CPB Document

Machiel Mulder and Gijsbert Zwart

No 110
February 2006

Government involvement in liberalised gas markets

A welfare-economic analysis of the Dutch gas-depletion policy

CPB Netherlands Bureau for Economic Policy Analysis
Van Stolkweg 14
P.O. Box 80510
2508 GM The Hague, the Netherlands

Telephone	+31 70 338 33 80
Telefax	+31 70 338 33 50
Internet	www.cpb.nl

ISBN 90-5833-260-8

Abstract in English

This report analyses the welfare effects of two major components of the Dutch gas-depletion policy: the offtake guarantee for small-fields gas and the cap on production from the Groningen field. We conclude that the benefits of offtake guarantee currently may outweigh the costs, but a further development of the gas market would reverse this picture. The cost of the offtake guarantee is that it gives operators reduced incentives to respond optimally to short-term changes in market conditions compared to a competitive market. Regarding the cap on Groningen (42.5 bcm per year), we find that this measure is inefficient when the cap is binding, i.e. restricting the production from the Groningen field. The costs of capping Groningen production follow from shifting returns to the future. The benefits of this measures consist of slightly positive effects on small-fields production and positive benefits for security of supply.

Key words: gas depletion, gas market, gas policy, competition, cost-benefit analysis

Abstract in Dutch

Deze studie onderzoekt de welvaartseffecten van twee belangrijke onderdelen van het Nederlandse beleid voor de gaswinning. Deze onderdelen zijn de gegarandeerde afzet voor gas dat in de zogenaamde kleine velden geproduceerd wordt, en een plafond op de productie van gas uit het Groningen-veld. Uit de analyse blijkt dat de maatschappelijke baten van de afzetgarantie voorlopig nog hoger zijn dan de kosten, maar dat dit beeld om kan slaan wanneer er een goed ontwikkelde gasmarkt is ontstaan. De kosten van de afzetgarantie bestaan uit geringe prikkels voor producenten om te reageren op korte-termijn veranderingen in de gasmarkt. De baten van een plafond op Groningen (van 42,5 miljard m^3 per jaar) wegen daarentegen niet op tegen de kosten van deze maatregel. De kosten van het plafond komen voort uit het naar achteren schuiven van opbrengsten uit gaswinning. De baten van deze maatregel bestaan uit wat hogere winsten bij de winning van kleine-velden gas en het naar achteren in de tijd schuiven van investeringen voor alternatieve opties voor flexibiliteit, zoals gasopslag.

Steekwoorden: gaswinning, gasmarkt, gasbeleid, marktwerking, kosten-batenanalyse

Jel-codes: L3, L5, L95, Q3, Q4,

Contents

Preface

Since the oil crises of the early 1970's, the Dutch government has pursued the policy of conserving gas in the huge Groningen field while encouraging production from other gas fields, the so-called small fields. This policy has been effective as it raised production from the small-fields whereas the Groningen field has merely been used as a swing supplier, i.e. producer of gas during peak-demand periods. Although this Dutch gas-depletion policy has existed for several decades, an analysis of its efficiency has not been made. This report is meant to fill this gap by offering a systematic analysis of costs and benefits of the Dutch gas-depletion policy.

During the project, many experts acted as a useful sounding board. In a number of meetings, we had lively discussions with representatives of the gas industry, i.e. NAM (Wim Groenendijk), Gasunie Trade & Supply (Martien Visser), Gas Transport Services (Adriaan de Bakker), IRO (Hans de Boer), NOGEPA (Bram van Mannekes), Total (Lucy Zima) and Wintershall Nederland (Rob Beers), and the Dutch government, i.e. Energie Beheer Nederland (EBN) (Peter Rosenkranz) and the Ministry of Economic Affairs (Florette Tiemersma and colleagues). We thank them for their valuable comments in the course of the project.

We also benefited from discussions during meetings at the Norwegian Ministry of Petroleum and Statistics Norway, both in Oslo, the conference of European Energy Economics in Bergen (Norway), the International Energy Agency in Paris, the Dutch Energy Council in The Hague, the Energy Convention Groningen, a brown-bag seminar at the Faculty of Economics in Groningen, and the Dutch Ministry of Economic Affairs.

In addition, we received highly appreciated information and comments on drafts of this report from a large number of individuals. We would like to mention Rob Aalbers (SEO/University of Amsterdam), Jaap Breunese and colleagues (Netherlands Institute for Applied Geoscience TNO-NITG), Oscar Couwenberg and Mark Helmantel (University of Groningen), David Cox (ILEX, Oxford), Robert Haffner (Netherlands Competition Authority NMa), Bas Heijs and colleagues (Ministry of Finance), Kim van Nieuwaal (VU Amsterdam) and Jonathan Stern (Oxford Institute for Energy Studies).

The responsibility for the contents of this report is of course entirely ours. From within the CPB, regular feedback was given by Casper van Ewijk, Mark Lijesen and Victoria Shestalova. Ali Aouragh and Jeannette Verbruggen supported the authors by collecting information and editing the report.

Casper van Ewijk
Deputy Director

Summary

This report analyses the welfare effects of two major components of the Dutch gas-depletion policy: the offtake guarantee for small-fields gas and the cap on production from the Groningen field. We conclude that the benefits of the offtake guarantee currently may outweigh the costs, but a further development of the gas market would reverse this picture. Regarding the cap on Groningen (42.5 bcm per year), we find that this measure is inefficient when the cap is binding, i.e. restricting the production from the Groningen field.

Debate on Dutch gas-depletion policy

For several decades, the offtake guarantee for small-fields gas as well as the cap on Groningen have been implemented as part of the Dutch gas-depletion policy, although the design of the cap changed a number of years ago. According to the adherents of this policy, it has created favourable conditions for small-fields production, raising state revenues from gas production as well reducing import dependence of the Netherlands. Others have doubts about the efficiency of these measures. As the policy favours the production from relatively expensive fields while it conserves the less expensive Groningen field, it would raise costs of gas depletion. A consideration put forward more recently is that these measures do not fit in a liberalised gas market: a liquid market gives a guarantee to producers that they can sell their gas as well. In this report, we offer an integral assessment of these effects.

Analysis of market failures: why should the government intervene?

From a welfare-economic point of view, government policies are advisable if market failures exceed failures of such policies. A market fails if it results in levels of production or consumption deviating from the socially optimal levels. Several factors make the natural gas market sensitive to inefficiencies following from market power. Those factors are in particular geopolitical factors, economies of scale and regional restrictions on trade. The geopolitical factor consists of the growing import dependence on a number of exporting countries and the still large influence of governments in energy markets, both in exporting and importing countries. The presence of huge economies of scale in transport together with regional restrictions in trade give suppliers in regional markets power to charge higher prices. Another source of market failures is related to consumption: individual consumers do not take into account the impact of aggregate consumption on import dependence. Inefficient market outcomes can also follow from governments if they cannot commit to non-intervention in energy prices in cases of extremely tight market conditions. As a result, private investments will be below the socially optimal levels.

The analysis of market failures therefore provides a number of reasons for government intervention in gas depletion. Reduction of sources of market power, for instance by extension

of the international transport capacity, improves the functioning of the European gas market resulting in more efficient prices. Measures to deal with the abovementioned consumption externality are enhancing domestic gas production as well as increasing energy savings: both measures would reduce import dependence. If market parties insufficiently invest in flexibility, governments could choose to invest themselves, for instance by conserving gas fields having high swing capabilities. The question, however, is whether such government measures are efficient as they also cause costs.

Other often mentioned reasons for government intervention in the gas industry are difficult to base on an analysis of market failures. In the debate on the small-fields policy, the limited window of opportunity of the offshore infrastructure is frequently put forward as a factor calling for government intervention. According to this argument, only a short period of time is left for small-fields exploitation due to the aging of the infrastructure. However, this aging as well as the costs of extending the lifetime of the infrastructure can be taken into account in decisions to be made by the gas industry, implying that this issue does not refer to an externality. On the other hand, the limited remaining (economic) lifetime of the offshore infrastructure may call for government actions to raise the efficiency of licensing procedures.

Offtake guarantee for small-fields gas is efficient for the time being

The net welfare effect of the offtake guarantee is positive for the time being, but a further development of the gas market likely reverses this picture.

The offtake guarantee offers all producers of small-fields gas the option to sell the gas to Gasunie Trade & Supply. As a result, these producers do not have to adapt the production profile of their fields to the demands of the market. The same holds for the quality of the gas (such as energy content): small-fields producers have the right to sell all kinds of gas to Gasunie Trade & Supply.

Given the currently still not well-developed gas market, the offtake guarantee is an efficient measure for pooling gas having different production profiles and qualities. This advantage of pooling vanishes, however, when the gas market has become more liquid. Then, the gas market enables producers to sell their gas efficiently, as is now already the case in the United Kingdom. Coordination by a market generally is more efficient than coordination by one agent. The major cost item of the offtake guarantee, therefore, is that it results in less efficient production as well as consumption decision. In the current system, one agent, i.e. Gasunie Trade & Supply decides how to match different profiles of production and consumption. In a market system, on the contrary, all players, both producers and consumers, assess whether changing their production or consumption is efficient.

So, the cost of the offtake guarantee is that it gives operators reduced incentives to respond optimally to short-term changes in market conditions compared to a competitive market. These costs of inefficient production might be compensated by a benefit of reduced dependence on imports. However, that benefit can also be realised by other measures such as energy savings.

Although the offtake guarantee theoretically could hinder the development of a liquid wholesale gas market, the actual development of the Dutch TTF does not as yet indicate any important barriers suggesting that the offtake guarantee is not currently restricting this market.

Cap on Groningen is expensive measure

A reason for imposing a cap on Groningen production is myopic behaviour by firms resulting in a welfare-economically too high level of production. In that case, imposing a cap can be efficient although the risk exists of setting the cap at a too low level. However, economic literature provides no clear evidence for myopic behaviour by firms. On the contrary, the existence of market power on the gas market results in too low levels of production, calling for measures which increase production above the profit-maximising level.

From our analysis it follows that the welfare effects of a production cap are negative in most scenarios. Only when the cap is not binding, costs equal benefits as both are zero (not taking into account transaction costs of imposing the cap). If the cap does restrict production, costs exceed benefits in all scenarios and variants analysed. The costs of capping Groningen production follow from shifting returns to the future. The benefits of this measures consist of slightly positive effects on small-fields production and positive benefits for security of supply.

Small-field producers benefit from a cap on Groningen if it raises the price of gas and, hence, increases their inframarginal profits. A cap hardly affects the level of small-fields production as the small fields are not the marginal producers on the European gas market. Reduced production by Groningen as a result of the cap merely impacts imports to Europe. In addition, it causes a demand response.

The benefits of the cap for security of supply follow from postponing investments in alternative options for flexibility. In our analysis, we used investments in gas storage as the alternatives for the flexibility of the Groningen field. The benefits of the postponement of these investment appear to be significantly smaller than the costs of the cap. Note that our estimation of the benefits for security of supply likely is an overestimation as it is known that gas storage is more expensive than other options to deal with the temporary shortages on the gas market, such as demand responses. Moreover, government investments in flexibility may crowd out private investments.

Alternative policy regarding the Groningen field

A policy regarding the Groningen field potentially having positive welfare effects is increasing production above the profit-maximising level. Because of the market power of the Groningen field, production from this field likely generates results different from the welfare maximising strategies. We find that including consumer welfare in Groningen's deployment decision substantially advances production resulting in higher production levels in the beginning of the scenario periods. In a scenario with a low level of competition on the European gas market, inclusion of consumer welfare in the object function on Groningen raises average annual production by 3.9 bcm, resulting in a net welfare effect of about 4 billion euro.

Note, however, that implementing a 'floor' in production from the Groningen field would raise the risk of setting the floor at a too high level from a welfare-economic point of view. A more efficient way for taking the level of Groningen production close to the socially optimal level is improving competition. After all, these results imply that improving competition on the European gas market would increase Dutch welfare: the loss of producer surplus because of lower gas prices is largely compensated by higher profits from advanced Groningen production and increased consumer surplus for Dutch consumers. Although profits of small-field producers would decrease, because of the lower gas price, improving competition on the European gas market has a positive net-welfare effect for the Netherlands.

Samenvatting

Deze studie onderzoekt de welvaartseffecten van twee belangrijke onderdelen van het Nederlandse beleid voor de gaswinning. Deze onderdelen zijn de gegarandeerde afzet voor gas dat in de zogenaamde kleine velden geproduceerd wordt, en een plafond op de productie van gas uit het Groningen-veld. Uit de analyse blijkt dat de maatschappelijke baten van de afzetgarantie voorlopig nog hoger zijn dan de kosten, maar dat dit beeld om kan slaan wanneer er een goed ontwikkelde gasmarkt is ontstaan. De baten van een plafond op Groningen (van 42,5 miljard m^3 per jaar) wegen daarentegen niet op tegen de kosten van deze maatregel.

Discussie over het Nederlandse depletiebeleid

De afzetgarantie voor het kleine-velden gas en het plafond op het Groningen-veld maken al decennia lang deel uit van het Nederlandse gasdepletiebeleid, zij het dat het plafond tot voor kort op indirect wijze was vormgegeven. Door velen wordt gesteld dat dit beleid gunstige effecten heeft voor Nederland omdat het zou leiden tot meer productie van kleine-veldengas, hogere gasbaten en geringe afhankelijkheid van buitenlandse aanvoer. Het beleid heeft inderdaad geleid tot meer productie van gas uit de kleine velden en tot conservering van het Groningen veld. Anderen plaatsen echter vraagtekens bij deze maatregelen. Een al lang bekende kanttekening is dat dit beleid voorrang geeft aan de winning ui dure velden en de winning van goedkoop gas naar de toekomst schuift. Een kanttekening van meer recente datum is dat dit ingrijpen in de markt niet past in een geliberaliseerde gasmarkt: een liquide gasmarkt vormt ook een garantie dat het gas kan worden afgezet. In deze studie analyseren we al deze effecten en wegen we ze tegen elkaar af.

Analyse van marktfalen: waarom een rol voor de overheid?

Om te bepalen of de overheid een rol te vervullen heeft in een bepaalde markt, moet die markt eerst onderzocht worden op het bestaan van marktfalen. Een markt faalt als deze niet tot de efficiënte uitkomsten leidt, dat wil zeggen dat productie of consumptie op een maatschappelijk gezien te hoog of te laag niveau liggen. Bronnen van marktfalens op de gasmarkt zijn het gebrek aan concurrentie op de internationale markt, met name door de invloed van geopolitieke factoren, schaalvoordelen bij het transport en de distributie van gas en de daarmee samenhangende belemmeringen in de internationale handel. Een andere bron van marktfalen ligt bij consumptie: individuele consumenten houden geen rekening met het effect van hun gasverbruik op de importafhankelijkheid en daarmee op de politieke afhankelijkheid van een land. De overheid kan ook een bron van inefficiëntie zijn: als marktpartijen vrezen dat de overheid de gasprijs zal reguleren tijdens periodes van grote krapte, dan zullen ze te weinig investeren in flexibiliteit, zoals gasopslag. Ze zullen dan immers deze investeringen niet kunnen terugverdienen uit hoge piekprijzen.

De analyse van marktfalens levert dus argumenten voor ingrijpen van de overheid in de gaswinning. Vermindering van bronnen van marktmacht, bijvoorbeeld door uitbreiding van internationale transportcapaciteit, leidt tot betere prijsvorming. Als tegenwicht voor het teveel consumeren door consumenten doordat ze geen rekening houden met het effect op importafhankelijkheid kan de overheid binnenlandse productie dan wel energiebesparing bevorderen, wat de import zal verlagen. Wanneer marktpartijen te weinig investeren in flexibiliteit, dan kan dit worden gecompenseerd door bijvoorbeeld zuinig te zijn op gasvelden met een hoge flexibiliteit, zoals het Groningen-veld. De vraag is echter of deze maatregelen efficiënt zijn omdat overheidsmaatregelen ook met kosten gepaard gaan.

De analyse van marktfalens levert dus wel enige argumenten voor het Nederlandse gasdepletiebeleid. Het vaak gehoorde argument van de beperkte ‘window of opportunity’ valt daarentegen moeilijk te relateren aan een gebrekkig functioneren van de gasmarkt. Dit argument zegt dat er nog maar een beperkte periode beschikbaar is om het kleine-veldengas winstgevend te exploiteren vanwege de (economische) veroudering van de infrastructuur. Deze veroudering is echter geen reden voor overheidsbeleid omdat markpartijen rekening kunnen houden met zowel de veroudering als de kosten van mogelijke levensduurverlenging. De beperkte economische levensduur van de infrastructuur maakt het wel efficiënt om procedures, zoals bij productievergunningen, zo snel mogelijk te laten verlopen.

Afzetgarantie voor kleine-veldengas voorlopig nog efficiënt

Het netto welvaartseffect van de afzetgarantie voor kleine-veldengas is voorlopig nog wel positief, maar dit beeld kan omslaan wanneer er een goed ontwikkelde gasmarkt is ontstaan.

De afzetgarantie biedt alle producenten van gas uit kleine velden de mogelijkheid om hun gas te verkopen aan Gasunie Trade & Supply. Hierdoor hoeven deze producenten minder kosten te maken om het in de tijd variërende productieprofiel van hun gaswinning aan te passen aan de eveneens in de tijd variërende vraag naar gas. Hetzelfde geldt voor de kwaliteit van het gas (energie-inhoud en dergelijke): producenten kunnen gas van alle soorten kwaliteit aan Gasunie Trade & Supply verkopen.

Bij de huidige, nog beperkt ontwikkelde gasmarkt is de afzetgarantie een efficiënte manier van ‘poolen’ van gas met verschillende volumes en kwaliteiten. Dit voordeel verdwijnt echter grotendeels wanneer de gasmarkt zich verder heeft ontwikkeld. In dat geval kunnen afzonderlijke producenten hun gas ook ‘gegarandeerd’ afzetten, zoals dat nu bijvoorbeeld al in het Verenigd Koninkrijk gebeurt. Decentrale coördinatie via een markt is in de regel efficiënter dan centrale coördinatie door een organisatie. De belangrijkste kostenpost van de afzetgarantie is daarom dat het tot inefficiënte productie- en consumptiebeslissingen kan leiden. Bij de afzetgarantie is het een speler, te weten Gasunie Trade & Supply, die beslist hoe de verschillen in productieprofielen en gaskwaliteiten worden aangepast aan de wensen van de vraag. In een marktsysteem daarentegen bepalen alle spelers, zowel producenten als consumenten, of aanpassing van hun productie of consumptie efficiënt is.

Inefficiënte binnenlandse gasproductie kan per saldo positieve effecten hebben zijn als het leidt tot minder import en daardoor tot minder (politieke) afhankelijkheid van gasexporterende landen. Deze bate kan echter ook op andere, mogelijke efficiëntere, wijzen worden gerealiseerd, zoals bevordering van energiebesparing.

Een mogelijke andere kostenpost is dat de afzetgarantie een belemmering vormt voor de ontwikkeling van de liquiditeit van de gasmarkt en daarmee voor de welvaartsbaten die een liquide markt voortbrengt. In de praktijk lijkt echter van een dergelijke belemmering nauwelijks sprake te zijn, gezien de groei van de liquiditeit van de gasmarkt in Nederland (in het bijzonder het TTF).

Plafond op Groningen is dure maatregel

Een reden voor het instellen van een plafond bestaat wanneer bedrijven ‘kortzichtig’ zijn, dat wil zeggen dat ze op korte termijn zoveel mogelijk winst willen behalen, en daardoor op een hoger niveau produceren dan maatschappelijk optimaal is. Het opleggen van een productieplafond kan dan efficiënt zijn, al bestaat het risico dat de overheid het plafond op een te laag niveau stelt. Voor kortzichtigheid bij bedrijven bestaan echter geen duidelijke aanwijzingen. Het bestaan van marktmacht op de gasmarkt is eerder een aanwijzing dat bedrijven op een te laag niveau produceren. In dat geval ligt stimulering van de productie meer voor de hand dan het beperken ervan.

Uit de analyse van verschillende scenario’s blijkt dat het netto welvaartseffect van een plafond op de productie van Groningen vaak negatief is. Alleen wanneer het plafond niet ‘knelt’ en dus geen effect heeft op de productie, zijn de kosten en baten in evenwicht, namelijk beide nul (afgezien van transactiekosten). In dat geval heeft het plafond vanzelfsprekend ook geen nut. Wanneer het plafond wel knelt, dan kunnen de kosten beduidend groter zijn dan de baten. De kosten van een plafond op Groningen bestaan uit het later ontvangen van de opbrengsten. De baten van het plafond bestaan uit licht positieve effecten voor de kleine-veldenproductie en positieve effecten voor de leverings- en voorzieningszekerheid.

De kleine-veldenproducenten profiteren van een plafond op Groningen als daardoor hun gasprijs wordt verhoogd waardoor ze meer winst maken. Een plafond op Groningen leidt overigens nauwelijks tot extra productie uit de kleine velden. Een plafond heeft vooral gevolgen voor Europese importen en de vraag naar gas: een vermindering in Groningen productie wordt in Europa vooral opgevangen door meer gas te importeren en minder gas te consumeren.

De baten voor de leverings- en voorzieningszekerheid komen voort uit het naar achteren in de tijd schuiven van alternatieve opties voor flexibiliteit. In dit onderzoek hebben we gerekend met investeringen in gasopslag als alternatief voor flexibiliteit die door het Groningen-veld geleverd wordt. De baten van een plafond op Groningen in termen van het naar de toekomst verschuiven van die investeringen blijken in alle scenario's beduidend kleiner te zijn dan de kosten van het plafond. De op deze manier berekende baten zijn bovendien overschat omdat uit andere studies al is gebleken dat gasopslag een kostbare aangelegenheid is en dat andere maatregelen, zoals tijdelijke afschakeling van sommige eindgebruikers, efficiënter kan zijn. Daarbij komt dat overheidsinvesteringen in flexibiliteit, via een plafond op het Groningen-veld of via investeringen in gasopslag, private investeringen kunnen verdringen.

Een plafond blijkt evenmin een efficiënt middel te zijn om Groningen te gebruiken wanneer de Europese gasmarkt gebukt gaat onder hoge gasprijzen. Het welvaartsverlies van uitgestelde productie blijkt groter te zijn dan de welvaartswinst van lagere prijzen in de toekomst door het langer kunnen gebruiken van het Groningen-veld.

Alternatief beleid voor Groningen

Een beleidsmaatregel voor Groningen die mogelijk wel welvaartsverhogend werkt is het verhogen van de productie boven wat de winstmaximaliserende producent doet. De verhoging moet dan gebaseerd worden op het maximaliseren van de welvaart, dus inclusief de voordelen van prijsverlagingen voor de consumenten in Nederland. Bij een gemiddelde jaarlijkse verhoging van bijna 4 miljard m^3 in een scenario met weinig concurrentie op de Europese gasmarkt zou de totale welvaart bijna 4 miljard euro hoger uitkomen. Een dergelijke maatregel is echter moeilijk te implementeren vanwege het risico dat de overheid de 'vloer' in de productie voor Groningen op een te hoog niveau vaststelt.

Een andere manier om het productieniveau van het Groningen-veld dichter bij het welvaartsmaximaliserende niveau te brengen is de concurrentie op de Europese gasmarkt te verbeteren. Uit onze analyse volgt dat de lagere gasprijzen als gevolg van de sterkere concurrentie weliswaar leiden tot een lagere winst per m^3 voor het Groningen-veld, maar dat dit welvaartsverlies ruimschoots gecompenseerd wordt door een hogere productie en een groter consumentensurplus voor Nederlandse consumenten. Voor producenten van kleine velden is dit evenwel minder gunstig omdat zij te maken krijgen met een lagere gasprijs. Het netto-welvaartseffect voor Nederland van meer concurrentie op de gasmarkt is echter positief.

1 Introduction

1.1 Background

1.1.1 Emergence of competition in European gas markets

The European natural gas market started its development in the 1960s, after the discovery of the giant Groningen gas field in the Netherlands. The importance of natural gas increased after the 1973 oil crisis, as Europe strived to decrease its dependence on the Middle East oil producing countries. This process was encouraged by the new gas finds in the North Sea, i.e. in the British, Norwegian, Dutch and Danish sectors of the continental shelf. These gas-producing countries mainly supplied consumers in North-western Europe. Consumers in other parts of Europe were increasingly supplied by producers in Russia and Algeria, making these countries with their huge gas reserves prominent suppliers on the European market[1].

Historically, the European gas market was dominated by state owned monopolists controlling trade and domestic supplies. International trade took place mainly through long-term (i.e. several decades) contracts with take-or-pay clauses, at oil-linked prices. These long-term contracts were considered necessary to give investors certainty about recovering the large initial investments in network and production infrastructure. Supplies to end-users were priced according to the substitution principle, so that gas prices were set according to the market prices of substitute fuels (typically, fuel oil for industrial end users, and gas oil for domestic consumers).

Liberalisation in Europe started in the United Kingdom in the 1980s and 1990s. Competition among gas producers was established and independent traders were introduced into the market. This led to the emergence of short term trades, including the establishment of a liquid spot market[2]. The function of grid management was conferred to an independent company. As a result, gas prices in this country increasingly follow from competition among traders and producers on the gas market, i.e. gas-to-gas competition emerged. The so-called wholesale price constitutes one component of the prices for end-users. Other components in these prices are related to costs of system services, the margin for distribution, and taxes.

At a slower pace, continental Europe is following the British liberalisation process. The process in the European Union is managed through gas regulations, i.e. the European Gas Directives, proscribing non-discriminatory third-party access to the networks in order to accommodate entry by competitive suppliers, and making end user markets contestable for competing

[1] See e.g. Seeliger (2004) for an overview of historic developments

[2] Due to their long-term nature, contracts including oil-linked prices which have been concluded in the recent past still constitute a significant fraction of gas trades in the British market, (see e.g. ILEX, 2004).

suppliers. This process is not fully realised yet in all EU-countries. Currently, 74% of the gas in the EU-15 countries is consumed by end-users who are free to choose their gas suppliers.[3] Although competing market places and supply by new trading companies are gaining importance in various countries, the position of the former monopolists remains strong in most countries on the Continent. In many EU-countries, the number of suppliers on the wholesale market is no more than one, while in other countries a few wholesale firms dominate supply. Cross-European competition on the wholesale level is restricted by inefficient linkage of national pipeline systems (see European Commission, 2005).

1.1.2 Searching for the role of government in the gas industry

Governments remain heavily involved in the gas industry. They still have shares in gas companies, regulate production and transport, and sometimes favour the creation of 'national champions'. Also in the Netherlands, the government is involved in upstream, midstream parts as well as downstream parts of the gas industry. At the upstream level, i.e. the production side, the Dutch government participates in exploration, development and production of gas fields, gives private firms licenses to operate, imposes standards for private activities, regulates the commodity market[4] and levies several taxes. At the midstream and downstream side, government intervention compromises ownership of a part of the joint venture with Exxon and Shell, Gasunie Trade & Supply, and full ownership of the gas transmission grid. Moreover, local public authorities are shareholders of energy distribution firms.

