long-term contracts are better for the customers due to security of supply considerations. The incentives for entering into long-term contracts from the buyers' side changes with a new market structure, and new contract partners emerge.

Thus, when new contracts are more directly determined by market conditions and made also directly with the customers, they will be less long-term than today. The transmission companies now balance out geographical and sectorial differences in customer demand. These differences will appear more directly to the producer in a liberalized market. The larger the producer and the more it is possible to take over the wholesaler function of the present transmission system, the more even and long-term the total contract portfolio may become so that large fluctuations in individual markets may be balanced against a more even total market. It is however important to remember that the present transmission systems not only buy and sell Norwegian gas, but also markets the gas and assures it a place in the total consumer picture. Unless the producer develops a marketing organization that can replace this function, the possibility for long-term contracting in a liberalized market, and through that assuming parts of the wholesaler function of the transmission companies, is diminished.

In the wake of a spot market, new ways of adapting/reducing risk will also emerge. This holds for tools of financial character, like instruments for a futures market and/or an options market, as we see it within the trade of crude oil and currencies. Secondly, downstream companies may be interested in vertical integration upstream.. Vertical integration will reduce the increased price risk entailed in market liberalization. Vertical integration may improve the possibility for taking parts of the value in the gas chain. At the same time, market knowledge improves.

For a producer, there are many rational arguments also for horizontal integration. To defend the large investments which are being made in infrastructure, there are many smaller fields, for instance on the Norwegian shelf, which should be jointly considered. To defend field development, joint oil and gas production and economies of scope, it may for a producer be rational to coordinate sales. That the producer does this for the buyers are advantageous compared to a situation where the buyers make the coordination. The economic, technical and resource rationality behind such coordination may on the other hand easily be met by EU rules, which desire to prevent the establishment of such coordination. ESA's criticism of the GFU, which led to its abolishment, is an example that such arrangements will be more difficult in the future, if they mainly are seen as a way to gain market power.

Beyond this, it does not seem to be possible to draw any unambiguous conclusion about what effect any degree of increased volatility and short-term prices and contracts will have relative to changing price levels and any improved market access, as a basis for considering investments in new pro-

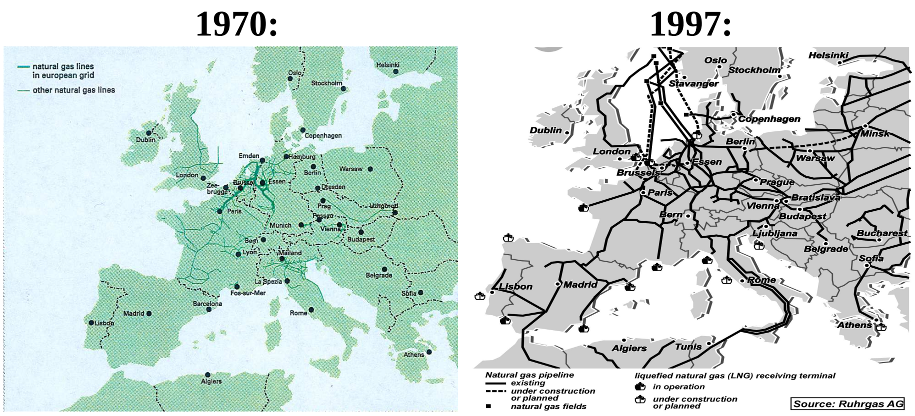

Figure 12.5: The European Natural Gas Grid in 1970 and 1997

duction capacity. It will depend on the development of end user markets, how market organization and measures are reorganized, how access to transportation are made for example by vertical integration, how the contract portfolio is structured, and what the negotiation position for producers is relative to the buyers. Last, but not least, the producer must have an opinion about the political development in the purchasing countries, particularly how the structure of energy taxes will change.

The uncertainty in the future European gas market increases for the producers. Part of the problem lies in the fact that it takes a long time between the decision to develop is made and the time when the production enters the market. The producer must make new field decisions about investments based on a number of assumptions on how these central conditions will develop over many years. European infrastructure for natural gas has been growing rapidly over the past 30 years, cf. Figure 12.5.This development is not certain to continue unless specific means are introduced for it to happen, for instance by EU financial support.

From the outset gas fields are more vulnerable than oil fields due to the natural characteristics of the sector and the long-term view of the industry. Fields, which does not show the required yield at a given point in time may be delayed. A delay means a reduced supply of gas in the long term and probably higher gas prices following. Existing fields (producers) may then reap advantages from a delay. Both for buyers and producers this also becomes a question about how the total supply can be orchestrated into the market so that a sensible total utilization of gas as a non-renewable resource is accomplished over time, across producing nations.

Security-of-Supply

The concept of security of supply has usually been made as a volume argument, while it may equally often be considered as a price argument. The vulnerability of an importing country to the supply of oil and gas may (in peacetime) often be expressed more precisely as a vulnerability to high petroleum prices through a considerable transfer of economic rent from consumers to producers. For importing countries this means an unacceptable increase in import costs. Too high petroleum prices may lead to unemployment, inflation, foreign trade deficit and economic recession. In this way a market and price risk also becomes a political risk, cf. Chapters 10 and 11.

Market liberalization for European gas may contribute to improving the security of supply for consumer countries, by splitting existing producers and production areas in several units, by liberalizing the access to the pipeline and (particularly) by physically building more pipelines and gas storages. That the transmission pipeline has presently committed to buying and supplying gas (take-or-pay and deliver-or-pay) is a formal safety for physical supplies and predictable prices, but not necessarily a real safety in a more serious crisis situation.

Institutions like The International Energy Agency (IEA), consuming nations in Europe, the EU herself and superpower U.S., are among those who are concerned with the further development of networks and storage systems to improve security of supply to reduce a continued vulnerability to new, dramatic events in the Middle East (oil shock where increased gas use contributes to diversification) and to reduce the effect of larger disruptions in the supply or transport of gas. For the consumer countries, market interest will in this case coincide with the desire to avoid political pressure from producers and transporters.

Proper security of supply is however also dependent on satisfactory amounts of gas being produced and supplied to the customers. While production of gas is reasonably constant throughout the year, demand varies. This puts great demands on transportation and storage of gas to even out their timing differences. Whether a new market organization leads to sufficient amounts of gas being produced over time to cover total demand, is uncertain. Another aspect is whether the transmission systems and the storage system will function well enough in a liberalized market. A division of transport, storage and wholesale services (unbundling) may both strengthen and weaken security of supply and market efficiency. An unbundling that prevents economically rational integration may lead to reduced security of supply, while an unbundling which leads to reduced market power and lower prices on the service affect, may strengthen it.

