CPB Document

No 66

October, 2004

Gas exploration and production at the Dutch Continental Shelf

An assessment of the 'Depreciation at Will'

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ISBN 90-5833-192-X

Abstract

This report analyses the effects of Depreciation at Will (DAW) on offshore gas production, government budget and employment in the gas industry. The DAW enables firms to accelerate deprecation of investments in platforms and other offshore equipment. The interest advantage due to the postponed payments of taxes raises the profitability of investment projects and, hence, could raise the level of investments. The key question in the debate on the DAW is whether the higher tax base compensates for the interest losses due to postponed tax receipts. The econometric analysis has shown that the DAW increased only the number of development drillings during the period this measure was implemented (1996-2002). A moving long-run average of the oil price has appeared to be a significantly explaining variable behind the level of exploration drillings as well as development drillings. Using the current value of that oil price, 25 dollar per barrel, we find a large number of profitable exploration projects. In the current circumstances, introduction of the DAW will not raise the level of investments in the near future, as several non-financial factors appear to be bottlenecks, such as the duration of licensing procedures.

Key words:

Fiscal policy, investments, resource rents, oil price, natural gas

Abstract in Dutch

Dit rapport analyseert de effecten van de Willekeurige Afschrijving Continentaal Plat (WACP) op de gasproductie op de Noordzee, het overheidsbudget en de werkgelegenheid in de gassector. De WACP stelt bedrijven in staat investeringen in platforms en dergelijke versneld af te schrijven. Het rentevoordeel als gevolg van uitstel van belastingbetalingen verhoogt de winstgevendheid van investeringsprojecten en daarmee mogelijk de omvang van investeringen. De centrale vraag in de discussie over de WACP is of de toename van de belastingbasis door de extra investeringen de renteverliezen bij de overheid als gevolg van de maatregel compenseert. De econometrische analyse laat zien dat de WACP in de periode 1996-2002 het aantal ontwikkelingsboringen heeft verhoogd. Een meerjarig voortschrijdend gemiddelde van de olieprijs blijkt een significante variabele achter het niveau van gasboringen te zijn. Bij de huidige waarde van die grootheid (25 dollar per vat) blijkt er zonder de WACP een groot aantal rendabele exploratieprojecten te bestaan. In de huidige omstandigheden introduceren van de WACP zal daarom niet het aantal investeringsprojecten verhogen omdat verschillende niet-financiële factoren, zoals de lengte van vergunningprocedures, dat belemmeren.

Steekwoorden:

Belastingen, investeringen, grondstoffen, olieprijs, aardgas

Contents

Preface

In order to encourage gas production at the Dutch Continental Shelf, the Dutch government has taken several measures in the past decades. Recently, however, the Depreciation at Will (DAW), a fiscal measure favouring offshore activities, has been abolished. Since the abolishment of that measure in 2003, representatives from the gas industry have warned for the alleged dramatic effects on gas production and government budget. As a consequence, the Dutch government, encouraged by questions from members of the Parliament, has asked the CPB to conduct an analysis of the effects of the DAW.

During our research, we received highly appreciated cooperation from Jaap Breunese and his colleagues from the Netherlands Institute for Applied Geoscience (TNO-NITG) and Peter Rozenkranz from the Energie Beheer Nederland (EBN). We are grateful to both organisations for providing support in analysing the consequences of the DAW on the financial prospects of offshore gas activities. We also had several useful meetings with representatives from a number of upstream gas firms active at the Dutch Continental Shelf, i.e. BP, Gaz de France, NAM, Petro-Canada, Total, Wintershall, and associations of firms, i.e. Nogepa and IRO. These meetings gave us valuable in-depth information on factors affecting investment decisions. In addition, we benefited from the discussion with Bob George, Chris Rachwal and Paul McGhee at the office of Gaffney, Cline & Association in Bentley, United Kingdom. Finally, Corné van Langen, Sandra Quick and Jos de Groot of the Ministry of Economic Affairs and Michiel Geschiere and Wim van Tol of the Ministry of Finance gave useful advice during the project.

The project team which conducted this research included Ali Aouragh (information analysis), Arie ten Cate (econometrics), Joeri Gorter (macroeconomics) and Machiel Mulder (energy economics and project management).

Henk Don
Director

Summary

Scope of the research

For several decades, the Dutch government has encouraged production of natural gas from the Continental Shelf. This policy, which is called the small-fields policy, aims at conserving the reserves in the huge Groningen gas field and at maximising offshore gas production. This policy contributed to the steady increase in gas production on the Continental Shelf. Since the early 1990s, however, exploration activities have shown a declining pattern, while the annual growth in production has altered in stabilisation. In response to these developments, the Dutch government took several measures to improve conditions for the gas industry. One of these measures was the introduction of Depreciation at Will (DAW) in 1996. That measure gave gas firms the opportunity to postpone tax payments and hence raising the profitability of investments projects. As a result, firms were expected to raise the level of investments and hence production of gas. In the Tax Plan 2003, the Dutch government abolished this fiscal facility, and others, in order to simplify the tax system.

In response to a request of the Parliament, the government decided to monitor and evaluate the effects of the abolishment. The Ministries of Economic Affairs and Finance have requested the CPB to conduct this evaluation. This research focuses on the effectiveness of the DAW, answering the following questions:

- What were the effects of the introduction and abolishment of the DAW on natural gas depletion on the Dutch Continental Shelf, the government budget and employment?
- What would be the effects of the re-introduction of the DAW on natural gas depletion at the Dutch Continental Shelf, government budget and employment?

In this project, we will not assess the welfare effects of the small-fields policy as such. We do not address the question whether the small-fields policy is an efficient policy. Answering that question would require an analysis of the relationship between depletion of the Groningen field and depletion of the offshore fields, including an assessment of costs and benefits of conserving the former field by enhancing production of the latter fields.

Oil price and DAW affected offshore activities

The level of known natural gas reserves at the Dutch Continental Shelf has not much altered since the mid 1970s. Recently, however, the level of reserves has shown a decreasing pattern, mainly as a result of the relatively low level of new finds. Whether this development indicates a declining geological prospectivity of the Dutch offshore area is not fully clear.

The econometric regressions show the main determinants of exploration and development as one would expect. The revenue based on a long-term average oil price is a major determinant. Exploration and development seem to react quite fast to changes in the oil price: already after a few years, rather than after decades. Development drillings responded stronger to the level of the long-term oil price than exploration drillings.

The econometric analysis has produced a mixed picture on the effect of the DAW on mining activities. This fiscal measure had a temporary effect on the level of exploration activities and a continuing effect on development activities. The effect on exploration might be a one-time increase of 80%, meaning that the introduction of the DAW resulted in an immediate 80% increase in the level of exploration drillings in the same year which effect fully vanished in the years after. The effect on development is estimated as a 50 to 80% increase during the DAW period.

Summarising and explaining the above two conclusions: compared to development drillings, exploration drillings appear to be less sensitive to financial factors such as the oil price and the DAW. The high financial sensitivity of the former is related to the position of development in the chain of mining activities: development decisions come only to the fore when an exploration drilling has been successful. As a result, the expected cash flow of the development project is one of its major determinants. Exploration drillings depend, however, on many other factors, such as geological research and licensing and environmental procedures.

North Sea offers fairly favourable investment conditions

The North Sea area, including the Dutch part, still is a relatively favourable area for gas production due to its political stability and proximity to major European consumer markets with a growing demand for gas. Also other conditions for offshore investment at the Dutch Continental Shelf have been favourable, such as the guaranteed offtake by Gasunie, the well-developed infrastructure and the shallow water. Compared to other North Sea countries, the Netherlands have an average fiscal environment to the upstream industry. Factors which could hamper activities of the industry as a whole are the rather lengthy licensing and environmental procedures and the inactivity of several license-holders.

DAW relieves financial restrictions

The DAW affects the (expected) profitability of all exploration and development projects. This impact differs strongly between projects. Although all projects benefit from the DAW, only a part of the projects do really need this facility. Depending on the choice of the financial criterion, 60 to 70% of all exploration projects which are profitable with the DAW appears also profitable without this fiscal facility. In absolute terms, 120 to 250 projects are not financially restricted. This number exceeds largely the number of projects currently undertaken (about 10 per year) and the highest level achieved in the past (about 40). So, other, non-financial factors, such as pre-drilling activities (geological research, interpretation of data, etc), environmental and licensing procedures and insufficient access to profitable prospects by new firms, determine the magnitude of offshore activities in the near future. Improving financial conditions by implementing the DAW would, therefore, under current circumstances not affect that magnitude.

… but has likely a negative impact on government budget

The DAW affects not only marginal projects, but also already profitable projects, resulting in a 'dead weight loss'. If we assume that all projects could immediately be undertaken, the present value (discounted against 6%) of the 'dead weight loss' amounts to about 0.25 or 0.40 billion euro. This involves about 60 to 70% of all projects already profitable in case of a DAW. The profitability, measured by the internal rate of return (IRR), of many projects within this category rise to levels far above 20%.

If all financially-sound investment projects would be undertaken immediately, the net impact on (the present value of) state revenues would be between −200 and 400 million euro. However, if we do take into account the impact of other factors affecting the level of mining activities, the net effect on state revenues would be negative. After all, firms would benefit from the fiscal facility on projects already profitable without the DAW. Tentative calculations based on general economic research support the conclusion that a reduction of the tax rate for the gas industry would result in a negative net impact on state revenues.

… and hardly any effect on employment

As the measure will have a little effect on the magnitude of offshore mining activities in the near future, the employment effects would be negligible. In addition, the industry supplying to the upstream industry increasingly operates on a global market, partly due to mature characteristics of the North sea area. Changes in the level of demand from the Dutch upstream sector, therefore, could be mitigated by developments in other regions.

Improving other conditions could encourage investments

The above conclusions on the effects of the DAW does not imply that no other changes within the fiscal regime should be reconsidered. In order to achieve a better performance of a change within the fiscal regime, the measure could focus on the reduction of the marginal effective tax rate. In other words, reducing the tax burden on marginal projects without relieving the tax burden on infra marginal projects would have positive effects on gas activities and government budget. As to determine whether such a measure could practically and legally be implemented, additional research could be useful.

The question remains whether the government should take other measures regarding the offshore gas activities. In order to answer that question, we have to determine the outlook for this sector when no additional policies would be taken.

Contrary to what is often said, the prospectivity, i.e. the geological outlook, of the Dutch Continental Shelf has hardly changed in the past years. The net changes in the magnitude of the reserves have fluctuated around zero resulting in a rather stable level of remaining reserves. Also other indicators for prospectivity, such as average field size times success rate, do not give worrying signals. Looking at the past relationships between oil price and offshore activity, we expect that the number of exploration and development drillings will increase in the near future. After all, at the present level of the moving average annual oil price, a large number of projects appear to be profitable, even if we use relatively strong financial criteria which some firms seem to use.

A major factor which influences the size of offshore activity seems to be the market structure. Many of the firms currently active on the Continental Shelf apply rather high financial criteria in their investment decisions due to insufficient competition on the upstream market. In order to encourage offshore activities in the medium term policy measures could be directed at competition on the upstream market. Options to do so, are improving licensing procedures and increasing the transparency of the market in order to attract new players to the offshore area and, hence, reduce the importance of ranking of profitable investment projects on the number of projects actually executed. In this respect, experiences in other countries could offer useful lessons. The United Kingdom, for instance, has recently introduced several measures to attract new players to the North Sea. Those measures include the fallow field initiative encouraging activity on acreages which have had no activity for a number of years and a measure increasing access to infrastructure.

Additional research would be needed to assess the cost-effectiveness of the several options to encourage investments at the Continental Shelf. In that further research, attention should also be given to the benefits of the ‘small-fields’ policy. Only then it is possible to determine the optimal design of government policy regarding the exploitation of the domestic natural-gas resources.

Samenvatting

Achtergrond en doel van de studie

De Nederlandse overheid voert sinds meerdere decennia beleid om de gasproductie op de Noordzee te bevorderen. Dit beleid wordt het 'kleine-velden beleid' genoemd. Het heeft tot doel de reserves in het grote Groningen gasveld zo lang mogelijk te behouden en de gasproductie uit de 'kleine velden' op de Noordzee te maximaliseren. Dit beleid heeft geleid tot een geleidelijke toename in de offshore gasproductie. Sinds het begin van de jaren 1990 laten de exploratieactiviteiten echter een dalend patroon zien, terwijl de productieomvang niet meer groeit. In reactie op deze ontwikkelingen heeft de Nederlandse overheid in deze periode diverse maatregelen getroffen om de condities voor de offshore industrie te verbeteren. Een van die maatregelen was de introductie van de Willekeurige Afschrijving Continentaal Plat (WACP) in 1996. Teneinde het belastingstelsel te vereenvoudigen heeft de overheid bij het Belastingplan 2003 deze maatregel weer afgeschaft.

De WACP biedt bedrijven de mogelijkheid om investeringen in boorplatforms en gaspijpen in een zelf te kiezen tempo fiscaal af te schrijven. De bedrijven kiezen ervoor de investeringen versneld af te schrijven, zodat belastingbetalingen naar de toekomst worden geschoven. Dit uitstel van betalingen levert de bedrijven rentevoordeel op. De andere kant van de medaille is uiteraard dat de overheid belastingen later ontvangt en dus een renteverlies leidt. Wanneer bedrijven als gevolg van de maatregel meer gaan investeren en daardoor meer gas gaan produceren, kunnen de baten voor de overheid per saldo toch positief worden. De centrale vraag is daarom in welke mate bedrijven door de invoering van de willekeurige afschrijvingen meer gaan investeren.

In reactie op vragen uit de Tweede Kamer heeft de regering besloten de effecten van de afschaffing van de WACP te monitoren en evalueren. De Ministeries van Economische Zaken en Financiën hebben vervolgens het CPB gevraagd onderzoek naar de effecten van de WACP te verrichten. Dit onderzoek richt zich op de volgende twee vragen:

- Wat waren de effecten van de introductie en afschaffing van de WACP op gasproductie, overheidsinkomsten en werkgelegenheid in de gasindustrie?
- Wat zouden de effecten zijn van herintroductie van de WACP op gasproductie, overheidsinkomsten en werkgelegenheid in de gasindustrie?

In dit onderzoek zijn niet alle effecten van het kleine-velden beleid geanalyseerd, zodat geen antwoord wordt gegeven op de vraag of dit een efficiënt beleid is. Om die vraag te beantwoorden moet ook worden gekeken naar de relatie tussen het gebruik van het Groningen-gasveld en de productie op de kleinere velden.

Olieprijs en WACP beïnvloedden gaswinning op de Noordzee

De omvang van de bekende reserves op het Nederlandse deel van het Continentaal Plat zijn niet veel veranderd sinds het midden van de jaren 70. Recentelijk echter vertoont deze omvang een dalend patroon, voornamelijk als gevolg van de relatief geringe nieuwe vondsten. Het is niet duidelijk of deze ontwikkeling op een verslechterde geologische situatie duidt.

Uit de in dit onderzoek uitgevoerde regressie-analyses komen de belangrijkste determinanten van exploratie en ontwikkeling die men zou verwachten. De opbrengst, gebaseerd op een meerjarige gemiddelde olieprijs, is een belangrijke determinant. Exploratie en ontwikkeling lijken snel te reageren op veranderingen in de olieprijs: reeds na een paar jaar, en niet pas na een paar decennia. Exploratieboringen zijn boringen waarmee naar gasvelden wordt gezocht. Ontwikkelingsboringen zijn boringen om een gevonden gasveld verder tot ontwikkeling te brengen.

Uit het onderzoek komt verder naar voren dat de WACP gedurende de periode 1996 tot en met 2002 inderdaad effect heeft gehad op de investeringen in gaswinning: ze heeft geleid tot een vergroting van het aantal ontwikkelingsboringen voor de duur van de maatregel, met 50 tot 80%. De exploratieboringen lijken erdoor naar voren te zijn gehaald; het totale aantal van deze boringen is er echter niet door verhoogd. Hierbij speelt de olieprijs, waaraan de gasprijs is gekoppeld, een belangrijke rol. In tegenstelling tot wat wel wordt beweerd, blijkt de genoemde lange termijn olieprijs een belangrijke variabele voor de activiteit van winningsbedrijven. Op dit moment ligt die prijs op ongeveer 25 dollar per vat.

De twee voorgaande conclusies samenvattend en verklarend: vergeleken met ontwikkelingsboringen lijken exploratieboringen minder gevoelig te zijn voor financiële factoren zoals de olieprijs en de WACP. Exploratieboringen hangen ook van diverse andere factoren, zoals de snelheid waarmee vergunningsprocedures doorlopen worden.