For several years now, the role of government in the gas industry has been subject to debate. This debate was partly induced by the offtake of liberalisation of the European natural gas market. As a result of this fundamental change in the structure of the gas market, Dutch government is reconsidering its role in the midstream and downstream parts of the gas industry. One outcome of this process already is the recently implemented acquisition by the state of the shares of Shell and Exxon in the transmission part of Gasunie (N.V. Nederlandse Gasunie, with its subsidiary Gastransportservices, GTS). The participation of the state in the supply part of this incumbent (Gasunie Trade & Supply) has not changed yet but remains likely subject to debate. Another outcome of this process is the proposal of the government to impose ownership unbundling on the energy-distribution industry.[5] After the implementation of this measure, the local public authorities are allowed to sell their shares in the production and trade firms while the network firms may be privatised up to 49%.

The process of liberalisation and privatisation in the European natural gas market has also generated concerns about the ability of market parties to take those measures which are needed

[3] Source of this paragraph is Eurostat, Competition indicators in the gas market of the European Union, Statistics in Focus, 08/2005.

[4] E.g. by appointing a gas exchange, or providing obligations on parties for ensuring gas supplies in severe winters.

[5] See Mulder et al. (2005) for a cost-benefit analysis of a full unbundling of the energy-distribution industry.

from a societal point of view. These concerns focus in particular on the issue of security of supply.[6] Security of supply issues arise both in the short and the longer term. In the short term, security of supply of gas refers to the ability of the market to deliver gas from a specific quality at any moment in time. In the longer term, the issue of security of supply refers to the exhaustion of domestic resources and dependence on resources in other regions. Although the latter developments are not caused by the process of liberalisation, the question is whether the market is able to efficiently deal with it.

Until recently, the Dutch government charged Gasunie with the task of guaranteeing a secure supply of gas for the next 25 years (EZ, 1996). This obligation has been dropped, as a result of the liberalisation of the market, but the subject has not been removed from the political agenda. Still, GTS has a task in securing short-term supplies in severe winter conditions. The looming exhaustion of gas resources in western Europe, notably in the United Kingdom but also in the Netherlands, raises European dependence on imports from more distant regions. As this larger import dependence could cause a higher risk of supply disruptions, governments consider security of supply measures which fit in a liberalised European gas market. As disruptions within the market could also result from insufficient investments by private parties in flexibility, governments also consider measures regarding reliability of the gas system such as arrangements of last-resort supplier.

1.2 Government involvement in gas production in the Netherlands

1.2.1 Policy goals and instruments

The discovery of the huge Groningen field at the end of the 1950s led to the formulation of the Dutch gas policy which has been largely unchanged over the past 40 years.[7] Generally, the aim of the gas policy is to maximise the contribution of the gas fields to the Dutch economy (see e.g. EZ, 1976). In many documents published by the government in the past decades, the aim of the gas policy is expressed in terms of resource management. In EZ(1979), the government stresses the importance of gas policy to reduce risks in the supply of energy. In EZ (1984), the government formulated as key goals of the gas policy: “continuity in supply, optimal use of domestic resources and diversification of energy use”. In its 3rd White Paper on Energy Policy (EZ, 1996), the government states that the gas policy is directed at securing national supply. In its more recent paper (EZ, 2004a), the government concludes that the policy objective is to

[6] See for instance IEA (2004a), stating that the key question is “whether the market itself will value security of supply and deliver timely signals and competitive incentives for investments to guarantee secure and reliable gas supply all the way to the final consumer.”

[7] Minister of Economic Affairs, Nota inzake het aardgas, Letter to the Lower House of the Parliament, Kamerstukken II, 1961-1962, no. 6767.

maintain the level of mining activity at the same high level for the coming fifteen years, maximising the total recovery of natural gas.[8]

In EZ (2004), the government formulates three major targets of the gas policy: security of supply in the long term, reliability of supply in the short term and environmental effects of energy production. Encouraging domestic production is seen as an effective measure to raise the long-term security of supply. As the swing capability of the Groningen field is seen as a major component in guaranteeing a reliable supply in the short term, managing that capability is viewed to be important for the short-term reliability of gas supply. From a global environmental point of view, domestic production of gas is viewed to be preferable above imports as "environmental criteria applicable to gas production are less strict in countries such as Russia. Moreover, when gas is transported over large distances, part of it is lost because of leakages." (EZ, 2004).

In order to reach these goals, the government uses a variety of instruments. The major components of the Dutch gas policy are the close relationship between government and private firms, coordination of production and supply. This results in three types of measures being implemented (see table 1.1). In the next sections, we elaborate on each of these types.

Table 1.1 Government measures regarding gas production

Type of measure	Measure
Ownership	Participation of the State in exploration and development activities
	Participation of the State in Gasunie Trade and Supply (T&S) and, since recently, full ownership of Gas Transport Services , GTS (through its parent company N.V. Nederlandse Gasunie)
Regulation	Guaranteed offtake of small-fields gas by Gasunie Trade & Supply
	Licenses for gas fields
Financial instruments	Fiscal measures
	Other financial measures

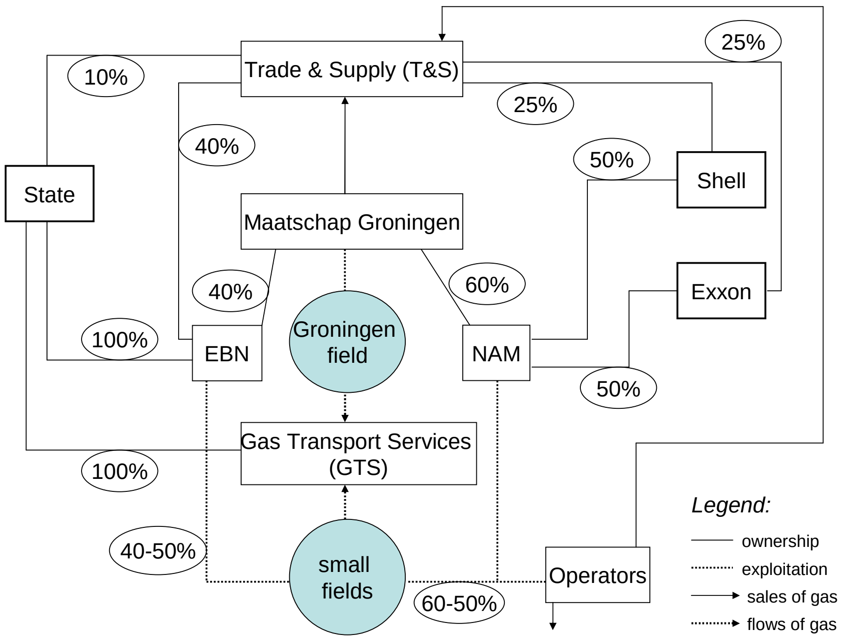
1.2.2 Ownership

The government participates in (almost all) mining activities via Energie Beheer Nederland (EBN), a 100% state firm. The 'Maatschap Groningen', which manages the production from the Groningen field, is owned by EBN (40%) and NAM (60%) which is a 100% subsidiary of Shell and Exxon (see figure 1.1). The concession to exploit the Groningen field was exclusively given to NAM. The Maatschap Groningen is obliged to sell the gas to Gasunie Trade & Supply, which is a joint venture of EBN (40%), the Dutch state (10%), Shell (25%) and Exxon (25%).

[8] "Het beleidsdoel is het mijnbouwactiviteitenniveau nog zeker vijftien jaar stabiel te houden, zodat in zijn totaliteit zoveel mogelijk aardgas gewonnen wordt". (EZ, 2004a)

Gasunie, exclusively responsible for trade and transport, has recently been split into two separate companies: Gas Transport Services (or N.V. Nederlandse Gasunie), which is in charge of transport of gas, and Gasunie Trade & Supply. The former is now fully owned by the State, while the latter still is a joint venture of the Dutch State, EBN, Shell and Exxon.

Figure 1.1 Involvement of state and private firms in gas production, transport and trade in the Netherlands



The State, via EBN, also participates in offshore as well as onshore mining activities. EBN has a 40 or 50% participation in all small-fields exploration and production projects. This participation reduces the risks for gas firms as it enables them to have a more diversified portfolio of projects.

1.2.3 Regulation

Until recently, as said above, the coordination of production and supply was realised through the government authority to annually approve long-term (25 years) plans submitted by Gasunie regarding total gas supply as well as export and import volumes, and to approve exploration and production activities of other gas firms. The state also regulated the gas prices through the 'market-value'-principle as basis for the sale of gas (see e.g. Correlje et al., 2000). This principle states that the price of gas is to be set at the maximum level not giving consumers an incentive to substitute to another fuel. Consequently the principle enables the government to skim a significant part of the consumer surplus. As different groups of end-users have different substitution possibilities, different price levels resulted. Generally, gas prices were linked to oil products, and hence, to the oil price. Above this price, Gasunie has been able to charge an additional price as reward for flexibility in its supplies.[9]

The introduction of competition in the European natural gas market has changed this kind of state involvement in production and trade. Gasunie Trade & Supply is not obliged anymore to annually submit long-term production and supply plans while gas prices are now determined by market forces. In long-term contracts, future gas prices can still be linked to other energy prices, but spot market prices of gas are increasingly becoming important as reference price in such contracts.

The state is still involved in production and supply decisions through the Small-fields policy. “The essence of this policy is that small fields are produced in preference to the Groningen field” (EZ, 2004). This aim is pursued by two policy measures: the offtake guarantee and a cap on production from the Groningen field.

According to the offtake guarantee, Gasunie Trade & Supply is obliged to buy all gas offered from small fields against “reasonable conditions and at market prices” (EZ, 2004). This offtake guarantee is meant to reduce costs as well as uncertainty of offshore projects and, hence, to encourage the level of offshore mining activities. Related to the offtake guarantee of Gasunie Trade & Supply is the obligation for the transport system operator, Gas Transport Services, to “ensure that gas from small fields can be taken up in the gas transport system”.[10]

The cap on Groningen production is meant to conserve its swing capability which is needed by Gasunie Trade & Supply to offer the offtake guarantee (EZ, 2005a)[11]. Until recently, production from the Groningen field was indirectly restricted through a ceiling of 80 billion m^3 on total Dutch gas production. The difference between this level and the actual small-fields production determined the cap on Groningen. As small-fields production is expected to decline in the (near) future, the indirectly determined cap on Groningen would rise and, hence, the flexibility capability of this field would decline earlier which, in turn, is claimed to raise costs of small-fields production. This decline will partly be compensated by additional investments in the so-called Groningen system, which includes the Groningen field and storage facilities (see EZ, 2005a). Nevertheless, a ceiling on Groningen production is viewed to be necessary to secure the

[9] See e.g. Asche et al. (2000) who find significant higher prices for German import from Netherlands compared to imports from Norway and Russia while Norwegian gas was priced above Russian gas. These price differences follow from the fact that “Dutch gas contracts are known to specify highest volume flexibility while Norway has a fair swing component whereas the Russians deliver the base load with a limited amount of swing.”

[10] Besides this task as a part of the small-fields policy, the transport system operator is obliged to guarantee deliveries of additional gas below an effective temperature of – 9° Celsius and intervene if a supplier defaults on the supply of gas to small-scale users. See http://www.gastransportservices.com/gastransport/en/aboutgts/company/services/public_tasks.

[11] “Het ging en gaat er om te verzekeren dat het Groningenveld zijn functie voor het kleine veldenbeleid kan vervullen”. (EZ, 2005a).

future availability of flexibility. The abovementioned indirect ceiling has been replaced by a specific cap on Groningen which is formulated in terms of a maximum average annual production over a period of five years (EZ, 2005a). Over the period 2006 - 2015, Gasunie Trade & Supply is allowed to take 425 billion cubic metres from the Groningen field, which is an average annual cap of 42,5 billion cubic metres.

1.2.4 Financial instruments

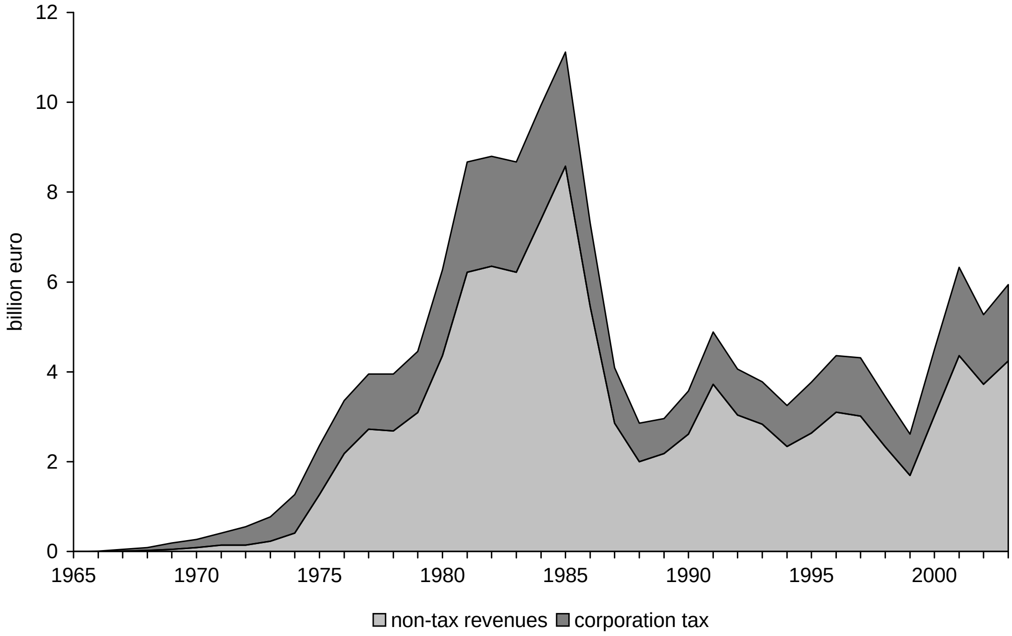
Another group of government measures affecting the gas industry are financial instruments consisting of tax measures and other financial measures. The tax measure directed at the mining industry is the corporation tax which is the profit-related tax applicable to all corporations. This tax generated approximately 30% of total government revenues from the gas industry in the past twenty years (see figure 1.2). The non-tax financial measures comprise a number of measures, notably royalties, payments on the state's shares in EBN (100%) and Gasunie Trade & Supply (10%), and petroleum tax. The royalties, which are a lump-sum tax independent on size of revenues, are only charged for onshore fields.

As EBN is a 100% state firm, the government receives EBN's total profit. The share of the state in the profit of Gasunie Trade & Supply is subject to a threshold and the so-called "rule of additional returns of Groningen gas"[12]. The profits of Gasunie Trade & Supply depend on the difference between the purchase price, i.e. the price paid to the Maatschap Groningen for the delivery of gas, and the selling price, i.e. the price received from the buyers of gas. Profits up to the threshold of 36.3 million euro are paid to the shareholders as dividend (see Annual Report of N.V. Nederlandse Gasunie, 2004[13]). Profits above this threshold are distributed between the Maatschap Groningen and the Kingdom of the Netherlands according to the above rule of additional returns on Groningen gas. The higher the difference between the purchase price, which is an internal transfer price, and the selling price, which is the market price, the higher the share of the state in the profit of Gasunie Trade & Supply. According to AR (1999), this share varies from 66,67 to 95%.

[12] In Dutch: 'Meeropbrengstregeling Gronings Aardgas' (MOR). The rationale of this rule is that the state should receive the largest part of additional profits following from price increases (see e.g. EZ, 1976). A detailed description of the (financial) relations between state and the other agents involved in the gas industry is given in a memorandum of the Minister of Economic Affairs,Tweede Kamer, vergaderjaar 2004–2005, 28 109, nr. 6.

[13] In 2004, Gasunie Trade & Supply was not yet separated from the N.V. Nederlandse Gasunie.

Figure 1.2 Government revenues from gas production, 1965 - 2004 (billion euro)



Source: EZ (2005).

The petroleum tax is the share of the state in the profit of the mining firms. This profit share differs between small fields, both onshore and offshore, and the Groningen field. For the small fields, the tax rate is 50%, for the Groningen field it is significantly higher. This tax rate applies to the taxable profit which depends on, among others, fiscal rules for depreciation[14] and uplift. The abovementioned corporation tax is deductible of the petroleum tax, implying that a change in the former, e.g. lower tariffs, is compensated by a change in the latter.

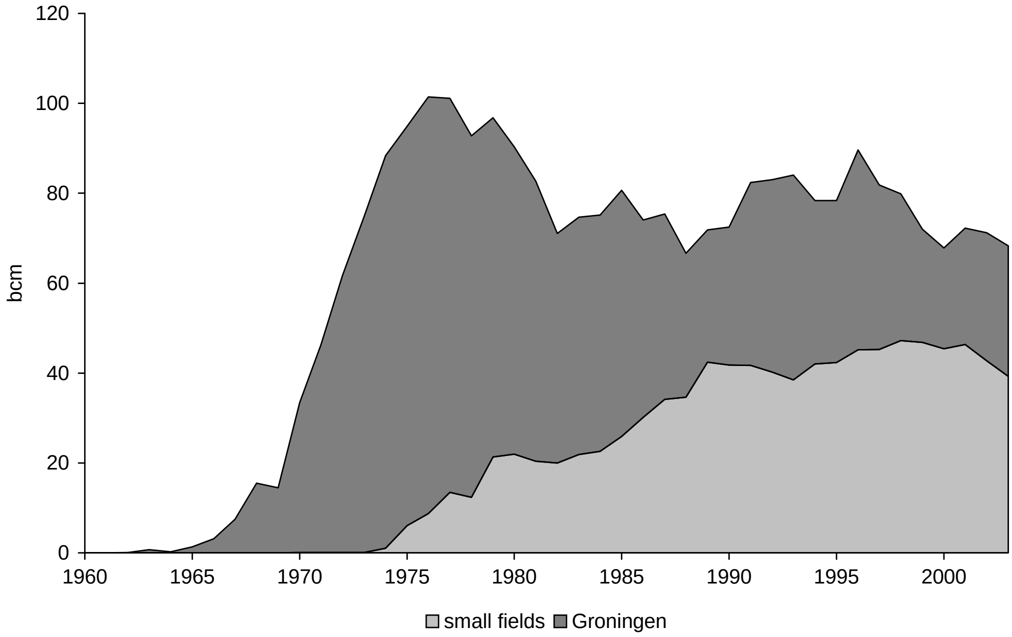
1.3 Debate on the guaranteed offtake and the cap on Groningen

According to many authors, the small-fields policy (comprising both offtake guarantee and cap on Groningen) has been effective in raising production from the offshore are. Quoting Peebles (1999), the small-fields policy “has resulted in the development of many small deposits of gas which otherwise may have been uneconomic for the producers and thus left in the ground”. Figure 1.3, depicting the production from both the Groningen field and the small fields since the offtake of Dutch gas production, shows that initially the production from the Groningen field grew strongly, resulting from the government’s policy to exploit this field rapidly (EZ, 1996). After the first energy crisis in the early 1970s, the Dutch government, worried about future ability of energy resources, formulated the policy to give fields outside Groningen a preferential treatment, which is the small-fields policy. As a result, production from Groningen declined

[14] See Mulder et al. (2004) for an analysis of the effects of the abolition of depreciation at will.

while production from the small fields increased strongly. Because of its impact on the conservation of the Groningen field and its flexibility capability, the small-fields policy is believed to have contributed to the security of gas supply (IEA, 2004).

Figure 1.3 Production from Groningen and small fields (in billion cubic metres)



Source: EZ (2005)

According to EZ (2004), the outlook for small-fields production strongly depends on the flexibility capability of the Groningen field. When this field is not able any more to act as a swing producer, costs for the exploitation of some small fields would allegedly become prohibitive as the costs of managing the load profile of these fields rise. Restricting the production of the Groningen field, by the above mentioned cap, is therefore seen as a necessary policy to maximise production from the small fields. The offtake guarantee is also viewed as “crucial for an optimum exploitation of the Dutch gas reserves” (EZ, 2004).

Although the effectiveness of the small-fields policy is generally recognised, the efficiency is more subject to debate. The relevance of that question has increased due to the growing importance ascribed to market factors in the gas markets. In their overview of four decades of Dutch gas policies, Correljé et al. (2000) state that releasing the restrictions on production from the Groningen field would contribute to achieving a competitive gas market where gas would be available at lowest costs for consumers. The OECD (2004), in its economic survey of the Netherlands, suggests that “with the ongoing liberalisation and development of the European gas market various market participants could perform the balancing role hitherto played by the

Groningen field as part of the small-fields policy”.[15] One can doubt whether an offtake guarantee given to private firms as well as a volume restriction imposed on production from a particular field fit in a liberalised market. Both measures lead to reduced costs for small-fields production but the question is whether the benefits of these measures exceed these costs. The OECD (2004), therefore, advises to “evaluate the net present value of different resource management approaches to assess whether or not the small-fields policy should be maintained in the future”.

In addition, one can wonder whether the small-fields policy is an efficient policy to reach the targets formulated by the government (on security of supply, environment and contribution to the Dutch economy; see above). The IEA (2004), for instance, states that the security of supply target can also be pursued by other measures in stead of the small-fields policy as “theoretically, small fields production (…) can be replaced by gas imports to maintain Groningen’s capabilities” although that would require additional investments in the infrastructure. Although the IEA (2004) states that specific policy is needed to encourage production from the small fields, this institute advises to constantly assess the small-fields policy from a longer-term perspective, using the cost-benefit methodology developed for assessing security of supply issues.

1.4 Market failures and government policies

From a welfare-economic point of view, government policies are advisable if market failures exceed failures of such policies. A market fails if it results in levels of production or consumption deviating from the socially optimal levels. In Mulder and Zwart (2006), we extensively analyse whether the presence of market failures in the natural gas market calls for government intervention. We conclude that several factors make this market sensitive to inefficiencies following from market power. Those factors are in particular geopolitical factors, economies of scale and regional restrictions on trade. The geopolitical factors consist of the growing import dependence on a number of exporting countries and the still large influence of governments in energy markets, both in exporting and importing countries. The presence of huge economies of scale in transport together with regional restrictions in trade give suppliers in regional markets power to charge high prices.

Other market failures which may call for policy measures are externalities related to production. Without these measures, a private gas producer might not fully internalise the effects of its production on other producers (i.e. tragedy of the commons), on future consumption or environment. Consumption also may cause an externality as individual consumers do not take

[15] To illustrate the developing European gas market, the OECD refers to the rising interconnection capacity and the development of spot and forward markets “offering a liquid market for small producers to sell output and hedge risks”.

into account the impact of aggregate consumption on import dependence. Inefficient market outcomes can also follow from governments if they cannot commit to non-intervention in energy prices in case of extremely tight market conditions. As a result, private investments will be below the socially optimal level. Other arguments for government intervention in the gas industry, in particular the limited window of opportunity for gas production and the indirect economic effects of the gas industry, are difficult to base on an analysis of market failures.

Relationship with other recently published CPB reports on gas depletion

In recent years, CPB has published several reports on gas depletion in the Netherlands. Each of these reports is directed at specific aspects of this issue.

In a study on risks on energy markets and energy policies, De Joode et al. (2004) analyse the efficiency of several security-of-supply measures, including a production cap on the Groningen field. Only taking into account the benefits of a cap on security of supply, this report concludes that this measure is highly expensive. In this report, we assess not only security-of-supply benefits but also the impact of a production cap on small-fields production. This more extensive analysis does, however, not change our conclusion on the efficiency of the cap.

In a paper presented at the 19th World Energy Congress, De Joode and Mulder (2004) assess the efficiency of advancing production from the Waddenzee area in order to extend the swing capabilities of the Groningen field. Implicitly assuming that the gas market is unaffected by Dutch depletion policy, the question dealt with is which field - Groningen or Waddenzee - should be used first for the supply of base-load demand. They find that the costs of advancing production from the more expensive field, i.e. the Waddenzee area, are lower than the benefits of extended flexibility of Groningen. In this report, we do take into account the impact of depletion policy on the gas markets, resulting in the conclusion that there is hardly a trade-off between Groningen production and small-fields production as changes in the former merely affect imports.

An analysis of the efficiency of one specific fiscal measure directed at small-fields gas production, i.e. the Depreciation at Will (DAW), is given in Mulder et al. (2004). This report concludes that the DAW improves the profitability of all exploration and production projects but that an introduction of this fiscal measure would hardly affect the magnitude of offshore activities because of other restricting factors, such as geological research and licensing procedures. As a result, introduction of DAW would merely result in a ‘dead-weight loss’ following from inframarginal projects benefiting from this measure. From that analysis follows that more efficient changes in the fiscal regime would be measures reducing the tax burden on marginal projects without relieving the tax burden on inframarginal projects. In this report, we focus on other measures directed at small-fields production, taking into account an impact of taxes on the effectiveness of these measures.

Governments have different options to address market failures, varying from ownership, structural measures, regulation and financial measures. However, market failures do not necessarily require direct government intervention to solve them as this intervention also causes costs and market forces themselves may be capable of solving of these failures. Consequently, before implementing government measures, careful analyses of both market failures and government failures have to be made.

1.5 Scope of this report

In this report, we assess the welfare effects of proceeding with the current Dutch gas-depletion policy. The key question here is whether it is efficient to maintain the existing policy measures directed at activities of the upstream gas industry. This analysis focuses on two major components of this policy: the cap on production from the Groningen field and the offtake guarantee for small-fields production.

In order to answer this question, we assess both the costs, including the costs of a transition to another policy, and the benefits of these measures. We will also pay attention to the distribution of welfare, both national and international. We focus on the costs and benefits for the Netherlands, implying that effects on foreign countries, e.g. higher consumer prices or environmental benefits, are not taken into account. Regarding the welfare effects on Dutch production and consumption, we assume that these effects remain in the Netherlands. We distinguish welfare effects for two groups of producers (Groningen and small fields) and two groups of consumers (high-quality and low-quality consumers).

Chapter 2 presents the general framework of the cost-benefit analysis, paying attention to the definition of the policy alternatives, the choice of the discount rate and the definition of background scenarios. Chapter 3 presents the cost-benefit analysis of the offtake guarantee while the analysis of the cap on Groningen is the subject of chapter 4. Chapter 5 presents the overall conclusions.

2 Framework for the cost-benefit analysis

2.1 Introduction

This chapter offers a framework for analysing the costs and benefits of the small-fields policy. This framework is based on Eijgenraam et al. (2000), who presented a guideline for conducting cost-benefit analysis of infrastructure projects, and De Joode et al. (2004) who applied that framework to energy policies. The framework consists of a number of steps to be taken. The starting point for any cost-benefit analysis consists of the definition of policy options (section 2.2). Afterwards, the choice of the discount rate (section 2.3) as well as the definition of background scenarios (section 2.4) have to be addressed.

2.2 Policy options

The policy options we are going to assess are the cap on the Groningen field and the offtake guarantee for small-fields gas. We call these two options our *'project alternatives'.* In the Dutch natural gas act (article 55 of the so-called 'Gaswet'), the Minister of Economic Affairs introduces a ceiling on production from the Groningen field over a period of 5 years, which replaces the national production cap which had existed before. In a recent letter to the Parliament, the Minister of Economic Affairs (2005a) has set the ceiling on Groningen on 42.5 billion cubic metres on average per year.[16] In our calculations, therefore, we assume a cap on Groningen of 42.5 bcm per year. In line with current practice, this cap only limits aggregate annual production, and allows for larger production in high demand winter seasons and low production in summers.[17]

We assess the welfare effects of the project alternative by comparing it to the so-called *'null alternative'* in which these measures are cancelled but other policy measures regarding the gas industry currently implemented, such as fiscal schemes and licenses regimes, remain. Although the offtake guarantee for small-fields gas and the cap on Groningen do not exist in the 'null alternative', this does not imply market parties have not implemented compensating measures. To the contrary, in the 'null alternative' market parties respond to changes in their environment. For instance, without the offtake guarantee Gasunie Trade & Supply might still be active on the market for small-fields gas. The key issue here is which solutions will be found by these parties and to which extent these market solutions generate market failures. Clearly, whenever market failures are absent, the welfare effect of any intervention can only be zero or negative.