For large industrial end users, security of supply for natural gas is also a question about alternative sources of energy. If they use interruptible gas contracts they may release gas volumes for other customers in a crisis situation. Industrial customers with few possibilities for alternative sources of energy will be more vulnerable to price shocks and interrupted supply. This will most likely create a market for a form of insurance through back-up supplies. The consequence may be that security of supply for these customers becomes a question about willingness to pay (for security). Regardless, diversification both between energy sources, sources of supply and alternative transport routes or means, increase security of supply for gas users.

The fact that more pipelines continue to be built and gas consumption is on the rise will usually improve and assure producers' market access. Norway becomes less vulnerable to potential exclusion from markets and less sensitive to pressure from individual players. Supply security for a producer will (during peace times) as a rule not revolve around whether the producer is able to sell the gas or not, however, but at what terms it is sold. Liberalization will lead to more price volatility, the possibility of excess supply in the short and medium term, and higher taxes introduced. There is a potential for decreased security of demand for the producers in a liberalized market.

Security of supply must also be seen in a more general perspective of foreign and security policy. Simultaneously to the liberalization processes, Norwegian gas exports are increasing to nearly 7O BCM per annum, which makes Norway a dominating player in the market in Northern and Continental Europe, together with Russia. The size of the gas exports makes Norway a strategic player in a market of vital interest for the energy supply of Western Europe, cf. Chapter 10. Norwegian production of (oil and) gas creates a dependency with consequences for strategy and security policy both for Norway and the receiving countries. The infrastructure tied to the production and transportation of oil and gas is of strategic importance for the consumer countries and NATO. An attack or threat of attack against the installations may have serious repercussions for the economic interests of NATO countries and lead to a reduced NATO capacity. Even though the threat of an extensive attack on NATO in this area seems absent today, NATO thinks that there is a continuous risk for attack or injury in particular of vulnerable infrastructure at sea (Kibsgaard 1999). In this context, it is not primarily the market changes that create a new security situation for Norway, but the position gained in (oil and) natural gas markets.

Environment and Environmental Policy.

The alternatives to gas as the cleanest form of energy are not many. For one, nuclear power is presently considered an unlikely alternative. Even in the governments where nuclear power is thought of as a safe form of energy the public opinion is largely against the building of new plants. Secondly, new oil and coal power plants are also expensive when they have to remove or reduce their emissions. These power plants will regardless release more

CO_2 per produced unit of electricity than a gas power plant. Until renewable energy sources (sun, wind, wave energy or other) become profitable to a larger extent than today, there will internationally not be any production of power more environmentally friendly than gas power. Gas power becomes particularly advantageous when the plants can combine the production of heat and electricity (combined heat and power, CHP) for an industrial plant or local community.

The increase in the number of gas power plants is already high and may become even higher as the previous East-European countries are going to adapt to the relatively strict EU environmental requirements. This means that gas may receive an implicit price premium relative to other fossil fuels because the cleaning costs for gas will be lower than for oil and coal. In practice this may mean that gas prices will increasingly be indexed against the price of electricity. Increased demand for gas for producing electricity and the liberalization of the electricity market then becomes, through environmental concern, a driver for also liberalizing the gas market. The question is again if gas market liberalization at the same time will lead to a lower supply of gas over time.

A number of directives have been passed to reduce emissions from cars and industry and some are under preparation, among other to protect the ozone layer. Regulations express themselves primarily as excise taxes. This should give a skewing away from coal and oil and towards gas. There has been a continuous pressure towards a comprehensive and committing agreement about reduced CO_2 emissions. The Kyoto agreement of 1997 is a milestone, even if its actual accomplishment still is somewhat uncertain.

In the EU, the proposal of a common CO_2 tax for the EU had to be shelved at the middle of the 1990s. The excise taxes were however still introduced relatively quickly (Reinsch, Considine & MacKay 1994). Several EU countries have now, through excise taxes on oil products, larger ”oil income” than Norway or even Saudi Arabia. The excise taxes have most likely contributed to the real decline crude oil prices during the 1990s (Austvik 1996). Even though environmental arguments often are used to introduce or increase excise taxes on petroleum, the severe increase in oil product taxes in the last decade is most often due to other causes. The most important reason seem to be fiscal, i.e. that energy taxes have become an important source of finance for public budgets.

In the gas market, the end user price is today determined by the price on its alternatives, mainly oil products. This means that the gas prices increase if the price of crude oil or the taxes of for instance fuel oils increase. Norwegian gas export may then gain from higher taxes on oil products. Taxes on the use of the gas itself are in the EU far lower than on oil products. As the margins of the distribution and transmission networks are nearly constant and the consumer price is determined by the price on alternatives to gas, gas taxes will however often have to be paid in their entirety by producer/exporter. If excise taxes on gas become more common in EU countries in the future, Norwegian revenues from gas exports may then become far smaller than expected. In the European gas market Norway is at the start of a possible similar process, where liberalization, taxes and market power in various stages of the chain will have decisive effects in a different way than before, for how Norway's gas revenues will develop. This is more part of the new international political economy than it is based on environmental arguments (or the "Geopolitics of Energy", Kibsgaard et.al, 2000).

Environmental policy has in general become central for oil and gas policies in Norway as well as internationally. In an international context, the EU was an important driver early in the 1990s, and Norway joined in supporting such a policy, even though it has in the 1990s become clearer that there is a conflict of goals between the oil and gas policy on one side and the environmental policy on the other side. The Norwegian debate about the construction of gas power plants is closely tied to the introduction of trade in CO_2 quotas. Here there are often strong coalitions from outside the energy sector that drive the process. Not only is there a strong interest in environmental efforts in the population and among the leaders of some European countries. There are also forces within the EU Commission and in the EU parliament who has environmental policy as a highly prioritized area, where at the same time energy is a continuously more attractive product to tax in order to cover fiscal needs.