Condities voor gaswinning op Noordzee zijn tamelijk gunstig

Het Noordzee-gebied is een gunstig gebied voor gaswinning vanwege het stabiele politieke klimaat en de locatie dichtbij grote consumentenmarkten. Ook andere voorwaarden voor investeringen in gaswinning op de Noordzee zijn gunstig, zoals gegarandeerde afzet door de Gasunie, de goed ontwikkelde fysieke infrastructuur en het relatief ondiepe water. In vergelijking met de andere Noordzee-landen heeft Nederland een gemiddelde fiscale omgeving voor investeringen.

WACP verlicht financiële restricties

De WACP beïnvloedt de (verwachte) winstgevendheid van alle exploratie en ontwikkelingsprojecten. De omvang van die invloed verschilt evenwel per project. Uit de financiële analyse van afzonderlijke investeringsprojecten blijkt dat een deel de WACP nodig heeft om rendabel te worden. Afhankelijk van het financiële criterium waarmee de projecten worden beoordeeld is 60 tot 70% van de projecten rendabel zonder de mogelijkheid tot willekeurige afschrijving.

Wanneer met een olieprijs van 25 dollar per vat de verwachte winstgevendheid van alle (979) geologisch vermoede gasvelden wordt berekend, dan blijken er zonder de WACP 125 tot 250 rendabele projecten te bestaan. Dit aantal ligt ver boven het aantal dat in het verleden ooit in één jaar is gerealiseerd. In het afgelopen decennium lag het jaarlijkse aantal exploratieboringen op ca. 15. Het hoogste aantal boringen dat sinds de start van de offshore gaswinning ooit is gerealiseerd bedraagt ca. 40.

… maar heeft waarschijnlijk een negatieve invloed op het overheidsbudget

Als gevolg van andere factoren is het dus niet realistisch te veronderstellen dat al deze rendabele projecten op korte termijn zullen worden uitgevoerd. De duur van vergunningprocedures, de toegankelijkheid van blokken (dat zijn bepaalde gebieden op de Noordzee) voor nieuwe bedrijven, en fysieke capaciteitsgrenzen bepalen namelijk ook de snelheid waarmee de gasboringen kunnen worden verricht.

Bij de hoge olieprijs die nu voor de toekomst wordt voorzien heeft verdere stimulering via fiscale faciliteiten daarom geen invloed meer. Door herintroductie van de WACP zou het aantal rendabele exploratieprojecten met nog eens 80 tot 100 toenemen bovenop het genoemde aantal van 125 tot 250. Gezien het voorgaande is het duidelijk dat dit weinig of geen effect zal hebben op het aantal boringen in de nabije toekomst. De maatregel zal alleen de winstgevendheid vergroten van de projecten die toch wel uitgevoerd worden. Per saldo leidt de maatregel tot een renteverlies voor de schatkist, en vergroting van de winst van de winningsbedrijven.

… en vrijwel geen effecten op de werkgelegenheid

Aangezien de maatregel nauwelijks effect zal hebben op de omvang van de offshore mijnbouwactiviteiten zullen de werkgelegenheidseffecten verwaarloosbaar zijn. Daarbij komt dat de toeleverende industrie in toenemende mate op een mondiale markt opereren en daarmee minder afhankelijk worden van de omzet op de, relatief geringe, Nederlandse offshore markt.

Andere beleidsopties kunnen wel leiden tot meer investeringen

Bij een structureel lagere olieprijs zou de maatregel op termijn wel positief kunnen uitpakken voor het overheidsbudget. Ook dan zouden de effecten voor de overheid echter gunstiger zijn wanneer de maatregel wordt gericht op marginale projecten. Bij de huidige vormgeving profiteren immers alle, ook heel rendabele projecten, van de fiscale faciliteit. Nader onderzoek zou kunnen uitwijzen in hoeverre een op een dergelijke manier vormgegeven maatregel praktisch en juridisch uitvoerbaar is.

Een factor die ook invloed heeft op de omvang van de offshore activiteiten is de marktstructuur. De bedrijven die momenteel actief zijn op de Noordzee hanteren tamelijk strenge selectiecriteria bij hun investeringsbeslissingen wat samenhangt met de beperkte concurrentie in het Noordzeegebied. Door voor nieuwe spelers de toegang tot het gebied te bevorderen zou de investeringsactiviteit kunnen toenemen. Mogelijke maatregelen hiervoor zijn vergroten van de transparantie van de markt, verbetering van vergunningsprocedures en enige regulering van tarieven voor de infrastructuur. Ervaringen die andere landen, zoals het Verenigd Koninkrijk, hiermee opdoen kunnen nuttige lessen verschaffen voor de invulling van het beleid om de offshore gaswinning te bevorderen.

Aanvullend onderzoek zal nodig zijn om te bepalen in welke mate de andere beleidsopties kosteneffectief zijn. In een vervolgonderzoek zou ook aandacht kunnen worden besteed aan de baten van het kleine-velden beleid. Alleen dan is het immers mogelijk om de optimale vormgeving te bepalen van het overheidbeleid voor de exploitatie van de nationale aardgasreserves.

1 Introduction

1.1 Background and aim

For several decades, the Dutch government has encouraged production of natural gas from the Continental Shelf. This policy, which is called the small-fields policy, aims at conserving the reserves in the huge Groningen gas field and maximising offshore gas production. The benefits of this policy consist not only of the volume of gas produced offshore, but also of its impact on the capability of the Groningen field to act as swing producer. The main component of the small-fields policy is the guaranteed offtake of offshore gas by Gasunie.

The small-fields policy contributed to the steady increase in gas production on the Continental Shelf. Since the early 1990s, however, exploration activities have shown a declining pattern, while the annual growth in production has altered in stabilisation. In response to these developments, the Dutch government took several measures to improve conditions for the gas industry. One of these measures was the introduction of Depreciation at Will (DAW) in 1995. That measure gave gas firms the opportunity to postpone tax payments raising the profitability of investments projects. In the Tax Plan 2003, however, the Dutch government abolished this fiscal facility.

This abolishment has caused commotion: several parties, including members of Parliament, expect that it would result in a significant decrease in offshore drilling activities. This would lead to a lower level of depletion of the offshore gas fields, a decline in natural resource rents the government would receive, and loss of economic activity.

In response to a request of the Parliament, the government decided to monitor and evaluate the effects of the abolishment. The Ministries of Economic Affairs and Finance have requested the CPB to conduct this evaluation. This research should deliver sufficient information on the effects of the DAW on the exploration and production of gas, the government budget, and employment. The general aim of this research is to assess the DAW as a policy tool encouraging production of natural gas, taking explicitly into account the impact on government budget.

1.2 Research questions and method

As to determine the effectiveness of the DAW we use two approaches: an ex-post analysis and an ex-ante analysis. The former one focuses on the impact of the DAW in the past; the latter assesses the likely future impact of the DAW if this measure would be implemented again. As a result, the report answers the following two questions:

1. What were the effects of the introduction and abolishment of the DAW on natural gas depletion on the Dutch Continental Shelf, the government budget and employment?
2. What would be the effects of the re-introduction of the DAW on natural gas depletion at the Dutch Continental Shelf, government budget and employment?

In order to answer these questions, we have analysed information from several sources. These sources include:

- Literature on tax regimes and investment decisions;
- Data on offshore activities and policy measures regarding the gas industry given by EBN, TNO-NITG and the Ministry of Economic Affairs;
- Research reports, results from model analyses, and discussions with researchers from TNO-NITG, EBN and Gaffney, Cline & Associates, and, finally;
- Plenary and bilateral meetings with representatives of gas firms active at the Dutch Continental Shelf, i.e. BP, Gaz de France, NAM, Petro-Canada, Total, Wintershall, and associations of firms, i.e. Nogepa and IRO.

1.3 Focus of the analysis

In this project, we will not assess the welfare effects of the small-fields policy as such. We do not address the question whether the small-fields policy is an efficient policy. Answering that question would require an analysis of the relationship between depletion of the Groningen field and depletion of the offshore fields, including an assessment of costs and benefits of conserving the former field by enhancing production of the latter fields.[1]

1.4 Structure of the document

Chapter 2 explores the rationale behind and the contents of specific fiscal policies regarding the gas industry. The next chapter deals with the ex post analysis. This chapter describes the (econometric) analysis of past relationships between the DAW and other factors, such as the oil price, on the one hand, and offshore activities of the gas industry on the other. Chapter 4 offers the ex ante part of the research. This part consists of an analysis of financial restrictions on project level as well as a macroeconomic analysis of relationships between tax measures and investments. The final chapter summarises the main results and gives some policy implications.

[1] In its latest review of Dutch Energy Policies, IEA (2004) advices to conduct such a cost-benefit analysis. See also De Joode and Mulder (2004) for an assessment of costs and benefits of conserving the swing function of the Groningen gas field.

2 Fiscal policy and production of natural gas

2.1 Introduction

This chapter gives an introduction on the design of fiscal policies related to the mining activities. First, we explore theoretical motives behind specific fiscal measures regarding the upstream natural gas industry. Then, we concisely describe fiscal measures currently in place in each of the North Sea countries. Finally, we go deeper into the Dutch polices regarding the offshore gas industry including a description of the DAW.

2.2 Taxation of natural resource rents and market failure

Theoretically, two factors determine the design of tax systems regarding mining activities: the existence of economic rents due to natural circumstances and the presence of market failure. The former explains why mining activities should be taxed relatively strongly while the latter could account for lower or higher levels of taxation.

Economic rents generated by mining industry follow from scarcity of its resource. The value of products produced by this industry follows only partly from the costs involved and mainly from the scarcity of the product. The latter component of the value of the product is called 'rent'. These rents belong to the owner of the natural resources, generally the state. In order to receive those rents in cash, the resources have to be discovered and exploited. If private firms execute these activities, they require compensation for their costs and a remuneration of the risks undertaken. This implies that taxation of the natural resource rents must on the one hand leave sufficient incentives to private firms for exploration and exploitation and, on the other hand, distribute an appropriate part of the rents to the state (Neher, 1999).

As economic conditions of exploitation alter during its lifetime, the tax regime should be reconsidered frequently. Theoretically, the more an area approaches maturity, the more depletion costs rise, the lower should be the resource rent tax.[2] This holds, of course, only if the tax is set at the optimal level when depletion took off. "If the fiscal system is directly and accurately targeted on economic rents then investment decisions regarding exploration and development should not be distorted. In practice, however, the great majority of fiscal systems are not directly targeted on economic rents." (Kemp *et al.*, 1992b).

[2] According to the British Department of Trade and Industry (DTI), the British North Sea fiscal regime "is kept under continuous review and many adjustments have been made to it to reflect changes taking place in the United Kingdom Continental Shelf" ("Regulatory Regime" at www.dbd-data.co.uk). In order to encourage long-term investment in the North Sea, the British government recently abolished royalty and introduced 100 percent allowance for most investments in the North Sea (message of DTI at www.og.dti.gov.uk).

In a study directed at the effects of fiscal terms in a number of countries, including the Netherlands, Kemp et al. (1992a) conclude that “overwhelmingly the systems are not well-targeted on economic rents. In jurisdictions incorporating traditional royalty and conventional tax instruments the systems are regressive[3] in relation to oil price”. According to these authors, “the inaccurate targeting generally emanates from the absence of a specific allowance for the required return to the investor from the activity of petroleum exploitation.”

The second reason for giving a special fiscal treatment to a specific sector is the existence of externalities. According to the adherents of the small-fields policy, the exploitation of the Continental Shelf has several positive externalities which private firms do not take into account. It should contribute to the conservation of the Groningen field as a swing supplier. Moreover, it should postpone dependency of the Netherlands on foreign, more risky suppliers of natural gas. In addition, within the offshore area, positive externalities should exist regarding the use of the existing infrastructure for gas depletion. The existing infrastructure, consisting of pipelines and platforms owned by several gas firms, offers significant scale-effects in the investments costs. In this report, as said in Chapter 1, we do not assess the magnitude of these externalities in order to determine the efficiency of tax facilities for the offshore gas industry. In stead, we focus on the efficacy of one fiscal measure, the DAW.

2.3 Fiscal regimes on gas and oil production in North Sea countries

This section provides a global description of the fiscal regimes regarding gas and oil production in the North Sea countries: United Kingdom, Norway, Denmark Germany and the Netherlands. Profits from gas and oil production are subject to three types of fiscal charges: royalty, corporate income tax and petroleum taxes. In addition, the degree of participation of the state affects profits of firms. Table 2.2 summarises the main components of the fiscal regime of each North Sea country.

Classification of tax regimes

According to Mommer (1999), two archetypes of fiscal regimes on natural resource profits can be distinguished: a liberal fiscal regime and a proprietorial fiscal regime. In the former regime, the marginal fiscal take is zero. “The state taxes only excess profits, carefully avoiding obstructing the free flow of investment”. In the latter regime, the marginal take is positive.

[3] Regressive taxes are non-profit based, such as royalties. The lower the profitability, the higher the effective tax rate. Profit-based tax schemes, such as production sharing and profit tax, result in a higher effective tax rate if profitability rises.

Petroleum fiscal regimes can also be distinguished in concessionary systems and contractual systems.[4] The former system allows private ownership to mineral resources while in the latter the state retains ownership of these resources. Most European countries, including Denmark, The Netherlands, Norway and the United Kingdom, have a concessionary system. In such a system, private firms have exclusive rights to explore and produce at its own risks and expenses. “In the traditional concessionary system, the company pays a royalty based on the value of the recovered mineral resource, and one or more taxes based on taxable income.” (Coastal Marine Institute, 2004).

State participation

Germany as well as the United Kingdom has no arrangement concerning state participation in upstream activities. Norway has limited the average state share to less than 40% since 1996. Denmark participates in all recent licences through a subsidiary of the entirely state-owned firm DONG A/S. In the Netherlands, oil and gas exploration and production is done as a partnership between the State and private firms. The state is represented by the agency Energie Beheer Nederland (EBN). EBN bears 40% of production and exploration costs, and in turn receives 40% of profits from oil and gas production ventures.

Table 2.1 Fiscal terms for the upstream natural gas industry, per North Sea country, 2003

	Netherlands offshore	Netherlands onshore	United Kingdom	Norway	Denmark	Germany
Royalty (%)	0	0– 7	0	0	0	10– 36
Petroleum taxes (%) a)	50 (SPS)	50(SPS)	0(PRT)	50(SPT)	70(HCT)	n.a.
Corporation tax (%)	34.5 b)	34.5 b)	40	28	30 c)	50.8 d)
Marginal fiscal rate (%)	50	50	40	78	30 e)	50.8 d)
State participation (%)	0/40/50	0/40/50	None	40	20	none

a) SPS = State Profit Share; PRT = Petroleum Tax; SPT = Special Petroleum Tax; HCT = Hydrocarbon Tax.
b) Credible against SPS.
c) Deductible against HCT.
d) Combination of Corporation and Municipal taxes.
e) Referring to the Danish Energy Agency estimates, GCA expects no HCT is likely to be payable for the foreseeable future. Therefore, the effective marginal rate is 30 in stead of 70%.

Source: Gaffney, Cline & Associates (2003)

Royalty

In the Netherlands, royalties have to be paid on onshore fields only. In the United Kingdom, royalty payments have been abolished as from January 1, 2003. Before that date, royalty was

[4] See e.g. presentation of Alfred Kjemperud, Bridge on Petroleum Fiscal Regimes; Basic Concepts, September 2003.

charged at 12.5% of gross value of oil and gas won in a particular area, but only applied to fields given development consent before April 1, 1982. The Norwegian revision of Petroleum Tax Act in 1992 has phased out royalty on pre ’86 gas fields. Moreover, royalty will be abolished for the remaining two fields (Oseberg, Gullfaks) in 2005. In Denmark, no royalty is due for new field developments. In Germany, royalties are set at a minimum of 10% and vary among the federal states.

Petroleum taxes

In the United Kingdom and Germany, no petroleum taxes on the development of new oil and gas fields are due. The UK Petroleum Revenue Tax (PRT) is a field-based tax meaning that costs of developing a particular field cannot be set against the profits from another field. Losses can, however, be carried forwards or backwards indefinitely.

In the Netherlands, only one fiscal regime is applied to offshore and onshore production. This regime holds for all firms, domestic or foreign, active at the Dutch Continental Shelf. The regime imposes a 50% tax to new exploration licences after deduction of the 10% uplift. In all production projects, the government agency Energie Beheer Nederland (EBN) carries 40% of the costs and, hence, receives, 40% of the profit made with that project. The profit share refers to the profits of the company after deduction of EBN’s participation. This implies that the government receives 40% of the profit (due the EBN participation) and 50% of the profit of the firms, making governments share in the profit 70%.