[16] In individual years the actual production may be higher as the cap is formulated as a maximum production of 425 billion cubic metres over the period 2006 - 2015.
[17] The Minister of Economic Affairs (2005a) also expects that the cap will restrict production from the Groningen field as Gasunie Trade & Supply assumes higher production levels in its business analysis.

Generally, effects of policy measures are distinguished in direct, indirect and external effects. Direct effects are defined as those effects following directly from the policy measure. More specifically, in the case of gas market policies, direct effects are the effects on the natural gas market. These effects may expand to other markets, the so-called indirect effects. Some of the indirect effects are merely redistributions of welfare, or transferred direct effects. The third category of effects are external welfare effects, i.e. effects which are not internalised by markets and, hence, reflect market failures. In this analysis, we focus on the direct effects of the policy measures as the indirect and external effects are relatively small. [18]

2.3 The discount rate

Discounting future cash flows forms an important component of a cost-benefit analysis. Although we will not be able to quantify all effects of the small-fields policy, in some cases quantification is both possible and useful. We therefore have to choose which discount rate we will use.

One of the key issues here is whether the discount rate, i.e. the required rate of return, of the government should be different from the one chosen from a private investor's point of view. An alleged reason for the possible distinction between the social hurdle rate and the companies' required rate of return is the presence of capital-market imperfections, resulting in higher capital costs for companies. Another reason for lower governments discount rates might be myopic behaviour of companies making them not taking into account benefits in the more remote future. Although the role of both capital-market imperfections and myopic behaviour are subject to debate in the economic literature, it is generally viewed that the government should use the same discount rate as companies (see e.g. Ministry of Finance, 2003).

So, where private investors demand a return on investments that is commensurate with the (undiversifiable) risks in the investment, the government (on behalf of the tax-payer) should value this risk in the same way. The rate of return demanded by private investors as a compensation of risk is a good indicator of the discount rate to be used for a government appraisal of the economic viability of investments in gas projects. The reason is that the firm's discount rates are a reflection of the risk inherent in the investment. Governments experience the same risk, and should value it therefore as well.[19] The valuation of the Groningen gas field is no exception to this rule. The major systematic risks in cash flows, faced by private sector

[18] See for instance De Joode et al. (2004) where it is demonstrated that indirect and external effects of energy policy measures are relatively small compared to the direct effects.

[19] One component of risk to which governments may be less exposed than private firms is regulatory risk. This may more likely be classified as specific risk (i.e. risk that can be diversified through spreading investments over various sectors and countries), and as such does not warrant a risk premium. Regulatory risk may, on the other hand, be a rationale for involving governments in investments, e.g. in joint ventures.

and government alike, stem from uncertainty over future gas demand and, hence, future gas prices.

In order to determine the appropriate discount rate, three components have to be determined: the risk-free real interest rate, the real rate of return in the stock market, and the systematic risk of a project, i.e. the relationship between the risk of a project and the risk in the market which is called ‘the beta’.

In the Netherlands, but also in many other countries, the official risk-free rate is determined at 4% (Ministry of Finance, 2003). Compared to the current real interest rate, this rate is fairly high. Over the last decades, the real risk-free interest has declined to the current level of about 2%.

The real rate of return in the stock market and the level of systematic risk of a project determine the risk premium which has to be added to the risk-free interest rate. In order to determine this risk premium, the governmental commission on risk appraisal (Ministry of Finance, 2003; see also van Ewijk and Tang, 2003) recommends the use of the following rules of thumb:

- Compare the project to a similar project in the private sector. If available, use the discount rate of that project. “The yield which the benchmark project is expected to generate, or its beta, provides a good indication for the degree of risk associated with a comparable public sector project.” (Van Ewijk and Tang, 2003).
- If no such project is available, check whether any systematic risk is involved in the project. A systematic risk is the risk which is systematically correlated to the level of national income and, therefore, not can be eliminated by spreading this risk across the economy. If no systematic risks are attached to the project, use the risk-free real interest rate.
- If the project involves systematic risks, (i.e. future cash flows associated to the project depend on risks that are non-diversifiable, such as risk correlated with economic growth), try to establish what risk premium is associated with the risk and add it to the risk-free discount rate.
- If it is impossible to establish a risk premium associated with the particular risk, use the central value of 3% as risk premium.

Using the official risk-free rate of 4% and a risk premium of 3%, a discount rate 7% follows.[20] Given the current real interest rate of about 2% and the relatively low systematic risk in the long-term cash flows of gas production, also lower discount rates are conceivable. We will assume a real discount rate of 5% as a plausible rate, based on current interest rates. As variants

[20] This percentage is approximately equal to the real rate of return to investments in large companies over the period 1926-1990, and is also advised by the US Office of Management and Budget for standard cost-benefit analysis (Newell et al., 2004).

we consider real rates of 3% and 7% as the lower and upper ends of a range of plausible discount rates, given uncertainty about long-run interest rates and the beta. Therefore, we calculate the costs and benefits using three different discount rates: 3%, 5% (base case) and 7%.

Discount rates and constraints for mining activities

Discount rates used by globally oriented firms are said to be above the rates mentioned in this section. These higher hurdle rates may follow from the inclusion of non-systematic, diversifiable risks as well as the shadow prices of constraints on capital and human resources. These firms operate in a global market place and cherry-pick those projects that offer highest returns. The reason for this is that exploration and production of gas involve both large amounts of capital and potentially scarce human resources. The exploration and production industry responds to such scarcity of production factors by focussing on the most profitable business opportunities, and consequently ranks projects in a merit order where only the more profitable projects are undertaken. As a result, scarcity costs are reflected in higher hurdle rates. In the longer term, however, changes in the availability of resources translate into price changes, reducing the rate of return of all projects and making projects on the bottom of the merit order negative present-value projects.

An example of a capital constraint which is reflected in price rises is the limited availability of moveable rigs used for exploration drilling. When exploration activities become more profitable, the demand and hence the price for such rigs increases . As the August issue of World Oil reports: “As is always the case when the rig market tightens, day rates are on the rise. In January of this year, North Sea jackup market rates ranged from $50,000/day to $100,000/day. In June, North Sea jackups were on contracts ranging from $85,000/day to $145,000/day.” In the longer term, sustained high prices are expected to provoke new investments, leading to prices reverting to average price levels. Indeed, “The fact that offshore rig demand will outstrip supply this year has not been lost on some rig owners and market speculators. Since January 1, orders for 24 new rigs have been placed with shipyards, bringing the total number of rigs under construction worldwide to 41. Of these, four are being built specifically to work for national oil companies, three have contract commitments, and the remaining 34 are being built on speculation. Thirteen are being built by companies that fall outside the traditional drilling contractor category, i.e., they are true market speculators.” (World Oil Magazine (2005)).

Another possible restriction on mining activities is the availability of financial means for Exploration and Production activity (E&P). When profitability in this industry increases, however, more financial means become available. Indeed, Norwegian MPE/NPD (2005) observes that “Rising demand for oil and gas has contributed to a stronger exploration effort. As a result, the petroleum industry is investing more money worldwide on exploration than has been usual in recent years”.

Finally, on the human resource side, experienced personnel is scarce and training of new personnel requires time. Again, this may be expected to translate into higher rates for subcontractors, as well as potential competition on the employment market resulting in higher wages.

2.4 Scenarios of European natural gas market

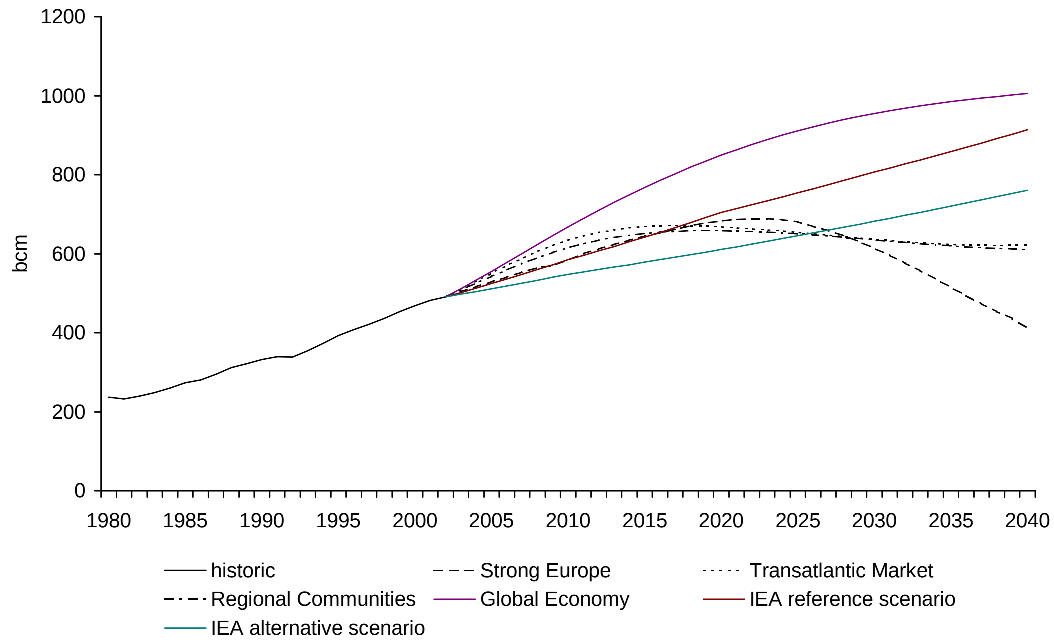
2.4.1 Introduction

In order to analyse consequences of policy options, background scenarios have to be defined. After all, the consequences of implementing a policy measure depend on the development of the market, in particular the demand for gas, the degree of competition on the European market, and the price on the global energy markets, in particular oil and LNG-prices. We first elaborate on the outlook for each of these factors (section 2.4.2) and then define the scenarios we will use in our analysis (section 2.4.3).

2.4.2 Outlook for demand, competition and prices

In the recent past, a number of institutions presented scenarios for the European gas market, such as IEA (2004a), CPB/RIVM (2004), Energy Markets[21], ExxonMobil (2004)[22], European Commission (2003) and OIES (2006).

Figure 2.1 Scenarios of gas demand in OECD-Europe (bcm)



Source: IEA (2004a) and Bollen et al. (2004).

Figure 2.1 shows demand for natural gas in OECD-Europe, both for the past period since 1980 and the future up to 2040 according to scenarios of the IEA (2004)[23] as well as CPB/RIVM (Bollen et al., 2004) while table 2.1 presents the average annual growth rates of the demand for gas for these and other scenarios.

In the past 20 years, demand for gas increased annually by 3.2% on average. In its Reference scenario, the IEA assumes that gas demand in OECD-Europe will grow by 2.2% up to 2010 and at a lower pace in the following decades. The IEA Alternative scenario shows significantly

[21] See http://www.gasandoil.com/goc/marketintelligence/energymarkets/welcome.html.
[22] See http://www.exxonmobil.com/Corporate/Citizenship/Imports/EnergyOutlook05/slide_18.html.
[23]As the IEA scenarios ends in 2030, we have extrapolated these up to 2040.

lower levels of growth in gas demand, which results from the implementation of fierce environmental and energy-security policies in IEA-countries.

In the Global Economy scenario of CPB/RIVM, the historical trend is pursued. In the first decades of the scenario period growth is projected to be even 4.3 % per year. Later, this growth decreases because of a lower economic growth and higher gas prices inducing substitution to other energy carriers. Also the Transatlantic Market scenario and the Regional Communities scenario show an increasing demand in the first decade of the scenario period, but in both scenarios the growth comes to a halt in the second scenario period. The reasons for this stagnation in both scenarios differ. In Transatlantic Market scenario, the constrained supply and corresponding higher gas prices put a downward pressure on demand for gas; in Regional Communities, a low economic growth drives down energy demand. In Strong Europe, gas demand rises less in the first scenario period and declines when international climate policies strongly increase energy prices and, hence, reduce energy demand.

Table 2.1 Annual growth of gas demand in OECD-Europe, historical and in a number of scenarios

	1980-2002	2002-2010	2010-2020	2020-2030	2030-2040	2000-2020	2002-2030
Historical realisations	3.2						
IEA Reference scenario		2.2	1.9	1.4	1.3	2.0	1.8
IEA Alternative scenario		1.4	1.1	1.1	1.1	1.2	1.2
CPB Strong Europe		2.5	1.4	– 1.5	– 3.6	1.9	0.7
CPB Transatlantic Markets		3.4	0.3	– 0.5	– 0.2	1.7	0.9
CPB Regional Communities		3.0	0.5	– 0.5	– 0.4	1.7	0.9
CPB Global Economy		4.3	2.2	1.1	0.4	3.1	2.4
European Commission							0.9
Energy Markets Big Bang						2.5	
Energy Markets Middle Way						2.4	
Energy Markets Slow fuse						2.1	
ExxonMobil							1.5
OIES						1.5	

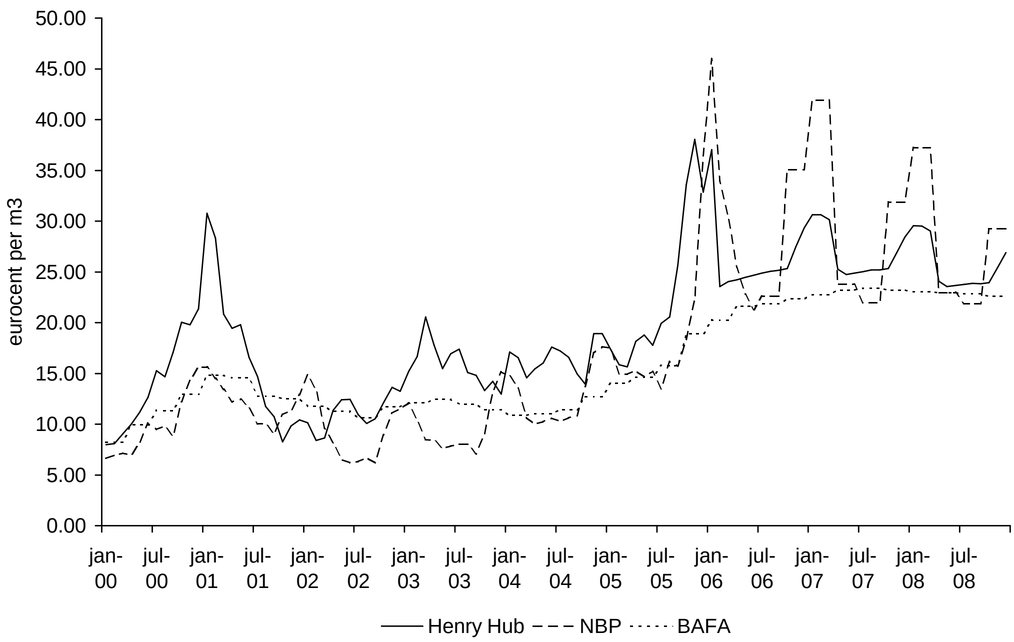
Source: IEA (2004a) and Bollen et al. (2004); own calculations.

The European Commission (2003) assumes that gas demand in Western Europe will increase by 1.4% up to 2010 but that it will stay at a constant level in the next two decades. Over the period up to 2030, gas demand of the European Union is expected to grow with 0.9% annually. The three gas market scenarios of the ‘Energy Markets’ present a rather strong growth in gas demand in OECD Europe, i.e. 2.1 to 2.5% on average per year. ExxonMobil (2004) presents a 1.5% growth of gas demand in its scenario of global energy markets. In a bottom-up analysis of gas demand in the European electricity industry, the Oxford Institute of Energy Studies (OIES) expects an annual growth of 1.5% of total gas demand in the EU-25 up to 2015, based on 2.7% growth in the power industry and 1% growth by the other gas consumers (Honoré, 2006).

Competition and LNG-prices

The IEA (2004a) assumes that gas prices remain linked to the oil price. Regional differences will continue to exist, determined by different supply and demand conditions, but these differences are expected to decrease because of increased spot trading of LNG which enables arbitrage between regional markets. For Europe, the IEA (2004a) expects a gas price of 3.30 dollar per Mbtu in 2010 which gradually increases to 4.30 dollar per Mbtu in 2030. These prices correspond to 11 and 14 dollar per m^3, respectively. The European Commission (2003) projects an increase in the European gas price to 28 euro per barrel, which would amount to about 12 eurocent per m^3. Also the European Commission believes future results on the European gas market will be determined by global conditions as “regional price differentials are expected to diminish significantly over the next 30 years, reflecting more comparable gas supply mixes by 2030. This is due to increasingly interconnected gas markets, with the same producers exporting to different consuming regions”.

Figure 2.2 Gas prices at NBP and Henry Hub, and BAFA-prices, January 2000 - January 2009



Data up to January 2006 refer to realised prices, later data refer to forward prices.

Indications for both level of the future gas price and the spread between winter and summer prices can be derived from historic and forward prices at Henry Hub, NBP and the BAFA prices[24] (see figure 2.2). Until the beginning of 2005, average gas prices in these markets were generally between 10 and 15 eurocent per m^3, but since that date prices have increased to an average level of about 25 eurocent due to current restrictions in the gas market. It is expected

[24] BAFA prices are German border prices which appear to be a good proxy for oil-linked prices at the European continent.

that prices will go down in the medium term when these restrictions have been lifted, for instance by increased investments in pipelines and LNG-infrastructure.

2.4.3 Definition of our scenarios

Using the results of the above scenarios regarding future demand for gas, degree of competition in Europe, and LNG-prices, which depend on global competition, we define four scenarios: Baseline scenario, Competition scenario, Sellers-market scenario, and High-price scenario (see table 3.1). [25]

In the Baseline scenario, competition on the European gas market is modest, meaning that competition is to a certain extent restricted, e.g. by insufficient cross-border transmission capacity and a limited number of suppliers in national markets.

Table 2.2 Definition of scenarios

	Baseline	Competition	Sellers' market	High prices
Degree of competition on gas market	modest	high	low	very low
Annual growth of gas demand (%)	1.5	1.0	1.5	2.0
Average threshold price for LNG (euro / m^3)	0.15	0.13	0.18	0.28

In the Competition scenario, conditions for competition are more favourable resulting in fairly fierce competition on the natural-gas market. Moreover, the development of the global LNG-market depresses prices for which LNG would become available for Europe. Prices above which LNG becomes available are on average around 0.13 euro per m^3 (in real terms), which is comparable to an oil price of about 30 dollars per barrel. We further assume a spread between winter and summer prices for LNG of 0.04 euro per m^3 (in all scenarios), comparable to the US spread in forward prices between seasons (see figure 2.2).

In the Sellers-market scenario, market power for suppliers is stronger than in the Baseline case, both in the European natural gas market as well as in the global energy markets. Threshold prices for LNG to become competitive are significantly above the baseline prices, comparable to (real) oil prices of about 40 dollars per barrel.

In the High-price scenario, economic growth and increased demand for gas by in particular gas-fired power plants generate a relatively strong increase of the demand for gas while high oil prices, strategic behaviour of non-EU suppliers and high prices needed to attract LNG to Europe cause prices to remain around current high levels.

[25] Other assumptions, e.g. on production and transportations costs, are described in Zwart et al. (2006).

2.4.4 Scenario results

Using the NATGAS model (see text box 'NATGAS) and the above scenario definitions we are able to make quantitative outlooks for each scenario.

NATGAS

The NATural GAS model is an integrated model of the European wholesale gas market providing long-run projections of supply, transport, storage and consumption patterns in the model region, aggregated in 5-year periods, distinguishing two seasons (winter and summer). Model results include levels of investment in the various branches, output and consumption, depletion of reserves and price levels.

The NATGAS model computes long-term effects of policy measures on future gas production and gas prices in Europe. NATGAS is an equilibrium model describing behaviour of gas producers, investors in infrastructure (pipeline, LNG capacity, as well as storage), traders and consumers. NATGAS covers the main European demand regions, including the United Kingdom, Germany, the Netherlands and Italy. Moreover, it covers the main origins of supply on the European market, such as Russia, Norway, Algeria, the Netherlands, the United Kingdom and LNG.

Dutch production is modelled as small-fields production and Groningen production. Markets are differentiated between various gas qualities, low- and high-calorific. Low calorific gas is produced in the Groningen field and German fields, and consumed in sectors of Dutch, German, Belgian and French demand. The majority of gas used in Europe is high-cal gas. There is a relation between the two separated networks in the form of quality conversion: at a cost, high-cal gas can be diluted (e.g. by mixing with lower calorific gas or with nitrogen) to produce low-cal gas.

Producers are assumed to behave strategically, i.e. optimising gas supplies to consumption regions by taking into account the effects of their supplies on prices. Apart from that, producing regions may have separate (policy guided) constraints on gas production and export. Other agents are assumed to act as price takers.

Consumer demand is a function of economic growth and prices. The relationship between gas price and demand, i.e. the price elasticity of demand, is based on a review of econometric studies (see Stam, 2003). This review concludes that the long-term own price elasticity of the demand for gas in a number of studies varies between 0.18 and 0.65. In our model, we use an elasticity of 0.25.

In Zwart et al. (2005), we give an extensive description of this model.

Figure 2.3 depicts the development of supplies to Europe from major sources in the baseline scenario. In this scenario, the total supply to the European market increases from the current level of about 500 billion cubic metre to above 700 billion cubic metre after 30 years.[26] Production from the Dutch small fields declines strongly in the coming 30 years from now. Algeria, Norway and Russia show an increasing supply to Europe. Due to its relatively low costs, Algerian supply is an important source for meeting the growing demand for gas in the near future. When the costs within this country increases, Russia gains a larger market share. This holds as well for LNG-sources which expand strongly after 15 years (see also figure 2.4).[27] In the baseline scenario, the share of LNG in total supply to OECD-Europe increases to about 10% in 2030. In the high price scenario, LNG is so costly that it is not imported. The decrease

[26] Note that IEA (2004) expects a growth in gas demand in OECD Europe from 491 bcm in 2003 to 807 bcm in 2030.

[27] Note that IEA (2004) forecasts an increase in import dependence for OECD Europe from 36% in 2002 to 65% in 2030.

in LNG-shares in the first period in all scenarios follows from reduced restrictions on Europe's pipeline capacity resulting from investments in the beginning of this period.

Figure 2.3 Origin of natural gas to Europe, baseline scenario (in billion cubic metre per year)

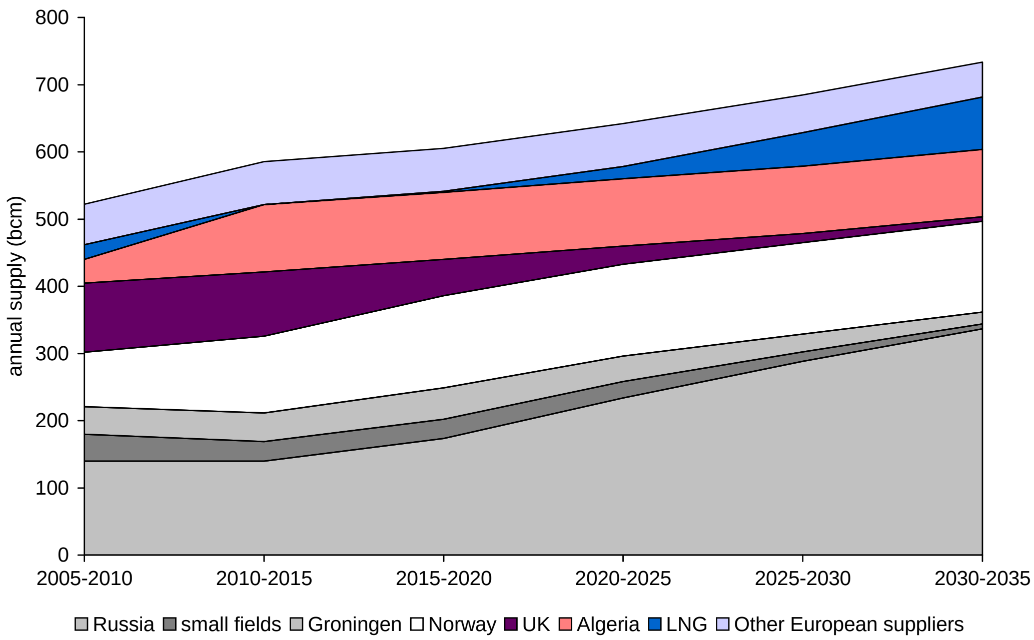
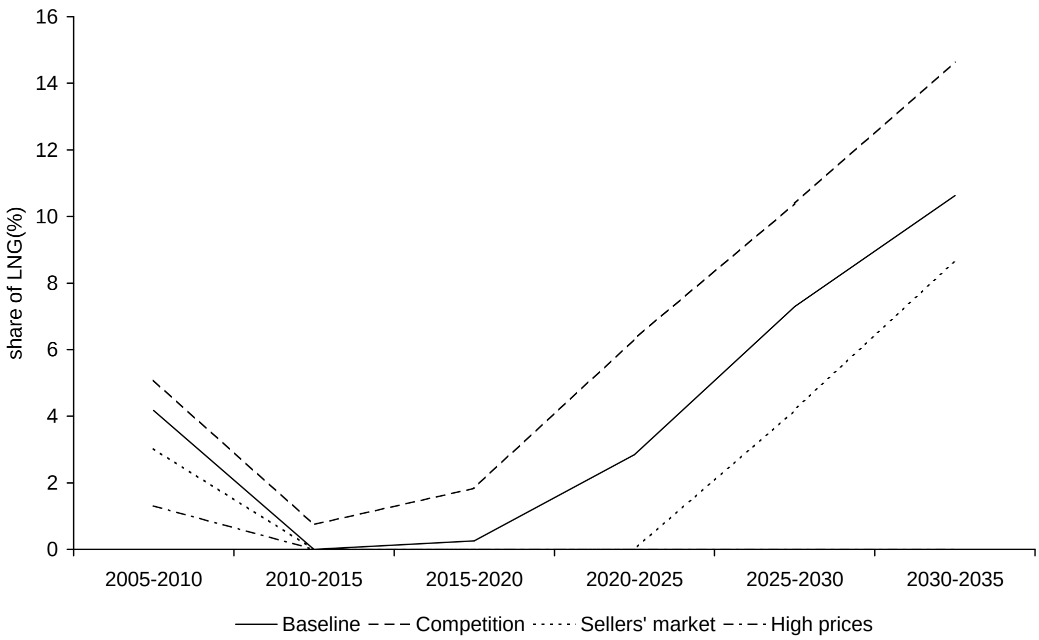
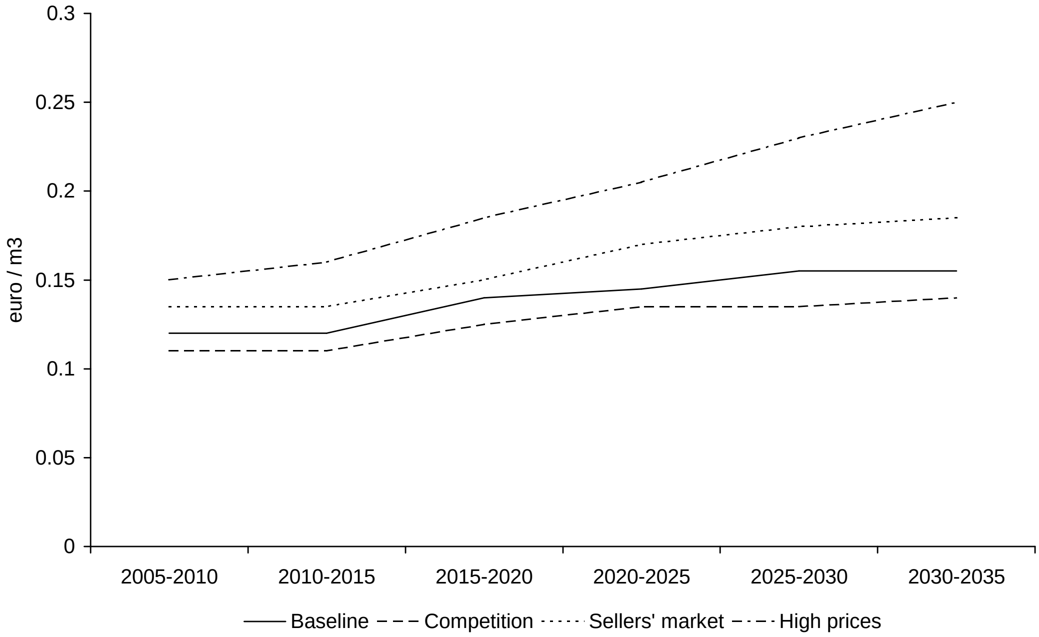


Figure 2.4 Share of LNG to OECD-Europe, in four scenarios (%)



The average gas price in the Netherlands increases from about 12 to 16 eurocent per m^3 in 2030. (see figure 2.5). Of course, the High-price scenario shows a strongly increasing gas price during the scenario period. The Competition scenario shows lower gas prices due to increased supply.