13 Norway as a Major Natural Gas Exporter

As the EU Single market is expanded and deepened, substantial economic growth is expected to take place in a number of countries. Without significant technological breakthroughs in the use of energy, this growth must be followed by demand for more energy. Few alternatives are commercially available. If renewable energy sources are not developed in a much larger scale than before, non-renewable fossil fuels (oil, gas and coal) must cover most of the growth. In Europe, natural gas is "the winner". According to forecasts, European gas demand shall increase some 75 per cent over the next two decades. The sources for supply that shall meet this demand are limited to a few large production areas and fields, many of them at locations far from the market. Russia is and will remain the key supplier, but Norway will also be important. These two countries will dominate gas exports to Northern Europe. This Chapter discusses challenges Norway is facing in this new period for the Norwegian gas industry.

Three Periods in Norwegian Natural Gas Developments

The development of natural gas on the Norwegian continental shelf can be described in terms of three periods.

The *first period* started in 1973 with sales negotiations for gas from the Ekofisk fields to the Continent and from the Frigg field to Great Britain, cf. Chapter 2. The group of companies who were licensees of the relevant areas negotiated the contracts. The contracts were of the depletion type (all reserves sold under the same contract). The price clause consisted of a formula with a base price linked to the price development of fuel oils. Since these contracts established the fundamental collateral for investment in field and pipelines (Refvem, 2002), strict take-or-pay (TOP) clauses were established, and there were no clauses of price revisions or renegotiations. These contracts also provided the buyers with an important increase in supply to undertake significant investments in downstream expansions.

The *second period* started with the US initiative in 1982 to block further increase in natural gas exports from the Soviet Union to buyers in Western Europe, cf. Chapter10. The Afghan invasion in 1980 and the Polish Marshall law in 1981, and the ensuing «evil empire» position taken by President Reagan triggered this intervention. In the late seventies Norway had a rather heated political discussion on depletion policy. The main element was which annual production level to aim for between 50 and 90 million tons of oil equivalents (mtoe), in order to limit the adverse impact of the oil activity on Norway's economy in general. To the outside observer, this of course indicated considerable room for maneuver, and the US pointed to an acceleration in Norway's gas production policy as the obvious alternative to make up for the shortfall in further Soviet supplies.

The giant Troll gas field was discovered a couple of years earlier, but as the water depth of 300 meters was at the limit of technological feasibility, the licensees were conducting time consuming studies to establish a viable production concept. Eventually, acceleration of Troll development became an important priority both for Norway and her NATO partners. The Troll contracts concluded in 1986 established a price formula that represented a significant drop in gas prices compared to earlier contracts. For the first time the "supply contract» was introduced in major Norwegian gas sales, whereby a defined volume profile was sold regardless of field reserves. This was also the start of the system with the Gas Negotion Committee (GFU) whereby the Norwegian Ministry of Petroleum asked the Norwegian oil companies Statoil and Norsk Hydro, and later also Saga, to undertake joint sales negotiations. It was a period of very rapid development of new gas pipelines to Germany, Belgium and France.

With Troll production capacity as the guarantor of deliveries, a number of smaller fields and associated gas from oil production was also released for sale. Increasing the recovery of oil from existing reservoirs has always been a prime consideration of Norwegian depletion policy. During this second period the amount of gas reinjected into oil producing formations increased to a level of 40 BCM while the level of gas sales increased from 18 BCM in 1980 to 50 in 2001 with contractual increases up to 65 BCM in 2005. This very active growth period resulted in new combined oil and gas production records up to 230 mtoe, far in excess of the targets considered in the late 70-ies.

The *third period* was initiated by the liberalization of the European gas market. The integration of EU economies and the need for even competition rules, as well as a desire for more efficient markets *and* more gas, more pipeline routes and storage capacity all makes the market “more liberal” than before. The launching of the EU Gas Directive in 1998 was the important milestone, cf. Chapter 2. It required that barriers to the free movement of gas should be abolished, to improve market efficiency and increase the number of producer-consumer relations, and hence competition.

In addition, in 2001, the EU-Commission issued its "Statement of Objections" regarding the GFU-organization of Norwegian gas exports. The issuance of a claim that all Norwegian gas contracts entered into over the last 15 years were established on an illegal basis, formally after 1995 when Norway entered into the EEA-agreement, obviously was a big surprise to the Norwegians. EU argued that the buyers under these contracts should have the freedom to choose whether they wanted to cancel, renegotiate or maintain these agreements. The SO was however cancelled in summer 2002.

The reorganization of the Norwegian gas industry in 2001 implied not only that the coordinated gas sales were terminated, cf. Chapters 2 and 6. It also gave new challenges in the coordination between oil and gas production, resource management and the exploitation of scope benefits in production and transportation of gas. Obviously, in mature parts of the Norwegian shelf this could be dealt with more easily than in undeveloped areas in the Norwegian and Barents Seas.

Reorganization of the Norwegian Gas Industry

The Ministry of Petroleum and Energy (MPE) has from the very beginning in the 1970s strongly controlled production, transport and sale of Norwegian gas. It has been the responsibility and duty of the MPE to award concessions and appoint delivery fields to the contracts, as well as approving the commercial agreements. Main instruments in doing this were from the mid-1980s first the GFU and then also the FU, cf. Chapter 2.

The system worked in a way that producers who want transportation of gas must negotiate for transport solutions and conditions with the pipeline companies. The companies who own gas, but do not have a share in the transportation system in question (3rd parties) have in general paid more for transportation than those who also own a part of the transportation system, cf. Chapter 6. High transportation tariffs move profit from the fields to the pipeline companies. The arrangement has perhaps been perceived as disadvantageous for ”smaller” gas fields that do not defend the development of new pipelines and where the producer does not have an ownership share in the pipeline. At the same time, the concentrated ownership of the pipeline companies reflects a corresponding concentrated ownership on the production side, with the Norwegian State through SDFI, Statoil and Norsk Hydro as the most important players. This system by and large has assured long-term investments and a realization of considerable economics of scope between (oil and gas) production and transportation for the bulk of Norwegian gas.

The GFU and FU arrangements and transportation solutions were defended from a national point of view in connection with the introduction of the Gas Directive and ESA's controls and evaluation of competitive conditions on the Norwegian shelf. The arguments were that ”free competition” in production and sale between companies may contribute to a weaker resource management, as well as a larger supply of gas in the market and a pressure towards lower prices, particularly in the short and medium term, cf. Chapters 5 and 12. Impaired possibility of exploiting economics of scope by opening the Norwegian pipelines through a TPA arrangement could technically make things more complicated and more expensive. The advantages of scope between Norway as a total gas seller and the large transmission companies on the continent, expressed through the long-term TOP contracts, were also pointed out. Maintenance of the model would assure that Norway should still be able to appear as a stable supplier of gas with ”factory gates” in Emden, Zeebrügge, Dunkerque and St. Fergus. A change of the joint management could put long-term investments at risk and through that weaken the supply of gas in the long-term, which might be a disadvantage also to purchasing countries.