In Norway, the Petroleum Tax is applied at a rate of 50% on income from petroleum production. Uplift is granted for a period of 6 years at a rate of 5%. With effect from the 2004 accounting year, the special investment allowance provided for in the Danish Hydrocarbon Tax Act – the hydrocarbon allowance – will be reduced to 5% over six years instead of 25% over ten years. For investments made prior to January 1, 2004, the hydrocarbon allowance will be reduced from 25% to 10% a year. Deductibility stops when the investment is more than ten years old. The hydrocarbon tax rate will be reduced from 70% to 52%. The field-based tax assessment will be abolished as from the 2004 accounting year.

Corporation tax

Corporation tax on company’s profits is charged at 40% in the United Kingdom.
Companies now receive a 100% first-year allowance for capital expenditure incurred for the purposes of their ring fence trade. In Norway, the corporation tax base is rated at 28%. In Denmark the corporation tax charged on company’s profit is rated at 30%. The Dutch corporation tax is currently set at 34.5%. This tax is credible against the state profit share implying that any change in the corporation tax does not affect the total tax take (see above). Germany has the highest corporate tax take, at 50.8%.

Exploration costs may be charged as an expense and be written off immediately. In the Netherlands, from January 1st 2003, the Depreciation at Will (DAW) has been abolished. The capital expenditures can no longer be depreciated at will. In Norway, a linear depreciation schedule applies to production installations and pipelines. The annual depreciation rate is 16 2/3 %, starting from the year the investment was made. In Denmark and Germany, the annual tax is rated at 30% and 50.8% respectively.

Marginal tax take[5]

For the Netherlands, the marginal tax rate is 50%. In the United Kingdom and Norway, the marginal tax ranges from 40% in the United Kingdom to 78% in Norway. Germany and the Netherlands have both marginal rates of about 50%. Denmark has the lowest marginal tax take: 30%.

2.4 The 'small-fields' policy in the Netherlands

The Dutch policy directed at the upstream gas activities, which is called small-fields policy, encourages the production of small, mainly offshore fields on the one hand, and the conservation of the reserves of the huge Groningen field on the other. The intention of the latter is to conserve "Groningen as a buffer stock for the long term and as the swing supply source in winter months when demand was high in both the Netherlands and exports markets" (Peebles, 1999). As small-fields production enables to lengthen the use of Groningen as a swing supplier, it positively contributes to the security of gas supply (IEA, 2004). Conversely, conservation of the Groningen fields favours offshore gas production as the swing capacity of that field enables the Gasunie, the Dutch body made responsible for execution of a part the small-fields policy, to guarantee a stable offtake of offshore gas.

According to the Ministry of Economic Affairs, the main goal of the Dutch gas depletion policy is to ensure that 'in the long term as much gas as possible is extracted from the ground in the Netherlands" (Ministry of Economic Affairs, 2002). It is broadly recognized that this policy has been very successful. 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". Several authors, among which IEA (2004) doubt, however, whether the small-fields policy is an efficient policy to reach security of supply targets as, "theoretically, small fields production (…) can be replaced by gas imports to maintain Groningen's capabilities".

[5] Note that the marginal tax rate differs from the marginal effective tax rate. The latter depends on all factors determining the tax burden on marginal projects, such as compensation of losses incurrred on other projects (see also section 4.4).

Table 2.2 **Major measures of government affecting offshore activities , 1994 – 2003**

Year	Measure	Direct impact on private firms
1994	participation of the government agency Energie Beheer Nederland in production of fields with licenses given after 1983	this measures reduces the share of firms in costs and profits before taxes.
1996	a. 40% participation in production (and profits) by the government agency Energy Beheer Nederland (in stead of 50%)	a. this reduction raises the share of firms in costs and profits (before taxes) by 10% points
	b. introduction of Depreciation at Will in the Corporate Tax Scheme in retroaction as from 1 July 1995	b. this measure enables firms to postpone tax payments
1998	introduction of Depreciation at Will in the State Profit Scheme in retroaction as from 1 July 1995	this measure enables firms to postpone tax payments
2000	40% participation in exploration by the government agency Energie Beheer Nederland	this measure reduces the magnitude of capital firms have to invest in an exploration project
2001	a. tariff of levy ('cijns') is set at 0%	a. reduction in taxes
	b. integration of tax systems resulting in one system for all licenses (with 50% profit share of the government and 10% uplift of costs)	b. increased opportunities for consolidation of losses and profits on all projects
2003	a. abolishment of the Depreciation at Will	a. as a result of this measure, firms have to apply the Unit of Production rule or a straight line rule, which advances tax payments compared to the DAW

Besides the guaranteed offtake by Gasunie, several fiscal measures favour production at the Dutch continental shelf. Since the introduction of the small-fields policy, upstream firms could apply a relatively fast depletion rate of 7.2 percent for offshore fields compared to 5 per cent for onshore fields other than Groningen (Peebles, 1999). Table 2.2 offers an overview of the major measures taken since the mid 1990s.

These measures reduced the risks for private firms (participation of the state in exploration), postponed their tax payments (introduction of DAW), reduced the government share in profits (reduction of the state participation in production) and increased opportunities to consolidate losses and profits of several projects. The abolishment of the DAW as of 2003 has been the first policy measure negatively affecting financial conditions for offshore gas depletion. See the text box for a more information about the introduction and abolishment of this measure.

Depreciation at Will [a]

The Dutch government introduced the DAW in 1995 and abolished this fiscal facility in 2002. In a discussion with the Parliament in 2003, the government mentioned two reasons for the introduction: the low oil prices and the low level of activities at the Continental Shelf in the mid 1990s. [b] In its explanatory memorandum to the 2003 budget, the government states that the abolishment of the DAW would contribute to simplification of the tax system. In order to monitor the consequences of the abolishment on offshore activities, that memorandum announced monitoring and evaluating activities.

The DAW was introduced in two stages. In the first one, the measure holds only for the Corporate Tax. In the second stage, the DAW was extended to the calculation of the state profit share (see Table 2.2).

According to information given by the Ministry of Finance, annual investments appealing for DAW varied from 100 to almost 400 million euro in the period the DAW was implemented. As a result, annual postponements of tax receipts during this period varied from 25 to 100 million euro.

The DAW enables firms to treat investments in platforms and pipes as expenses in the determination of the taxable income. This fiscal facility holds for both oil and gas related investments. The alternative option is that investments have to be entered on the tax form on a unit of production basis or on a straight line basis. The immediate impact of the DAW compared to the other regimes is the postponement of tax payments. This postponement of payments delivers an interest advantage to firms. Of course, the government bears an interest disadvantage as it receives tax payments later. If firms raise the level of investments, the net impact of the fiscal facility on government budget could be positive due to a higher level of gas production and, hence, increased tax earnings. The key question in the debate on the DAW is therefore, to which extent interest losses due to postponed tax earnings are compensated by an increased tax base.

Several reports show the impact of the DAW on project profitability, such as Gaffney, Cline and Associaties (2003) and Wood MacKenzie (2002). The former concludes that the abolishment of the DAW has reduced the attractiveness of the Netherlands to investors. The latter states that the abolishment of the DAW has reduced the value of projects by about 10%. This author is, however, “not able to show that any specific projects have clearly become unprofitable under the new rules.” Nevertheless, he expects, that because of the increased uncertainty about future government measures “the net effect is likely to reduce investment and to hasten the decline of production”. Note, however, that the latter conclusion seems to be based on speculation in stead of economic analysis.

[a] The official name in Dutch is ‘Willekeurige Afschrijving Continentaal Plat’, abbreviated as WACP.
[b] Answers of government on questions of Second Chamber of Parliament, no. 28.607.

Besides these measures directly affecting financial outcomes of mining activities, the government took some other measures. One of those, following a directive of the European Union, is the abolishment of the obligation for offshore firms to deliver all the gas to the Gasunie. Currently, the government is considering measures which could attract more firms to the Dutch offshore area.

3 Analysis of past developments at the Dutch Continental Shelf

3.1 Introduction

In this section, we discuss the mining activities on the Dutch Continental Shelf in the past decades. The focus of this discussion is on the question: to which extent can changes of the level of these activities be explained by changes in policies taken by the Dutch government?

At forehand, we have to make a disclaimer. Quoting Pesaram (1990, p. 367): ‘Modelling of oil exploration and extraction is a formidable undertaking and involves important economic, geological and political considerations’. This statement holds for natural gas likewise. Hence it is a priori doubtful whether an econometric model could provide us with clear answers on the above question. At the end of this chapter, however, we will see that the econometric analysis of past offshore activities enables us to make statistically significant statements about the impact of factors affecting these activities.

This section is organised as follows. First, we describe the activities at the Dutch Continental Shelf. Next, we depict an econometric model used to explain these activities and the results of that analysis. Appendix B gives all the background information on this analysis. The chapter ends with the conclusions following from the econometric analysis.

3.2 Activities at the Dutch Continental Shelf

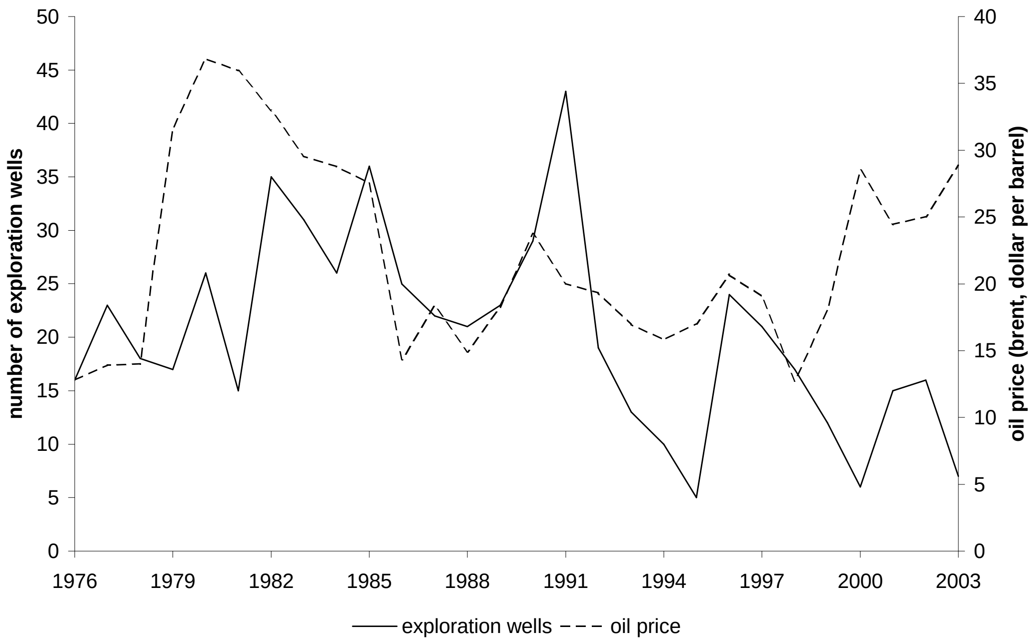
3.2.1 Exploration

Exploration for gas on the Dutch Continental Shelf started approximately 40 years ago (see Figure 3.1, where exploration is combined with the oil price). In the first 30 years of the exploration period, the number of explorations wells increased steadily towards its peak of 43 wells in 1991. Immediately after that peak, exploration activity declined strongly: in the mid 90s, the level of activity approached the low level realised at the start of the exploration. The second half of this decade showed a recovery in exploration activity. Since the start of the new century, however, exploration is at a historically low level again.

Looking to the whole period since the start of the exploration, we see a clearly rising trend in the first three decades and a down going trend since the early 90s. This trend is also reflected by comparing the average annual activity among periods of several years. In the period 1968-1982, 18 wells per year were drilled; in the period 1982-1992, the number of wells is 29, while in the period 1992-2002 15 wells per year were drilled.

Related to this development, the area under license has decreased since 1990 (EBN, 2003). In 1990, more than 70% of the total Dutch Continental Shelf was licensed to gas firms, either for exploration or for production. Currently, this figure is approximately 40%. This decline is fully due to the decrease in exploration licenses. Several firms have relinquished their exploration licenses.

Figure 3.1 Annual number of exploration wells drilled at the Dutch Continental Shelf and the nominal oil price



Source of the number of wells: Ministry of Economic Affairs (2004)

Note the peak in exploration drilling in 1991, for which we have not found an explanation. The cause of the peak in 1983-1986 might be the oil price boom in 1980-1986.

In 1996, when the DAW was introduced, the number of wells increased from 5 to 24. However, immediately after that year a gradual decrease started, until in 2000 only 6 wells were drilled. In the next section, we will try to determine a relationship between the oil price, the DAW and the level of exploration activity.

3.2.2 Development

After the discovery of an economically recoverable field, the field has to be developed before production can take off. The number of development drills showed a steadily increase up to late 1980s (see Figure 3.2). The oil price boom in 1980-1986 might be the cause of the large number of wells drilled in 1983-1986. In 1986, the number of offshore development wells peaked at a level of about 35. Since then, the number of wells has shown a slightly decreasing pattern. In

2003, the number of development wells were less than half the 1986 peak. On the first sight, there seems to be no obvious effect of the DAW in the years 1996-2002. In the next section, we will test whether such an effect existed.

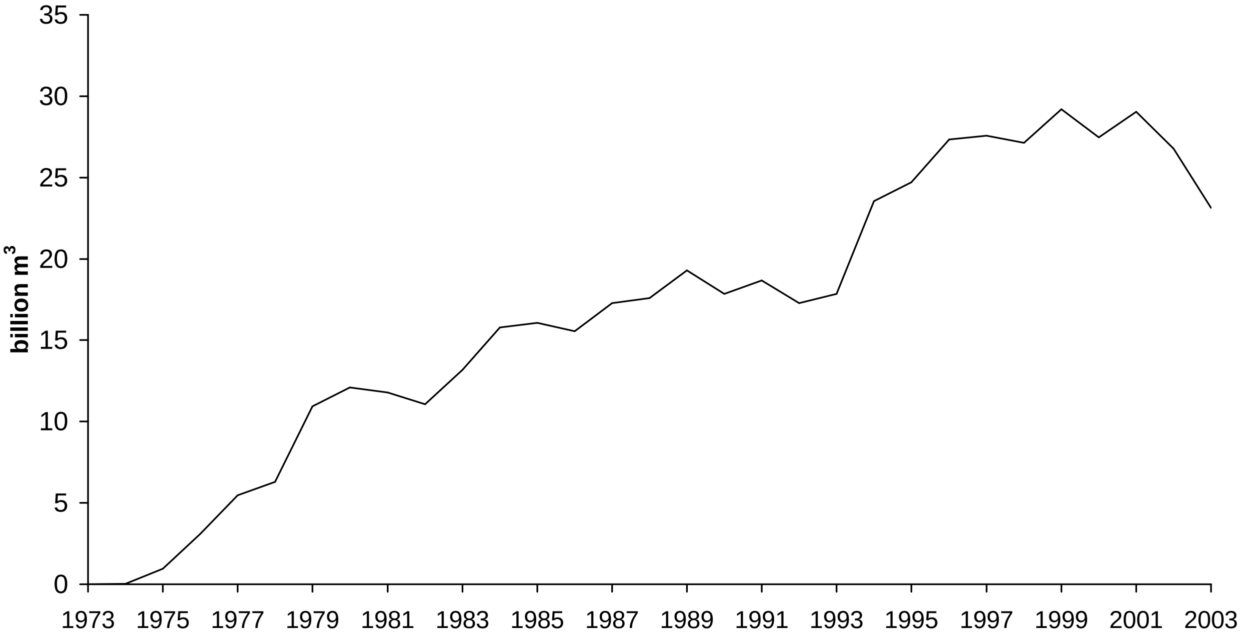
Figure 3.2 Annual number of development wells drilled on the Dutch Continental Shelf

Source of the number of wells: Ministry of Economic Affairs (2004)

3.2.3 Production

Approximately a decade after the exploration at the Continental Shelf took off, production started (see Figure 3.3). In the 1970s, total Dutch offshore production showed a strong increase. In 1980, the Dutch offshore gas production reached a level of about 12 billion m^3. In the 1980s, production kept growing although at a lower pace. In 1990, the Netherlands produced about 18 billion m^3 natural gas from the Continental Shelf. Except a temporary reduction in 1993, production kept growing up to the late 1990s. Until recently, annual production fluctuated just below 30 billion m^3 per year. In 2001 and 2002, however, production showed a relatively strong decline resulting in an annual level of about 22 billion m^3.

Figure 3.3 Annual production of gas from the Dutch Continental Shelf



Source: Ministry of Economic Affairs (2004)

3.2.4 Prospectivity

The prospectivity of an area, i.e. the probability of finding new gas reserves, alters due to the activities of the gas industry. Production decreases known reserves, but exploration and appraisal drillings can result in new reserves. Figure 3.4 shows how several activities contribute to changes in the gas reserves while Figure 3.5 depicts the annual level of Dutch offshore gas reserves.