Figure 2.5 Average annual gas price in the Netherlands in four scenarios (euro / m^3)

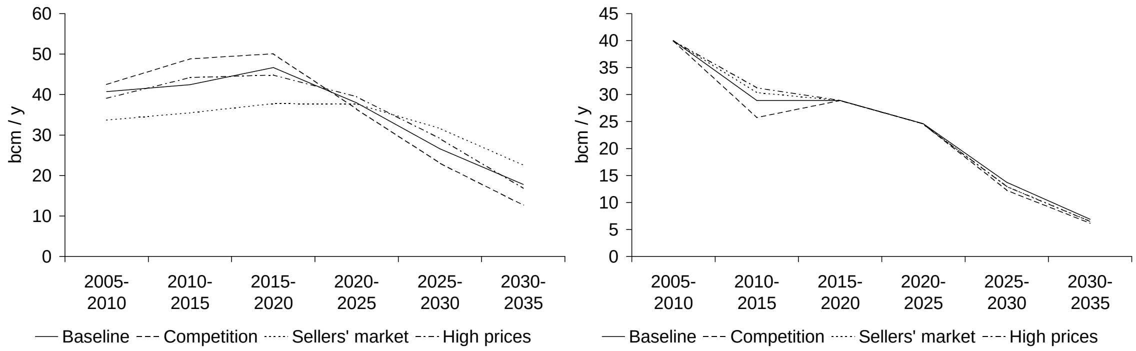


The additional supply in the Competition scenario stems from several sources, including the Groningen field. The average annual production by this field is about 10% higher than in the Baseline scenario (see figure 2.6).[28] Production by the Dutch small fields in the longer term is hardly affected by the lower gas prices as these producers remain inframarginal, i.e. other suppliers to the European market are the marginal suppliers and will reduce their output in response to the lower prices. If prices rise strongly, however, small-fields production will increase as more fields will become profitable. Production over the first twenty years averages around 30 bcm annually.

In the Sellers-market scenario, prices are above the baseline prices. Here production from Groningen is about 10% below the baseline production up to 2020; afterwards, production here is above the base line level due to the earlier exhaustion in that scenario. Consequently, a close link exists between the degree of competition and the production profile chosen by the operator of Groningen.

[28] Note that current annual production of Groningen is about 30 bcm while the small fields now produce about 40 bcm per year (see chapter 1).

Figure 2.6 Annual production of Groningen (left) and small fields (right) in four scenarios (billion cubic metre per year)

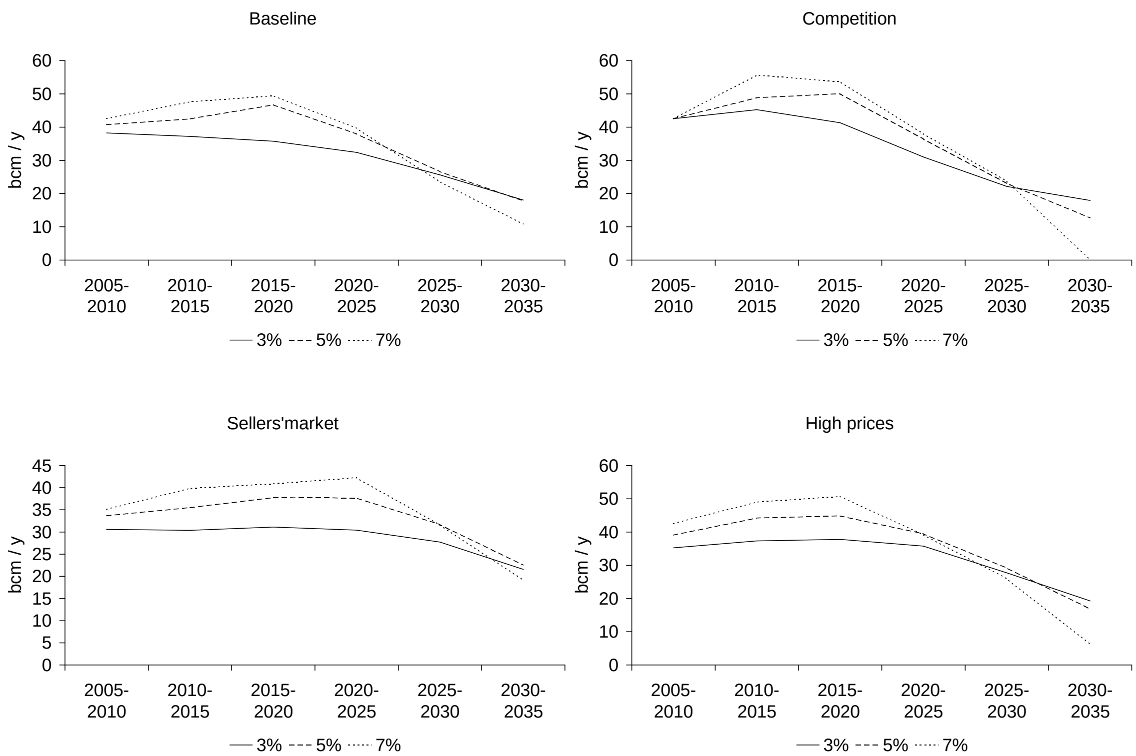


2.4.5 Sensitivity analysis of scenario results

The differences between the scenarios remain when we change key assumptions. Here we investigate the sensitivity of the results to other values for the discount rate, other assumptions on exogenous LNG price levels, different rates of decline of the offshore infrastructure at the Netherlands Continental Shelf, and different levels of tax distortions.

Discount rate

Figure 2.7 Effect of lower (3%) or higher (7%) discount rates on Groningen production, in four scenarios

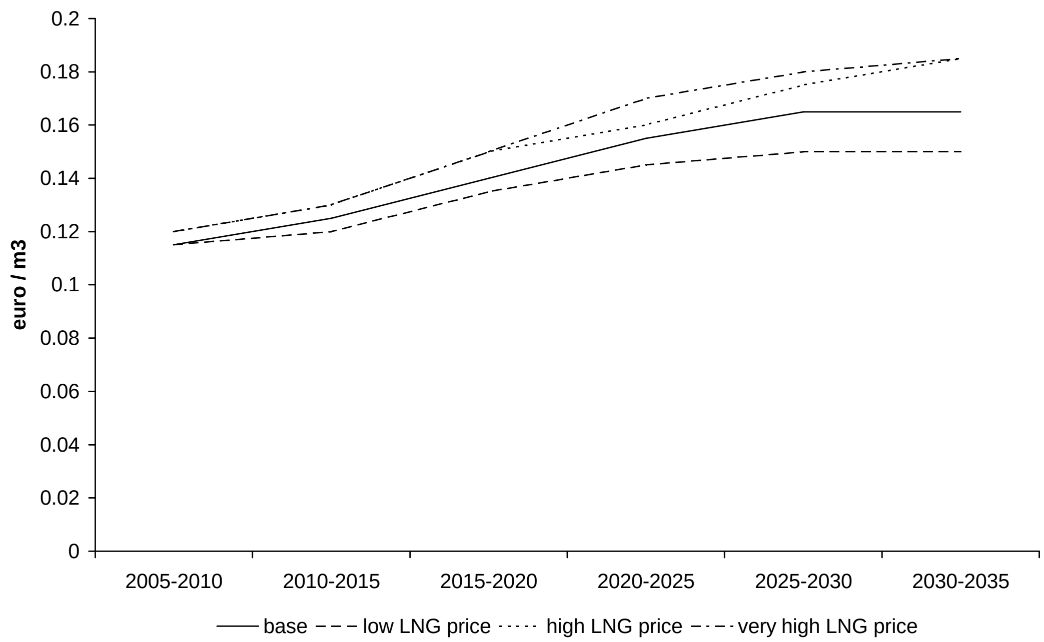


Different assumptions about the discount rate (i.e. 3, 5 and 7%) do result in different levels of production by Groningen. A lower discount rate makes postponing production less expensive and, hence reduces current production. This holds for all scenarios (see figure 2.7). Consequently, different discount rates do not affect the above conclusion on the relationship between the degree of competition and the production profile of Groningen.

LNG-price

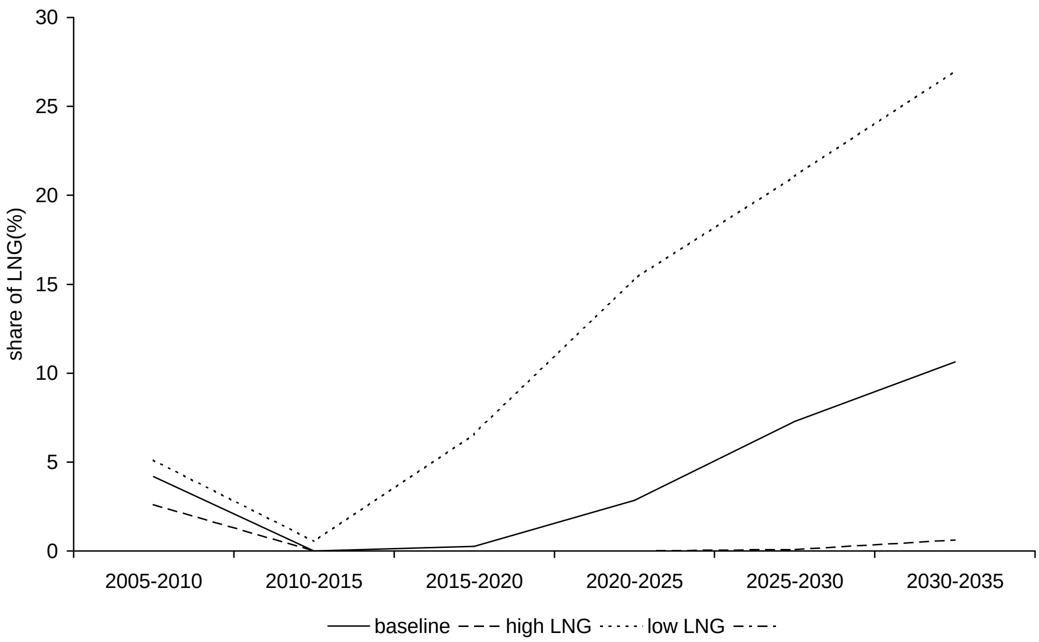
We also explore the sensitivity to our assumption on LNG prices by comparing, in the Baseline scenario, the effect of changing the average LNG threshold price to 13 cents (low), or 18 cents (high). In figure 2.8 the resulting price paths are plotted.

Figure 2.8 Effects of different LNG price levels on Dutch prices, Baseline scenario (euro / m^3)



We see that the effect on prices is relatively small initially, since LNG imports are minor in the first periods of the scenarios. As indigenous gas resources are depleted and the share of LNG increases, the effect on prices also becomes larger. The effect on volumes of LNG in 2030 is shown in figure 2.9. While in the high-price variant, LNG does not play any role of significance before 2030, the share of LNG in the low-price variant increases to 27%, or 200 bcm per year, compared to 10% in the Baseline scenario. In this variant, LNG mainly displaces future imports of gas from Russia and Norway, the sources of marginal gas for Europe. With high LNG prices, the shortfall of LNG , conversely, is compensated by increased pipeline imports from these regions.

Figure 2.9 **Effects of LNG price levels on shares of LNG, Baseline scenario (%)**



Infrastructure availability

Another sensitivity we explore involves the rate of depletion of Dutch small fields. There is uncertainty over rates of exploration and production of small fields futures as well as over the total volume of futures. Uncertainty arises at least partially from constraints on availability of infrastructure. We evaluate the effects of various rates of decline of infrastructure availability, resulting in different decline rates of Dutch small fields production. In table 2.3, the effect of these variants on average annual production of both Groningen and the small fields of these different assumptions is shown.

Table 2.3 **Effect of varying rates of decline of small fields production on average production from Groningen and small fields in first 20 years, Baseline scenario (billion cubic metre per year)**

	Baseline	High decline	Low decline
Small-fields production	30.0	27.0	32.0
Groningen production	42.0	42.1	41.8

We see that slightly changing assumptions have an impact on small-fields production but that the Groningen production is hardly affected. On the European scale, these differences are quite small and do not change the picture of prices and flows significantly.

Tax distortions

Finally, we explore the impact of varying distortion caused by taxes. In the determination of our scenarios we assumed neutral taxes (such as Brown taxes, state participation) (see text box

‘Effect of taxes’). Actual tax systems include non-neutral instruments, the distortion of which may to a greater or lesser extent be mitigated by measures such as uplifts or accelerated depreciation schemes. The actual distortions in fiscal regimes in various regions depend subtly on the structure of tax regimes, and is beyond the scope of this study. However, to analyse the robustness of our results, we investigate the sensitivity to a relative distortion that increases perceived investment costs in the Netherlands compared to other regions by 20% (i.e. 20% higher investment costs).

Effect of taxes

In the determination of the scenarios we do not explicitly take into account differing tax regimes in the various gas-producing countries. Taxation would have an impact on production decisions if it affects the profitability of marginal fields. In particular in the presence of large differences between tax regimes, relative production levels between the various producing regions would alter.

For North Sea producers, currently taxation mainly consists of a profit tax. Royalties, for instance, which are distortive as they raise positive tax from zero profit projects, have generally been abandoned for offshore production. Profit taxes are neutral if they are levied in fixed proportion of each project’s net cash flow in each period, giving a tax rebate when net cash flows are negative. Such a tax is sometimes called a Brown tax. One way of approximating such a system is by introducing government participation (as EBN does for Dutch gas fields), where the government bears a fixed part of the costs, and receives the same proportion of revenues.

Corporation tax usually is not neutral as it defers remuneration of capital expenses according to the depreciation schedule of the investment. Under such regimes, differences in tax rates do affect relative distortion between regions. Measures to counteract the non-neutrality of corporation tax may be uplift allowances, which offer extra tax relief for capital expenditures, tax deductibility of returns on equity analogous to the fiscal treatment of interest on debt capital, or introduction of accelerated depreciation or ‘depreciation at will’, DAW. The latter measure restores neutrality if expenditures can immediately be fully deducted.

In Mulder et al (2004), DAW as implemented on the Dutch Continental Shelf was investigated. A disadvantage of that mechanism, counterbalancing the benefit of reducing distortions, is the loss of tax revenues on inframarginal fields. This loss was found to more than offset the advantage of increased production under current circumstances. It was suggested to improve the design of the DAW to focus it more accurately on the marginal fields, in order to retain neutrality without the foregone revenues on inframarginal projects.

In our scenarios, we implicitly assumed neutral tax regimes in the various regions. In reality a bias may be introduced by distortive elements in the tax instrument mixes in the various regions, favouring capital expenditures in one region compared to the other. To investigate the impact of such a potential bias on our conclusions, we conducted a sensitivity analysis of the results to relative changes in capital costs. This is reported as a variant. Increasing (relative) capital costs for Dutch gas production has low impact on the scenarios, while, though quantitatively affected, the conclusions of the cost-benefit analysis remain unchanged.

The effect of this change on scenario results for the four scenarios (at 5% discount rate) is rather small (see table 2.4). In particular, the impact on the Groningen production schedule is largest in the Competitive scenario, where average annual production declines by 0.5 bcm/year over the first 20 years. For small fields production, one finds an effect of at most 2.4 bcm/year, again in the Competitive scenario.

Table 2.4 **Effect on Dutch production of 20% increased capital costs, in four scenarios (billion cubic metre per year, over first 20 years)**

	Baseline	Competition	Sellers' market	High prices
Groningen	– 0.3	– 0.5	– 0.1	0.1
Small fields	– 1.4	– 2.4	– 0.3	– 0.6

In the cost-benefit analysis of the cap on the Groningen field, in chapter 4, we will also look into the impact of the different assumptions on the discount rate, the LNG-price, infrastructure availability and tax distortions.

3 Welfare effects of the offtake guarantee

3.1 Introduction

It is claimed that the offtake guarantee enables small-fields producers to optimise the production profile from a technical-economic point of view without taking into account the costs of adapting the production to standards demanded by the market. In section 3.2, we describe more extensively the arguments behind the offtake guarantee and the related coordinated pooling of differences in gas volumes and qualities.

A cost of the offtake guarantee might be that it reduces efficiency of production decisions. The offtake contracts may not give operators the right signals about the value of their production. In addition, the contract may include favourable conditions subsidising small-fields production. Section 3.3 explores the validity of these costs.

Another cost of the offtake guarantee might be its negative impact on the liquidity of the wholesale market. The guaranteed offtake of small fields gas makes it attractive for small-fields operators to sell directly to Gasunie Trade & Supply, and makes them less inclined to participate in the wholesale market directly. This factor may hamper the development of a liquid wholesale market and its associated benefits. This effect is analysed in section 3.4.

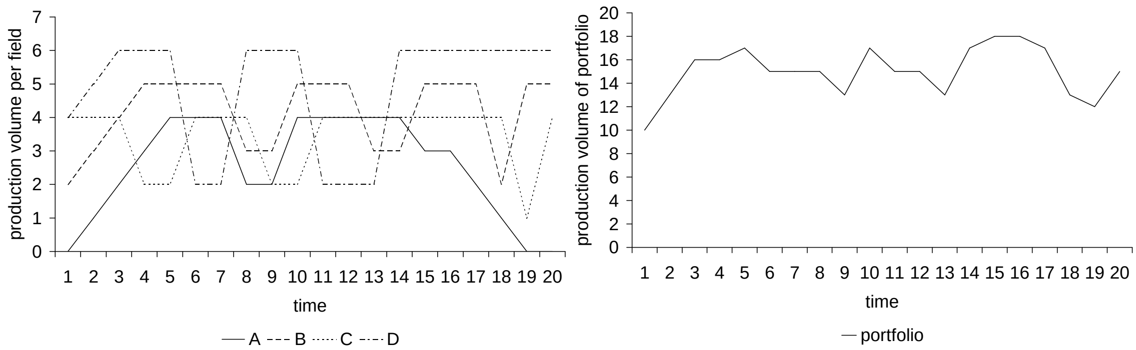
A benefit of the offtake guarantee could be its cost-reducing effect of coordinated pooling. In order to assess this question we have to analyse what would happen without this coordinated pooling. In cost-benefit terms, how does the market operate in the null-alternative case in which these policy measures do not exist? As an alternative to centralised pooling in one portfolio, adjustment of quantity fluctuations can also be resolved in a decentralised manner through a liquid market. In such a market, producers interact, directly or through intermediates, with each other. Surpluses in production from one producer are cancelled against shortages of another by trades among producers. In order to structure individual gas production profiles from different fields, short-term trade is necessary (e.g. ranging from daily contracts to annual ones). Such a mechanism for pooling production through market trading is operating, for instance, in the UK gas market, in Norwegian gas production, and in many restructured electricity markets. Section 3.5 examines indications of transaction costs in such markets. In this section, we also analyse experiences in the Dutch wholesale gas market.

Another benefit of the offtake guarantee may arise through an effect on market structure of the small-fields contracts. If these long-term contracts either confer market power to Gasunie Trade and Supply, or if pooling succeeds in effectively coordinating pricing decisions, pooling may have consequences for market power. Although such market power will normally decrease total welfare, the isolated effect on Dutch welfare may be positive due to the higher realised export prices. Section 3.6 goes into this effect.

3.2 The arguments behind coordinated pooling

From the technical-economic point of view, the optimal production profile for a gas field is determined by its physical characteristics. The natural depletion profile of a field consists of an initial phase in which gas output gradually increases, a plateau phase with a more or less constant maximum production rate, and a final phase in which production capacity gradually falls off (as explained e.g. in AER, 2005). During the whole depletion period, maintenance activities and technical outages may cause short-term reductions in production volume generating a stronger volatility in the production profile (see upper part of figure 3.1). This profile, however, does not fit into the profile demanded by wholesale traders. Wholesale trade in gas in longer term contracts typically involves structured gas, i.e. quantities that are more or less constant over the duration of the contract. For a producer to sell his gas in such contracts (with accompanying long term security), the irregular production profile needs to be structured.

Figure 3.1 Production profiles per field and total portfolio



While the deviation between a single field's output and the structured gas flows traded in the market may be large, the deviation between the aggregate portfolio of all gas fields' production and such structured gas is likely to be much smaller. This is a consequence of a pooling effect: periods of lower production in one field are compensated by higher production in other fields (see lower part of figure 3.1). For this reason, it is argued that bundling production by one buyer establishes an important reduction of (structuring) costs, compared to the sale of gas to different buyers. In addition, a single-buyer may be expected to speed up contract negotiations. This is one argument for the offtake guarantee as this removes the obligation for offshore producers to structure their gas flows individually.

A second argument for pooling contracts within the hands of Gasunie Trade & Supply is related to its control over the Groningen field (through its contracts with the field's licensee, the Groningen Maatschap). The low-cost flexibility provided by this field can be used to cheaply adapt total production to changing demand: in particular, backing down the Groningen field in the low demand summer season allows the small fields to produce at high load factor. This also provides another argument for conserving the Groningen field: as the field is depleted, its ability to act as a balancing field diminishes, and costs of balancing will increase. Conserving the field and using that field for balancing purposes, hence, reduces the balancing costs of small-fields production (see further chapter 4 on this effect of the cap on Groningen).

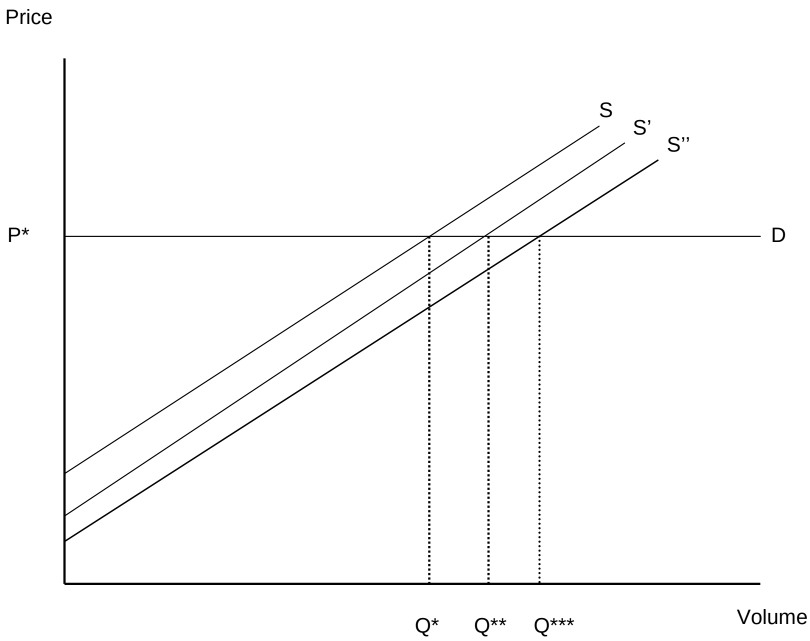
The argument that pooling reduces coordination costs may also apply for gas quality, i.e. heat content, but also presence of other gases such as CO_2. The gas transmission system can only accommodate gas within certain quality bounds. Gas from different fields may have qualities that deviate from this range. Such gas can only be accepted if compensated by injections of additional gas from other sources that offset the quality deviation. Again, cooperation is necessary to achieve required coordination in gas quality; bundling all contracts in one hand gives a means to economically carry out such coordination.

Summarising, coordinated pooling reduces the costs for adapting both volume and quality of small-fields gas to the requirements of the market. So, as these measures reduce the costs of producing small-fields gas, these measures shift the supply curve to the right (in figure 3.2, from S to S'). Given a guaranteed offtake (depicted by D in the figure), two effects emerge: a rise in the producer surplus for all existing gas fields and an increase in the number of fields taken into production.

The reduction in production costs resulting from coordinated pooling makes more small gas fields profitable and, hence, raises the total size of small-fields production. This effect on volume can be enlarged by the existence of economies of scale. An extension of the infrastructure could reduce marginal transport costs and, hence, increase the number of profitable project which further raise the volume of small-fields production: the supply curve shifts from S' to S''.[29]

[29] See also Adelman et al. (2002) who show that the improvement of the industry-specific infrastructure, such as pipelines, shifted the supply curve of non-OPEC countries to the right.

Figure 3.2 Impact of coordinated pooling on production



3.3 Offtake guarantee may reduce efficiency of production

Generally, centralised coordination of production gives lower incentives for efficiency than coordination by a market which lets individual producers decide whether it is efficient to change production. A cost of coordinated pooling might be that it hinders efficient responses to market shortages by operators. How a market system gives signals to operators can be learnt from the British experience. As UKOOA, the UK organisation of offshore operators, explains, "Contracts between a producer and a shipper will typically specify a minimum and a maximum quantity of gas which may be nominated, i.e. called for delivery, by the shipper day by day. It is the producer's responsibility to deliver the nominated quantity at the beach-head. Nominations take place ahead of delivery, being confirmed on the day before, although as demand is not exactly predictable in advance re-nomination is allowed during each day. This nominations system is, therefore, crucial to the response of producers to variations in demand." (UKOOA, 2005). Consultant Lexecon econometrically demonstrates that price responsiveness of production is significant, in a study commissioned by Centrica in its case for the British Competition Commission in its take-over of the Rough storage facility.

However, it should not be concluded that such price responsiveness of supply is in principle incompatible with the Dutch centrally pooled mechanism. Also in the current situation in the Netherlands, the offtake contracts specify so-called Daily Contract Quantities (DCQ), that are regularly updated, at the initiative of the producer. The buyer of the gas typically has the right to daily nominate gas within a bandwidth surrounding the DCQ, obligations are on the producer to deliver this nominated quantity (or face a penalty).[30] Larger bandwidth (and hence higher flexibility for the buyer) translates into higher contract prices. In principle, the single buyer of Dutch gas could be able to feed through market signals into its nominations for gas. The case for introducing competition in promoting efficient off-take contracts is therefore not clear-cut.