Obviously, the arguments for optimal resource management and the exploitation of economics of scope are something that also the EU should take into consideration and further in their liberalization efforts. The principles for how FU worked were then not automatically at variance with EU's single market principle, as long as MPE does not discriminate between who will receive licenses on the NCS. On the other hand, the argument to strengthen the market power of Norwegian gas is contrary to the principles of a liberalized market and the interests of the consumer countries (the EU members).

At the same time, it is not obvious that GFU in its old shape was an organ that had sufficient dynamics in it to safeguard Norwegian interests when many smaller and more short-term contracts evolved in the market. The market had been undergoing fundamental changes for some time through a more extensive infrastructure and growth, which gradually required that Norwegian gas should be sold to more customers under more variable conditions than before. A changed role of the GFU could have been in Norwegian interest, but not necessarily the maintenance of it as a single monopoly seller only.

Thus, the GFU arrangement was for a long time under pressure both politically and from the market. Market developments and political actions pointed towards that producers to an increasing extent would sell gas directly to the customers of gas (distribution companies, the industry and gas power plants). The buyers of ”new” Norwegian gas (new contracts) would not (only) be the same as before (the transmission companies), but the transmission companies’ customers. Thus, in the “New World”, the sales of gas should be made on a more fragmented basis than before. For the reorganization of the sector it led to the question about who should actually be considered the *producer* on the Norwegian shelf.

Let’s assume that liberalization takes place downstream in the market but not on the NCS. This was a Norwegian argument made before the Gas Directive was politically accepted to become part of Norwegian legislation. If Norwegian gas had continued to be sent to the market as one commodity through one seller, it would mean that the GFU (or a corresponding arrangement) would sell directly to the customers from the “factory gates” at the landing points for the Norwegian pipelines. This is illustrated by arrow I in figure 13.1. Depending on the total growth in supply relative to the growth in demand, this might have been an improvement for Norway,

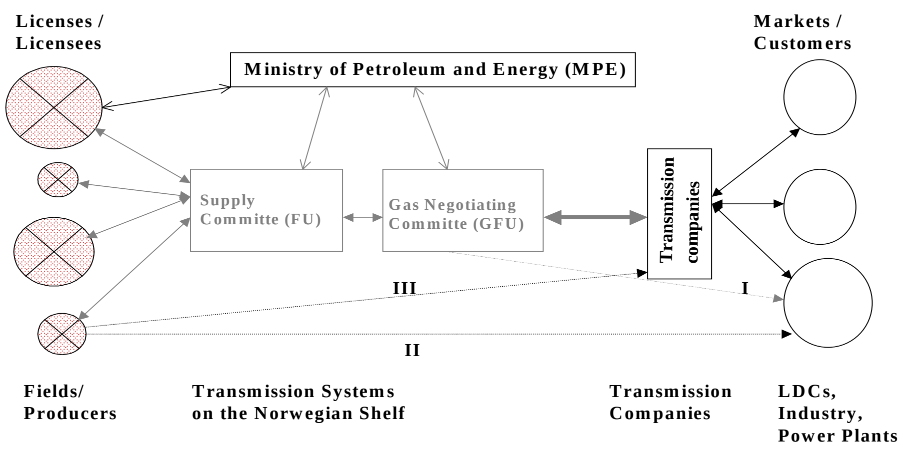

Figure 13.1: Models for the Sale of Norwegian Gas After 2001

as it would have strengthened Norway's relative negotiating position in the market, transaction costs disregarded. Obviously, the EU countered such an outcome, both from a principle and interest point of view.

The result of the discussions between Norway and the EU was that TPA should be introduced also on the NCS. From an EU competitive point of view, as much competition as possible should be created among Norwegian gas producers. This would happen when each individual license holder in the fields sells their gas independently. This would split and make each seller as small as possible. If downstream liberalization also works, the buyers will be the customers of these licensees (arrow II). On the paper, both buyers and sellers of gas should then operate on an as competitive basis as possible.

However, it does not seem likely that such an arrangement can be fully realized on either the demand or the supply side. On the demand side it is possible that not as much will happen downstream as is the intent behind the directive. For example, within the Gas Directive, it is up to the national authorities whether there will be a negotiated solution or publicly regulated tariffs for transportation. Most countries has chosen regulated tariffs, but for example Germany has chosen a negotiated tariff system. Obviously, one difficulty with maintaining such a negotiated TPA arrangement over time is that a party may bring what is considered an excessive tariff before the EU for evaluation, for instance by the Competition Directorate DGIV. When such complaints emerges, it is possible that a regulated TPA arrangement might be enforced in all countries. The possibility that the EU might introduce any form of de facto regulatory authority puts a moderating pressure on implicit and explicit tariff arrangements of all transmission companies. However, Germany prolongs the period where they to a larger extent maintain a situation they consider more advantageous for themselves than just to adhere to the EU.

It may be also imagined that the transmission companies continue to be the buyers of gas to a relatively great extent. In addition, the European gas industry tends to concentrate around larger units, rather than smaller ones. E.on's acquisition of Ruhrgas in 2002 is a step in this direction. Gaz de France is also integrating horizontally outside France. A (limited) splitting up of the sale of Norwegian gas may then actually impair the collective Norwegian negotiation position (arrow III), and not be to the advantage of the marginal fields on the NCS.

On the supply side, "perfect competition" between the licensees is not likely to be accomplished either. A licensee with a given percentage of a field may not sell more gas than what the share accounts for, and this volume depends over time on what all the other licensees are selling. Together with gas production there is also offer an important production of crude oil. From the point of resource optimization, the production of oil and gas must be optimized with regards to each other in order for the reservoirs to be optimally exploited. It would *over time* be nearly impossible to carry out a comprehensive sale from one licensee in a field without coordination with the other licensees. This point towards the lowest possible de facto level for defining a producer over time will have to be production area or field.