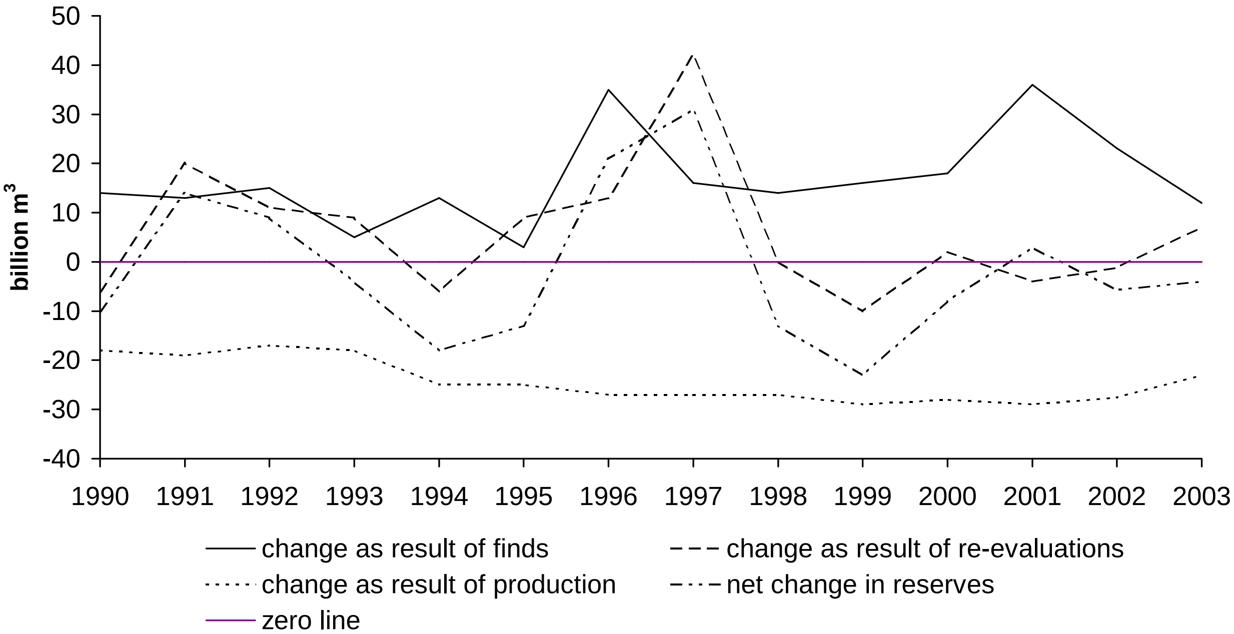
As is described in the previous section, production has steadily increased in the past decades, accounting for a growing negative impact on the remaining reserves. On the other hand, exploration has resulted in annual additions to the reserves, which has largely compensated for the losses of reserves due to production. As a result, the annual net change in reserves has been fairly similar to the annual changes resulting from re-evaluations, as can be seen in Figure 3.4.

The level of reserves on the Dutch Continental Shelf, as known at the time, which is the result of these activities, has not strongly altered since the early 1990s (see Figure 3.5). This level has been rather stable on a level of approximately 325 billion cubic metre[6]. Recently, however, the level of reserves has shown a decreasing pattern, mainly as a result of the relatively low level of

[6] It might be interesting to compute how much of the reserves has been extracted. At the end of 2003 the total production was 514 bcm and the residual reserves as a fraction of the initial reserves were 323/(514+323) = 39%. Here we use the dotted line in figure 3.5, without the change in the definition of the reserves. With this change (solid line), the result is 278/(514+278) = 35%. (Data from Ministry of Economic Affairs, 2004.)

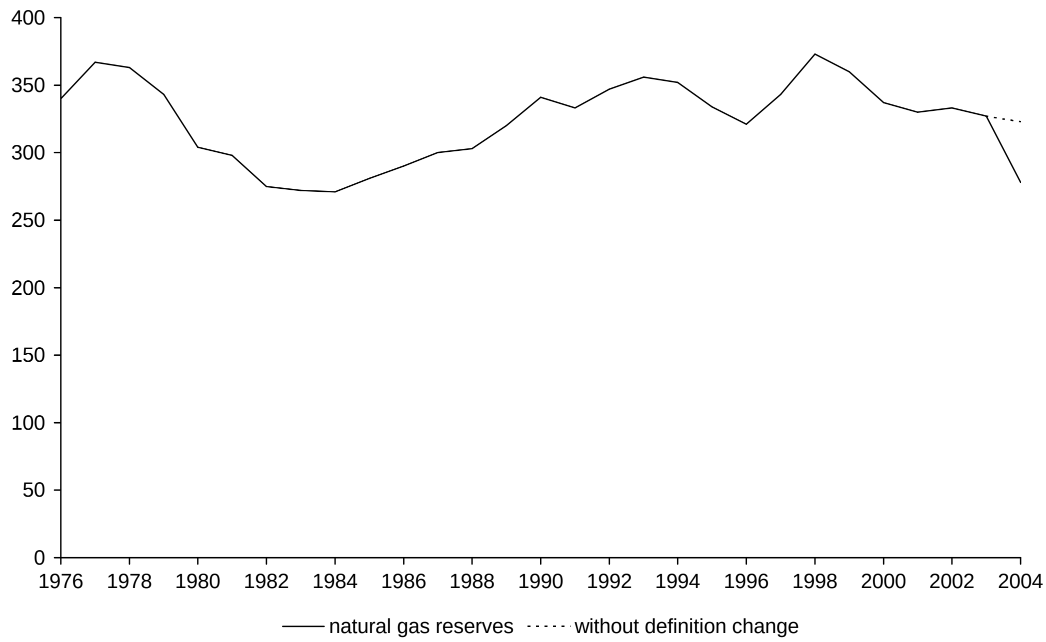
new finds. Whether this development indicates a declining geological prospectivity of the Dutch offshore area is not fully clear. After all, the recent decline in the reserve level could also be the result of a temporarily low level of exploration activities.

Figure 3.4 Components of the changes in gas reserves at the Dutch Continental Shelf (1990-2003)



Source: Ministry of Economic Affairs (several years, from www.nitg.tno.nl)

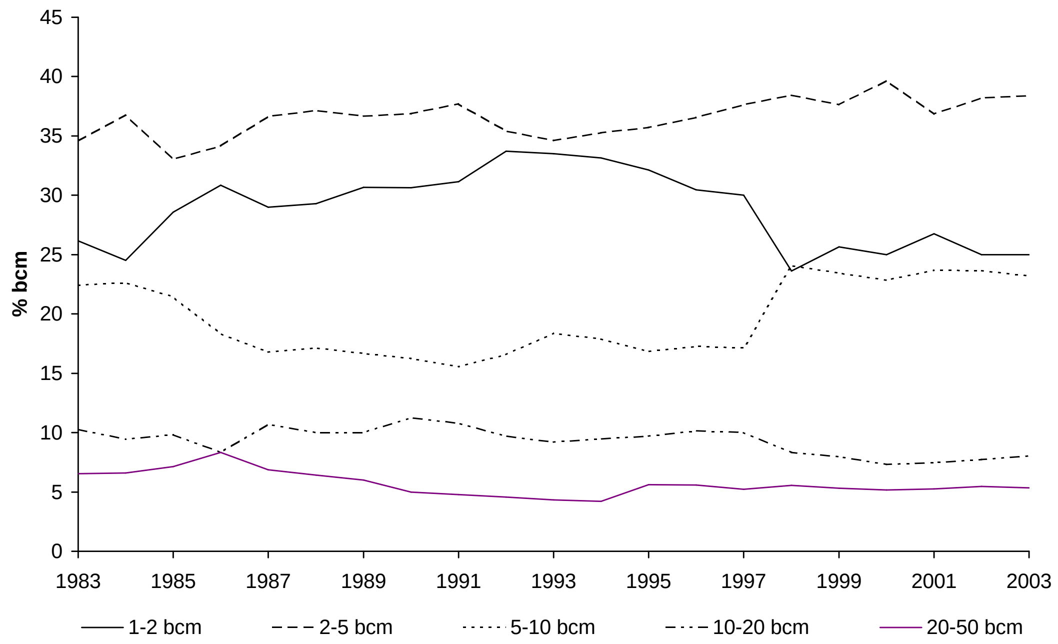
Figure 3.5 Reserves of natural gas at the Dutch Continental Shelf (1-1-1976 - 1-1-2004)



Source: Ministry of Economic Affairs (2004). Note that the decrease at the end, from 1-1-2003 to 1-1-2004, is due to a change in definition: 88 billion m^3 (Continental Shelf + territorial) of sub-economic reserves have been removed from the definition of the reserves.

Another indicator for the geological prospectivity of an area is the field size distribution. Figure 3.6 depicts the share of several field size classes in the cumulative reserves. From this figure we can conclude that the contribution of fields between 1 and 2 billion cubic metre has decreased since the early 1990s, while fields between 2 and 5 and between 5 and 10 billion cubic metre has grown in their relative contribution. As Breunese et al. (2003) conclude, the relative importance of the largest size classes (classes above 10 billion cubic metres) has remained fairly constant since 1984. This figure does not give, however the full picture as fields below 1 billion cubic metre are not included. Information given by EBN says that the share of these fields increased by a few percentage points in 1983 to 2003. Moreover, one should also compare the field size distribution of the existing fields with the size distribution of prospects. According to non-official information given by TNO-NITG, the prospects show larger shares for the lower size classes which would indicate that prospectivity of the Dutch Continental Shelf is declining.

Figure 3.6 Relative distribution of gas field sizes



Source: Breunese et al. (2004)

Although the number of exploration wells has decreased and the average size of the fields discovered remained fairly constant, the volume of annual discoveries of new gas reserves does not show a declining pattern (see Figure 3.3). This indicates an increased exploration efficacy. According to Breunese et al. (2003), the technical success rate has gradually improved from

0.30 to 0.40. This implies that fewer exploration wells are needed to realise a given magnitude of discoveries.

This agrees with Figure 16 in Gaffney, Cline & Associates (2003, p.75), which shows the success rate and find size, both averaged backwards in time. The success rate has increased and the find size has decreased. Their product has decreased about 6% from the average over the past 35 years to the average over the past 5 years. This is about 12% decline from the start of the period to the end, or 0.4% per year.

In concluding we note that we can not find persuading evidence that the geological outlook for this offshore area has altered very much. See also the discussion of prospectivity in section 3.3 below.

3.3 Econometric analysis

3.3.1 Introduction

In order to test whether past activities of the offshore gas industry have been affected by the DAW, we have conducted an econometric analysis. The next section describes the main outline of the model. Section 3.3.3 gives the results of the econometric analysis. Appendix A offers information on econometric literature about modelling activities of oil and natural gas industry. Appendix B explains some of the econometric details of our analysis and the data we have used.

3.3.2 Specification of our model

The estimation of the effect of the DAW (or its abolishment) on exploration and development requires a model which includes not only the DAW itself, but also the other factors which determine exploration and development. The reason for this is evident. Using a hypothetical example, let the time of the DAW regime coincide with a low value of the oil price (or some other relevant factor). Let these two factors more or less cancel each other out. Then, a model with only the DAW might lead to the incorrect conclusion that the DAW had little effect.

Our model consists of two equations, each explaining a number of wells drilled: one equation for exploration wells and one for development wells. We have not estimated an equation for production flow, because we are interested in investment and we expect that once a well has been developed for production, production generally follows. The two equations are the following:

(1) Number of exploration wells drilled (irrespective of success) = a function of:

Expected revenue: long run oil price minus costs (+)

Prospectivity of mining in the Dutch part of the continental shelf (+)

DAW (+?)

Other fiscal measures (+)

(2) Number of development wells drilled = a function of:

Expected revenue: long run oil price minus costs (+)

Previous successful exploration wells in the same block (+)

DAW (+?)

The (+) indicates an expected positive effect. The (+?) indicates that the effect of the DAW is uncertain a priori, being the subject of our analysis.

The regressions contains lags of several years between causes and effect; see Appendix B. Below we discuss the explanatory variables; here also Appendix B gives more details.

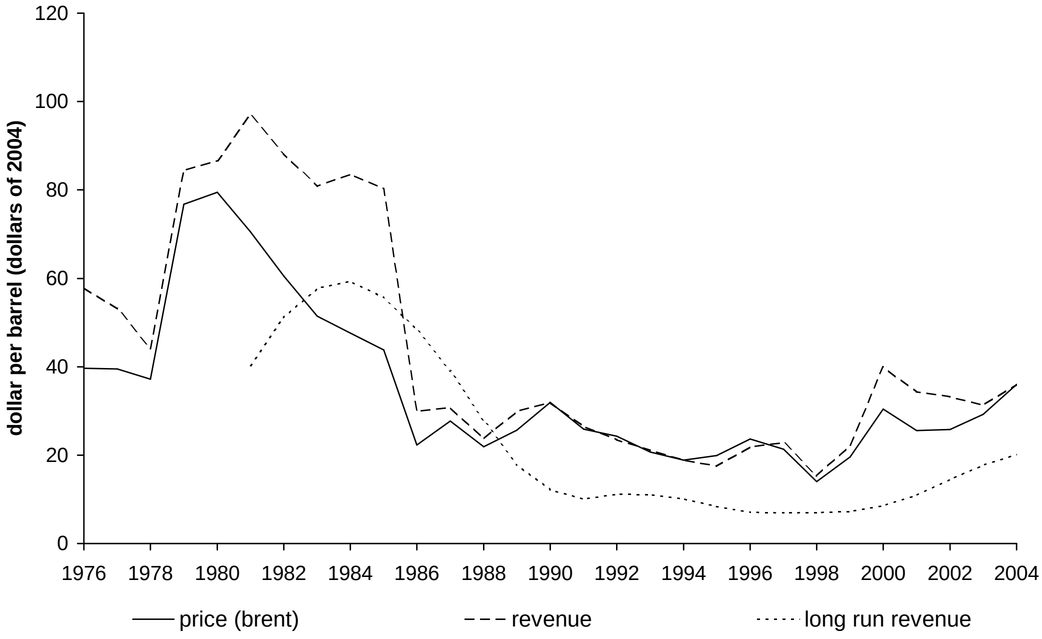
Revenue

The main determinant of all drilling is the expected revenue from selling the product. The price of oil is used as an indicator here. The costs must be subtracted from the price, giving the revenue per barrel of oil. This must be deflated and also corrected for the dollar/euro exchange rate variations. See Appendix B for details. The resulting revenue is 10 to 30 dollars (of 2004) per barrel for most of the time. In the period of 1979-1985 this is much higher. See Figure 3.7.

Of course, what matters is the net revenue, after taxes. Since we will use the logarithm of the revenue in the regression, a constant tax rate has no effect, just as for instance a change from dollars to dollar cents would have no effect. The *variations* in the tax regime are dealt with separately; see below.

This revenue must be averaged over several years to obtain the expected future revenue. As we saw above in the exploration drilling (Figure 3.1) and even more so in the development drilling (Figure 3.2), this number of years might be rather small: the main peak in the development follows quickly after the main peak in the oil price. It turns out that the most likely time average goes up to five years back. Figure 3.7 also includes this long run revenue. Note that the revenue is smaller than the price in some years because the former is “corrected” for the dollar per euro exchange rate fluctuations.

Figure 3.7 **Real oil price, real oil revenue (dollar/euro-corrected) and long-run oil revenue (dollar/euro-corrected)**



The inclusion of the oil price in the regressions is somewhat controversial. Representatives of the gas firms state that they use a “reference price”: an expected oil price which depends on a 20 years period. Hence the observed oil price in the not-so-distant past is practically irrelevant. More about this, see below, where the results of the regressions are discussed.

Successful exploration

For the number of development wells, another important explanatory variable is successful exploration. The available data on exploration and development are in the form of lists of wells drilled, showing the block where the well was drilled, and in what year the well was drilled. This enables us to use the presence of previous successful exploration in the same block as an explanation for development (the equation for the number of exploration wells itself is estimated using aggregated time series only).

Prospectivity

The geological prospectivity of mining, i.e. the geological potential of an area, depends on geological knowledge regarding that area on the one hand and cumulated past production on the other. In section 3.2 above, we have concluded that the numerical data indicate that the prospectivity of the Dutch Continental Shelf might be declining modestly.

As changes in the prospectivity affects mining activities, we included in the exploration regression the level of remaining reserves shown in section 3.2 above. This produced a negative regression coefficient in the exploration regression, which is contrary to what would be expected.

Also we estimated the exploration regression with a correction for a negative trend of 0.4% per year, as computed in section 3.2 above. This had virtually no effect on the outcome.

The DAW and other fiscal measures

Lastly, the DAW is included as a “dummy” variable: for most years it is either zero or one. This holds more or less the same for the combined other fiscal measures, which are mainly relevant for the exploration; see section 2.4.2 above. The relevant policy measures are given in chapter 2. The DAW is represented in the model by a dummy variable which is 0.8 in 1996 and 1997, unity in 1998 through 2002, and zero in all other years. (For an explanation of this 0.8, see chapter 2 above.)