Efficiency in centrally coordinated mechanisms is considered to be negatively affected by reduced incentives for the individual agents. The argument is made for instance in Wilson (2002), where the author discusses the advantages and disadvantages of coordinated pooling in electricity markets. If the central coordinator would have perfect information on costs of solving balancing problems (by producers, consumers or other market operators), he could obviously reach the first-best optimum solution. In the context of asymmetric information on costs, however, small-fields producers, who are partially insured against short-run fluctuations in gas prices and who therefore do not face the real-time opportunity costs of gas at each moment have reduced incentives to respond optimally to short-run changes in market conditions. While these producers may respond efficiently to the incentives that they do face, moral hazard results in a loss of productive efficiency.

The advantage of decentralising balancing decisions, is that balancing operations, and resulting market clearing prices, can be contested by competing providers of gas flexibility. Producers are exposed to real-time prices, and benefit from adapting optimally to these conditions. This creates a drive towards more efficiency compared to the centrally coordinated system whose operations are isolated from competitive offers.

Another inefficiency may arise through the conditions of the offtake guarantee which are “reasonable” and against “market prices” (EZ, 2004). These conditions possibly create a cost if the prices paid by Gasunie Trade & Supply do not fully reflect the market value of potentially generous conditions in the offtake contracts. This may in particular result from pressure to also accommodate gas of lower reliability or poor quality, without efficiently charging for the costs these fields’ offtake imposes. Such prices would function like subsidies encouraging production of fields which would be unprofitable in a market situation. Information about the prices paid by Gasunie Trade & Supply, and the associated contract conditions is not publicly available. The fact that all small-fields producers offer their gas to Gasunie Trade & Supply[31] at least suggests that the conditions must be satisfactory to these producers. So, the offtake guarantee may include an implicit subsidy for small-fields production which may result in inefficient production activities (in addition to transfer of wealth from Gasunie Trade & Supply (and the Dutch and the other shareholders) to the small-field producers).

[30] In addition there is an Annual Contract Quantity, which is the sum of DCQs. The buyer commits to a take-or-pay obligation for this amount. Some quantity of gas may be transferred among years.

[31] Total small-fields production about equals total purchase of small-fields gas by Gasunie Trade & Supply (in 2004: 44.9 billon m3, see Gasunie, 2004).

Such a subsidy, increasing total production beyond efficient quantities, might find a rationale in security of supply concerns (see section 4.5 for a more elaborate discussion on security of supply). If market failures are such that risks of foreign imports are insufficiently reflected in market prices, this would bias supplies of gas towards such less reliable sources, which would result in an inefficient mix of supplies. Since (nearby) small fields may be considered more reliable, and if market failures cannot be solved more directly, there could be merit in subsidising production from these fields.

Concluding, the offtake of small-fields gas by one player, Gasunie Trade & Supply, implies there is little scope for competition in contract structures. This may impede incentives for efficiency on small-fields operators. In particular in the presence of asymmetries of information on short-run costs and constraints from individual market participants, centralised pooling without (contestable) marginal prices decreases incentives on efficient operation. Furthermore, the off-take conditions, in particular the prices paid for small-field gas in relation to the allowed flexibility of delivery, may include a subsidy component which would encourage inefficient production. Although total gas production might be raised by this measure, the effect of welfare would be negative due to the inefficiency of the production. However, this negative welfare effect might be compensated by a benefit of reduced import dependence. Hence, such a subsidy could be rationalised as a response to security of supply market failures.

3.4 Offtake guarantee may hinder liquidity of the wholesale market

A liquid market gives a number of benefits to market players, both at the supply and the demand side. Apart from a loss in efficiency as a result of a failure in adequate trading among players, a lack of volume and depth of the wholesale market is also likely to prove an entry barrier for new players investing in the Dutch market. A liquid market lowers transaction costs for new players in the market (e.g. entrants in the retail supply market) and facilitates entry of independent investors in for instance LNG terminals by reducing potential hold up problems. Liquidity of the gas market strongly decreases the asset specificity and the ensuing need for long-term contracts (see text box ‘Liquidity of the market and investments’).

Liquidity of the market and investments

Assets in the gas market (such as LNG terminals, storage facilities, production) are of a long-lived nature. Market parties, in their decision to invest, will only invest if the prospect of reaping the future rewards for these investments is sufficiently certain. Risks may include both price and volume risks. Of particular concern is the danger of opportunistic behaviour when large initial, relation-specific investments are involved (Williamson, 1979). After the investment has been sunk, a buyer has the incentive to exploit its bargaining power to expropriate the resulting rents. Anticipating this, the investor does not invest, or is 'held up'.

The standard answer to such hold-up problems is the use of long-term contracts, which indeed abound in the gas industry. For Dutch gas producers, such contracts are mainly used to mitigate volume risk: contract prices are renegotiated annually, with prices within the year being updated on the basis of price movements in baskets of traded commodities. Most long-term contracts have some degree of price flexibility (see e.g. Creti and Villeneuve, 2003), or link the price to some external benchmark (e.g. the UK NBP price).

Volume risk, or the risk that one's output cannot be sold against market prices, is of particular concern if the number of potential buyers is limited, which indeed make investments relation-specific. Liquidity of the gas market strongly decreases this specificity and the ensuing need for long-term contracts. A liquid gas market by definition is able to absorb gas sales at market prices. Quoting Newbery (2000) on the UK gas market, "In the past the lack of a competitive market for gas has meant that gas development faced the same problems of opportunism as other capital-intensive sunk investments tied to a single market, which they managed by signing long-term contracts. If there is a genuinely competitive gas market with a sufficiently large number of buyers and sellers, [...] then these problems of opportunism are reduced, and only commercial risks remain. Oil companies are familiar with these potential problems, and manage them with rather shorter-lived contracts, futures, and by shifting the remaining risks onto their shareholders who can hold diversified portfolios."

The fact that liquid gas markets reduce investment risk (or risk of hold-up) is illustrated by the Ormen Lange project, a multi-billion dollar investment connecting a Norwegian gas field to the UK market, as described by Stern and Honoré (2004): "Many of these companies have said on many occasions that it would be impossible to invest in multi-billion dollar projects without long term contracts. And yet, it is striking that although the project is under construction, no long term contracts have been announced and Norsk Hydro has said that it does not intend to sign any such contracts for its share of the gas. The only company which could use an existing contract is Statoil which has a contract with Centrica for 5 Bcm/year for 10 years at NBP prices for delivery at that location. It appears that other sellers intend to develop a portfolio of long, medium and short term sales and possibly also arbitrage between UK and Continental European gas markets depending on price differentials." Stern and Honoré cite the liquidity of the UK market as one of the explanations. Similarly, Newbery (2000) describes the developments of the UK market in the period 1995-1998: "The development of increasingly liquid spot and futures markets created a serious alternative to long-term contracts for producers and suppliers [...]. Contract lengths shortened, producers were encouraged to release supplies, and prices dropped [...]."

Liquidity of a market should not be confused with volatility of prices. Liquidity refers to the degree prices reflect shortages while volatility refers to the movement of prices. Hence, a liquid market can go together with large volatility, as has been the case in for instance the British gas market. On the other hand, a high volatility may be caused by a low liquidity, i.e. individual transactions strongly impacting prices. While liquidity of a market encourages investments, high volatility could hinder investments if short-run price movements cannot be sufficiently hedged, because of uncertainty about future rewards. The latter relationship will be dealt with in chapter 4 on security of supply.

The emergence of liquid markets may also change the motivation for investment. Whereas in the past, market parties would invest in e.g. storage in accordance with their needs to balance their own supply portfolios, increased market liquidity offers more opportunities to build storage capacity for the purpose of trading, making use of (shorter-term) fluctuations in supply and demand[32]. This increases the focus on flexible short-term storage such as salt caverns.

It should not be concluded that competitive and liquid markets will call forth more investments in infrastructure than relatively non-liquid markets dominated by incumbents. Indeed, one of the goals of liberalisation was to avoid overinvestment in infrastructure. Dominant incumbent parties typically do not face hold-up risks if they themselves control the end-user markets and can shift costs towards captive consumers. It does seem true, however, that liquid markets, by removing a barrier for entry, can attract a more diverse range of investors, introducing investment competition that favours the more efficient investors.

Impact of offtake guarantee

In the pre-liberalisation era, the small-fields producers represented, by and large, the complete market, taking the internal coordination through the Gasunie Trade & Supply portfolio sufficiently close to the optimum. After liberalisation, however, many more participants have entered the market. These include large consumers (such as power generators), competing suppliers to end users, gas companies from abroad investing in storage or LNG import facilities. Efficient decision making among all these participants requires an efficient market to conclude transactions. In particular, pooling quantity fluctuations will be more efficient if also fluctuations from the demand side, and from traders having access to imports and storage facilities are incorporated.

Another cost of the offtake guarantee may be a negative impact on the liquidity of the wholesale market. As the offtake guarantee reduces participation of gas from producers in the developing wholesale market, this development may be impeded because of the existence of network externalities (see e.g. Economides and Siow, 1988). This means that the benefits of having a market is an increasing function of the number of players because the number of options for carrying out efficient transactions grows as the number of market players active in the market increases. As individual trading parties in a market are not fully able to capture these benefits, a market may therefore fail to develop.

Whether this effect is substantive is an empirical question. In the Netherlands, the active market places for wholesale trade are mainly the Title Transfer Facility (TTF) and the Eurohub. The TTF is a virtual market place which offers market players the opportunity to sell and buy gas

[32] For example, in NRC, January 2006, Nuon CEO van Halderen comments on his company's investment in new salt cavern capacity: "We mainly want to use our storage for daily trading".

which is already within the system.[33] In this market, four gas quality categories can be traded: High quality (H), Low quality (L), Groningen quality (G) and Groningen plus quality (G+), although so far H-gas trade strongly dominates the TTF-trade. An investigation by DTe (2005) into the development of Dutch gas markets showed that volumes and number of transactions in high-cal gas grew significantly in recent years. The churn-factor, i.e. the ratio between traded volume and physical transported volume, increased from 1.9 in 2003 to 2.6 in 2004, which is, however, still low compared to for instance the Zeebrugge market place (about 5), or the NBP (over 10). The number of registered TTF-traders has increased from 12 in 2003 to more than 30 now which indicates low entry barriers on this market. The relatively low spread between bid and selling rates, compared to Zeebrugge and NBP, suggest that the TTF is already fairly liquid (DTe, 2005).

The Eurohub, which is a market place at the junction of pipelines in the Emden / Oude Statenzijl / Bunde area[34], has low liquidity. The number of traders on the Eurohub has hardly increased while the volume of trade is low with a churn-ratio of 1 (in 2003) (DTe, 2005). Actually, Eurohub appears to be a transporting facility instead of a trading facility.

Although liquidity on the Dutch wholesale market is increasing, whether the offtake guarantees will prove a significant obstacle to the market reaching maturity cannot yet be assessed. Anyway, the offtake guarantee by Gasunie Trade & Supply takes away the incentive for the small-fields producers to participate in the wholesale market, which limits the amount of gas to be traded and the number of players in this market. While this would be of no consequence if these players were the only market participants (as was by and large the case before market liberalisation), in the current liberalised markets market liquidity is required for efficient coordination between producers, consumers and other player.

3.5 Coordinated pooling may reduce transaction costs

3.5.1 Introduction

A benefit of the offtake guarantee could be its cost-reducing effect of coordinated pooling. In order to assess this question we have to analyse what would happen without this coordinated pooling. In cost-benefit terms, how does the market operate in the null-alternative case in which these policy measures do not exist? In order to answer that question, we analyse experiences in the British gas market, the Norwegian system of pooling of gas production, the Dutch electricity market and, finally, the Dutch wholesale gas market.

[33] See website of the TSO: http://www.gastransportservices.com/gastransport/en/2006/gastransportservices/ttf
[34] See http://www.eurohubservices.de/eurohub_home_hub.htm.

3.5.2 The British gas market

In the UK gas market, producers sell their gas into the wholesale markets through contracts with shippers (see text box 'The British gas market' for an overview of arrangements). Fluctuations in gas production for an individual producer affect the input into the gas transmission system by the shipper that contracted the gas. Given the shipper's delivery commitments, this change in input would cause the shipper to incur an imbalance. The shipper therefore has to trade in the market to resolve this imbalance, or, ultimately, is forced to trade with the system operator at the system buy or sell price. Since this holds for all shippers, imbalances in individual production portfolios are pooled through market trading.

The British gas market

The British gas market is the largest national gas market in Europe. UK gas production comes mainly from offshore fields on the UK Continental Shelf (UKCS). Producers on the UKCS need shippers to deliver their gas into the onshore gas transmission system. Shippers may include large consumers, supply companies, traders and producers. Shippers, who transport their gas on the domestic gas system operated by National Grid Transco (NGT), are obliged to conform to the Network Code. Important components of this Code are the balancing arrangements. Under these arrangements, shippers have to balance their gas offtakes from the system and their inputs into the system over each day. Failure to do so results in an obligatory balancing trade with the system operator NGT, who buys excess gas from shippers, and sells gas to shippers who are short. The prices used for these balancing trades (the so-called System Buy Price and System Sell Price) are related to the prices NGT itself pays for settling any remaining net system imbalance. Because of the balancing obligations, shippers have an incentive to balance their projected offtakes and inputs themselves, by trading with each other.

The UK Department of Trade and Industry (DTI, 2002) estimated that in 2001, 91% of all gas was produced by companies who also had a shipper status, while companies producing 66% of the gas were active downstream as a supplier. Non-shipper producers have several options to sell the gas: selling to larger producers that have equity stakes in the same fields, selling to aggregators at the beach (this may be an independent shipper or one of the major companies), or contracting an agent shipper to take the gas into the system for them. According to DTI (2002), the second option was the most common one. Prices for the gas supplied to the aggregator are determined by the NBP price, minus charges for bringing the gas into the system.

Liquidity and transaction costs

Efficiency of pooling fluctuations in gas output from different producers depends on the transaction costs of such trades among producers and shippers. Transaction costs of trading out imbalances in the wholesale market among market participants depend on the liquidity of this market. In a highly illiquid market, it will be difficult or impossible to find a counterparty to deal with, and transaction costs will be high. This would for instance be reflected in high bid-ask spreads, the difference in prices between offers to buy or sell gas. In liquid markets, counterparties and trades are more abundant, and competition between them drives the costs down.

The UK gas market is considered to be quite liquid. As ILEX (2004) note, in a report commissioned by the offshore industry in the country, "the UK, however, has a highly liquid market ... with a retrading ratio (the number of times a unit of gas is retraded before it is delivered) of around 14." ILEX concedes that there has been a slight drop in this number. DTe (2005) also quotes evidence for liquidity on the UK gas market. The number of active shippers (potential counterparties) is high, at 80. APX, the commercial exchange operating an on-the-day-commodity market in the UK, where intraday gas is traded, notes that the number of trades in July 2005 amounted to some 4,000, with a traded volume of around 8 TWh, or circa 0.8 bcm.[35]

Some indication of actual transaction costs of trading imbalances in this market may be gained from the size of bid-ask spreads in these markets: how large is, on average, the discrepancy between the mid-price point in a market and the price at which one may be able to strike a deal. Estimations of the difference between buy and sell prices for 2004 in DTe(2005) show these to average 3 to 6% over months in 2004, for day-ahead contracts. System operator NGT's average difference between system-buy and system-sell prices over 2004 equals slightly over 1 eurocent per m^3, indicating that the deviation from the system average price of a balancing trade with NGT is on average around 0.5 eurocent per m^3. This may be viewed as an upper bound, as trading with NGT will be the last resort for firms to correct their imbalances. Global Insight (2005) notes that for the spot market "bid-offer spreads are generally tight, around 0.1 p/therm[36] although rising in conditions of high volatility, which is to be expected. This is a healthy sign."

Assuming these figures to give a fair estimate of the transaction costs of balancing short term fluctuations in output in the gas market in the UK, one may convert these costs into an average over all produced gas. For instance, assuming 10% of all output of a field to be due to unforeseen short-run fluctuations, the transaction costs of pooling these fluctuations through the market would amount to 0.005 to 0.05 eurocent per m^3 produced. For comparison, current gas prices are of the order of 15 to 30 eurocent per m^3.

The NBP market is a volatile market. Short-term technical difficulties with producing fields or other installations can have relatively large effects on short-term prices. Producers that sold their gas on longer-term contracts, facing difficulties in production, will have to make up their deficit by buying against the (higher) spot market price. Is this an additional cost of market based pooling?

First let us notice that, especially under tight system conditions, real social costs of loss of gas may be significant: higher gas prices do reflect higher (social) costs of gas. To the extent spot

[35] APX press release August 2005.

[36] around 0.05 eurocent per m^3

gas prices do reflect these costs, passing the costs on to producers gives the correct incentives. Indeed, a central purchase system that would not reflect such costs, but instead socialise them over the complete portfolio, would result in insufficient investment in field reliability.

Second, upward price excursions are not only a penalty to producers suffering an outage, but also benefit the majority of producers not having an outage at that moment. This would be expected to remain true even if these producers would sell all their gas in longer-term contracts, and would not be directly exposed to this short-term volatility. Spot prices are reflected through arbitrage also in longer-term contract prices. As Global Insight (2005) notes
"Our investigations indicate that the UK gas market does indeed arbitrage highly efficiently. ... Related but distinct markets and transactional forums such as the IPE, the OTC market , the On-The-Day Commodity Market (OCM) all arbitrage efficiently. Forward prices converge with spot prices as would be expected."

Global Insight (2005) assessed whether spot price volatility was indeed a genuine reflection of market fundamentals, and concluded that at least in the view of market participants this was the case. "Anecdotally, it has been confirmed to us by all the market participants we have talked to that spot prices can 'always be explained', at least after the event, in terms of fundamental factors." In fact, confidence in spot prices appears sufficient that "at least one of the largest UK producers comfortably sells all its substantial volume of gas not already committed under long-term contracts, into the spot and month-ahead forward markets".

The transaction costs of the trades per se are not all that should be considered. Additional costs arise from the need for producers either to become shipper themselves and operate a trading desk managing fluctuations in output, or from the charges to be paid to intermediates (such as aggregators or shippers acting as agents) taking care of these market operations for them.
In practice, most gas from production wells is sold on long-term contracts. UKOOA(2004) notes that "It is estimated that some 75% of the gas produced is sold to wholesale buyers (known as shippers) at beach-head terminals under long-term contracts, with the balance being sold under short-term arrangements." As discussed above, a large part of these contracts can be with affiliated shippers or suppliers. The allocation of the responsibility for, and the costs of, balancing supply fluctuations will be arranged in these contracts. Costs borne by the receiving shipper will presumably be reflected in the contract price. As mentioned in the box, in the UK, the vast majority of gas is produced by firms who act as shipper, trader, or supplier themselves. The costs of operating a trading desk for these firms is therefore pooled with other parts of the gas supply chain.

The large degree of vertical integration suggests that costs of gas sales can be decreased by cooperation.[37]

Whether the smaller proportion of independent producers face higher costs partly depends on the amount of competition between counterparties willing to buy their gas in long-term contracts, as this determines whether small producers can obtain competitive offers for such contracts. UK industry and government are cooperating in a joint task force to address potential barriers of entry into the industry. Difficulties in finding channels for selling output were not addressed as an important concern. DTI(2002) notes that since 2000 ten new licensees entered the business who had no previous involvement in UKCS production, indicating that costs of selling gas into the market do not seem prohibitive.

3.5.3 Pooling in the Norwegian gas market

In Norway, experience with the conversion from a centralised pooling mechanism towards a decentralised trade system is more recent. Until 2001, all Norwegian gas sales were controlled by the state through the Gas Negotiation Committee, GFU, in which the individual operators were represented. Under the system, contracts for sales were coordinated centrally, to ensure adequate pooling of the production profiles of individual fields. The flexible giant Troll field acted as a balancing field. Under pressure from the EU, this construction was abandoned in 2001, and from then on producers had to individually contract with each other for the required flexibility to balance their portfolios. In practice, this may have meant that many producers kept trading with one counterparty, state-controlled Statoil.

According to the Norwegian Ministry of Petroleum and Energy, the system of bilateral negotiations does not pose significant difficulties on companies. Gas contracts in the Norwegian system are typically concluded for the aggregate portfolio of each producer, which reduces transaction costs. This is in line with the fact that interest for production and exploration licenses from new companies has increased considerably over the ensuing years (MPE/NPD, 2005). Gas production in Norway is steeply increasing and expected to increase further.

3.5.4 Pooling in the Dutch electricity industry

A similar mechanism of pooling through markets can be observed in the Dutch electricity industry (and in many other restructured electricity markets). Dutch electricity production used to be coordinated by one joint company, SEP, until the late 1990s. Market restructuring led SEP to be dissolved, and divided the responsibilities of electricity production among individual producers, with a system operator, TenneT, responsible for overall system balance. A central role in the market is played by the system of programme responsibility, whereby each group of

[37] Around two-thirds of the producing companies in the UK is affiliated to downstream supply companies, reducing the need to trade. As DTI (2002) concludes, “The arrangements which tend to concentrate the gas produced on the UKCS into the hands of a few major producers seem to be driven largely by cost considerations. The services offered by larger producers and agent shippers enable smaller producers to participate.”

players (e.g. a generator, a trader, a supply company) is required to individually balance his production and consumption. The means for these parties to individually balance is to trade with each other, and as a result various trading platforms have arisen (see e.g. van Damme (2005) for a description of this process).

Efficiency of such trading depends on the transaction costs, which are related to the liquidity of the market. Regulator DTe voiced some concerns over the level of liquidity in its electricity market surveys. Again, here, overly burdensome transaction costs would lead to increased vertical or horizontal integration. One does observe some trend to consolidation in the sector. As an example, in August 2005, various smaller supply companies announced to team up into one programme responsible party, citing as an argument the reduction of imbalance costs due to pooling. In general, it is common for the many small generators (often industrial users who use combined heat and power generators in their production processes and generate excess electricity as a by-product) to use energy companies as intermediates in their dealings with the market (see Newberry et al., 2003). Transaction costs are then reduced by having larger market parties manage the portfolios. There is, in addition, competition between energy companies for the opportunity to manage these portfolios, including by new entrants to the sector who offer portfolio management services to small producers and large consumers.

As balancing requirements in the electricity industry are significantly stricter than in the gas sector, the need for coordination is proportionally greater. It is remarkable that the transition from a centrally coordinated pooling system to a market based decentralised system in restructured electricity markets went relatively smoothly as far as maintaining short term system integrity is concerned. The transition to the new system has generated greater efficiency of plant operation, as moral hazard related to the former command-and-control regime has been taken away. Bushnell and Wolfram (2005), and Markiewicz et al. (2004) study technical efficiency increases in restructured electricity markets. For the Netherlands, there is anecdotal evidence that producers react faster to e.g. outages in bringing back equipment on line.

3.5.5 Pooling in the Dutch wholesale gas market

In the Netherlands, wholesale gas markets are less mature than either the UK gas market or the Dutch electricity market. DTe published a consultation document on the development of the wholesale market (DTe, 2005) and noted that in particular on the Dutch Title Transfer Facility, liquidity is developing. Some industry observers view TTF as currently the most liquid gas market on the continent. However, it may be expected that at least initially, transaction costs may be higher than in the UK. On the other hand, Norwegian experience, where transactions occur mostly on a bilateral basis and no liquid spot market exist, indicates that impact on production may be minor. It will remain uncertain how transaction costs will develop as more gas would be sold through third parties.

Conditions in both the UK and the Norwegian sectors are different from the Dutch Continental Shelf: fields are considerably smaller in the Dutch area. The smallness of these fields may be argued to provide more difficulties in portfolio management. An incident in a larger field will typically occur in one of many drill holes, and the loss of production may be compensated by an increase from the other wells. For a smaller field, on the other hand, there may be only one well for the entire field, and no compensating action can be taken within the field. However, operators should be able to adjust production from other fields instead, and it seems more appropriate to ask whether aggregate Dutch production portfolios are significantly smaller than in the neighbouring countries.

Figure 3.3 UK and Dutch 2004 offshore production, by field operator

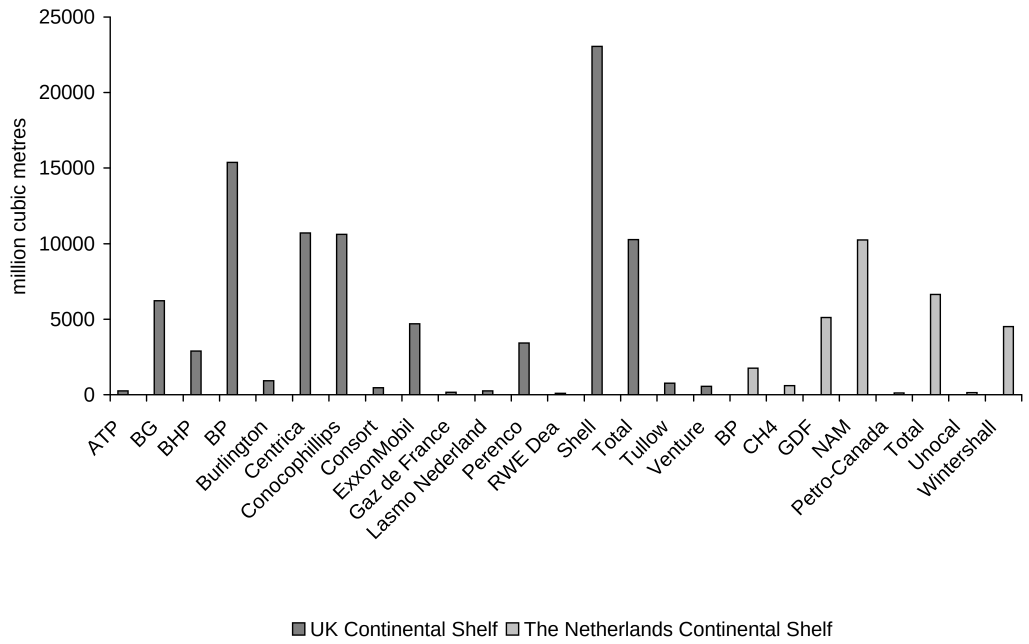


Figure 3.3 compares Dutch continental shelf portfolios with UK production, by field operator (for the UK we only look at operators that are active in dry gas fields, but for these we analyse total gas production, i.e. including associated gas). It is evident, firstly, that the number of parties active as field operator on the UK Continental Shelf is higher (17) than on the Dutch CS (8). Total UK offshore production equals roughly three times Dutch offshore production, and the largest parties in the UK are significantly larger than the largest Dutch portfolios. On the other hand, it turns out many companies succeed in operating in the UKCS, that are comparable in size to the smallest Dutch players. Apparently, the size of typical Dutch player portfolio does not prevent participation in a liquid market.

The comparison is based on assignment of gas to the operator of each field, while one might more appropriately compare equity shares per field. In general, EBN participates in fields (but does not operate), total equity of Dutch firms is lower. In the UK, however, also equity is shared in most fields. As an example, operator BHP never owns over 46.1% of equity of any of the fields. In addition, some players do own equity, but are not an operating party for any field.