Furthermore, the bulk of Norwegian gas production comes from a few fields, with Troll as the dominant one. In addition there is a strong concentration of owners with a Norwegian State dominance across the fields. SDFI alone represents more than 40 percent. SDFI, Statoil and Norsk Hydro together represent 70-80 percent. There will still be a strong concentration around the same players who have sold gas until now. And finally, the establishment of the new GasLed system opens up the pipelines and the terminals for the NCS for 3rd parties, but the tariff levels will roughly be maintained and it does not comprise all of the system, cf. Chapter 6. Thus, the abolition of the FU-GFU system may not necessarily fundamentally change the seller concentration measured by field or companies on the Norwegian shelf, although it modifies it.

Our discussion concentrates around what is sound resource management arrangements and how competition can be enhanced. These concerns and interests color the choice of organizational model from the producer to the burner tip. Norway, as a exporter of gas from large and costly fields, need a model which gives an overview over the different advantages of scope and profit distribution throughout the gas chain, and the EU will also have to share many (but not all) of these interests and points of view. As gas is a non-renewable resource, there are sound reasons for some degree of control of how the resources are extracted and sold, also based on the long-term interest of the consuming countries. It will be impossible to find simple, once-and-for-all solutions that both increase competition, ensures a prudent resource management, and the long-term supply of gas.

The economic rent may in a liberalized market in various ways end up with the producers, the treasuries of the producing countries, the transmission companies, the customers, as consumer surplus or the treasuries of the consumer countries. Political actions and commercial strategies will influence the final distribution of the economic rent. Norway is in a conflict of interest with the purchasers of gas, concerning the distribution of rent. Norway cannot count on parties with other economic interests to reach arrangements about what is the ″correct″ model for the European market from the individual producer to the burner-tip as long as the principles can be interpreted differently (remember Adam Smith's term: "There is no such thing as a free market").

Max Weber's classic definition accentuate the likelihood that individuals or groups get their way in a relationship based on opposing interests or conflict. In such a perspective, material resources and formal position will be central to the analysis, while the framework for exercising such power will usually be built-in imbalances in generally accepted norms, concepts and authoritative knowledge. It is generally accepted that economic processes have a dimension of power and democracy. Weber discussed this within the framework of the national state: ′Processes of economic development are in the final analysis also power struggles, and the ultimate and decisive interest at whose service economic policy must place itself are the interests of national power′ (Austvik & Andersen, 2001).

Not only Norwegian external policies will influence the distribution av rent across economically integrated nations. The question about the organization downstream as well as on the Norwegian shelf must also be expected to be strongly politicized for the foreseeable future, where economic an political rationality must be balanced into the possibility and ability of the parties to reach their goals.

Threatening Gas Taxes

An increase in gas excise taxes may become particularly attractive for consuming countries' governments when rent is made available in the gas chain during liberalization process. This is what has happened in the oil market over the past 15 years. When crude oil prices dropped in 1986 and 1991, consumers could have derived the benefit from the loss of rent among producers. However, particularly in Europe, consuming countries raised oil product taxation, which stabilized end-user prices and to some extent suppressed demand and (delayed?) a potential later price rise on crude oil. As downward trends in crude oil prices and cost-savings in oil exploration and production can be used to increase oil product taxation, an upward trend in oil prices can be used to increase natural gas taxes, as was seen in Italy some 10 years ago. Even more important, gas taxes could rather easily be increased if gas prices are dropping, as in the oil market, as they most likely will do in a liberalized market with oversupply. This will pressure producer prices down for longer time, cf. Chapters 4 and 12, and transfer rent from producing to consuming countries' treasuries.

However, if long term stability and growth of the European gas market is to be secured, energy taxes should to a larger extent than today be set to reflect each carrier's environmental benefits and costs. Taxes on gas should be lower than on other fossil fuels and liberalization should take a form that increases gas consumption. Among fossil fuels, natural gas is the environment's best friend. This does not harmonize with the EU (1997b) proposal of equal rise in gas and coal taxation. Low gas taxes would benefit producers through more stable and foreseeable prices, consuming countries through stable and continued increases in supplies as well as it would give us all a better environment.

One of the biggest economic problems for producers is that purchasing countries through energy taxation have a political tool that, ex post, can derive (much of) their expected rent. Worst case scenario for exporters occurs when fields and pipelines are "fully" developed. At this stage, most producers' costs are sunk, and producers have no alternative but to continue supplying gas through existing facilities and grids even though prices are well below what was expected.

Because countries with open trade needs rules of minimum levels for taxation and cost-driving regulations, to avoid a "race-to-the-bottom" development; the EU set minimum rules for energy taxation, as well as in a number of other fields. This is an important reason for the pressure towards harmonization of energy taxation. For a large importing country, or a group of countries such as the EU, such taxes may pressure exporting countries' prices down. In fact, taxes may be orchestrated across borders in a way that maximizes purchasing countries social surplus (Austvik, 2002), in the same way an optimal tariff can do for large importing countries, as we know from international trade theory. Thus, national European gas taxes may, deliberately or not, serve much of a similar function as a customs tariff. Because such processes may lead to a pressure on exporting countries' prices and the distribution of rent among countries, gas taxation may become a major political issue between energy exporting and importing countries. Therefore, gas taxes should be included in EU and WTO trade agreements, in the same way as negative taxes, i.e., subsidies, already is.

Norway, Russia and the EU

The consumer countries share Norwegian interests in stability and long-term investments. In the question of price level, Norway will beyond certain limits have a conflict of interests with them. These interests Norway share, on the other hand, with other exporting countries like Russia and Algeria. This represents a new dimension of foreign policy balancing for Norway of particular national interests and considerations as a petroleum producer in the relationship to other western countries with whom Norway had more similar total interests before her oil and gas exports became as large as it is now.

The rate of growth in production may affect how increased downstream competition affects prices in a more liberal market. If supply grows faster than demand, prices to producers may come under pressure, cf. Chapter 5 and 12. Increased excise taxes on gas consumption will, regardless of the form of liberalization, put exporter margins under pressure, cf. Chapter 4. A disadvantageous development of the market liberalization and increased excise taxes on gas may both have an effect towards lower profits for producers. If the effects become strong, fields may become unprofitable. In order to prevent or limit an excess supply situation with a subsequent price drop and tax rise, it will in a more liberal market be important for the exporters (Norway, Russia, Algeria and the Netherlands) that the combined growth of gas exports does not exceed growth in demand.