As advised by the Ministry of Economic Affairs, we picked from the other fiscal measures, discussed in chapter 2 above, only the 40% participation in exploration by the EBN. This results in a dummy variable in the exploration regression which is 1 in 2000 and later, and 0 before that year.

Interaction between the revenue and the DAW

If the expected oil price is very high then many mining projects are profitable and non-financial restrictions may become binding. In that case the DAW will have little effect. Hence the effect of one variable may depend on another variable: the are said to interact. This interaction can be modelled by the multiplication of the variables; see Appendix B for a detailed description. See also the financial analysis of investment projects described in the next chapter.

Other details of the model

Note that even after one has chosen the above specification, decisions must still be made about the precise time lags, the precise definition of variables, etcetera. Some of these decisions are arbitrary but may have an impact on the result. Inevitably this leads to some “data mining”: repeatedly computing a slightly different regression and see if it gives a satisfactory result. We think that there is no point in, say, evaluating the effect of the DAW using an obviously nonsense regression with a negative influence of the oil price. Appendix B shows a few variants of the regressions, reminding us that the uncertainty about the estimates not only comes from the formal standard errors, but also from the uncertainty about the precise specification.

3.3.3 Results

The tables below show the estimation results for the two equations. The equations are estimated such that the coefficients of the numerical explanatory variables are elasticities, showing the percentage change in the variable to be explained resulting from one percent change in the explanatory variable. The effect of the DAW is given as a relative change in the variable to be explained. To find this relative change, the "raw" regression coefficient must be transformed into a relative change.[7] The value of the constant term is not shown, since it is a meaningless number here.

The development equation has been estimated for all blocks, and also separately for all K and L blocks (with the largest gas fields) on the one hand and all other blocks on the other.

The revenue (price minus costs) per unit of product plays an important role, in particular in the development equation: one percent increase in revenue gives one percent increase in development drilling. In the exploration equation, the coefficient of the revenue is smaller but still highly significant (in other words, the standard errors in both cases are small). As an explanation of this difference, note that in the development phase the revenue comes sooner and is less uncertain than in the case of exploration.

As discussed above, the use of the observed oil price is somewhat controversial. We find these regressions convincing enough to base our main findings on their outcome; note also the role of the oil price in past econometric research shown in Appendix A. In Appendix D we give results of the financial analysis for several alternative values of the long run oil price.

The successful exploration in the same block also has a large effect; also with a small standard error.

Table 3.1 Estimation results of the exploration equation

	"raw" regression result		transformed to rel. change	
	coefficient	standard error	coefficient	standard error
(Constant term)				
Expected revenue: long run deflated oil price minus costs	.4	.1		
Change in the DAW	.9	.3	1.4	.7

Note: Time period = 1981-2003; R^2 = 0.45

[7] This transformation is exp(*a*)–1, where *a* is the "raw" coefficient. This increases the value. For *a* near zero the increase is relatively small. See Appendix B for the mathematics.

Table 3.2 Estimation results of the development equations without interaction

	"raw" regression result		transformed to rel.change	
	coefficient	standard error	coefficient	standard error
All blocks				
(Constant term)				
Expected revenue: long run deflated oil price minus costs	.8	.1		
Previous successful exploration in the same block	1.0	.1		
DAW	.6	.2	.8	.3
Note: Used data of years × blocks = 769; R^2 (from OLS) = 0.14				
Only K and L blocks				
(Constant term)				
Expected revenue: long run deflated oil price minus costs	.5	.1		
Previous successful exploration in the same block	.6	.1		
DAW	.4	.2	.5	.3
Note: Used data of years × blocks = 408; R^2 (from OLS) = 0.06				
All other blocks				
(Constant term)				
Expected revenue: long run deflated oil price minus costs	1.3	.2		
Previous successful exploration in the same block	1.7	.2		
DAW	1.2	.4	2.2	1.4
Note: Used data of years × blocks = 361; R^2 (from OLS) = 0.26				

Table 3.3 Estimation results of the development equations with interaction (all blocks)

	"raw" regression result		transformed to rel. change	
	coefficient	standard error	coefficient	standard error
(Constant term)				
Expected revenue: long run deflated oil price minus costs	.8	.1		
Previous successful exploration in the same block	1.0	.1		
DAW	2.3	1.1	9.6	10.5
Interaction DAW × Expected revenue	– .729	.5	– .861	
Total DAW effect			0.5	

Note: Used data of years × blocks = 769; R^2 (from OLS) = 0.14

The ("pure") DAW effect of 9.6 means: with zero expected revenue, the DAW increases the number of wells 1+9.6=10.6 times. (Note however that, as discussed in Appendix B ("Double log"): with zero revenue the model outcome is zero wells.)
The transformed interaction is computed as ((25–10) $/barrel to the power –0.729) – 1 = –0.861. See Appendix B for the mathematics.
The total DAW effect is computed as (1+9.6) × (1–0.861) – 1 = 0.5

The results of the development equation differ between K and L on the one hand (with large fields), and the rest on the other. Outside K and L, development is more sensitive to the explanatory variables.

In the exploration equation, the DAW proved to be relevant only in the form of its change: when the DAW is introduced is has a positive impact on exploration activities. This effect disappears, however, quickly afterwards. The size of this “change effect” is considerable, with a small standard error. Maybe the firms suspected (correctly) that the DAW might possibly not be forever, and used the possibly limited time window for a one-time extra effort.

The exploration equation is shown without interaction. This choice was made after we estimated all four combinations of either the DAW itself or its change, combined with the model with or without interaction. Both with and without interaction, the R^2 of the DAW equation was about 0.26, compared to 0.45 with the change of the DAW. In our opinion, this rules out the DAW equation, in favour of the change DAW equation. However, the interaction term in the change DAW equation was +0.05, while a positive value is not logical. This value, however, is practically zero[8]. Also the coefficient is very small compared to its standard error of 0.8.

In the development equation, the effect of the DAW is related to its level and not to its beginning and ending. The existence of the DAW leads to 50 to 80 percent increase of development wells (all blocks). This effect is not visible in the aggregated data presented in Figure 3.2. So, the use of regression analysis with data per block has added insight.

The other fiscal measure (EBN participation) had a negative but not significant effect on exploration, as is shown by the sensitivity analysis depicted in Appendix B. Therefore, this variable has been omitted from the equation above.

The introduction of interaction in the development equation makes the results a lot more complicated. The effect of the DAW is split in two parts, the “pure” effect of the DAW and the interaction effect. These effects are very large and have opposite signs. The total DAW effect is given in the table, with its computation at the bottom of the table[9].

[8] For the appreciation of the magnitude of this coefficient, see the computations with the interaction coefficient at the end of the table with the results of the development equation with interaction. Here we have (15 to the power 0.05)–1=0.1, while the “pure” DAW effect in that regression is, transformed to a relative change, equal to exp(0.7269)–1=1.1.

[9] In principle, the interaction between two variables is symmetrical. Hence a similar total effect might be computed for the revenue variable. Analogously, the “pure” revenue effect is the revenue effect when the DAW is zero and the total revenue effect is the revenue effect with the DAW equal to some reference value. The latter has no meaning, but one might compute the total revenue effect with the DAW=1. This is simply the sum of the “pure” revenue effect and the “raw” interaction term: 0.8+(–0.7)=0.1. See Appendix B for the mathematics.

Finally, although in the development equation the revenue coefficient and the exploration coefficient have very small standard errors, the R^2 of this equation is not large. This is of course due to the use of data per block, with a lot of variation to be explained. Note that we explain the number of wells in a particular block (not just K or L, but K1, K2, L1, L2, etcetera) and in a particular year. If this was explained with a high R^2 then we would have made a mistake, since it is impossible to predict this with only the information used in the regression. (For micro-economic work an R^2 of 14% is a normal value.) The exploration equation, where we have used aggregated data, has a much higher R^2: 46%.

3.3.4 Results derived from the regressions

It is interesting to compute which oil price increase is required to give the same effect as the DAW – assuming the above estimates are the true values. For example, consider the development regression without interaction, for all blocks. The effect of the DAW is 0.8 and the elasticity of the revenue is also 0.8. Hence the effect of the DAW on development is equivalent to a revenue increase of 0.8 (DAW) / 0.8 (revenue) = 100%; this revenue increase gives (in the model) an increase of 80% in the number of development wells. With, say, a revenue of 15 dollar per barrel, this requires an increase in the revenue of 15 dollar per barrel. Considering the costs as fixed, this is also the required increase in the oil price. Given the uncertainty regarding the estimation results, this figure has to be viewed as the best estimate amidst a rather large confidence interval: plus or minus twice the standard deviation of the DAW effect gives a relative error margin of $\pm$ 2 $\times$ 0.3 / 0.8 = $\pm$ 3/4. Applied to the estimate of 15 dollar per barrel, this margin is about 11 dollar per barrel and gives an interval of 4 .. 26 dollar per barrel. (For simplicity, we ignore the small standard error of the revenue coefficient.) Using the results of the regression with interaction, a lower figure results.

Also it is interesting to compute at what long run oil price the effect of the DAW has reduced to zero due to the interaction between these two variables. This price is equal to the exp function applied to minus the ratio of the “pure” DAW coefficient and the “raw” interaction coefficient. (See Appendix B for the mathematics.) The result is exp(2.266/0.729) = 22 dollar per barrel. Assuming costs equal to 10 dollar per barrel, this gives a long run oil price of 32 dollar per barrel. Note that this 2.266 is given as 2.3 in the table. With the latter, the result would be 23 and 33 dollar par barrel, as the reader might easily figure out. However, working with several decimal places is of limited value here since the two numbers in the exp expression have large standard errors; with a margin of twice the standard error (as above) the result is useless, with the numbers in the exp expression having a negative lower bound.

3.4 Conclusions

- The level of known natural gas reserves at the Dutch Continental Shelf has not much altered since the mid 1970s. Recently, however, the level of reserves has shown a decreasing pattern, mainly as a result of the relatively low level of new finds. Whether this development indicates a declining geological prospectivity of the Dutch offshore area is not fully clear.
- The econometric regressions show the main determinants of exploration and development as one would expect. The revenue based on a long-term average oil price is a major determinant. Exploration and development seem to react quite fast to changes in the oil price: already after a few years, rather than after decades. Development drillings responded stronger to the level of the long-term oil price than exploration drillings.
- The econometric analysis has produced a mixed picture on the effect of the DAW on mining activities. This fiscal measure had a temporary effect on the level of exploration activities and a continuing effect on development activities. The effect on exploration might be a one-time increase of 80%, meaning that the introduction of the DAW resulted in an immediate 80% increase in the level of exploration drillings in the same year which effect fully vanished in the years after. The effect on development is estimated as a 50 to 80% increase during the DAW period. The 80% is equivalent to a 4 to 26 dollar per barrel oil price increase.
- Summarising and explaining the above two conclusions: compared to development drillings, exploration drillings appear to be less sensitive to financial factors such as the oil price and the DAW. The high financial sensitivity of the latter is related to the position of development in the chain of mining activities: development decisions come only to the fore when an exploration drilling has been successful. As a result, the expected cash flow of the development project is one of its major determinants. Exploration drillings depend, however, on many other factors, such as geological research and licensing and environmental procedures. In the next chapter, we will analyse, among other, the relative impact of all those factors.

4 Ex ante analysis of impact on gas production, government budget and employment

4.1 Introduction

This chapter goes deeper into the relationship between investment climate and level of activities of the gas industry. This chapter starts with a concise overview of factors affecting investment decisions of the upstream gas industry. Afterwards, we arrive at the core of this chapter: the financial analysis of the impact of the DAW on the profitability of investment projects at the Dutch Continental Shelf. Then, we analyse the relationship between fiscal measures and government budget. The last object of the analysis of this chapter is the likely impact of the DAW on employment in the upstream industry, including the industry supplying to it. The chapter ends with the conclusions on the effects of implementation of the DAW on the magnitude of offshore gas activities, the government budget and employment.

4.2 Investment climate

A number of factors affect investment decisions of the upstream gas industry. In order to get more insight in the impact of these factors, we had several meetings with representatives of the gas industry.[10] In addition, we studied several publications on this issue. As a result, we have made the next overview of factors affecting offshore activities at the Dutch Continental Shelf.

The small-fields policy of the Dutch government, in particular the guaranteed offtake by Gasunie, has offered favourable conditions for investments at the Dutch Continental Shelf.[11] The small-fields policy has had a positive effect on the cumulative size of offshore depletion (see e.g. Peebles, 1999). In the near future, however, "owing to market liberalisation and the foreseen split of Gasunie into transport and supply companies, it may no longer be possible for Gasunie to continue its present role" (IEA, 2004). Although the guaranteed offtake by Gasunie has provided a benefit to the producers, the dominance of this player could have negatively affected the annual magnitude of Dutch offshore production. Gaffney, Cline & Associates (2003) state that 'this has resulted in overall lower depletion rates for Netherlands offshore fields than for similar sized fields in other sectors".

[10] I.e. NAM, Total, Wintershall, BP, Gas de France, Nogepa (industry association) and IRO (association of suppliers in the oil and gas industry)

[11] Recently, however, uncertainty has arisen about the Gasunie policy in the near future. As Gasunie bought more than they were obliged in the past, it has the option to buy less than their contractual obligations in the future, which happened already in 2003.

The North Sea area is fairly mature with an alleged gradually declining prospectivity since 1990.[12] However, “its political stability and proximity to major European consumer markets have allowed it to play a major role in world oil and natural gas markets” (EIA, 2003). “North Sea natural gas has a geographical advantage over other world natural gas sources, as North Sea natural gas is closer and therefore less expensive to transport to major European markets. Most of continental Europe is already linked, directly or indirectly, to North Sea natural gas sources.” (EIA, 2003).

The Dutch offshore infrastructure has continually improved since 1990, which has reduced costs and time of development of new fields. In the future, however, several platforms will be abandoned which will make conditions less favourable for new projects.

The costs per unit of production steadily declined in the 1990’s[13] due to improvements in technology, such as more and better seismic data, which continuously enhanced efficiency and efficacy of exploration (Gaffney, Cline & Associates, 2003). Quoting Peedles (1999), giving an overview of Dutch gas market and policies, “The Netherlands is one of the countries at the leading edge of technological exploration and production advancement”.

The British Department of Trade and Industry (DTI) also sees a continuing cost reduction. According to information given at their website (www.og.dti.gov.uk) costs of gas production at the North Sea decreased from 26 pence per therm to 14 pence per therm in 2003 (in 2003 prices). For oil fields, including condensate fields, costs declined from 17 pound (or 25 euro) per barrel to 7 pound (or 10 euro) per barrel (again in 2003 prices).

Fiscal conditions were fairly stable and steadily improving until the abolishment of the DAW in 2003. According to the gas industry, the latter measure reduces the attractiveness of the Dutch offshore region strongly. In a press release issued during political debates on the abolishment of the DAW in the autumn of 2002, Nogepa, the industry association, alarmed that the abolishment would have dramatic effects on gas production, employment in the gas industry and state revenues.[14] The IEA (2004) advices to consider the reintroduction of the DAW when the cost-effectiveness of this measure has been determined.

In its Energy Report 2002 (Ministry of Economic Affairs, 2002), the Dutch government mentions regulation issues as an important factor affecting offshore activities. The time needed to pass through environmental and spatial procedures seems to be a serious obstacle for a timely

[12] This statement on a declining prospectivity is, however, not strongly supported by time series on Dutch offshore gas activities and remaining reserves, as is shown in Chapter 3.

[13] Although costs have risen recently due to increased demand for contractor activity following the high oil price.

[14] ‘Kabinet schiet in eigen voet door schrappen fiscale maatregel’, Press Release of NOGEPA, Association of Dutch Suppliers in the Oil and Gas Industry, September 2002.

further development of the offshore area. This factor is also mentioned by the IEA in its latest review of Dutch energy policies (IEA, 2004). This international agency sees political sensitivity of investments projects underneath environmentally valuable areas, licensing and permitting procedures as factors delaying projects. The IEA also mentions a policy option which the Dutch government would consider: “making licensing conditional on actual exploration and production activities because at present, some license-holders are not active and are consequently blocking the development of their area from other possible developers”. Further on in this document, we will refer to this policy option when we discuss the likely effects of the DAW.