In table 3.1 we compare production of gas based on equity shares for a selection of firms in the UK and the Netherlands Continental Shelves. We see a picture that confirms the analysis based on operating shares. The four largest portfolios (and therefore also the average sizes) are significantly larger than those on the Dutch Continental Shelf, with the exception of NAM. The smaller portfolios are of comparable size to the Dutch.

Table 3.1 Gas production of selected firms on the UK and Dutch Continental Shelf, 2004

United Kingdom		The Netherlands	
Name of company	Gas production (million cubic metres per day)	Name of company	Gas production (million cubic metres per day)
Exxon	34	NAM (offshore)	33
BG	33	Total	9
BP	33	Wintershall	5
Total	27	BP	5
ENI	11	PetroCanada	2
Perenco	9	Unocal	0.5[a]
Tullow	3		
BHP	2		
Venture	1		
RWE-DEA	0.5		

Note: a: data on the year 2000.
Source: company reports.

Coordinated pooling of quality variations

The resolution of quality fluctuations may be more difficult to achieve without direct coordination between producers. Gas from small fields may enter the gas transmission system (mainly the high calorific system) at circa ten places. Quality (heat content and other components of the gas) has to be within system bounds at entry into the central system for GTS to accept the gas. In general, therefore, achieving appropriate quality from mixing production from different fields requires coordination before the entry point by the fields using the particular offshore pipeline. Decrease or increase in production by one of the fields feeding into the pipeline may cause the overall quality of the mixture to change so much that al gas may have to be refused access to the system. Current contracts for purchase of gas typically involve clauses that allow buyers to refuse purchasing the gas if the quality of the overall mixture delivered at the entry point does not meet the contract specifications. If at the entry point, quality does not meet specifications, gas may still be accepted by GTS, subject to negotiation, if system security allows so. This might require system coordination of gas from different entry points.

Central purchase of all gas by one party allows for the required coordination to accommodate a wide range of quality specifications. Currently, after unbundling of GTS from Gasunie Trade & Supply, the presence of (foreign) suppliers using the offshore infrastructure but not selling to Gasunie Trade & Supply makes such coordination more difficult. Since coordination is mainly necessary among users of the individual offshore pieces of infrastructure, a natural alternative to coordination by a central buyer (Gasunie Trade & Supply) would be bilateral negotiations between pipeline users, possibly coordinated by the operator of that pipeline, which usually is a joint venture of various offshore operators involved. In the absence of quality pooling over different pipelines, there seems to be no particular advantage to centralised coordination of quality in a portfolio comprising fields feeding in over different trunk lines. Any quality coordination of gas between different entry points requires coordination with the system operator GTS.

The wide range of gases accepted by GTS[38] reduces the benefit of coordinated pooling by Trade & Supply: it is the responsibility of GTS to accommodate all gas meeting the entry point specifications, and GTS seems to be in the best position to coordinate all flows within the system, as observed above. In the current setting, Gasunie Trade & Supply may efficiently carry out such coordination and negotiation with GTS on behalf of the producers involved. In the absence of pooling through Trade & Supply, the required coordination would involve direct negotiations of those producers with GTS. This could also require bilateral agreements with other producers who deliver gas to the system with quality characteristics offsetting those of the off-spec gas.

It is unclear whether central coordination by another party than the system operator achieves a more efficient offtake of gas of different qualities. In the UK, allegedly, a smaller range of gas specifications (in terms of e.g. heat content) is accepted by the system operator than in the Netherlands. This may lead to problems with the increasing share of imports in the UK, which involve gas not necessarily meeting these specifications. In itself, this is not directly related to liberalisation, however. As ILEX (2005) note, “The differences in the specifications around Europe mainly stem from differences in the appliance population, themselves attributable to historic factors - e.g. the age, size and maturity of the British domestic (household) gas market.”

Abandonment of centralised pooling in the UK, where system bounds may be tighter and more coordination at entry point level is required, gave a mixed view on quality coordination,

[38] As specified in GTS’ s Transmission Service Conditions.

according to industry observers there[39]. In some cases, British Gas, the monopolist, could, using its command-and-control powers before liberalisation, make use of blending of gas flows from different sources to accommodate off-spec gas and still remain within system bounds. In other instances, the monopoly position was allegedly used to the detriment of development of small on-shore fields.

In summary, it remains unclear whether indeed central pooling through Trade & Supply outperforms coordination of gas quality by the system operator or individual pipeline operators in a decentralised market.

3.5.6 Conclusion

Pooling of quantity fluctuations between output of various gas fields can be facilitated by the central pooling, supported by the guaranteed offtake by Gasunie Trade & Supply. We discussed that pooling through liquid markets may be an alternative to this centralised pooling. From the UK gas market experience, we conclude that the high degree of liquidity of this market indicates that transaction costs of trade may not be a significant barrier to trading. In a review on improving conditions for gas exploration and production on the UK Continental Shelf, difficulty of structuring gas by smaller producers was not mentioned as a problem.

On the other hand, the relatively modest transaction costs do not necessarily mean that it is efficient for each individual operator to structure its own production through the market, as it is plausible that there exist certain economies of scale. As pointed out, smaller operators in the UK tend to pool their production either by selling to (larger) competitors, or to independent aggregators. Other scale advantages may be achieved by vertical integration.

There may be (transaction) costs involved if markets are not sufficiently liquid. In the UK gas market, transaction costs owing to low liquidity do not seem to be a major concern. Consolidation in the sector does provide evidence that economies of scale are present, but these are solved by market mechanisms.

In the Dutch gas market, which is not well developed yet, transaction costs of pooling through a market may be relatively higher initially. These initially higher transaction costs might consist of increased lead times for exploration, development and production. These costs in case of market pooling can be seen as transition costs from replacing the coordinated mechanism by a market mechanism. Whether these transition costs would be compensated by lower levels of transaction costs in the future is difficult to determine in advance. The Norwegian experience in gas production and the Dutch experience in electricity production show, however, that a transition from a centrally coordinated mechanism to market mechanism is not necessarily

[39] Personal communication with David Cox of ILEX Energy Consulting, Oxford, UK.

difficult to realise. In addition, comparison of the portfolio size of the operators on the British and the Dutch Continental Shelf make clear that the size of Dutch portfolios are on average smaller. In the UK, however, many producers with similar sized operations appear fully able to participate in the market.

Finally, it is unclear that the need for quality management is a valid argument against a market mechanism. Firstly, because management of the quality of gas is mainly conducted before the entry point making coordination of quality over different trunk lines not relevant. Coordination before the entry point could be performed by multilateral negotiations by pipeline users. Secondly, any additional need for quality management and coordination could be satisfied by the transmission system operator, rather than one of the shippers.

3.6 Coordinated pooling may create market power

Another benefit of the offtake guarantee might be that bundling production might increase the scope for charging higher prices for Dutch gas production. Increased market power for marketing Dutch gas would have an adverse effect on Dutch consumers. However, given that a large part of Dutch production is exported, the gain in Dutch producer revenues (at the cost of foreign consumers) may be expected to more than offset this effect.

Increased market power might result from two mechanisms. One possibility might be that small fields producers compete vigorously to supply to Gasunie T&S, but Gasunie T&S can subsequently exercise market power in selling the gas as a result of its long-term purchasing contracts with these producers. Another possibility is that pooling by Gasunie T&S might facilitate collusive behaviour among individual small fields producers. We subsequently discuss these two mechanisms.

In general, a market player's long-term contracts have the potential to affect his market power. For a market player that sells part of his production on long-term contracts, the incentive to behave strategically in the short term market is limited, since revenues on the contracted sales cannot anymore be affected. The argument is made explicit in e.g. Allaz and Vila (1993), Green (1999), and was studied empirically in an analysis of electricity markets by Bushnell et al. (2005). For the purchase of contracts, the argument is the reverse: buying gas long-term enhances market power in the sales market. Mahenc and Salanie (2004) show that, buying forward (rather than selling) commits a producer to set a higher spot price in order to increase the value of his position.

Typical contracts under the small-fields policy are depletion contracts: a given gas field's production is sold under contract for the entire life of the field. However, this price is regularly (annually) recalculated and subject to renegotiation. Although Gasunie T&S does purchase gas long-term from small fields producers, changes in shorter-term market prices would presumably be passed through to producers in these annual renegotiation rounds.

Another mechanism for increased market power may be that coordinated marketing of small fields gas facilitates collective behaviour by small fields producers, allowing them to jointly command higher prices. The force of this argument would depend on the competitive forces among small fields producers without such potential coordination, and on competition from external gas sources that would make such behaviour less attractive.

An indication of competitive forces among small fields producers can be gained from the shares of various operators on the Dutch Continental Shelf, see also figure 3.3. There is a fair amount of concentration, with the largest operator NAM being operator for approximately one third of the total off-shore volume.

To assess the competitive effect arising from interactions from international links, we now recalculate the industry equilibrium in the Baseline scenario when production decisions for small fields are coordinated to optimally exercise market power, and compare it to a situation with oligopolistic competition. The effects are given in table 3.2.

Table 3.2 Effects of coordinating small fields production on Dutch welfare, in four scenarios (billion Euros)

	Baseline	Competitive	Sellers' market	High prices
Effect on producer surplus Groningen	– 0.3	– 0.4	0.1	0.0
Effect on producer surplus small fields	0.3	0.3	0.0	0.0
Effect on consumer surplus Dutch low-quality consumers	0.1	0.3	– 0.0	0.0
Effect on consumer surplus Dutch high- quality consumers	– 0.5	– 0.3	– 0.8	– 0.3
Total	– 0.4	– 0.1	– 0.8	– 0.2

Increased market power would lower production volumes slightly, in an attempt to raise prices. There is a small effect on prices. When coordinating, small-fields producers have more incentive to reduce supplies to the Dutch high-cal market (and drive up prices). They can achieve this by increasing both exports and quality conversion to the low-cal market. The latter effect explains a pressure on prices on the low-cal market in most scenarios, and hence lower surplus for Groningen, and higher for Dutch low-cal consumers. We see that the aggregate of the consumer and producer effects on Dutch welfare is negative in these scenarios: the loss to Dutch consumers as a consequence of the rise in prices is higher than the gain of producers by exporting higher-priced gas. Facilitating such coordination to increase (export) prices therefore would not be in the interest of aggregate Dutch welfare.

4 Welfare effects of the cap on Groningen

4.1 Introduction

In order to analyse the welfare effects of a cap on Groningen, we have first to assess its impact on the production from this field in particular and the natural-gas market more generally. We use the NATGAS model to see what the effects of imposing a production cap on the Groningen field will be on the European natural gas market in each of the scenarios described in chapter 2.[40] What is the effect on prices, investments and use of infrastructure, international gas flows, of this policy measure? Section 4.2 answers these questions.

Section 4.3 goes into the costs of a ceiling on production. These costs mainly consist of postponement of revenues. The benefits of the cap on Groningen are the subject of section 4.4. These benefits consist of two types of effects: impact on small-fields production and impact on security of supply.

4.2 Effects of a cap on the European gas market

In estimating the effect of imposing a cap on Groningen production, one has to take into account the fact that Groningen produces low-cal gas, which is consumed only in a relatively small market.[41] Apart from the direct consumption by a part of the end users in the Netherlands, Germany, Belgium and Northern France, low-cal gas can also be marketed by mixing with high calorific gas that has larger than average energy content. Norwegian gas is an example of such gas, and given the expected increase in Norwegian imports, there is some scope for growth of the low-cal gas market there.

A decrease in Groningen production, as a result of a cap, would have to be compensated by an increase from other sources, or an increase in demand. In the low-cal gas market, the most important other sources are German production and high-cal gas that is quality converted into low-cal gas. For the latter, there is currently a limited capacity in the Netherlands, that is used at a high utilisation rate.[42] Additional capacity is available in Germany. Over time, higher inflow of this converted gas into the low-cal gas system (as a result of the lower Groningen production) would affect marginal prices there, and as a result, marginal production or imports of high-cal gas. On the short term, response from the high-cal market (including the Dutch small fields) would be limited as a result of the long-term sales contracts already in place for a large share of production. Some short-term supply response could come from LNG imports in the nearby

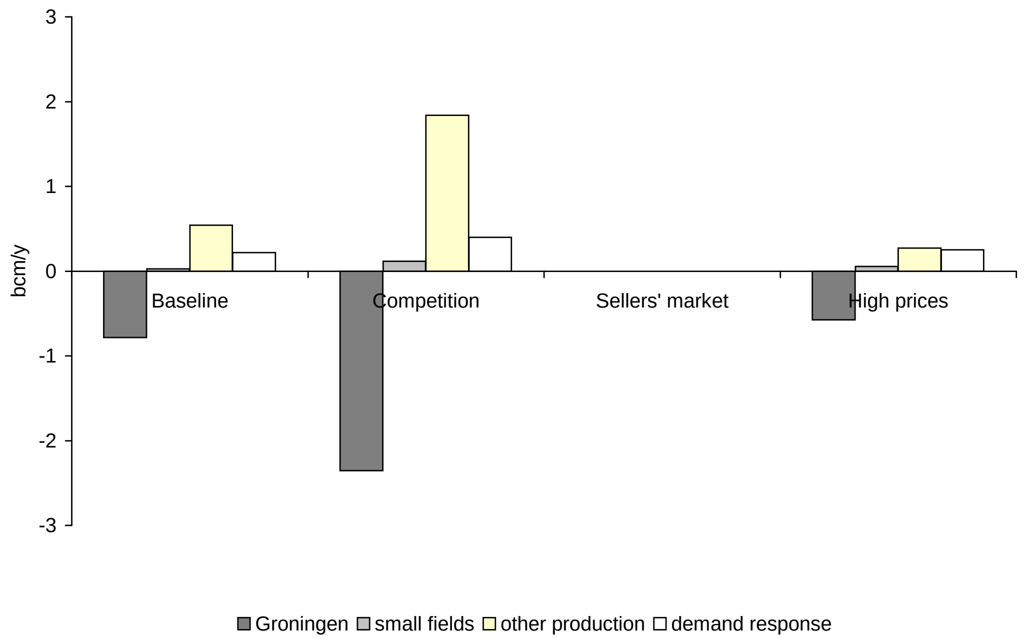
[40] See Zwart et al. (2006) for a description of the NATGAS model.
[41] See Mulder et al. (2006) for a description of the characteristics of the natural gas market.
[42] See e.g. DTe 2004 for a discussion of current available Dutch quality conversion capacity.

markets (e.g. Belgium and the UK), where LNG ships would be increasingly diverted to, for instance, the US, as prices would drop on the continent.

Response from the high-cal market will increase over time as new projects will be developed. A rise in high-cal prices will likely affect the highest long-term marginal cost projects relevant for North-Western Europe. Under the assumption that Russian supplies to Europe are partly politically driven (and therefore will not decrease), and apart from LNG imports, the highest marginal cost projects will be located mainly in the UK and Norwegian regions.

Small-fields production is hardly impacted by lower supplies to the low-cal gas system, as the marginal costs of these fields are below those of these regions (see Bos et al, 2003). In addition, the opportunity costs of Dutch offshore fields are lower than for e.g. marginal Norwegian fields. This is partly the consequence of the aging of offshore infrastructure: the loss of value of deferring Dutch small fields production is higher than that for other sources in less mature areas.

Figure 4.1 Effects of a cap on Groningen on the natural gas market, in four scenarios (first twenty years, in bcm per year)



On the demand side, higher prices may result in a slight decrease of consumption (perhaps mainly by low-cal gas fuelled power stations), accommodating the reduced production; in the longer run, lower gas production and higher prices may reduce investments in gas fired power plants, favouring other technologies.[43]

In our scenarios, we assume that the operator of the Groningen field is fully free to choose the production path which maximises its profit. If that production path is above the path defined by a cap (of 42.5 bcm per year), this policy measure causes additional production of Groningen when the cap is not binding anymore. As a result, the cap affects supplies of gas from other sources. A temporary shortfall in Groningen production triggers gas from e.g. imports or small fields, or demand response through price increases. In the later period when one enjoys the prolonged life of the field the effect is in the opposite direction.

Figure 4.1 shows the responses of Groningen itself, the Dutch small-fields, other production locations in Europe, as well as responses by consumers. If an annual cap on Groningen of 42.5 bcm is imposed, the operator of this field has to reduce its activities in the first period of three out of four scenarios. The competition scenario shows the largest impact on Groningen production (on average 2.5 bcm less annual production in the first 20 years), while in the Sellers-market scenario the cap has no effect. Small-fields production is only slightly affected by a cap in the other scenarios. In the Competition scenario, effects of the cap are largest. The total effect on small-fields production amounts to an increase of several bcm. The small effect on small fields is related to the full utilisation of the infrastructure: prices are too low for extension of the infrastructure but sufficiently high for full utilisation of the infrastructure (see also text box “Relationship between gas price and small-fields production”).

Relationship between gas price and small-fields production

Using a large database of geological prospects on the Dutch Continental Shelf, TNO-NITG analysed the impact of the gas price on the economic viability of these prospects (cited in Mulder et al., 2004). The analysis investigates the effect on total expected reserves for two levels of the oil price, 20 USD/bbl and 25 USD/bbl. These prices correspond to gas prices of around 9 and 11 cents per cubic metre (depending on the dollar exchange rate). The effect reported by TNO amounts to 65 billion cubic metres, i.e. with the lower oil price, 65 billion cubic metres of small fields gas become uneconomic. This effect, however, is only based on a field-level analysis, not taking into account restrictions on infrastructure level. If the infrastructure if fully utilised, high prices are needed to make additional production profitable. Hence, the relationship between gas price and small-fields production is not linear.

[43] Conversely, RWE CEO Roels (Energeia, 2005) argues that the recent higher gas prices will change the balance to increased investment in coal fired plant.

The effect of the cap on market prices is low. The cap has highest impact on the Dutch low-cal market, but even there price effects in the Competition scenario are restricted to at most 0.3 eurocent per m^3. Average price effects over the initial twenty years in the low-cal market are given, per scenario in table 4.1

Table 4.1 Price effects on Dutch low-cal gas market, average over first 20 years (eurocents per m^3)

	Baseline	Competition	Sellers' market	High prices
Price effect	0.03	0.07	0	0.07

Concluding, a cap on Groningen results in a minor change in the price on the European natural gas market due to responses by other producers and consumers. Effects on small-fields production are generally small.

4.3 Costs of a cap on Groningen

4.3.1 Introduction

The costs of a cap on Groningen mainly consist of postponed revenues, but consumers may also pay a price due to higher gas prices. We calculate the costs in two ways. First, we use a few assumptions to calculate the first-order effects of the first cost component, i.e. the effect of only a change in production profile (section 4.3.2). Afterwards, we use NATGAS to analyse the welfare effects in each of our scenarios, taking into account, among other issues, the effect of a cap on the gas price (section 4.3.3).

4.3.2 First-order calculation

Without using our gas market model, we can calculate the order of magnitude of the costs of postponed production of Groningen, i.e. without taking into account effects of the cap on the gas market and the prices. The costs equal the change in the present value of all future net revenues. These net revenues are the difference between the proceeds of the extra gas sales (price times volume) and costs of producing gas. These costs not only include the long-run production costs of Groningen gas (estimated at around 1 cent per cubic metre by TNO (2003) and IEA (1995), but also the opportunity costs associated to the loss of option value of Groningen's swing capabilities as a result of increased production (see Box). In De Joode and Mulder (2004), these were estimated at around 2 cents per cubic metre.

The cost of postponed production primarily depends on a number of assumptions, i.e. the impact of the cap on gas production, the gas price and the discount rate. Table 4.2 presents the results of calculations using different assumptions regarding the impact of the cap on annual gas production and different future gas prices, while the discount rate used is 5% in all these cases. We compare the net present value of (net) revenues of Groningen production under a constant production equal to the cap (of 42.5 bcm per year), with those resulting from a higher (constant) output rate. In the latter case, annual revenues in early years are proportionally higher, but the field is depleted sooner.

We compute this for several assumed price levels. The lowest price level in the table (0.10 Eur/m3) roughly corresponds to the cost of bringing LNG to the European market (see OME, 2004), and might be considered as the long-run price under competitive conditions on the global energy markets. The highest price in the table (0.20 Eur/m3) is comparable to current prices for gas in continental Europe, which are set on the basis of current high oil prices. Clearly, higher prices mean higher revenues and a larger present value effect of the cap, all other things equal.

The option value of the Groningen field

The value of the flexibility capability of the Groningen field can be assessed by using the real-options approach. This approach, which originates from finance theory, is a significant improvement of the discounted cash flow analysis that is a traditional tool in valuation procedures. The added value of the real-options approach is that it (1) acknowledges the fact that (most) investments are (at least partially) irreversible, (2) investments can be deferred (with more information becoming available in due time), and (3) future outcomes surrounding the investment are highly uncertain.

The potential applications of the real options approach are manifold. Paddock, Siegel and Smith (1988), for instance, apply the option value technique to estimate the value of an offshore petroleum lease and find that it provides a good guide for the optimal timing of development. Conrad (1996) and Reed (1992) both deal with the decision whether to harvest an old-growth forest or not. They construct an investment rule in the face of uncertain benefits (wood prices) and uncertain costs (foregone amenity flows). Burda (1995) uses option theory to analyse the issue of migration. In the face of positive option value, migration is less than computed under standard present value terms. Emery and McKenzie (1996) use the option value approach to evaluate the subsidy of a transcontinental railway in Canada. Chaton and Doucet (1999) use the real option approach to incorporate the effect of uncertainty in both input and output prices to assess the investment in generation capacity.

The characteristics of the depletion decision regarding Groningen gas satisfy the conditions for using the real-options approach. Firstly, the investment is 100% irreversible: once a cubic meter of gas is produced, it cannot be injected back into the reservoir. Secondly, at each future moment of time the owner of the Groningen field is able to interrupt extraction in order to wait for more favourable (price) conditions. Thirdly, the price at which either base load gas or 'swing gas' is sold is uncertain, but tomorrow's gas price is far less uncertain then the gas price a year from now.

Applying the real-options approach, De Joode and Mulder (2004) find a value of the flexibility capacity of the Groningen of 0.021 Eur/m^3 in their base case. This value strongly depends on the volatility of demand: the higher the volatility, the higher the value of swing. The lower and upper bounds of the estimates of the option value of swing are 0.01 and 0.03 Eur/m^3, respectively.

Table 4.2 **First-order calculation of present value of postponing Groningen net revenues, using different assumptions about impact of cap on production (billion euro; discount rate = 5%)**

Excess production over 42.5 bcm cap	Average price 0.10 Eur/m3	Average price 0.15 Eur/m3	Average price 0.20 Eur/m3
5 bcm / year	2.3	4.0	5.7
10 bcm / year	4.4	7.5	10.7
15 bcm / year	6.2	10.6	15.0
20 bcm / year	7.7	13.3	18.8

If the cap reduces annual gas production (during the first period) by 5 bcm, the present value of the direct costs is 2.3 billion Euro if the average future gas price is 0.10 euro per m^3. If the gas price is twice as high, i.e. 0.20 euro per m^3, the costs amount to 5.7 billion euro. The higher the impact of the cap on annual gas production, the higher, of course, the costs. This effect is, however, degressive as a higher annual production shortens the period of production as the size of the total reserves of Groningen is fixed.

4.3.3 Model analysis

This preliminary calculation does not reveal how large the direct effect of removing the cap is: if the cap turns out to be non-binding in practice, there is obviously no effect (and no benefits either). If the cap is effective and binds, one may expect present value effects of the order of several billions of Euros. In addition, the above analysis does not include an effect of the cap on gas prices. Using the NATGAS results presented in the former section, we are able to calculate the costs of the cap in each scenario and for different discount rates (see table 4.3, 4.4 and 4.5).

Table 4.3 **Direct costs of an annual cap of 42.5 bcm on Groningen in four scenarios (present value in million euro; discount rate = 3%)**

	Baseline	Competition	Sellers' market	High prices
Change in average annual production during first 20 years (in bcm)	0	– 0.47	0	0
Loss of producer surplus Groningen	0	– 45	0	0
Loss of consumer surplus Dutch low-quality consumers	0	– 110	0	0
Loss of consumer surplus Dutch high-quality consumers	0	– 15	0	0
Total	0	– 170	0	0

Table 4.4 **Direct costs of an annual cap of 42.5 bcm on Groningen in four scenarios (present value in million euro; discount rate = 5%)**

	Baseline	Competition	Sellers' market	High prices
Change in average annual production during first 20 years (in bcm)	– 0.8	– 2.5	0	– 0.6
Loss of producer surplus Groningen	– 360	– 540	0	– 30
Loss of consumer surplus Dutch low-quality consumers	– 120	– 380	0	– 240
Loss of consumer surplus Dutch high-quality consumers	– 20	– 55	0	– 10
Total	– 500	– 975	0	– 280

Table 4.5 **Direct costs of an annual cap of 42.5 bcm on Groningen in four scenarios (present value in million euro; discount rate = 7%)**

	Baseline	Competition	Sellers' market	High prices
Change in average annual production during first 20 years (in bcm)	– 2.3	– 5.0	0	– 2.8
Loss of producer surplus Groningen	– 590	– 1700	0	– 715
Loss of consumer surplus Dutch low-quality consumers	– 735	– 765	0	– 1050
Loss of consumer surplus Dutch high-quality consumers	– 200	– 190	0	– 210
Total	– 1525	– 2655	0	– 1975

We observe that the present value of the loss of producer surplus of Groningen production range from 0 to 1.7 billion euro, depending on the impact of the cap on production and the discount rate. In the Seller's market scenario, the cap has no effect and so, does not cause any costs. In the Competition-scenario, the discounted value of postponed revenues is 0.5 billion euro (5% discount rate). These costs are significantly lower than calculated above in the first-order calculation which is due to the impact of the cap on prices and, hence, the inframarginal profits. In other words: the costs of postponed production are partly compensated by higher profits on the remaining production.

Apart from the effect on the producer surplus from Groningen production, an additional cost arises through the impact on prices for gas for consumers. The largest effects occur in the low-calorific gas market, the quality that is produced by the Groningen field. A reduced supply from Groningen raises the price (because more costly sources of low-cal gas have to be used) resulting in a loss of consumer surplus.

In addition there is an effect on the high-cal market, which is, however, very small or negligible. The relatively low effect on these consumer prices is due to the long-term flexible supply on European level. A rise in Dutch prices would result in additional gas flows from in particular Norway and LNG sources.

The total costs of the cap on Groningen range from zero in the Sellers-market scenario to 2.7 billion euro in the Competition scenario.

These results also show that the choice of the discount rate significantly affect the costs of the cap on Groningen. As it will also affect the magnitude of the benefits, the question remains whether the final conclusion depend on the discount rate. In the next chapter, we will see that is not the case.

4.4 Benefits for small-fields production

4.4.1 Introduction

A cap on Groningen might affect conditions for small-fields production in different ways. If a cap raises gas prices, the producer surplus of these fields increases (section 4.4.2). In addition, a cap on Groningen might give additional benefits in terms of balancing (section 4.4.3).

4.4.2 Higher prices

A cap on Groningen increases wholesale prices and, hence, raises options for small-fields producers to increase their production. Table 4.6 gives the assessment of the additional producer surplus of small-fields gas owing to this mechanism. The direct effect on small fields production is likely to be low, firstly because a large part is already contracted under long term contracts, and secondly, as explained above, higher cost sources will react first. Only in the Competition scenario, the supply from small fields increases markedly (see figure 4.1), resulting in additional producer surplus of 145 million euro (5% discount rate). Changing the discount rate results in other effects on the consumer surplus.