A somewhat corresponding combination of common and conflicting interests like Norway has in relationship to Russia in the Western European gas market , is shared by member countries in the Organization of Petroleum Exporting Countries (OPEC). Every OPEC member has a common interest with the other OPEC members in that the common good, that is the price of oil in the global oil market, shall be reasonably high and stable. The countries have however conflicting interests when it comes to who shall pay for keeping the price high. This can be seen in the continuous discussions about production and quota distributions within OPEC, particularly in periods where demand for OPEC oil is low. All OPEC countries wish to influence the others to reduce their production so there will be more left for themselves, in order to be as much "free-riders" as possible.

In the European gas market, Norwegian gas now represents about 18 percent of the imports on average, rising to some 25 percent. These shares are far higher than her significance in terms of volume in the oil market. In the oil market Norway represent about 8 percent of the world exports and 4 percent of world production. Just like Norway evaluate market effects of her production policy for oil together with other oil exporting countries, she may also come to see herself served by evaluating market effects of her gas production policy.

As a part of a comprehensive strategy, Norway has in given situations good reasons for playing together with other gas producing nations to influence price stability and development by contributing in giving producers such power. Russia also sees long-term contract as the logical way to establish long term confidence between parties who need confidence in supply and confidence for irreversible pipeline investments. In this situation, producers can play an important role in achieving the joint interest in maintaining stable and foreseeable supplies to the European gas market. In order to do this, producers need stable and foreseeable prices as well as the instruments and ability to optimize gas extraction over time. Long-term stabilizing actions should not be in conflict with consumer country interests, unless the prices are higher than the long-term marginal costs (LRMC) for marginal fields supplying the market. Prices higher than LRMC will on the other hand include interests of conflict between buyers and sellers. But efforts to prevent stop-and-go developments in the supply will be an advantage to Norway, as well as important contribution to stabilizing the energy markets to the advantage of all

Obviously, the EU processes are influencing the competitive situation for Norway and Russia. Norway must adhere to EU competition laws and regulations. This influences her ability to decide how she wants to organize her gas production, transportation and sales. Russia has, on her side, organized gas production and transmission under one body (Gazprom). There are plans to unbundle and liberalize some Gazprom activities, but not to let Russian companies compete in export markets. Because Russia can maintain such a concentrated structure, and Norway not, Russia will be in a stronger position than Norway in the future in terms of market power.

Even though Russia is not affected directly by EU gas regulations in the way that she organizes her industry, she will meet the same uncertainty as Norway in terms of increased price volatility, cf. Chapter 3. There will be more short-term contracts and she will run the political risk that gas taxes may suppress EU import prices (Norway's and Russia's export prices). This could hamper investments in the large and remote new production fields and transportation infrastructure in Russia, as well as in Norway.

Russian gas may also over-supply the market if liberalized. Assume that Russian gas companies get the right and possibility (including access to domestic transportation) to sell gas abroad. The price they will get is higher in Western Europe than in the Russian market. Russian gas companies will, naturally, try to sell where prices are the highest. Better access and higher prices will lead to a lot of gas offered to Western markets and less gas sold to the domestic market (domestic demand will also decline due to the higher price alternatives), and, thus, create an oversupply in the market (a "gas bubble"). In this way, each company's logical action will lead to a drop in price in the European market (the common good) for everyone. The American gas bubble in the 1980s was similarly created as a result of the deregulation of the US gas market. The producers got access to customers they previously could not reach. Prices dropped some 30 per cent shortly after as a result over the oversupply, cf. Chapter 9.

An option for Russia is to turn her eyes to the growing Chinese market. If or when Russia starts to export gas to Asia, we will get an Eurasian gas market, linked through Siberian pipelines. This would change the dominant position of the EU as the most important buyer of Russian gas, and put Russia in an even stronger position as a world energy exporter.

Thus, for economic growth to continue as anticipated, Europe and the world are not only dependent on the continuous flow of oil from the Persian Gulf. Russian gas may become as important for both Europe and Asia. With as faster depletion of Norwegian resources, European dependency on Russian gas will increase over time. Because energy markets are interlinked, a tight market situation in natural gas will increasingly have the potential of spillover effects into the oil market, and not only the other way around. As gas consumption rises rapidly in Europe and in the rest of the world, a Siberian crisis may in 20 years time have corresponding fundamental effects on world economy as an oil crisis in the Persian Gulf.

In the energy dialogue between EU and Russia it seems to be a growing recognition on the EU-side that long-term contracts may be beneficial and that joint negotiations may be necessary for the parties who will develop large gas field and pipeline systems. It seems that it may be possible to live with the destination clauses in the existing gas contracts, and that one may find solutions to this issue in the case of new contracts that may follow. But it has taken a long time to arrive at these simple understandings, in a period of an historic Russian move to the west. Perhaps, without the events of September 11 2001, the parties would still not sufficiently have recognized the importance of such long term planning in the energy industry.

It is difficult to see that the EU simultaneously can achieve lower gas prices to consumers, high tax revenues from gas usage, and a growth in both demand and supplies as expected. However, because Russia is so important to EU energy supplies, it is possible that the two finds ways to solve this problem. One possibility is that the EU will subsidize some of the investments to compensate for the potentially lower Russian export prices. From a social EU point of view, this will be cheaper than to pay high prices for gas.

Norway's joint interest with the Russians to maintain prices at a certain level is a new element in her relation to her big nabour in the east, as well as to the EU. A closer analysis is however required of how such a cooperation in supply should be carried out and balanced towards remaining aspects of Norwegian foreign and security policies, including how to involve the EU and alliance partner and great power USA.

The Role of the Government

In the relationship to Russia and the EU it is of importance whether Norwegian policy is determined from a social point of view, or if it more or less is the sum of the actions by each company. Usually, a government will optimize the use of natural resources over a longer time horizon than do private companies. This is due to the fact that the state has more factors to take into consideration than just maximizing profit on short-term exploitation, including environmental concerns, macro-economic balance, market effects, etc. Involving aspects of security policy can be imagined, as well, as the country is more exposed internationally through high production, which may necessitate increased defense spending. The sum of a range of such considerations means that the government often has a lower discount rate when evaluating a future exploitation of resources. The lower the discount rate the higher the present value of a *future* production, cf. Chapter 5. This contributes to the Government in many situations arriving at a lower rate of extraction than private companies. Thus, optimization of national interests in petroleum policy gives the government an important role as a manager of resources.