In 2000 and 2003, Gaffney, Cline & Associates (GCA) conducted comparative studies of the offshore exploration and production climate in the Netherlands, United Kingdom, Norway, Denmark and Germany. These studies were conducted on request of Energie Beheer Nederland (EBN). Table 4.1 depicts the main results of the 2003 study. The Netherlands’ offshore area occupies a midst position among the North Sea countries. Denmark offers gas firms the best investment climate in all cases analysed in the GCA study while conditions in Norway and Germany are relatively bad. In its 2003 study, GCA concluded in addition to their conclusions on investment climate that the abolishment of the DAW in the Netherlands “has had a detrimental effect upon project economics” (GCA, 2003), confirming the statements of the gas industry mentioned above. GCA concludes further that “the effect of changes (especially the abolition of DAW) to the Netherlands’’ fiscal system from 2000 to 2003 (…) has reduced its attractiveness to investors in relation to what has happened to the other sectors”.

Table 4.1 Ranking of North Sea countries [a)] against investment climate [b)] for new entrants and tax efficient firms, in two oil price cases

New entrant		Tax efficient company	
Oil price of 18 dollar per barrel	Oil price of 24 dollar per barrel	Oil price of 18 dollar per barrel	Oil price of 24 dollar per barrel
Denmark (1.8)	Denmark (2.6)	Denmark (3.1)	Denmark (4.4)
Netherlands Onshore (0.1)	Netherlands Onshore (0.7)	Netherlands Onshore (1.3)	Norway (3.8)
United Kingdom CNS (– 0.4)	*Netherlands Offshore (0.2)*	United Kingdom CNS (0.1)	Netherlands Onshore (2.4)
Netherlands Offshore (– 0.6)	United Kingdom CNS (0.2)	*Netherlands Offshore (– 0.2)*	*Netherlands Offshore (1.3)*
United Kingdom SNS (– 0.7)	United Kingdom SNS (0.1)	Norway (– 0.2)	United Kingdom CNS (1.1)
Germany (– 0.9)	Norway (– 0.1)	United Kingdom SNS (– 0.3)	United Kingdom SNS (1.1)
Norway (–1.0)	Germany (– 0.8)	Germany (– 0.8)	Germany (– 0.5)

a) CNS: Central North Sea; SNS: Southern North Sea
b) Investment climate is measured by the ratio of the average Expected Monetary Value of investment projects (EMV) to the average Dry Hole Costs (DHC) (see section 4.4). The values of this ratio are expressed between brackets.
Source: Gaffney, Cline & Associates (2003)

How should we interpret that conclusion? Does it imply that the abolishment of the DAW would lead to a significant decline in offshore activities in the Netherlands as is warned by the industry association? In order to discuss this question, we organised a meeting with GCA. After the meeting, GCA wrote a letter describing their view on this issue (see Appendix C). Below, we summarise the view of GCA:[15]

- The DAW is a factor affecting investment decisions, but not the only one. The conclusion on DAW in the above-mentioned report depends very strongly on the assumptions made. It is appealing to focus on this fiscal measure, because it is fairly easy to analyse. As a result, this measure gets easily more attention that it deserves. Re-implementing the DAW would mainly affect the incumbents. Without any accompanying measures or conditions requested, this measure will likely not have a significant impact. If the government wants to re-implement this measure again, it should request some specified activities by the firms in return.
- Investments in the Dutch offshore area are seriously hampered by ill-functioning communication. Dutch websites don't give sufficient information on aims of the policy, rules and measures taken by the government, the availability of pipelines, geological data, etc. Websites of the UK, Norway and in particular Australia are much better. The Dutch government should primarily improve access to opportunities in the Netherlands' offshore area.
- The Netherlands have a very good infrastructure and location near to the market and a good culture, for instance regarding the use of pipelines and the rewards asked for it. Moreover, the Dutch region is characterised by shallow water which reduces costs. The Netherlands lack, however, scale. And, as said above, its communication is poorly developed.
- Most Dutch firms have been active in the region for many years. In the UK, for instance, much more dynamic exists: firms leave, firms arrive. An advantage of the latter is the availability of more new ideas on the way things could be done. Dynamics come, however, at a cost: changes in the firm structure coincide with transaction costs. The Dutch government should ask itself whether it needs more new players in the market or whether it prefers the stable structure currently present. If the former holds, the next question is: which measures should be taken in order to attract those new firms? Regarding the DAW: is this fiscal measure the most appropriate one to realise that goal?

[15] This section is based on a meeting with Bob George, Chris Rachwal and Paul McGhee at the office of Gaffney, Cline & Associates (GCA) in Bentley (UK), 26th of May, 2004. Appendix C contains a letter of GCA written after that meeting.

4.3 Financial analysis of investment projects

4.3.1 Introduction

In order to assess the economics of exploration and development projects, gas firms conduct cash flow analyses. These analyses aim at determining the net present value of all future costs and benefits of a project. Economically, a gas reserve is only recoverable if that value is positive. As fiscal measures directed at these projects affect the size of the net present value, both firms and government conduct financial-economic analyses to assess the impact of such measures. In the Netherlands, EBN and TNO-NITG have collected data and developed tools to analyse the effect of fiscal measures on the economics of investments projects in the upstream gas industry. Fortunately, both institutes supported us in analysing the impact of the DAW on the cash flow of the investments projects at the Dutch Continental Shelf. This section depicts the main results on that analysis, while Appendix D give more information on data and models used and the results of a sensitivity analysis. As the results of any cash -flow analysis strongly depends on assumptions made, we start this section with a discussion of the key assumptions. Next we describe the results and afterwards we formulate our conclusions.

4.3.2 Method and assumptions

As the expected impact of the DAW on investments strongly depends on financial assumptions made, we should give careful attention to the choice of these assumptions. Below, we motivate our choices for the financial criterion to select an investment project, the discount rates used by the gas industry as well as the government, and the oil price used by the gas industry to assess the future price of natural gas. Before discussing these financial assumptions, we have to stress the scope of the financial analysis.

Scope of the financial analysis

By means of the analysis of future cash flows, we determine whether investment projects are hampered by their financial characteristics. If this is the case, improving financial conditions could result in a higher number of investments in reality. If, however, investments are hindered by non-financial restrictions improving financial returns of a project does not affect investment decisions. Consequently, we should take in mind the existence of other possible restrictions when we interpret the results of the financial analysis. In case of offshore mining activities, institutional factors, such as the duration of licensing procedures and the access of new firms to blocks and infrastructure, restrict the pace by which projects could be undertaken. Moreover, characteristics of the physical infrastructure constitute a limit on the annual level of activities of the gas industry. The current size of exploration activities (about 10) is significantly below the historical peak level (40), but raising the number of exploration drillings to the historical peak level would costs several years in order to pass through regulations on environment etc.. Over and above, due to the licensing of spatial blocks the number of firms that could shortly undertake a profitable project in a certain block is restricted to the holder of the license.

Moreover, we should also take into account dynamic factors affecting the outcome of a cash flow analysis. For instance, not all financially-restricted projects which need the DAW to become economically acceptable for the gas industry will be cancelled for ever if this measure is not implemented again. Firstly, firms could sometimes redesign investment plans in order to raise profitability. In other words, the optimal design of a project depends on the characteristics of the economic environment, such as the fiscal scheme. Secondly, continuing technological improvements will further reduce the costs per unit and, hence, increase the volume of economically recoverable prospects. Projects which seem now to be uneconomic could turn profitable in the near future without any change in the fiscal regime.

Financial criteria

Investments projects are usually assessed by analysing the future cash flows of a project. The results of such an analysis can be expressed in several quantities. In our analysis we use the Net Present Value (NPV), the Expected Monetary Value of the NPV (EMV) and the Internal Rate of Return (IRR). The NPV, which is used for development projects, is the discounted value of all future cash flows in case of a successful drilling. The EMV, which is used for exploration projects, is based on the NPV, the probability of success and the costs in case the drilling is not successful (the dry hole costs). The IRR is the discount rate which equalises the present value of benefits to the present value of the costs, thus making the NPV or EMV equal to zero.

In addition to these criteria, firms use other criteria to rank projects against each other. One example of such a criterion is the Risked Value to Investment Ratio (RVIR) (see Appendix D). Another ranking criterion is the ratio used by Gaffney, Cline & Associates (GCA, 2003): Expected Monetary Value (EMV) to exploration exposure measured by the Dry Hole Costs (DHC) (see Table 4.1). The ranking of economically recoverable investment project does, of course, not imply that less profitable projects will never be executed. The impact of ‘ ranking’ strongly depends on the degree of competition. If competition is hampered, for instance due to restricted supply of capital, ranking will have a larger effect on investment decisions than when firms operate in a fiercely competitive market without barriers to entry or invest. In the latter case, the industry will execute any profitable project which is available.

Firms differ in the weight they attach to ranking of profitable investment projects. The relative importance of ranking depends on the number of projects a firm has worldwide in its portfolio and the goals of a firm regarding a specific area, such as the Dutch Continental Shelf. Contrary to the EMV criterion, which assesses a project by the cash flows it generates, a ranking criterion, such as RIVR, should be applied by comparing all projects in a firm’s portfolio. As this is impossible for us to do, we use a rather arbitrarily level of the RVIR (0.1) as threshold value. Below, we will present the results of the financial analysis using both the EMV and the RVIR criterion.

Discount rate

In every cash flow analysis of investment projects, discounting of future cash flows play a crucial role. The choice of the appropriate discount rate should depend, among others, on the risks stakeholders face. In the case of the DAW, we distinguish two stakeholders: gas firms and the government.

In making their investment decisions, gas firms have to deal with several kinds of risks: technical, economic and political. The technical risk refers to the volume of gas which could be produced by drilling a well. The economic risk is related to the price of inputs and the gas price. The political risk, finally, refers to uncertainty about future government measures as well as political stability of a region.

The Dutch region offers a stable economic and political environment. As a result, the discount rate used in this region is significantly lower than in other regions of the world. In less stable regions, firms use nominal discount rate of 15% or even higher. In the Netherlands, however, all firms seem to use nominal discount rates in the range of 11 to 13%.[16] Given a rate of inflation of about 2%, the real discount rate is 10%. This level equals the ratio used by Kemp et al. (1992) in their analysis of the impact of fiscal systems on activities of the oil industry at the North Sea. The same ratio is used by GCA (2003) in its comparative study of exploration and production climate at the North Sea Continental Shelf. Finally, the British Department of Trade and Industry (DTI) uses a discount rate of 10% in their analysis of the costs of producing oil and gas at the Continental Shelf (www.og.dti.gov.uk).

What is the appropriate rate for discounting the future government expenditures and receipts related to the project? There are two reasons why this discount rate should be lower than the discount rate used by firms. Firstly, the government faces fewer risks than gas firms investing in exploration and development. After all, the government only has expenditures, i.e. reduced tax receipts due to the DAW, when a firm invests in production facilities. At that moment, both firm and government fairly well know future returns of the project. That knowledge is primarily based on results of exploration, appraisal and/or development drillings done at an earlier stage. Those investments, in particular the exploration drillings, face a significantly higher risk. For instance, the average probability of a technically successful exploration drilling in the Dutch part of the Continental Shelf is approximately 40% (see Chapter 3). This fact is the main reason

[16] This conclusion is based on information given by representatives of several gas firms in several (bilateral) meetings at the office of CPB in June 2004..

why the appropriate discount rate for the government, related to the DAW, should be lower than the discount rate of the upstream gas industry. This does however not imply that the government does not face any risk regarding the DAW. After all, the returns of this instrument depend on the future gas price as that quantity determines the level of future tax obligations of the gas firms. The other reason for a lower discount rate for the government follows from the rule of large quantities. The government has, generally, far more options to diversify its risks than a private firm.

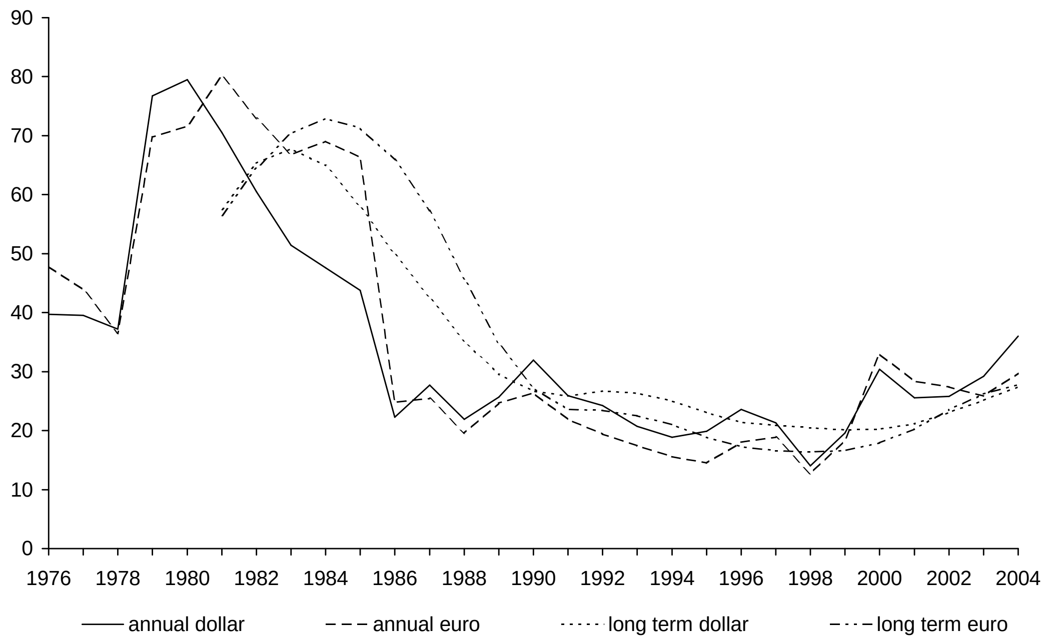
From this consideration, we conclude that the risk component of the discount rate for the government is relatively low. We assume 2% is a reasonable estimate for this component. The real discount rate includes this risk-component and the risk-free component. In the Netherlands as in many other countries, the risk-free rate is determined at 4% (Ministry of Finance, 2003). This rate is the average rate of return to government bonds over the past 200 years. As a result, the real rate for discounting government cash flows is 6%. In order to determine the sensitivity of the state revenues to the discount rate we also calculate the effects of 0%, 9% and 12% (see Appendix C).

Oil price

As the gas price is still strongly related to the oil price, the latter plays a crucial role in financial appraisals of investment projects of the upstream natural gas industry. The oil price which firms use in investment decisions refer to the long-term price. A proxy for that price is the long-term mean of historical levels. In the previous chapter we have analysed the relationship between mining activities and the oil price. It appeared that the 5 years weighted moving average of the real oil revenues (i.e. price minus costs) is a good explanatory variable of mining activities. The movements in this value are mainly determined by the volatility of the oil price. The 2003 value of the 5 years weighted moving average of the real oil price, corrected for changes of the euro-dollar exchange rate, was 26 dollar. The 2004 value will be 27 dollar if we use CPB’s latest forecast of this year’s oil price (36 dollar). As we can see in Figure 4.3, the current long-term moving average of the oil price in euro does hardly differ from the dollar price. In the results presented below, we have assumed an oil price of 25 dollars per barrel. The sensitivity analysis in Appendix D analyses the impact of an oil price of 20 dollar.

Our estimate of the long-term oil price, based on econometric analysis of past data, is about equal to the present long-term futures price, as is noted by Greenspan in a recent speech on energy prices: “Currently prices for delivery in 2010 of light sweet crude, roughly equal to West Texas Intermediate, have risen to more than 27 dollar per barrel. A similar pattern is evident in natural gas” (see www.federalreserve.gov). A recent press release of Shell (dated September 22, 2004) gives more proof to our finding that firms now use higher values for their long-term oil price than they did in the past. That release states that “Shell plans for medium term cash neutrality at around 25 dollar per barrel”.

Figure 4.1 Real oil price, in dollars and euro per barrel, both annual average as well as 6 years moving average



4.3.3 Results

This section gives the results of the financial analysis which is on our request conducted by TNO-NITG and EBN. Appendix D offers more information on the data and model used by the former institute and also gives the results of the sensitivity analysis.

Table 4.2 Impact of DAW on magnitude of economically recoverable prospects at the Dutch Continental Shelf, in two variants

Oil price = 25 dollar **Real discount rate:** **- firms: 10%** **- government: 6%**	EMV > 0		RVIR > 0.1	
	DAW	No DAW	DAW	No DAW
Total number of geologically defined prospects	974	974	974	974
Economically recoverable prospects:				
- number	357	258	204	121
- total size (billion m^3)	299	257	235	180
- state revenues (present value in billion euro)	4.86	5.06	4.39	3.98

Note: These results are based on the assumptions that all projects could immediately be executed.
Source: TNO-NITG

Introduction of DAW raises the number of economically recoverable projects from 258 to 357 (EMV > 0) or 121 to 204 (RVIR > 0.1). The impact of the introduction of this measure on the size of the recoverable projects appears to be smaller: this quantity increases from 257 to 299 (EMV > 0) or 180 to 235 billion m^3 (RVIR > 0.1). This implies that the DAW particularly affects relatively small projects, i.e. projects with a relatively low arithmetic product of field magnitude and probability of success. In other words, prospects with a low probability of success (i.e. a high risk of failure) or prospects of a small size benefit relatively strongly from the DAW.