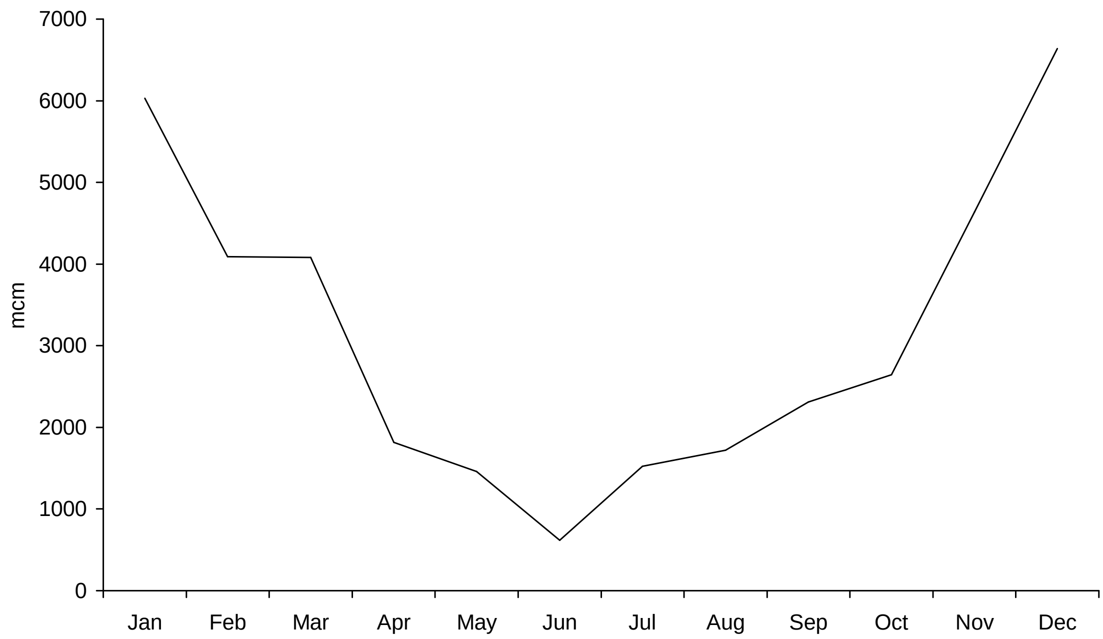
Table 4.6 Benefit of an annual cap of 42.5 bcm on Groningen for small-fields production in four scenarios, using different discount rates (present value in million euro)

	Baseline	Competition	Sellers' market	High prices
Additional producer surplus small fields				
- discount rate = 3%	0	15	0	0
- discount rate = 5%	35	145	0	35
- discount rate = 7%	305	330	0	345

4.4.3 The use of Groningen as a balancing field

A cap on Groningen may also affect its role as balancing field for small fields. This balancing function mainly consists of the enormous seasonal swing in production from the Groningen field, with June production at only 10% of production in winter months in 2004 (see figure 4.2). In this way, small fields can produce at a roughly constant rate, although small-fields production does show some flexibility. The surplus of (mainly high-calorific) gas in the summer is converted into low-calorific gas in order to serve to low-calorific market while Groningen output is reduced in this period.

Figure 4.2 Groningen production 2004 by month, in million cubic metres



Source: EZ (2004)

In order to determine the impact of the cap on this balancing function of Groningen, we need to answer two questions. Firstly, what is the relationship between the cap and the swing in Groningen production and, hence, the accommodation of small-fields volumes? Secondly, will the operator of Groningen, in its production decisions, take into account the value of future provision of balancing services?

Relationship between cap and swing

As noted, we observe today that, in the presence of the cap, the Groningen field produces at an enormous swing. This is consistent with optimal behaviour by the producer. Profit optimisation implies that in those periods of the year where production is not at its (technical) maximum level, production will be chosen such that prices are equalised[44]. Since the residual demand for Groningen gas at constant prices fluctuates in time with the demand for gas (in particular since most other sources of gas are relatively inflexible), total Groningen output shows its typical swing when production is not at the technical maximum. In the days where production is maximal, prices exceed this level value, with the highest prices occurring on days where

[44] Under profit optimisation, this price level equals the marginal cost of production, plus the shadow price of the cap, plus the opportunity cost of gas associated to the finiteness of the reserves in the field. See appendix A for a formal analysis of this mechanism.

residual demand for Groningen is at its highest (i.e. peak winter days). Prices under these conditions are set by peak sources of gas (such as LNG or other short-term storage, or demand response). In (investment) equilibrium, the average price in excess of the level price during most of the year would equal (annualised) marginal long-run investment costs for the field.

What changes occur in this picture when the cap is lifted? In those periods where production is not at its maximum, profit maximisation will still lead to level prices, which may be at a slightly lower level as a result of increased output. Over this period, output will be higher than with the cap, but will still equal residual demand, which fluctuates with total demand as it did under the cap. Over the period that production is not at its maximum, the swing in Groningen production will therefore remain the same as under the cap regime, but at a higher output level.

Obviously, if total maximum technical capacity remains unchanged, this would lead to a smaller swing in terms of difference between lowest (summer) and highest (winter) output level. In the extreme case, a sufficient increase in production without an increase in the maximum production capacity would result in the seasonal ‘troughs’ in production being filled up, tending to a more constant overall production level. However, this situation would not be an investment equilibrium.

In investment equilibrium, average price in excess of the (off-peak) level price should equal marginal investment cost. Since the level off-peak price would be expected to drop (slightly) as a result of increased output, and since prices in the highest price hours continue to be set by the marginal costs of alternative technologies (which do not change), we must have that total equilibrium capacity will be higher. Without the cap, a profit maximising firm increases investment, i.e. will sooner invest in capacity upgrade than without the cap, to achieve a higher average maximum output capacity.

As maximum capacity of Groningen increases, the field will produce at its maximum during a shorter period over the year. As a result, alternative technologies will be called upon on fewer occasions. Initially, therefore, the highest marginal cost sources of gas (presumably demand response) will be crowded out. In the longer term however, since this will lead to lower peak prices, peak production facilities will not recover their fixed costs. The new investment equilibrium therefore involves reduced investment in the highest fixed cost peak-technologies.

We conclude that removal of the cap leads to higher investment in Groningen capacity, with higher resulting annual swing. The other way round, imposing a cap affects the level of swing offered, but does not fundamentally change the role of Groningen as a balancing field.

Future balancing

Another impact of the cap might be that it lengthens the period of swing supply. After all, due to its depletion, Groningen's capability to offer swing is declining. Although full depletion of Groningen will take several decades, the capability to serve as a (major) swing supplier ceases much earlier. The ability to act as a swing supplier depends on several geological characteristics of the field, among which the pressure. It is a law of physics that pressure within a field decreases as the quantity of gas diminishes. The ability to supply swing depends partly on the difference between the pressure in a field and the pressure in the transport network.[45] This relationship between depletion and pressure implies that the swing capability decreases gradually. When the pressure in the Groningen field approaches the pressure of the transport network, the swing capability will become negligible, unless additional investments in compression are made such as the recently started Groningen Long-Term Project.[46] Another measure to manage the swing capability of the Groningen field is reducing the production, i.e. conservation.

The central question we have to address here is whether private decisions of the operator of the Groningen field take into account the future value of the balancing function. If not, there would be merit in the argument that the speed of depletion would be inefficiently high and production should be capped for this reason.

The value of (future) balancing services may be expected to be captured by the provider of these services when offered on the market. Balancing gas will be supplied into the system as a response to temporary shortages, reflected in price rises on the short-term market. The value of being able to supply under these conditions can be interpreted as an option value, where the supplier sells whenever prices rise above a certain value, as discussed in De Joode and Mulder (2004).

In its depletion policy, the operator of the field has an incentive to take into account the effect on the field's option value, provided prices in the market are allowed to be set freely reflecting temporary scarcity conditions. Failure of the short-term markets to adequately represent scarcity will affect decisions on depletion. This issue is discussed in the next chapter on security of supply. The solution to such problems, if they would occur, would lie primarily in repairing potential errors in design of the market.

Another possibility would be that the field's operator cannot capture the option value because his remuneration is not market conformal. Such a situation could occur if the operator would be

[45] "If the pressure in the Groningen field becomes smaller than the pressure in the pipeline system, pouring gas in a 'natural way' (i.e. without instalment of compression units) through the system becomes impossible" (Peeters, et al., 2002, p. 38).
[46] "Through this latest program of compression installation, Groningen, which is already the heart of the Dutch circulation system for primary energy, will be given a new lease of life."(Roels, 1999).

required to provide flexibility services at too low a charge, for instance because the price paid for accommodating small-field gas would be under the full market value of such services. In this situation small-field operators would effectively be subsidised by acquiring flexibility services at too low a cost. It is not clear whether this is the case (see chapter 3).

Internalisation of the problem of accommodating high-load factor gas from small fields is even more direct (and does not rely on a market price mechanism) for the production directly contracted by Gasunie Trade & Supply, which comprises most of that production (due to the offtake guarantee currently). In that case, Gasunie Trade & Supply itself has to make the commercial decision whether or not to use Groningen flexibility to accommodate those volumes in summer months, or to use other means of flexibility (such as exporting the gas).

Another option for internalising the flexibility value of the Groningen field is organising a tender as suggested by The General Energy Council (AER, 2005). In that way the true value of such flexibility would become more clearly apparent. In this respect it may be remarked that the Council regards the market for flexibility to be sufficiently competitive, given the abundance of storage facilities in the immediate vicinity of the Netherlands.

Concluding on this issue, if the owner of the Groningen field is able to capture the benefits of its flexibility capabilities, efficient decisions will be taken regarding the use of this field in balancing offshore gas production. Hence, imposing a cap does not generate additional benefits in the market for flexibility.

4.5 Benefits for security of supply

4.5.1 Introduction

Concerns about security of supply are often seen as a major reason for government involvement in energy markets. Although evidence is scarce about markets failing to internalise risks of disturbance, a few markets failures may exist.[47] Imperfect designs of markets and uncertainty about government policies in case of disturbances might result in non-optimal decisions, such as insufficient investments in flexibility and too high levels of consumption. A factor affecting profitability of investments in flexibility is private parties' assessments of low-probability-high-impact events and their valuation of credit risk. In the case of large-impact events, the resulting financial transfers may be large and firms may prefer defaulting on their obligations in stead of guaranteeing full security of supply. In section 4.5.2, we analyse whether capping Groningen might be viewed as an efficient response to such imperfection.

[47] See also Mulder et al., 2006, for a more extensive analysis of market responses to security-of-supply risks.

In addition, markets may not fully internalise the impact of energy use on political vulnerability owing to increased dependence on a limited number of exporting countries. Conserving the Groningen field might be an efficient measure to compensate for this market failure. In case of tight market conditions resulting from, for instance, a supply disruption or an extremely high demand caused by a severely cold winter, Groningen gas will be available for the Netherlands to prevent expensive imports. In that case, a crisis on the gas market merely results in distribution effects, i.e. from consumers to the owner of the Groningen field. Providing future countervailing power is an additional argument for conserving gas. The argument for countervailing power concerns the possibility of market power from external suppliers in the future (e.g. a future GASPEC). Section 4.5.3 analyses the efficiency of both uses of Groningen.

4.5.2 Benefits for reliability of gas supply

The flexibility of the Groningen field enables it to act as a short term back-up to make up for potential temporary supply or demand fluctuations. Imposing a cap on this field could extend this flexibility to a longer period of time.[48] As a result of such immediately available additional supplies from the Groningen field, in periods of sudden disruptions, either price fluctuations are dampened, or forced disconnections are avoided, or both. The extension of the period during which Groningen performs this back-up function implies that investment in alternative back-up functions to meet short-run supply problems, e.g. additional short-term storage, can be delayed. Hence, the benefit of this measure consists of postponement of the investments in these alternatives.

First, we have to analyse the impact of the presence of a back-up facility like Groningen on the behaviour of other market operators. Private investors in e.g. storage capacity or disconnection contracts with industry rely on periods of high prices for obtaining remuneration for their investments.[49] If, in periods of high gas prices, additional Groningen gas is injected into the market to keep prices within bounds, the attractiveness of such alternative investments will decrease, and the level of peak flexibility supplied by the market will be lower. This effect is known as *crowding out*. As a result of the ensuing drop in private investment, the necessity of the back-up would turn into a self-fulfilling prophecy.

The effectiveness of the back-up facility by Groningen gas, therefore, depends on the conditions under which the facility is used. If Groningen is already used at minor price rises, the crowding out effect will be larger, and the net additional flexibility will be lower, while if the back-up gas is only used under extreme events, the effect on other parties' investments is low. A similar problem was analysed in Lijesen and Zwart (2005), for the case of the Dutch electricity

[48] Note that this back-up function is restricted to the period in which Groningen is not producing at maximum capacity, which is the case typically in December and January.

[49] For example, an electricity producer investing in technology to switch fuels in case of high gas prices will only do so if gas prices can rise sufficiently to make this switching capacity sufficiently valuable.

market.[50] Like the case of the electricity market, we now suppose that the back-up facility provided by the Groningen field is only used in emergency situations to avoid forced disconnection of consumers. In this case, provided prices are set to high levels in these circumstances, the effect on market based investments, i.e. the crowding-out, is low.

In order to determine the effectiveness of capping Groningen on reliability of supply, we first define the type of crisis the back-up facility should be expected to ward off (see also De Joode et al., 2004). Then we analyse the benefits that may be derived from the policy measure of capping the Groningen field. In the analysis, we neglect the fact that during a limited period of the year additional capacity from Groningen would not be available because the field would be operating at maximum output already.

The crisis that is addressed could occur as a consequence of extreme demand conditions, or severe disruptions of supply to the Netherlands. Prices may be expected to rise under these conditions, firstly provoking maximum output from existing suppliers and storage to meet demand, and potential interruption of gas demand by large industry or power companies (switching to other fuels). However, for sufficiently severe crises, the system operator might have to revert to (involuntary) emergency interruption of parts of the grid, to balance the system. We define the crisis as an instance in which during 1 day a shortage of 20 million cubic metres per day can only be resolved by cutting off such smaller consumers. This quantity corresponds to around 10% of average January daily demand.[51]

The benefits from being able to avert this crisis by making up the shortage through increased Groningen production can be expressed as the costs of the cheapest alternative option. One alternative is in fact cutting off these consumers, where the cost (damage) would equal the value of lost load for these consumers. In this case, one has to take into account that additional damage would arise during the prolonged time, maybe several days, required to reconnect the consumers. An alternative, which we explore here, is investing in (additional) back-up storage to be used only in these emergencies.

Back-up storage as a safety net to be used only in case of imminent disconnection of small consumers can be provided only by storage facilities having a sufficiently high short-term send-

[50] In 2004, the Dutch Ministry of Economic Affairs decided that the system operator should contract for reserves to form a ‘safety net’, to mitigate possible negative effects in case of insufficient investments. The design of the instrument was chosen to have minimal impact on normal market functioning, in order to avoid distortion of the electricity market. The contracted capacity will only be employed as a last resort before forced disconnections of consumers, allowing market prices to rise freely to remunerate private investment in peak capacity.

[51] Note that such a crisis might only occur if flexibility offered by the private parties is unable to deal with the extreme market conditions. Hence, such a crisis can be viewed to have a low probability. An additional LNG-storage of 20 bcm can therefore be viewed as a pretty high level of security. However, as the costs of this facility are relatively low, the precise definition of the crisis does not affect our final conclusions.

out capacity. Natural options are LNG storage capacity (which GTS at present in fact uses for balancing the system under extreme circumstances) or storage in salt caverns. Compared to storage in e.g. depleted gas fields, these options have significantly lower costs as a function of send-out capacity.[52]

For providing short-term (one-day) back-up to avoid disconnection, LNG storage is most appropriate. Using an estimated range of annualised capital costs for such facilities of around 1.1 Euro per m^3/day deliverability at a discount rate of 5% (and slightly higher and lower at 7% and 3%, respectively), the annualised costs of providing back-up for the required one-day crisis amounts to a capital cost of circa 22 million Euro per year.

We assume that the investment in these alternative flexibility options occurs after the Groningen field's depletion has progressed so far that it cannot anymore provide the required flexibility. The exact moment is hard to predict; as in de Joode et al (2004) we assume this to occur when Groningen reserves have dropped to 400 bcm. The benefit of capping Groningen is to push this moment further into the future, by several years, depending on the scenario. In these years, one avoids the annualised costs of the back-up storage facility. The present value of the benefit therefore depends on the number of years the investment is postponed, as well as on the moment when the storage is to be built (because of discounting). We assume a time-to-build of five years.

Calculating the first-order effects, as we did in table 4.1, we compute the benefits as a function of the excess of Groningen production above the cap (see table 4.7). As an example, if the annual production without the cap would equal 50 bcm (the third column), while with the cap annual production equals 42.5 bcm, then with the cap the critical level for flexibility will be reached only after 17 years, while under annual production of 50 bcm this would occur in year 14. The back-up facility has to bridge the three years, and as a result of the five-year lead time, average costs for this facility would be incurred as of year nine. Using a 5% discount rate, the benefits amount to 43 million euro in this example.

Table 4.7 First-order calculation of benefits of postponing costs of back-up, using different assumptions about level of Groningen production (million euro; discount rate = 5%)

Groningen production level without cap (bcm)	45	50	55	60
Year when investment needed	16	14	13	12
Number of years to be bridged	1	3	4	5
Benefits	13	43	60	78

[52] Information on capital costs for such facilities is presented in Bos et al. (2003) (for caverns), as well as in CIEP (2005) (also for LNG).

Strictly speaking we should have included the costs of buying the gas and injecting it into the storage after it has been (partially) depleted in an emergency. On the other hand, there will be revenues when the storage is used, as the gas is then sold to shippers incurring the imbalance causing the system emergency. As in such emergency cases, prices will have increased to high levels, we may assume that these revenues should (more than) compensate the commodity costs.

We can also relate the results to the scenarios, by determining per scenario the year when Groningen volume drops below 400 bcm, both with and without the cap (and carrying out the computation as above). This gives the number of years that the investment in LNG storage would be postponed by implementing the cap.

Table 4.8 Benefits of postponing costs of back-up (million Euro), per scenario and different discount rates

Scenario	Baseline	Competition	Sellers' market	High prices
Discount rate = 3%	0	5	0	0
Discount rate = 5%	12	34	0	10
Discount rate = 7%	19	37	0	22

Note that since the availability of Groningen would be lower than that of the storage facility (no availability during the highest demand periods), the above computations overstate the value of short-run reliability provided by Groningen. Hence, the benefits for reliability of supply of capping Groningen likely are below 100 million euro (see table 4.8).[53]

4.5.3 Benefits for security of gas supply

As Dutch gas reserves dwindle over the next decades, the Netherlands will turn into a net importer. In this situation, the economy will be increasingly vulnerable to gas price rises: whereas currently higher prices are compensated by rising revenues from gas production, higher future prices lead directly to payments to foreign suppliers. Higher prices or even price crises might be incidental, for instance as a result of future severe winters, technical supply disruptions, or geopolitical conflicts. Gas prices might also structurally bye high, e.g. as a consequence of increased market power of a potential future gas cartel. In this section, we analyse consecutively capping Groningen as a means to provide 'strategic storage' to be used in times of incidental gas supply shortages, and, secondly, conserving the Groningen field to provide countervailing power against a future gas cartel.

[53] In De Joode et al (2004) a similar computation was done to evaluate the benefits of capping the Groningen field. Here comparison was made with the alternative of disconnecting customers in case of physical shortage. That analysis concluded that the (present value of the) benefit of preventing a physical shortage during 24 hours in the region The Hague - Rotterdam amounts to about 500 million euro.

Groningen and 'strategic storage'

If market failures lead market parties to be incompletely exposed to the risks of supply problems, they will invest too little to respond to low-probability supply problems. While solution of the market failure itself would be the optimal response to this situation, if this is deemed unfeasible, the government may step in to provide a backstop for risks of supply shortages and accompanying price crises, by releasing gas from strategic storages.

We here consider the case where Groningen is conserved in order to use its flexibility to mitigate future price effects of occasional severe winters or technical supply problems, instead of genuine strategic storage. By keeping prices lower in these circumstances, Dutch consumer welfare is increased. However, in analogy with our discussion on short-term reliability, one should recognise that by effectively capping prices, investments by others (such as builders of storage capacity, LNG import terminals) who rely on high prices to make their investment, are crowded out. Put differently, leaving the Groningen flexibility looming above the market to interfere when prices rise makes the investment climate for such parties less attractive.

Having said this, we can try to answer what the benefit would be of using Groningen to keep prices within reasonable bounds under periodic scarcity conditions. Similarly to our discussion on short-term reliability, a maximum bound on this benefit can be found by considering the cost of any other mechanism that would be capable of mitigating such periods of high prices. A natural candidate is having strategic storage capacity from which gas can be released in a price crisis. Some countries (in particular Italy) have invested in such strategic storage. As the costs of such a measure are viewed to be high (see IEA, 2004a), the maximum benefit of using Groningen to temporarily avoid investment in such facilities for price mitigating purposes can be significant.

We get an estimate for the maximum benefits of conserving the Groningen field by comparing it with the costs of installing strategic storage capacity. We assume that such strategic storage capacity would consist of storage of gas in depleted gas fields. As to the volume, we note that average monthly Groningen production was around 3 bcm below peak production in 2004. If we consider a price crisis of 3 months (in the oil markets, strategic reserves are required equal to 90 days' consumption), on average Groningen would be able to supply 9 bcm (assuming the cap to be dropped in such an emergency situation). To keep strategic storages available, these reserves have to be in place when the flexibility of the Groningen field are insufficient to produce this additional output, which we again assume to take place when the field's remaining reserves drop below 400 bcm.

An additional concern might be that not only is Groningen depleted sooner, but also spare capacity in Groningen is lower in the absence of a cap. Higher production leads to a faster decrease in maximum capacity, and therefore potentially smaller room for output increase. In assessing this effect, one should incorporate the effects of new investment (e.g. in compressors) in capacity. As we explain in appendix A, one may assume that in equilibrium, a profit-maximising producer without a cap will invest sooner in expanding capacity, to reach, on average, a higher production capacity than a capped producer (see also the discussion in section 4.5.2). Whether average spare capacity over the year increases depends on the question whether the period in which production is at its maximum level decreases. This would happen in the presence of constant returns to scale, while with decreasing returns to scale, the effect is ambiguous. With the relatively small changes in production in our scenarios, the effect in any case is not large.

Based on data from ILEX (2005) on storage costs, we estimate the total annual costs for providing storage in depleted fields at 0.05-0.07 Eur/m3/y for the various discount rate assumptions.[54] The effect of capping Groningen is to postpone the moment when such strategic capacity is necessary to replace the flexibility of Groningen. The timing of this moment again depends on the scenario. The computation is essentially similar to the calculation for short-term storage.

Table 4.9 Maximum benefit of cap for strategic reserves per scenario and discount rate (million Euro)

Discount rate	Baseline	Competitive	Sellers' market	High prices
3%	0	100	0	0
5%	200	500	0	100
7%	500	900	0	500

We see that indeed keeping strategic storage is costly, implying that using Groningen instead of storage entails large benefits (table 4.9). As other measures to deal with security of supply might be more efficient, such as demand responses, these calculations overestimate the benefits of Groningen in the field of security of supply. Moreover, the benefit estimates are biased upwards, potentially significantly so, as we ignore the crowding out effect, i.e. governments investments in flexibility, by capping Groningen or investing in storage, might reduce private investments in flexibility.

Groningen and a foreign gas cartel

Now, we analyse whether capping Groningen is an efficient measure to deal with a foreign gas cartel structurally raising the future price of gas. The value of being able to produce gas in times of future cartel prices comes potentially from two sources. First, sales of gas in this situation create more revenues (or from an aggregate national perspective, decrease net spending on gas procurement). Second, release of gas may mitigate external market power, decreasing overall

[54] The major costs of storage consist of capital costs of storing the cushion gas.

gas prices and thereby increasing national welfare.[55] The first effect is internalised by the profit-maximising producer. The second source of benefit, reducing gas prices by strategic release of gas, will not be taken into account by individually rational investors, as these benefits accrue to (Dutch) consumers, and are external to the producer. The benefits of this source may therefore warrant policy measures. By retaining some production capacity for the importing phase, strategic release of gas can put downward pressure on prices, and hence increase Dutch welfare. One should of course recognise that part of this welfare effect will migrate across the borders, as demand for Dutch gas from neighbouring countries will also increase.

Let us now analyse the welfare effects of a cap on Groningen in the case of future prices which are structurally above current levels, as a result of for instance increasing market power of foreign producers. In sections 4.2 and 4.3, we analysed the welfare effects of imposing a cap in the High-price scenario were gas prices are high because of high LNG prices and the exercise of market power by non-EU suppliers, for instance by a global gas cartel reducing global production of gas. Although the Groningen producer takes into consideration the possibility of saving gas at present, in order to benefit from the increased price in the future, the net impact is that the operator advances production, compared to the baseline scenario (see figure 2.6). Tables 4.3 and 4.4 have shown that imposing a cap in the High-prices scenario reduces welfare, implying that the negative effect of a cap in early years was not compensated by positive effects on consumer welfare in the further future: welfare drops by 0.3 (5%) and 1.9 (7%) billion euro as a result of the cap. Hence, imposing a cap is not an efficient measure to deal with the risk of high prices in the future.

One may wonder whether other actions than a cap might be more appropriate for providing countervailing power to future cartel behaviour. An option might be increasing production above the profit-maximising level of an industry with market power, as these producers typically reduce the rate of extraction of the resource compared to the social optimum, thus harming consumer surplus.[56] In the final chapter we will explore the efficiency of such a policy.

[55] In order to have this benefit, it is required, of course, that the level of Groningen production has an impact on (Dutch) prices. It is conceivable that the level of Groningen production can impact prices, in particular on the low-cal gas market. Groningen's market share on the low-cal gas market amounts to around 40%. DTe (2005) recently concluded that the operator of this field possesses market power in the market for short-term flexibility. Whether Groningen can also appreciably affect high-cal gas prices (for which the market appears bigger) is not so evident.

[56] See Mulder et al. (2006) for a note on the relationship between degree of competition and optimal depletion paths.

5 Conclusions

5.1 Introduction

This chapter summarises our conclusion on the welfare effects of the Dutch gas-depletion policy. First, we present the conclusion for the offtake guarantee (section 5.2), then we go into the welfare effects of the cap on Groningen (section 5.3). In the last section, we discuss an alternative policy regarding the Groningen field.

5.2 Welfare effects of the offtake guarantee

The offtake guarantee generates a number of welfare effects. On the one hand, it might reduce efficiency of production and hinder the development of liquid wholesale market, while, on the other hand, it might be an efficient way of pooling as well as a source for market power. Although it is impossible to determine the magnitude of these effects, the above analysis enables us to assess their significance.

- The guaranteed offtake likely gives operators reduced incentives to respond optimally to short-run changes in market conditions compared to a competitive market. Although the offtake contracts include conditions for daily flexibility, these do not necessarily result in optimal responses by operators. In addition, the market prices given by Gasunie Trade & Supply might be distortive resulting in inefficient production. However, the costs of these inefficient (domestic) production might be compensated by a benefit of reduced dependence on imports.