If for instance Saudi-Arabia were to select production rates only on (short term) commercial criteria, there would be a range of companies wishing to invest in the country for this purpose (assuming that other political conditions were favorable). It is however not certain that Saudi-Arabia as a nation would be served through increasing the production volume to maybe 20-30 mfd/day, with subsequent effects on prices and revenue. It was the nationalization of the oil companies in the 1960s and 1970s, which many have seen as a necessary condition for OPEC countries to coordinate supply following the 1973 Yom Kippur war. A reprivatization of the decision making in petroleum policies following for example an American control over the Persian Gulf area may, if unrestricted lead to higher production and lower oil prices in the short and medium term. In the long-term however, oil prices may become higher as dependency on Middle East oil increases and resources are exhausted. It is the role of the government to balance such short and long-term interests.

The government has a role to maintain the collective interests when each of the companies are to small to handle, or which is not their concern. If resources is to be managed with a long-term view in an optimal manner, and production managed to stabilize markets, the government will need to impose restrictions on private companies. The conflict between producing a lot now (the individual company) and to wait a while (the government) will become more visible when private companies have strong interests in production decisions. In this process, it is often the case that public employees transfer to the companies. Company competency may often become stronger than for instance in the ministry in question and among politicians. In this way the companies may «trap» the government into accepting decisions they themselves want (here: high production).

The problem of production regulations in the petroleum sector might be particularly difficult between large, multinational companies and small countries with limited resources in competence and strategic management. This is known as a «principal-agent» situation, and occurs often as a problem when public authorities are to regulate the behavior of companies in imperfect markets, where the companies often are relatively few. This pose higher requirements on the competency and strength of the government to take care of public interests than when publicly owned national companies are the dominating ones, cf. Chapter 7. This challenge must of course be weighted against the importance for most oil producing countries in engaging private (and often multi-national) companies in search and exploitation, in order to obtain capital, updated knowledge and technology for the activities.

When the government actually should decide on a lower gas production volume than the sum of what the companies want each by themselves, it may, corresponding to when it chooses rate of development for oil, mainly choose between three instruments:

a) delayed award of exploration permits,

b) delayed development of proven gas fields, or

c) reduced production in developed field.

Delayed award of exploration permits will not help in counteracting a short-term drop in prices in a liberalized market, but would signal to the market a more long-term restraint. It will however be the most important element in performing an optimal resource management over time.

The development of a petroleum field must on its side carry interest throughout a later production phase. By delaying production the companies will contract increased costs. This instrument will mainly also have long-term effects and signal effects on the market.

Reduced production at developed fields will represent a financial loss for the companies (and through that also a loss for the government). In this situation, all costs (both fixed and variable) are approximately the same for full production or reduced production. This instrument is typically limited in time and can only be used in an effort to stabilize the market. The reduced supply must then lead to a larger price increase in percent than the per cent decline in production in order for the reduction to be profitable, or to a degree of stability assessed to be more valuable than the loss of revenues from production. In a liberalized European gas market short term production regulations could however be important in order to mitigate short-term fluctuations, in the same way as SGRs would be on the demand side, cf. Chapter 11.

Security-of-Supply

Easier access to pipelines, new pipelines built and expanded storage facilities should all improve security-of-supply for purchasing EU countries in a liberalized EU gas market. On the other hand, more volatile, uncertain and lower producer prices could lead to a drop in large investment projects and weaken supply security in the long run. This is an experience already made in the American gas market. After the deregulation in the 1980s, prices dropped (the "gas bubble"). While demand for gas increased with economic growth and low prices, there has not been much expansion of production capacity. The unused U.S. capacity from the 1980s was gradually absorbed and prices increased, cf. Chapter 9. Eventually prices have now reached a level higher than in the European market. Only in the past couple of years capacity has started to increase slowly, following the higher prices. Thus, liberalization lead to stop-and-go reactions in long term investment decisions. With the considerable time lags between investment decisions and when production actually reaches the market, price volatility may increase over time, as well as in the short and medium term.

The liberalization of energy markets in Europe is a very important and necessary process. However, if a very rapid liberalization is to be applied, resulting in wide renegotiations and years of dramatic market moves, it may have serious effects for long term supplies in addition to involve interest conflicts between EEA-member Norway and external partners Russia and Algeria. For all buyers and sellers it should be essential to liberalize markets and at the same time respect agreements and secure a responsible resource management and long term supplies. Therefore, market reform and liberalization should be modified in a way that prices are stabilized over time, to give supply a better chance to grow in line with demand. In this way security of supply is de facto improved, and the chance of a new major energy crisis is less obvious. It should be an important element in Norwegian (and Russian) international gas policies to influence EU market liberalization to optimize these short- and long-term interests.

Norwegian Foreign and Security Policy

The oil crises around the Persian Gulf and the conflict around the construction of the Soviet gas pipeline were examples that energy was one of the most central objectives for great power rivalry during the cold war. The access to petroleum resources, the trade and the prices had great significance both for the military systems and for the development of Western societies. After the fall of the Berlin Wall and the Soviet Union, international politics have changed character with the U.S. as the only global superpower, but with many regionally strong states. The petroleum resources of the world are still found in countries with considerable political instability, with room for major market disturbances.

For Norway, security political dimensions to the oil and gas activities have been particularly in focus in connection with the possibilities for production in the polar areas. The potential for future activities are assumed to be great both on the Norwegian and Russian sides. In the polar areas Norway face several exceptional and crucial challenges in connection with possible oil and gas activity. For one there is still unsettled borderlines between Norway and Russia in the Barents Sea. Because of the vulnerable nature in the area, environmental concerns will be a limiting factor for production and transportation of petroleum. The continued great strategic significance of the Kola bases implies that petroleum activity may seem negative for the operational conditions for the Russian Northern fleet, and particularly for the strategic submarines (Kibsgaard 1998).

Even if the problems have received less focus in the last decade, the exceptional situation in the Barents Sea may again be of political interest and the development of the Snøhvit field outside Finnmark is a move in the direction to open the area up for more exploration. There will however be a need for legal, political and economic analyses of how the petroleum activity in the area should be developed. The cold war is over, with a Russia on a slow development towards market economy as the great power of the area. In a world with more liberalized trade and freer communication between countries, the potential for cooperation and conflict may also be changed and possibly improved. At the same time, many of the same barriers in security policy, environment and economy remains.