The overall impact of the introduction of the DAW on (the present value of) the state revenues would be about 0.20 billion euro negative (EMV > 0) or 0.40 billion euro positive (RVIR > 0.1). This impact is made up of two components (see Table 4.3). On the one hand, projects which are economically recoverable without the DAW benefit from this facility without being affected. In these cases, expenditures on the DAW are a 'dead weight loss'. The size of this loss is about 0.25 to 0.40 billion euro. On the other hand, marginal projects which benefit from the DAW could be affected by the introduction of this measure, raising the level of activities and, hence, resulting in additional tax earnings. In these cases, the net impact on tax earnings is about 0.20 to 0.65 billion euro. The difference between these two effects is the above mentioned – 0.20 to 0.40 billion euro being the total impact on state revenues.

Table 4.3 Net tax earnings and ' dead weight loss' of DAW, in two variants (in billion euro)

Oil price = 25 dollar **Real discount rate:** **- firms: 10%** **- government: 6%**	EMV > 0	RVIR > 0.1
'Dead weight loss' (= tax expenditures on profitable projects) [a]	– 0.40	– 0.25
Net tax earnings on marginal projects [b]	0.20	0.66
Net tax earnings on all projects	– 0.20	0.41

[a] profitable projects are defined as projects with a positive EMV/RVIR > 0.1 without the DAW
[b] marginal projects are defined as projects with a positive EVM/RVIR > 0.1 due to the DAW
Note: These results are based on the assumptions that all projects could immediately be executed.
Source: TNO-NITG

In order to test the sensitivity of these results to assumptions made, TNO-NITG conducted also a sensitivity analysis on our request. Appendix D depicts the results of that analysis. It will be obvious that the choices of the discount rate, the oil price and the financial criterion strongly affect the magnitude of the model results. In all cases, however, introduction of the DAW has a positive effect on the number and the total size of economically recoverable prospects.

Figure 4.2 Relationship between depreciation rule, screening oil price and number of recoverable projects (variant: EMV > 0)

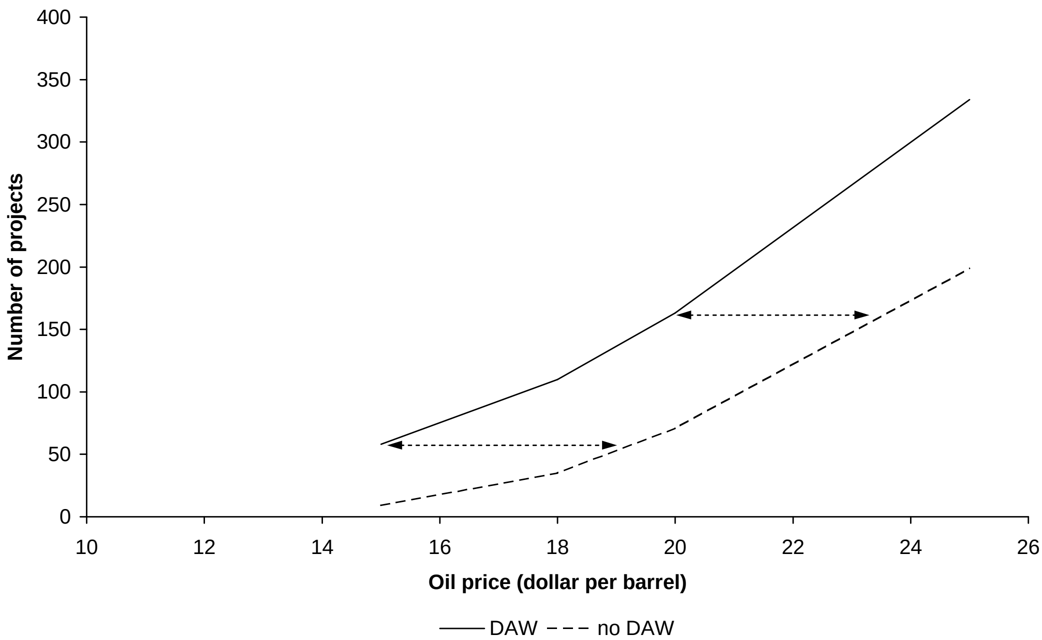
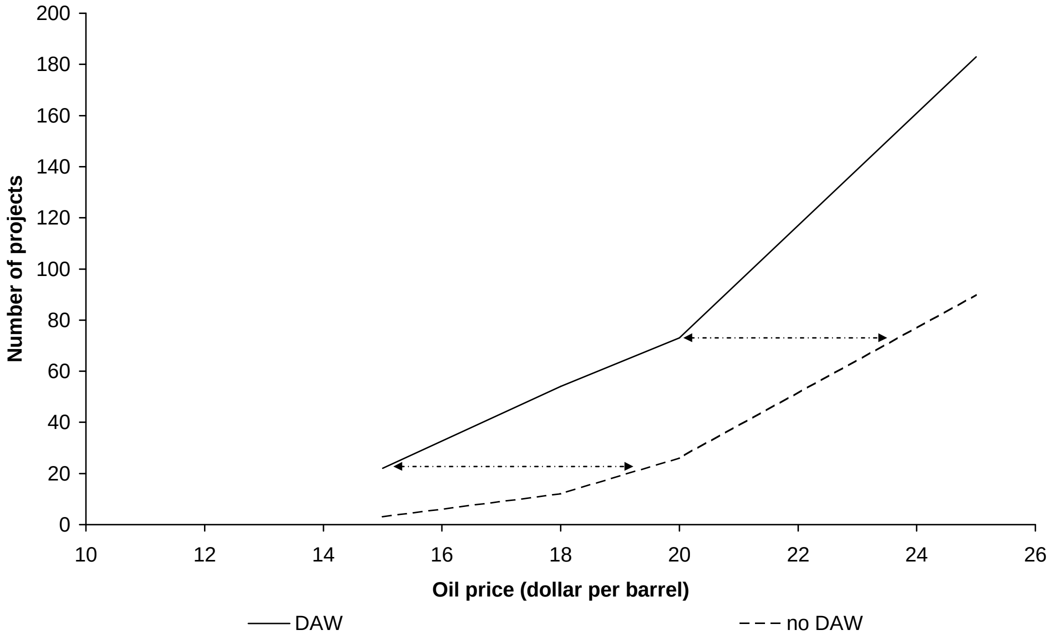


Figure 4.4 shows the impact of the DAW on the number of profitable projects in relation to the assumed oil price. No matter the level of the oil price, introduction of the DAW raises the number of economically recoverable prospects. This figure enables us to express the impact of the DAW in an increase of the oil price. It appears that this impact is about equal to a 4-dollar rise in the oil price, no matter whether we use the EMV or the RVIR criterion.

Figure 4.3 **Relationship between depreciation rule, screening oil price and number of recoverable projects (variant: RVIR > 0.1)**



Non-financial restrictions

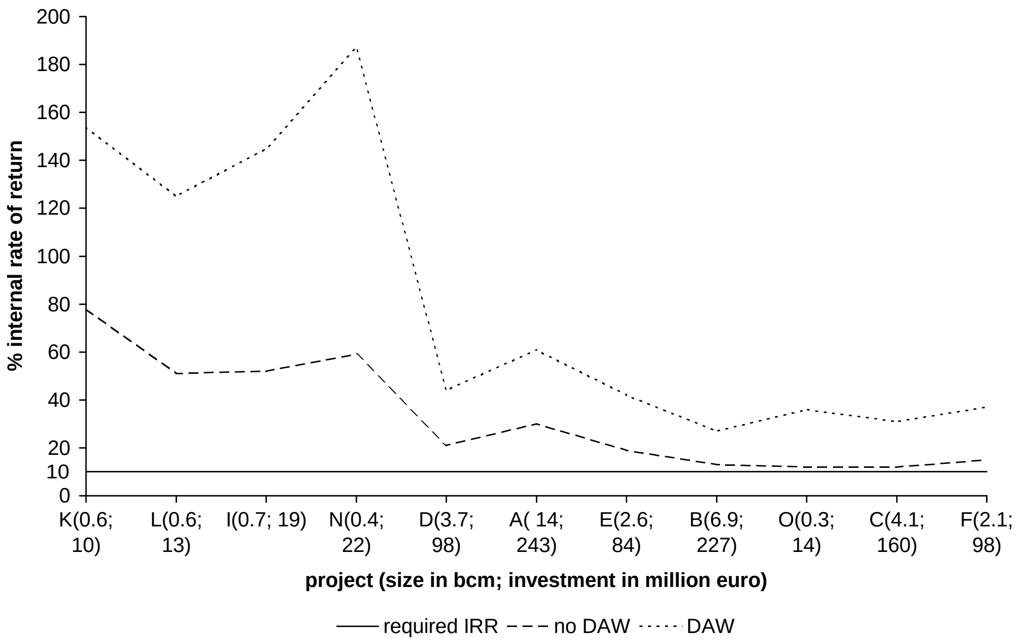
The results presented above only hold if no other restrictions would hamper investments. This is, however, not the case. The size of offshore activities is also limited by other factors, such as institutional factors and the characteristics of the physical infrastructure. Before a profitable project could be executed, regulatory procedures have to be passed through. In addition, each of the pipelines at the Continental Shelf has a maximum capacity. Historical maximum levels of activity give an idea of the magnitude of these restrictions. The highest number of exploration drilling in the past was about 40 (1992) while the average annual of exploration drillings in the 1980-s, the peak period of offshore activity, was about 30. If we compare that level with the number of financially sound projects without DAW (see Table 4.2), we have to conclude that the financial characteristics do not constitute a restriction on offshore activity in the near future.

4.3.4 Analysis of ‘ dead weight loss’

The TNO-NITG analysis has shown a significant volume of dead-weight loss. In order to increase our understanding of this effect, we analysed a number of individual projects using data and model results of EBN (see Appendix E). From this analysis follows that the DAW influences the profitability of *all* projects, but that it does not affect the investments decisions in all cases. These investment projects can be called ‘free riders’ as they would benefit from this fiscal facility without being affected. The tax expenditures directed to these projects are the ‘dead weight loss’ of the DAW.

A large number of projects generate a positive net present value and a relatively high internal rate of return without the DAW. Figure 4.6 shows the Internal Rate of Return (IRR) of several development projects in relation to the DAW. Four, relatively small projects have a high IRR without the DAW (i.e. between 50 and 80%), while the IRR of three projects is about equal to the required level (of 10%). The DAW raises the profitability of all projects (far) above the required level.

Figure 4.4 Internal rate of return of several development projects, with and without DAW (source: EBN)



4.4 Relationship between fiscal measures and government budget

In this section, we give a concise survey of economic literature on the impact of changes in national tax regimes on location decisions of firms. What is the impact of national fiscal measures on investments and location decisions? Should governments pursue an internationally competitive fiscal regime in order to encourage economic activities within the national domain?

There is a fair amount of consensus that hosting a large capital stock is beneficial for national welfare. It concords with a high labour productivity and a broad capital income tax base. Therefore, countries attempt to attract capital by nourishing a favourable fiscal climate and a good infrastructure network. For instance, the Dutch fiscal authorities directly negotiate with large foreign investors about their tax treatment, and the government heavily subsidises rail and road links as well as industrial estates.

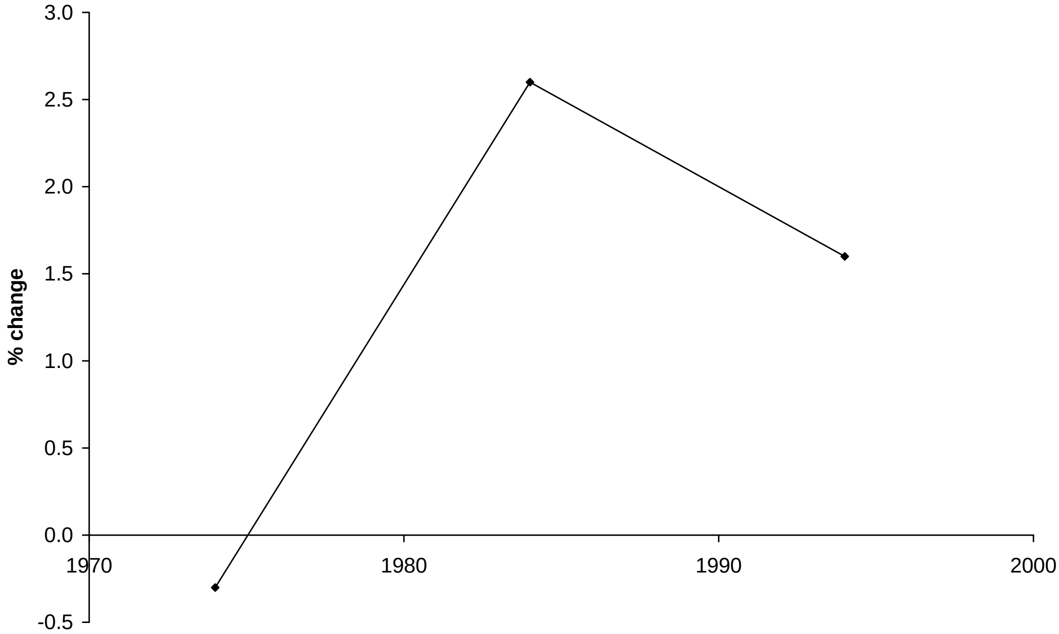
Countries thus compete for the same capital. Whether this process of policy competition is good or bad for social welfare is subject to a vigorous debate. Left wing politicians tend to favour the view that it leads to a race to the bottom with capital income tax rates, and erodes and distorts public expenditure. Right wing politicians, in contrast, tend to favour the view that it constitutes a useful check on their tendency to proliferate and guides public expenditure towards useful projects, namely those that increase the marginal capital productivity.

This section summarises the insights that economic science brings to bear on policy competition. It discusses the traditional, neoclassically flavoured, literature on tax competition, but also the more recent “New Economic Geography” in which the advantages of co-location of business activity play a central role. For its analysis and empirical example it draws heavily on a recent pre-advice by De Mooij et al. (2003).

The archetypical model of tax competition has been coined by Zodrow and Mieszkowski (1986). It contains two countries that supply public goods, financed by a capital income tax. Since capital is mobile internationally, supplying public goods involves a positive external effect: the necessary taxation leads to capital flight, beneficial for the other country. Hence, in the non-cooperative equilibrium, both governments set capital income tax rates that are excessively low from a communitarian perspective. They find themselves in a situation that resembles the prisoners’ dilemma.

Whether the Netherlands should adopt an aggressive strategy regarding capital income taxation depends on the degree of international capital mobility. This is an empirical matter. De Mooij and Ederveen (2002), in a state of the art meta-analysis of the existing literature, conclude that the point-elasticity of real foreign direct investment with respect to the effective capital income tax rate is roughly three percent. This means that if the Netherlands would increase its effective capital income tax rate by one percentage point, real foreign direct investment would in the long run decrease by three percent.

Figure 4.5 **Average effective capital income tax rate in the European Union**



Source: Martinez-Mongay (2000)

Is this a large or a small effect? European governments do not seem to think so. There is at best mixed evidence that they engage in tax competition. Figure 1 shows the changes in effective tax rates on capital income since 1970. In spite of the integration of European capital markets, these rates have increased, not decreased as was to be expected on the basis of analyses of the Zodrow and Mieszkowski type. The same holds true for social expenditure and other areas in which countries may engage in policy competition. The starting shot for the race to the bottom has as yet not sounded.