- Although the offtake guarantee theoretically could hinder the development of a liquid wholesale gas market, the actual development of the Dutch TTF does not as yet indicate any important barriers suggesting that the offtake guarantee is not currently restricting this market.

- The main alleged benefits of the offtake guarantee - efficient pooling - can likely also be realised by a liquid market as the British experience shows. In the Dutch gas market, which is not well developed yet, transaction costs of pooling may be relatively higher initially. These initially higher transaction costs in case of market pooling can be seen as transition costs from replacing the coordinated mechanism by a market mechanism. Whether these transition costs would be compensated by lower levels of transaction costs in the future is difficult to determine in advance. The Dutch experience in electricity production shows, however, that a transition from a centrally coordinated mechanism to a market mechanism is not necessarily difficult to realise.

The benefits of centralised pooling to achieve coordination on quality of gas seem also to be modest. As coordination to achieve satisfactory gas quality relates to each individual group of users of a pipeline (the mixture of gases should be within system quality bounds to allow entry into the transmission system), it seems more appropriate to arrange for such coordination through the contracts with the transporting company, rather than through centralised pooling.

- Another direct benefit follows from the offtake guarantee if it gives Gasunie Trade & Supply power to charge higher export prices. The net effects of exercising such market power on Dutch welfare appear to be negative in our scenarios.

Concluding, given the current degree of liquidity of the gas market, the system of coordinated pooling might be efficient. This advantage of the offtake guarantee vanishes, however, when the market becomes well developed.

5.3 Welfare effects of the cap on Groningen

The welfare effects of a cap on Groningen depend on the extent it restricts production from this field and the resulting changes in the European gas market. In our Baseline scenario, the cap has a modest effect on actual production: about 0.8 bcm annually. In the Competition scenario, the effect on annual production is much higher: about 2.5 bcm. In this scenario, the high level of competition on the European market reduce the options for strategic behaviour resulting in additional production. In the High-prices scenario, benefiting from the current high prices appear to be more profitable than waiting for the future higher prices. When the gas market is characterised by low competition, i.e. the Sellers' market scenario, the cap is above the profit-maximising level of production and, as a result, is not effective. The different impacts of the cap on production volumes implies that the cost and benefits also differ between the scenarios.

- The total costs of the cap on Groningen range from zero in the Sellers-market scenario to 975 million euro in the Competition scenario (see table 5.1).

- Benefits of the cap for small-fields production only appear in the Competition scenario as only in this scenario production from these fields is affected by the cap. The (present value of the) additional producer surplus for small-fields production in this scenario amounts to 145 million euro In the other scenarios, small-fields production is restricted by the capacity of infrastructure while the gas prices are too low for making infrastructure extension profitable. In addition, this infrastructure is fully utilised in the other scenarios as the small-fields have relatively low marginal costs making them inframarginal suppliers to the European gas market.

Table 5.1 Welfare effects of a cap (of 42.5 bcm) on Groningen, in four scenarios (in million euro; discount rate is 5%)

	Baseline	Competition	Sellers' market	High prices
Costs	500	975	0	280
Benefits				
Additional producer surplus small fields	35	145	0	35
Extension of balancing function	.	.	.	.
Reliability of supply	< 10	< 20	0	< 10
Security of supply	< 200	< 500	0	< 100
Net effect	< – 255	< – 310	0	< – 135

- Imposing a cap on Groningen does not generate additional benefits for small-fields through an extension of its balancing function as the owner of this field is able to capture the benefits of its flexibility capabilities. As a result, the owner will make efficient decisions regarding the use of Groningen in balancing offshore gas production.

- Capping Groningen might have a benefit for reliability of supply, provided this measure does not crowd out private investments in alternative flexibility options. The benefits of this measure consist of postponing reliability investments which have to be taken when Groningen is not able anymore to deliver the required flexibility. In the Competition scenario, this benefits are estimated at about 20 million euro. The other scenarios show lower values.

- Another benefit of capping Groningen in the field of security of supply is its value as strategic storage to be used during periods of temporarily extreme shortages in the market caused by economic, technical or political circumstances. Also here, the benefits consists of postponing investments in alternative investments in strategic storage. In the Competition scenario, these benefits amount to 500 million euro while the other scenarios produce lower values of this benefit.

- A final benefit of capping Groningen might be its role in damping the costs, i.e. high prices, caused by a foreign gas cartel. Imposing a cap in the High-price scenario shows that the net effect for consumers is negative, implying that the benefits of additional production later or not enough to compensate for the loss of production in the near term. Consequently, using Groningen to mitigate the effects of foreign gas cartel does not produce net benefits.

The net welfare effect of capping Groningen on annually 42.5 bcm ranges from zero (in the Sellers market scenario) to – 310 million euro (in the Competition scenario).

Table 5.2 Welfare effects of a cap (of 42.5 bcm) on Groningen, in four scenarios (in million euro; discount rate is 3%)

	Baseline	Competition	Sellers' market	High prices
Costs	0	170	0	0
Benefits				
Additional producer surplus small fields	0	15	0	0
Extension of balancing function	.	.	.	.
Reliability of supply	0	< 5	0	0
Security of supply	0	< 100	0	0
Net effect	0	< – 50	0	0

Table 5.3 Welfare effects of a cap (of 42.5 bcm) on Groningen, in four scenarios (in million euro; discount rate is 7%)

	Baseline	Competition	Sellers' market	High prices
Costs	1525	2655	0	1975
Benefits				
Additional producer surplus small fields	305	330	0	345
Extension of balancing function	.	.	.	.
Reliability of supply	< 19	< 37	0	< 22
Security of supply	< 500	< 900	0	< 500
Net effect	< – 700	< – 1390	0	< – 1110

- Different assumptions of the discount rate (3 and 7%) have significant effects on both costs and benefits, but do not change the conclusion that the net-welfare effect is negative if the cap is binding (see tables 5.2 and 5.3).

- The conclusion on the efficiency of the cap on Groningen is also not affected by other assumptions about LNG-price, the availability of infrastructure on the Netherlands Continental Shelf and the level of tax distortions (see Appendix C).

5.4 Alternative policy for the exploitation of Groningen

In our analysis of the cap on Groningen, we saw that a private operator of this field does not take into account externalities on (Dutch) consumers which asks for the analysis of an alternative policy regarding Groningen. An alternative policy regarding the Groningen field, in stead of a cap on the annual level of production, is changing the goal of production. In the above analysis, the owner of Groningen is supposed to maximise profit. Because of the market power of the Groningen field, this production goal generate results different from the welfare maximising strategy.

Suppose the owner of the Groningen field wants to maximise Dutch welfare, which production profile results? Inclusion of total Dutch welfare gives an incentive on the Groningen producer to lower Dutch prices. Effectively this means that the Groningen producer has an incentive to increase production (so as to lower Dutch prices) in all periods. However, since total Groningen resources are fixed, a trade-off will occur between expanding output in the first periods, and raising immediate consumer welfare gains, and saving gas to produce in later periods, when the effects of foreign suppliers' market power is greater and prices are higher.

We find that including consumer welfare in Groningen's deployment decision substantially raises production in the first periods. This holds in particular for the Sellers' market scenario, where the inclusion of consumers welfare in the object function on Groningen raises average annual production by 3.9 bcm (see table 5.4).[57] The discounted value of the net benefit in this scenario is 4.2 billion euro.

This result is essentially the effect of market power of Groningen production: individual profit-maximisation leads to lower production levels and higher prices than when the negative effect on consumer welfare is taken into account.

Table 5.4 Effect of internalising Dutch consumer welfare in the object function of Groningen, in four scenarios (in million euro; discount rate = 5%)

	Baseline	Competition	Sellers' market	High prices
Change in average annual production during first 20 years (in bcm)	1.2	0.5	3.9	1.1
Welfare effects				
Producer surplus Groningen	1700	1300	1700	0
Producer surplus small fields	– 300	– 100	– 1200	– 400
Surplus Dutch low-quality consumers	2100	1300	3700	3000
Surplus Dutch high-quality consumers	200	0	600	100
Reliability of supply	< – 12	< – 10	< – 25	< – 12
Security of supply	< – 300	< – 250	< – 600	< – 300
Net effect	> 3390	> 2240	> 4175	> 2390

[57] Inclusion of Dutch consumer welfare is implemented by including the costs of buying gas for Dutch consumers in the optimisation for Groningen production.

From this follows that raising production of Groningen above profit-maximising levels generates more welfare than removing the cap. This conclusion holds, of course, for the current structure of the European gas market. If this gas market is more competitive, the production profile of the private owner of this field deviates less from the welfare-maximising profile. Note, however, that implementing a ‘floor’ in production from the Groningen field creates the risk of setting the floor at a too high level from welfare-economic point of view.

A more efficient way for taking the level of Groningen production more close to the socially optimal level is improving competition. After all, the above results imply that improving competition on the European gas market increases Dutch welfare: the loss of producer surplus due to lower gas prices is largely compensated by higher profits from advanced Groningen production plus increased consumer surplus for Dutch consumers. Small-fields producers would, however, face lower profits because of the reduced price of gas.

References

Adelman, M.A., M.C. Lynch, 2002, Natural Gas Supply to 2100, International Gas Union.

Algemene Energieraad (AER), 2005, Gas voor morgen, The Hague.

Allaz B. and J.-L. Vila, 1993, Cournot competition, forward markets and efficiency, *Journal of Econ. Theory* ,59, pp.1-16.

Algemene Rekenkamer (AR), 1999, Aardgasbaten, The Hague.

Asche, F., P. Osmundsen and R. Tveteras, 2000, European market integration for gas? Volume flexibility and political risk, CESifo Working Paper Series no. 358, Munich, November.

Bollen, J., T. Manders and M. Mulder, 2004, *Four Futures for Energy Markets and Climate Change*, CPB/RIVM, Special Publication 52, April.

Bos, C.F.M. and J.N. Breunese, 2003, Gas data input to CPB's NATGAS model, Netherlands Institute of Applied Geoscience TNO, TNO-report NITG 03-044-B, Utrecht.

Burda, M., 1995, Migration and the option value of waiting, CEPR Discussion Paper 1229.

Bushnell, J., E. T. Mansur, C. Saravia, 2005, Vertical Arrangements, Market Structure, and Competition: An Analysis of Restructured U.S. Electricity Markets, CSEM WP 126, February 2005.

Bushnell, J. and C. Wolfram, 2005, Ownership Change, Incentives and Plant Efficiency: The Divestiture of U.S. Electric Generation Plants, CSEM WP 140.

Chaton, C. and J.A. Doucet, 1999, Uncertainty and investment in electricity generation: the case of Hydro-Quebec, University of Laval, Working Paper 9914.

Clingendael (CIEP), 2005, The European Market for Seasonal Gas Storage, CIEP Discussion paper, August 2005.

Conrad, J.M., 1999, Resource Economics, Cambridge University Press, Cambridge, UK.

Correlje, A.F., P.R. Odell, 2000, Four decades of Groningen production and pricing policies and a view to the future, Energy Policy 28, pp. 19-27.

Creti, A., B. Villeneuve, 2003, Long-term contracts and take-or-pay clauses in natural gas markets, University of Toulouse working paper.

Damme, E. van, 2005, Liberalising the Dutch electricity market 1998-2004, Energy Journal, Special Issue 2005.

DTe, 2005, Onderzoek groothandelsmarkt gas, March 2005.

DTI, 2002, DTI response to consultation on gas issues, URN 02/1306.
Economides, N. and A. Siow, 1988, The division of markets is limited by the extent of liquidity, The American Economic Review 78(1), pp 108-121.

EIA, 2003, Caspian Sea Region; Environmental Issues, February.

Eijgenraam et al., 2000, *Evaluatie van infrastructuurprojecten, Leidraad voor kostenbatenanalyse,* SDU-uitgevers, Den Haag.

Emery, J.C.H. and K.J. McKenzie, 1996, Damned if you do, Damned if you don't: an option value approach to evaluating the subsidy of the CPR Mainline, *Canadian Journal of Economics*, Vol. 29, pp. 255-270.

European Commission, 2003, World Energy, Technology and Climate Policy Outlook 2030 - WETO, EUR 20366.

European Commission, 2005, Energy-Sector Inquiry, Issues Paper, November 2005.

Ewijk, C. van, P. Tang, 2003, How to price the risk of public investment?, *De Economist,* no. 151, pp. 317-328.

Gasunie, Jaarverslag 2004.

Global Insight, 2005, Ensuring Effective and Efficient Forward Gas Markets, A Report to the DTI.

Green, R., 1999, The electricity contract market in England and Wales, Journal of Industrial Economics, 47, pp.107-124.

ILEX Energy Consulting, 2004, Gas Prices in the UK, Report to UKOOA, October 2004.

ILEX Energy Consulting, 2005, Storage, gas prices and security of supply, October 2005.

International Energy Agency (IEA), 1995, The IEA Natural Gas Security Study, Paris.

International Energy Agency (IEA), 2002, Flexibility in natural gas supply and demand, Paris.

International Energy Agency (IEA), 2004, Energy Policies of IEA Countries: the Netherlands, 2004 review, Paris.

International Energy Agency (IEA), 2004a, World Energy Outlook 2004, Paris.

International Energy Agency (IEA), 2005, Natural gas information 2004, Paris.

Joode, J. de, D. Kingma, M. Lijesen, M. Mulder and V. Shestalova, 2004, *Energy policies and risks on energy markets; a cost-benefit analysis*, CPB, The Hague, Special Publication 51.

Lijesen, M. and G.T.J. Zwart, 2005, Op zoek naar een onzichtbaar vangnet; hoe geven we de publieke rol in leveringszekerheid vorm zonder de markt te verstoren?, CPB, The Hague, CPB-Document 89.

Mahenc, P and F. Salanie, 2004, Softening competition through forward trading, *Journal of Econ. Theory* , 116, pp. 282-293.

Markiewicz, K., N. Rose and C. Wolfram, 2004, Does Competition Reduce Costs? Assessing the Impact of Regulatory Restructuring on U.S. Electric Generation Efficiency, NBER Working Paper Number 11001.

Ministry of Economic Affairs (EZ), 1976, Energienota, Tweede Kamer der Staten-Generaal, 1974-1975, 13 122, nrs. 1-2.

Ministry of Economic Affairs (EZ), 1979, Energiebeleid, Tweede Kamer der Staten-Generaal, 1979-1980, 15 802, nrs. 1-2.

Ministry of Economic Affairs (EZ), 1984, Actualisering Energiebeleid, Tweede Kamer der Staten-Generaal, 1983-1984, 18 100, nr. 2.

Ministry of Economic Affairs (EZ), 1996, Third White Paper on Energy Policy, The Hague, February.

Ministry of Economic Affairs (EZ), 2004, Gas production in the Netherlands; importance and policy, Publication code 04ME18.

Ministry of Economic Affairs (EZ), 2004a, Voorzienings- en leveringszekerheid energie, Tweede Kamer der Staten Generaal, 2004-2005, 29 023, nr. 6, 12 oktober.

Ministry of Economic Affairs (EZ), 2005, Olie en gas in Nederland; Jaarverslag 2004 en prognose 2005 - 2014, Den Haag, juni.

Ministry of Economic Affairs (EZ), 2005a, Voorzienings- en leveringszekerheid energie, Tweede Kamer der Staten Generaal, 2005-2006, 29 023, nr. 21, 22 december.

Ministry of Finance, 2003, Risicowaardering bij publieke investeringsprojecten, Rapport van de Commissie Risicowaardering, The Hague.

Ministry of Petroleum and Energy/Norwegian Petroleum Directorate (MPE/NPD), 2005, The Norwegian Petroleum Sector, Facts 2005, March.

Mulder, M., A. ten Cate, A. Aouragh, J Gorter, 2004, Gas exploration and production at the Dutch Continental Shelf; an assessment of the ‘Depreciation at Will’, CPB, The Hague, CPB, Document 66.

Mulder, M. and J. de Joode, 2004, Costs and Benefits of Swing Supply of Gas: an Application for the Northwestern European Gas Market, paper presented at the 19th World Energy Congress & Exhibition, Sydney, Australia, 5-9 September.

Mulder, M. and G.T.J. Zwart, 2006, Market failures and government policies in gas markets, CPB, The Hague, CPB-Memorandum 143.

Newbery, D. M. 2000, Privatization, restructuring, and regulation of network utilities, Walras-Pareto Lectures, MIT Press.

Newbery D.N., E.E.C. van Damme and N-H. M. von der Fehr, 2003 , Liquidity in the Dutch Wholesale Electricity Market, report of the Market Surveillance Committee, DTe, May.

OECD, 2004, Economic Surveys: Netherlands.

OGP, 2003, Enlarged EU/EEA gas supply and the policy framework, report nr. 340, April.

OIES, 2006, Future natural gas demand in Europe; the importance of the power sector, Oxford Institute for Energy Studies, Oxford.

OME, 2004, Future natural gas supply options and supply costs for Europe.

Peebles, M., 1999, Dutch gas: its role in the Western European Gas Market, in: *Gas to Europe: the strategies of four major suppliers*, edited by Robert Mabro and Ian Wybrew-Bond, Oxford University Press.

Paddock, J.L., D.R. Siegel and J.L. Smith, 1988, Option valuation of claims on real assets: the case of offshore petroleum leases, *Quarterly Journal of Economics*, Vol. 109, pp. 479-508.

Reed, W.J., 1993, The decision to conserve or harvest old-growth forest, *Ecological Economics*, Vol. 8, pp. 45-69.

Roels, H.J.M., 1999, Groningen field: past, present and future, *Netherlands Journal of Geosciences*, 80(1), pp. 12-14.

Stam, M.A., 2003, Is energie van elastiek? De prijselasticiteit van de energievraag, CPB/UvA.

Seeliger, A., 2004, Die Europäische Erdgasversorgung im Wandel, EWI Working Paper Nr. 04-2, February 2004.

Stern, J. and A. Honoré, 2004, Large Scale Investments in Liberalised Gas Markets: The Case of UK, Oxford Institute of Energy Studies.

UKOOA, 2004, Submission by UK Offshore Operators Association, Trade and Industry Committee – Inquiry into Fuel Prices, November 2004.

Williamson, O.E., 1979, Transaction costs economics: The governance of contractual relations, Journal of Law and Economics, 22, 233-260.

Wilson, R., 2002, Architecture of power markets, *Econometrica*, 70(4), 1299-1340.

Zwart, G.T.J. and M. Mulder, 2006, NATGAS: a model of the European natural gas market, CPB, The Hague, CPB-Memorandum 144.

Appendix A Data used in NATGAS

In this appendix we give a summary of some of the relevant input data in the NATGAS model, used in the specification of the scenarios. We show data on available gas resources in the various producing regions, production capacities and costs, and current demand in Europe by region. More detailed data on other issues (such as storage capacity and LNG import capacities) can be found in Zwart and Mulder (2006).

Table A.1 Reserves and total remaining resources in production regions, in bcm

	Proven reserves	Discovered and undiscovered potential	Total
Norway and Denmark	2467	2852	5319
United Kingdom	905	645	1550
Groningen	1068	0	1068
Dutch small fields	381	366	747
Germany and Austria	367	420	787
Italy	182	215	397
Eastern Europe	358	614	972
Algeria	4500	1136	5636
Russia	32960	44736	77696

Sources: individual countries' government information, and OGP (2003)

Table A.2 Current production capacities available for Europe, and average cost ranges per region

	Capacity (bcm/y)	Average costs (euro/m^3)
Norway and Denmark	83	0.05 – 0.08
United Kingdom	110	0.05 – 0.09
Groningen	76	0.005 – 0.01
Dutch small fields	44	0.04 – 0.06
Germany and Austria	29	0.05 – 0.08
Italy	14	0.03 – 0.05
Eastern Europe	28	0.05 – 0.08
Algeria	85	0.02 – 0.03
Russia	140	0.10 – 0.15

Sources: IEA (2005), EZ (2005), data from TNO-NITG

Table A.3 Initial demand figures, in bcm per year

Belgium	15
Eastern Europe	80
France	44
Germany, Austria, Switzerland	106
Iberian peninsula	26
Italy	77
Netherlands	50
UK and Ireland	105

Source: IEA (2005)

Appendix B Profit maximisation of Groningen production

We analyse the implications of profit maximisation for the Groningen producer in more mathematical detail. To this end, first we introduce some notation. Groningen produces in a market that is also supplied by other sources (partly through quality conversion facilities). The residual demand faced by Groningen, i.e. final demand minus supply from other sources, is both dependent on time (e.g. residual demand is higher in winter than in summer), and on price, since supplies from other sources as well as to some extent demand are price elastic. We write $D(t, p)$ for residual demand for Groningen. It is convenient to order time from highest demand periods ($t = 0$), to lowest demand periods ($t = T$), so that $D(t, p)$ is decreasing in t (at constant price p, this is known as a load duration curve). In equilibrium, total Groningen output $q(t)$ at each time equals $D(t, p(t))$ (this is called market clearing). We can also invert $D(t, p)$, to obtain the price $P(t, q(t))$ at each time, given Groningen output $q(t)$.

The Groningen producer is assumed to optimise total profits, subject to various constraints. Firstly, total output over all Groningen life should not exceed total Groningen reserves of around 1100 bcm. Secondly, under the production cap, total production in the cap-period should not exceed the cap. Thirdly, on each moment t, output $q(t)$ cannot exceed technical capacity. Each constraint gives rise to a shadow price. We will call these σ, for the resource constraint, μ, for the production cap, and $\lambda(t)$, for technical maximum output. Over the cap-period, σ and μ are constant: if the constraints bind, they bind equally strongly anywhere over the period. The $\lambda(t)$ shadow price is not constant, since this constraint is time specific: output cannot exceed technical capacity at each time t separately. $\lambda(t)$ will equal zero for each t where output is below the maximum (i.e. the constraint does not bind).

In this notation, for each t the producer's optimal output $q(t)$ will satisfy

$$\frac{d\pi(t)}{dq} - \lambda - \mu - \sigma = 0\,,$$

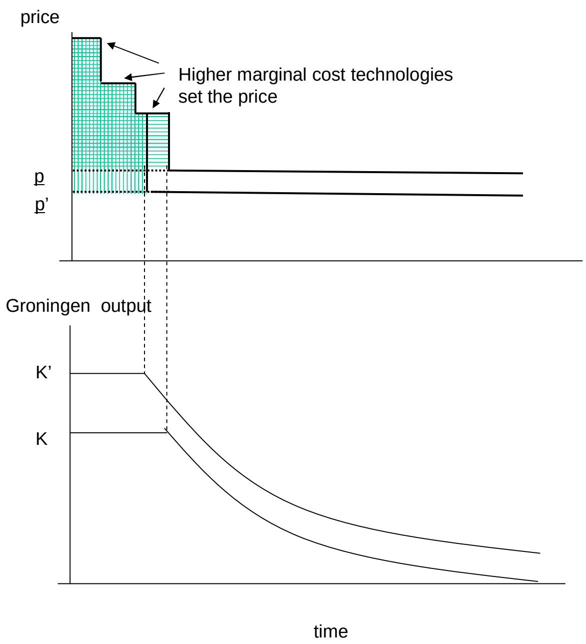
where $d\pi(t)/dq$ represents (short-term) marginal revenues minus (short-term) marginal production costs. If we assume competitive behaviour, this equals $p(t) - c$, while for a strategic firm, one would have

$$\frac{d\pi(t)}{dq} = p\left(1 - \frac{1}{\eta}\right) - c$$

where η is the elasticity of residual demand for the firm. Below, for convenience, we assume competitive behaviour.

From the equilibrium equation, we see that at all times when $q(t) < K$ (the technical capacity) and therefore $\lambda(t) = 0$, prices (or marginal short-term profits) are equal to $\underline{p}$, with $\underline{p} = c + \sigma + \mu$. Output under these conditions equals residual demand at this price, or $q(t) = D(t, \underline{p})$.
This means that output exhibits swing parallelling that of demand, i.e. low output in summer, high output in winter.
The situation is different when output equals capacity K. In those high demand periods, q is constant, but price changes as $p(t) = P(t, K)$.
This price in these high demand conditions will be set by the marginal costs of other sources of gas. Both price duration curve and Groningen production curve are depicted in figure A.1.

Figure A.1 Schematic price and Groningen output duration curves, with and without cap



We now analyse what happens as we lift the production cap. This will remove the constraint associated to μ, setting $\mu'=0$ (where primes denote the parameters without the cap). This is partially compensated by an increase in σ to $\sigma' > \sigma$, as an increase in production will make the resource constraint tighter. We still have that whenever output does not reach full capacity, K, prices are equal, $\underline{p}' = c + \sigma'$, and slightly lower than $\underline{p}$ as a result of increased output. Total output in these periods satisfies $q'(t) = D(t, \underline{p}')$, so that still q' swings with demand, though at a higher level. Since q' increases across the whole period, it will hit total capacity earlier, if we assume that K does not alter. This latter assumption, however, is not consistent with equilibrium. In investment equilibrium, we have that investment costs should be recovered exactly in those periods that the capacity limit is binding:

$$\int_0^T \lambda(t)dt = I$$

or

$$\int_0^T \left(p(t) - \underline{p}\right)dt = I$$

where I is marginal (annualised) investment cost. Since, when output equals capacity, prices are set by other technologies, prices in the highest demand periods remain unaltered. Since $\underline{p}' < \underline{p}$ this equilibrium condition will not be satisfied. Without the production cap, then, also maximum capacity levels will increase.

We in fact should expect d$P(t,K)$/dK = 0, at least for the peak demand periods where other sources of gas set the price. If marginal investment costs I are constant (constant returns to scale), in order to keep satisfying the investment equilibrium condition, with the lower $\underline{p}'$, K' should increase so that the duration of maximum output is actually reduced. This will have the effect of crowding out the highest fixed cost peak delivery sources. If I increases with capacity, the case is not as clear-cut and both higher and lower duration of maximum output are possible. It is conceivable that decreasing returns to scale will apply if additional investments are made to increase capacity further. On the other hand, in reality the increased capacity might be obtained *on average* by bringing forward in time planned investments. Indeed, if investments (in e.g. additional compressors or wells) are carried out more regularly over time, average available capacity will increase compared to the case when many such investments are postponed to be carried out simultaneously at a later date. In this case, decreasing returns to scale are less obvious.

In the non-capacity-constrained part of the year, gas production follows residual demand, and the difference between gas production at the summer trough level and the winter peak will consequently increase as the duration in which the cap is binding decreases. In particular,

$$K' - q(T) = D(\underline{p}', t') - D(\underline{p}', T) \ ,$$

meaning that the difference between summer and winter peak levels of production increases with decreasing t' , the duration of capacity constrained production. As it is likely that residual demand's variation with t does not change significantly with the (small) change in $\underline{p}'$ (i.e. the residual demand curve rises parallel with falling p) and since the duration t' that maximum capacity is reached decreases, the 'swing' increases if lifting the cap results in lower duration of binding production.

Appendix C Welfare analysis of variants

In chapter two, apart from the scenarios, we introduced a number of variants to investigate the sensitivity of scenarios to various assumptions. In this appendix we list the effects of these variants on the welfare analysis of the cap on Groningen. Table C.1 shows net welfare effects.

Table C.1 Net welfare effects of a cap (of 42.5 bcm) on Groningen for variants (in million euro; discount rate is 5%)

Variant	
Baseline	< – 270
Low LNG prices	< – 200
High LNG prices	< – 270
Low decline of small-fields production	< – 170
High decline of small-fields production	< – 280
Higher capital costs of Dutch production	< – 325