Security concerns are not limited to the polar areas. Norwegian installations may be imagined as targets in military conflicts as a part of both general conflicts in the vicinity, global political conflicts, and European economic and/or political conflicts. Oil and gas have both high value in itself as well as high strategic value. The threat to them largely depends on the international situation. It will increase in periods of conflicts where Norway, NATO, exporters and importers of energy are involved, and in areas where Norwegian companies are active. Importantly, strikes and attacks may come as a result of conflicts where Norway initially is not involved. The object might be to apply political or military pressure on Norway or on countries, which are dependent on energy supplies from Norway or the price development on energy where Norway has an influence. Norway does not have to be the primary target, but Norway may get involved in conflicts due to her importance for other exporters or importers. This can happen in peacetime and in periods of increased international tension. It may be terrorist attacks and sabotage due to the propagation of conflicts in other parts of the world (Kibsgaard, 1999).

Gas production and transportation may also be threatened through crises in the oil market. In a crisis situation with a sharp reduction in oil production in the Middle East, oil prices may increase considerably; particularly if there is no free production capacity other places. At the same time this increases the significance of natural gas, as oil and gas in many markets are substitutes for each other. Important importing countries will hardly sit quiet and simply accept such price increases if they can do something about it. In such a situation, it is reasonable to expect an increased pressure on

Norway from importing countries for keeping up and possibly increasing both oil and gas production. A policy, which entails closing down Norwegian petroleum production in a crisis situation, seems quite unacceptable for consumer countries, which are Norwegian allies. Closing down Norwegian production in such a situation would be a dream that come true for other producing countries if they are participants in conflicts over oil in the Middle East or gas in Russia or North Africa.

The dependency on Norwegian petroleum may cause consumer countries to want to defend the installations on the Norwegian shelf in a crisis if Norway does not do it herself. In the extreme, pressure from other warring countries may lead to consumer countries assuming control over North Sea production. This sharpens the requirement to a plausible Norwegian defense of the installations and the transportation systems connected to these. Even with a strong Norwegian defense in this area, Norway will however not be able to defend all the installations herself. It is necessary to prepare the defense of the shelf in cooperation with other countries, where the question of Norwegian control becomes a central one. "Norway's export of energy has made us vulnerable from all who wishes to affect large recipients of Norwegian energy. Norwegian foreign policy must behave actively with regard to these changing vulneralabilities and map out which interests coincide with Norway's under different circumstances. Concretely this means that states which are strategically vulnerable to a loss of Norwegian energy production, such as Germany, France and Belgium, form a new resource for military assistance which should be exploited" (Nyhamar, 1999). This indicate that it is those countries that receive Norwegian gas that have an interest in the shaping of Norwegian foreign and petroleum policy, particularly European powers such as Germany, France, Great Britain and Italy.

Norwegian gas strategy must therefore in a foreign policy context be shaped in the consciousness that the super power USA, purchasing countries like the European great powers Germany and France and competitor Russia will be interested in its content. Competing seller and purchasing countries have therefore an incitement to influence Norwegian energy and foreign policy, just like Norway has reason to try to influence the policies of other seller and buyer countries. Both foreign and defense policy must allow for the increased economic and strategic significance Norway has gained for other countries in the positioning of Norwegian interests as well as in the threat evaluation of security policy. The situation creates a possibility for strengthening Norway's international position, but it may also make her more sensitive and vulnerable towards other countries. Norway is a small nation with only one percent of the European population.

At the same time there is a reorientation process with regard to security policy going on in Europe. NATO receives other roles, and Europe will play a larger role by itself than previously. Norway must in general orient itself in this process, and put more emphasis on energy than before. Norwegian petroleum should now heavily affect the security thinking of the country, beyond the concerns about the Northern polar areas. The size of the gas exports makes Norway a strategic player in a market of vital interest for energy supplies to Northern Europe. The economic development and national security of the receiving countries are to a large extent dependent on secure supplies of energy at stable prices on an acceptable level. Norway has through her large petroleum production gained increased significance for the foreign policy of both other producing countries and for countries which buy oil and gas, and not only during unrest.

The Need of a Gas Strategy

The framework and the rules of the game for the international economic integration processes are today set globally through WTO in particular, and regionally in Europe by the EU. The Energy Charter (IEA, 1995) is among other things an attempt to introduce WTO's principles in the energy sector also for countries that are not members of the WTO. In these and other internationally important fora producers of raw materials are often in a minority and easily becomes a politically weak group. In the modern, internationally integrated economy the rules of the game are different from the time when ownership of the resources was decisive for the exploitation of them and the resultant profit through sales. The development and reorganization of the European gas market and the excise tax policy for oil and gas underline the fact that the power in the energy markets now lies to a large extent with the consumer countries. Even if Norway both economically, politically and in security policy is allied with the consumer countries and have many interests in common with these, Norway must be aware of the fact that she is quite alone in safeguarding her interests as a large petroleum exporter.

There will be looser and winners from market liberalization depending on how liberalization takes place, and how commercial and political players throughout the gas chain behaves, individually and together. As gas is a non-renewable and strategic resource in the European market, a liberalization of the market may have a somewhat different effect than in most other liberalized markets. The continued existence of an economic rent will make it more politicized than other markets.

Thus, a strategy for Norwegian gas production and sale must include holistic evaluations and juxtapositions of a range of different circumstances of technical, social, political and economic character. In order to become consistent, a Norwegian gas strategy must be developed based on an understanding both for economic and political circumstance in themselves *and* the relation between them. Market developments and political decisions together force new commercial strategies, increase the need for new forms of cooperation between the industry and Norwegian authorities, and put pressure on authorities to influence and cooperate with international agencies and purchasing countries' as well as other exporting countries.

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Norwegian Natural Gas; Liberalization of the European Gas Market is a comprehensive analysis of the ongoing liberalization of European gas markets and Norway's role as a major gas exporter. The book argues that liberalization of a market for a non-renewable resource like natural gas presents substantial challenges for the regulator as well as the regulated. It also demonstrates that the rent to be distributed in the gas chain, will make the European gas market more politicized than most other markets for the foreseeable future. The processes are important not only to Norwegian and European economic interests and trade, but also to diplomacy, foreign and security policy.

Main contents:

- Norwegian challenges in the European gas market
- Market developments and EU directives
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