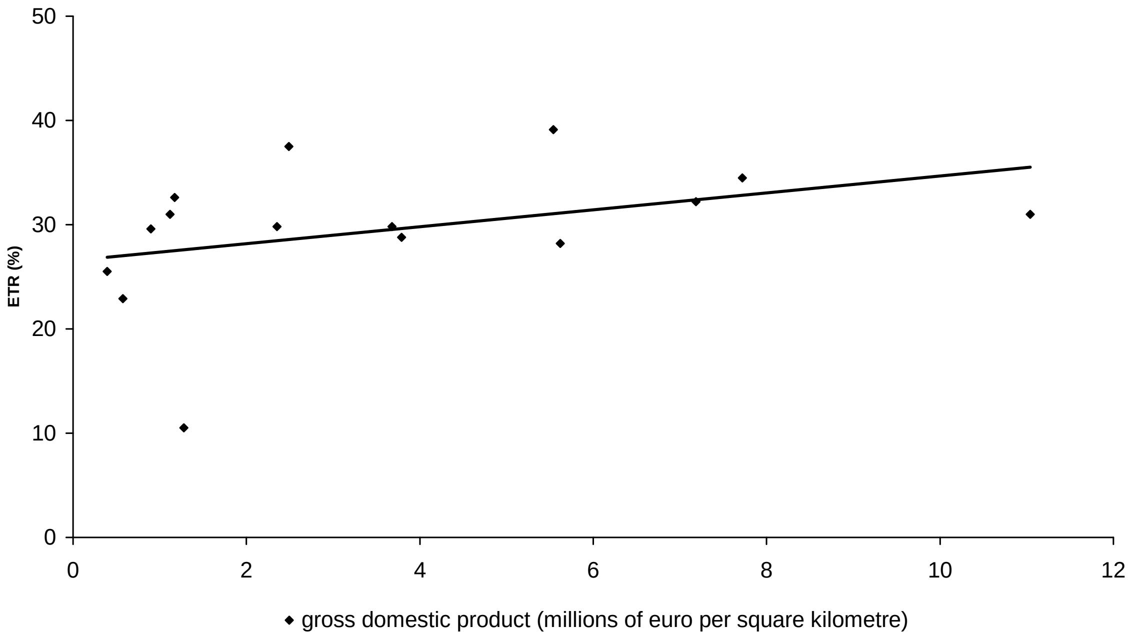
A recent development in economics - the 'New Economic Geography' - sheds light on the somewhat puzzling empirical evidence. Increasing returns to scale at the plant level imply that firms make location choices. Transport costs - broadly defined as anything that hampers trade between distant locations - imply that it pays off to locate close to the market. It yields benefits in the shape of lower costs due to cheaper inputs, and larger revenues due to larger sales.

These 'backward and forward linkages' create agglomeration externalities that precipitate as higher profits and wages in the core location compared to its periphery. They imply that, although capital is mobile ex-ante, it is immobile ex-post. This is what Kind et al. (2000) mean with a 'lumpy world', and Baldwin et al. (2004) with 'quasi fixed factors'.

The location specific rents in the core give rise to a 'sustain point tax gap', the maximal sustainable tax differential between the core and the periphery at which the core can keep its locational advantage compared to the periphery. As a corollary, economic integration not necessarily reduces the optimal tax on capital, but may also increase it. Ludema en Wooton (2000) and Baldwin et al. (2003) show that in the early phase of economic integration, the sustained point gap tends to raise due to increasing agglomeration rents. During this phase, economic integration may well lead to a ‘race to the top’.

Is there empirical support for a sustain point tax gap? Baldwin en Krugman (2004) report a positive difference between the corporate income tax rates in the European core - Germany, the Benelux, France, and Italy - and the periphery - Greece, Ireland, Portugal and Spain. A more sophisticated method is to regress the effective corporate income tax rate on gross domestic product per square kilometre - a measure of ‘coreness’ that evades the need for an arbitrary classification. Figure 2 shows that the estimate of the key parameter is positive and statistically significant, which backs up Baldwin and Krugman’s tentative observation.

Figure 4.6 Sustain Point Tax Gap



ETR: median effective corporate income tax rate calculated on the basis of the annual reports of medium and large corporations in the WORLDSCOPE database (Gorter and de Mooij, 2001).
SAMPLE: EU 15
PERIOD: 1990-1999

The existence of the sustain point tax gap in conjunction with the Netherlands pertaining to the core suggests that the Dutch government can, up to the sustain point, tax capital and still go scot-free. Giving tax allowances out of fear for capital flight is tantamount to panicky play.

(However true this may be taxation of capital income in general, the conclusions for gas depletion may be different due to the idiosyncrasies of the industry.) The New Economic Geography points at a number of conditions for strong agglomeration externalities. First, large economies of scale at the plant level raise the cost of spatially production. Second, a production process that requires a large amount of intermediate inputs enforces the forward and backward linkages. Third, intermediate transport costs tip the balance between the disadvantage of locating far away from final consumers in the periphery and the advantage of locating in the core in favour of the latter.

Agglomeration externalities thus lock capital into the core. This makes real investment less responsive to variation in tax rates than it would otherwise have been (but not totally immune). Whether it is still sufficiently responsive such that a decrease of the tax rate would result in an *increase of tax revenue* is an empirical question. We can apply the idea of the Laffer-curve (see Appendix E). In that Appendix, we conclude that the tax rate elasticity is likely smaller than −1. The responsiveness of the tax base is insufficient for the reintroduction of the DAW to be budget neutral. In other words, the positive impact of DAW in terms of a lower marginal effective tax rate and hence less distortions on investments decisions appears to be smaller than the negative impact of DAW in terms of a reduced tax burden on infra marginal profits.

Note, however, that we have made a number of assumptions in order to arrive at this result. Nevertheless, since we have loaded the dice in favour of Dutch revenue authorities, for example by abstracting from possible other restrictions of the gas industry, the guesstimate −0.91 should be interpreted as an upper bound of the responsiveness of investment to taxation.

4.5 Impact of DAW on employment

The impact of the DAW on employment of the gas industry is directly related to the impact on investments. If the DAW would raise the level of investment, employment in the gas industry as well as in the industry supplying to it would also increase. However, as the measure will hardly have any effect on the magnitude of offshore mining activities in the near future, the employment effects will likely be negligible. In addition, the industry supplying to the upstream industry increasingly operates on a global market, partly due to mature characteristics of the North Sea area. In its latest annual directory of Dutch suppliers in the upstream oil & gas industry, the IRO (the Dutch suppliers association) states that “it is important for the Dutch suppliers to spread their activities more internationally. Already, many companies have expanded their activities and, with their highly innovative technology, their success rate is high.” (IRO, 2004) Changes in the level of demand from the Dutch upstream sector, therefore, could be compensated by developments in other regions. As competition on the global market for gas supplies is rather fierce, the performance of the Dutch industry also depends on factors such as labour costs and productivity.

4.6 Concluding remarks

- Generally, conditions for offshore investment at the Dutch Continental Shelf are favourable due to the guaranteed offtake by Gasunie, the well-developed infrastructure, the shallow water and the location close to a large gas market. Compared to other North Sea countries, the Netherlands have a medium fiscal environment to the upstream industry. Factors which could hamper activities of the industry as a whole are the rather lengthy licensing and environmental procedures and the inactivity of several license-holders.
- DAW affects the (expected) profitability of all exploration and development projects. This impact differs strongly among projects. Although all projects benefit from the DAW, only a part of the projects do really need this facility. Depending on the choice of the financial criterion, 60 to 70% of all projects which are profitable with the DAW appears also profitable without this fiscal facility. In absolute terms, 120 to 250 projects are not financially restricted. This number exceeds largely the number of projects currently undertaken (about 10) and the highest level achieved in the past (about 40). So, other, non-financial factors, such as pre-drilling activities (geological research, interpretation of data, etc), environmental and licensing procedures and insufficient access to profitable prospects by new firms, determine the magnitude of offshore activities in the near future. Improving financial conditions by implementing the DAW would, therefore, not affect that magnitude.
- If all financially-sound investment projects would be undertaken immediately, the net impact on (the present value of) state revenues would be between −200 and 400 million euro. However, if we do take into account the impact of other factors affecting the level of mining activities, the net effect on state revenues would be negative. After all, firms would benefit from the fiscal facility on projects already profitable without the DAW. Tentative calculations based on general economic research support the conclusion that a reduction of the tax rate for the gas industry would result in a negative net impact on state revenues.

5 Conclusions

5.1 Effectiveness of the DAW

1. The ex post analysis suggests a mixed picture on the impact of the DAW on offshore drillings. The DAW had a once-only, but disappearing effect on the number of *exploration* drillings. Immediately after the introduction of the DAW this number surged, but rather quickly afterwards the number of exploration drillings decreased strongly. Consequently, the econometric analysis says that the DAW did not affect the overall level of exploration activities. Contrary to that result, the DAW did affect the number of *development* drillings during the period this facility existed.
2. The econometric analysis also suggests a strong relationship between mining activities and a moving long-term average of the oil price. Recent publications on the level of the future long-term oil price support this result. Both sources of information indicate that the current screening oil price has significantly risen due to the surge in the oil price in the past few years.
3. Compared to development drillings, exploration drillings appear to be less sensitive to financial factors such as the oil price and the DAW. The high financial sensitivity of the former is related to the position of development in the chain of mining activities: development decisions come only to the fore when an exploration drilling has been successful. As a result, the expected cash flow of the development project is one of its major determinants. Exploration drillings depend, however, on many other factors, such as geological research and licensing and environmental procedures.
4. The ex ante analysis of *exploration* projects, considering only the impact of financial restrictions for a group of (isolated) projects, has shown a positive effect of the DAW on the number of economically recoverable exploration prospects.
5. The immediate impact of the DAW also depends on other factors affecting investment decisions. If investments are hampered by other than financial restrictions, relieving the latter can not affect the investment. In the period when the DAW was implemented, revenues were significantly lower and projects, in particular development project, were hindered by financial constraints. Now, many exploration projects appear to be profitable without the DAW, even if we use a relatively strong financial criterion which some firms seem to use. In absolute terms, 120 to 250 projects are not financially restricted. This number exceeds largely the number of projects currently undertaken (about 10 per year) and the highest level achieved in the past (about 40). So, other, non-financial factors, such as pre-drilling activities (geological research, interpretation of data, etc), environmental and licensing procedures and insufficient access to profitable prospects by new firms, determine the magnitude of offshore activities in the near future. Improving financial conditions by implementing the DAW would, therefore, under current circumstances not affect that magnitude.

6. As the measure will hardly have any effect on the magnitude of offshore mining activities in the near future, the employment effects will likely be negligible. In addition, the industry supplying to the upstream industry increasingly operates on a global market, partly due to mature characteristics of the North Sea area. Changes in the level of demand from the Dutch upstream sector, therefore, could be mitigated by developments in other regions.

5.2 Efficiency of the DAW

1. The DAW affects not only marginal projects, but also infra marginal projects, i.e. projects being profitable without the DAW, resulting in a 'dead weight loss'. If we assume that all projects could immediately be undertaken, the present value (discounted against 6%) of the 'dead weight loss' amounts to about 0.25 or 0.40 billion euro. This involves about 60 to 70% of all projects already profitable without the DAW. The profitability, measured by the internal rate of return (IRR), of many projects within this category rise to levels far above 20%. In other words, the DAW wastes public means in many cases due to its non-targeted character.
2. If all financially-sound investment projects would be undertaken immediately, the net impact on (the present value of) state revenues could be a few hundreds of millions − positive or negative. If we include other factors affecting investments decisions in our analysis, which could postpone the execution of many projects, the net effect on state revenues would become negative. In the near future, the DAW would mainly generate 'dead-weight loss'.

5.3 Policy implications

The above conclusions on the effects of the DAW do not imply that no other changes within the fiscal regime should be considered. The effects of the DAW as stated above are comprised of two components: on the one hand, the DAW reduces the marginal effective tax rate and, hence, reduces tax distortions on investments; on the other hand, the DAW reduces the tax burden on infra marginal profits. It has appeared that the latter effect, in particular in the short term, is much larger than the former. In order to achieve a better performance of a change within the fiscal regime, the measure should focus on the reduction of the marginal effective tax rate. In other words, reducing the tax burden on marginal projects without relieving the tax burden on infra marginal projects would have positive effects on gas activities and government budget. In order to determine whether such a measure could practically and legally be implemented, additional research could be useful.

The question remains whether the government should take other measures regarding the offshore gas activities. In order to answer that question, we have to determine the outlook for this sector when no additional policies would be taken.

Contrary to what is often said, the geological prospectivity of the Dutch Continental Shelf has not strongly altered in the past years. The net changes in the magnitude of the reserves have fluctuated around zero, resulting in a rather stable level of remaining reserves. Also other indicators for prospectivity, such as the average field size times success rate, do not give worrying signs. Looking at the estimated relationships between oil price and offshore activities, we expect that the number of exploration and development drillings will increase in the near future.[17] After all, the North Sea area still is a relatively favourable area for gas production due to its political stability and proximity to major European consumer markets with a growing demand for gas.

A major factor which influences the size of offshore activity seems to be the market structure.[18] Many of the firms currently active on the Continental Shelf apply rather fierce financial criteria in their investment decisions due to insufficient competition on the upstream market. In order to encourage offshore activities in the medium term, policy measures could be directed at competition on the upstream market. Options to do so are improving licensing procedures and increasing the transparency of the market in order to attract new players to the offshore area and, hence, reduce the importance of ranking of profitable investment projects on the number of projects actually executed.

Experiences in other countries could offer useful lessons. The United Kingdom, for instance, has recently introduced several measures to attract new players to the North Sea. Although “it is difficult to quantify the scale of the impact of new entrants but clearly it will be positive” (Kemp, 2003). Those measures include the fallow field initiative encouraging activity on acreages which have had no activity for a number of years and a measure increasing access to infrastructure. The latter focuses on tariffs charged by the incumbents dominating the platform and pipeline infrastructure. The British Department of Trade and Industry (DTI) has aimed at reducing these tariffs and has pressed “the infrastructure owners to follow a code of practice, show processes are in place to set fair and reasonable tariffs, make tariffs more transparent and put in place a mechanism for DTI to intervene in negotiations” (Simmons & Company International, 2004). At the Dutch Continental Shelf, infrastructure tariffs are also set by the incumbents. As offshore transport costs form a significant part of total operational costs (30 to 50%), government interference with the process of determination of the tariffs could encourage access to the offshore infrastructure and, hence, raise investments by new players.

[17] After all, at the present level of the moving average annual oil price, a large number of projects appear to be profitable, even if we use relatively strong financial criteria which some firms seem to use.

[18] In 2002, 4 firms dominated Dutch offshore production (Simmons & Company International, 2004). NAM, a joint venture company between Shell and ExxonMobil, is the dominant producer with about 40% of total production. Total produced 24%, Wintershall produced 13% and Gaz de France produced 12% of the Dutch offshore gas in 2002.

Additional research would be needed to assess the cost-effectiveness of the several options to encourage investments at the Continental Shelf. In that further research, attention should also be given to the benefits of the ‘small-fields’ policy. Only then it is possible to determine the optimal design of government policy regarding the exploitation of the domestic natural gas resources.

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Appendix A Literature on modelling exploration and development activities

Introduction

The petroleum industry is very important for a modern economy. Hence there has been done a lot of applied econometric research about relationships among exploration, production, prices and taxes in this industry. Here we discuss the most important papers: what models and methods have been used, and what are the results?

The seventies

In the seventies of the last century, several empirical economic models of exploration and extraction of natural gas were published. At the time serious concerns existed in the USA about the effect of the maximum well-head price of natural gas.

Khazzoom (1971) estimated new discoveries of natural gas, depending on three factors: new discoveries in the recent past, the ceiling price of gas, and the price of oil and of natural gas liquids. His equation included also squared prices. He estimated this equation on a disaggregated level, with data not only over time but also over regions.

Erickson and Spann (1971) modelled wildcatting (drilling exploration wells in an unknown area) as a function of prices, previous success ratios and other geographical variables. They used US data over time and over regions.

MacAvoy and Pindyck (1973) reported on a simultaneous model developed at MIT. In this model, the number of exploratory wells is a function of revenues, costs, and risk measured by the variance of the success rate (p.477). It is impossible to appreciate the value of the revenue coefficient: 0.0003 in an unknown dimension. US data over time and over regions were used.

Pindyck (1974) compared Khazzoom (1971), Erickson and Spann (1971), and MacAvoy and Pindyck (1973), and re-estimated the first two.

Cox and Write (1976) model “investment in reserves”: successful exploration measured by its result.

Neri (1977) compared MacAvoy and Pindyck (1973) with the TERA model (Total Energy Resource Analysis) of the American Gas Association. This model explained exploration only by a profitability index.

Erickson *et al.* (1974) estimate a model of the optimal reserves, explained by the price of oil.

Walls (1992) surveys the empirical petroleum modelling. She discusses both engineering models and econometric models.

Recent research

More recently, several other studies have been published. Below, we summarise a few of those.

Pesaran and Favero introduced formal micro-economic modelling into the petroleum econometrics, with an optimising model. They use the "price of oil in the ground" as the revenue variable of exploration. Unobserved shadow prices like these must be estimated from auxiliary regressions. (In equilibrium this variable will be equal to the oil price minus extraction costs.)

Pesaran (1990) estimated an equation for exploration (number of wells) and an equation for extraction, using time series for the whole UK continental shelf. In the former equation, the log of exploration depends on the cumulated number of exploration wells (for depletion) and the log of the ratio of the price of oil in the ground. The time discount factor was set to zero, or equivalently the discount rate was set to infinity[19].

Favero (1992) extends Pesaran (1990) by including taxation into the model.

Favero and Pesaran (1994) extend Pesaran (1990), starting with a critical discussion of the latter. They add the development phase in between exploration and production, building a simultaneous three stage optimation model[20].

Favero, Pesaran and Sharma (1994) model the timing of development and production, as a function of - among others - the oil price and the volatility of the oil price.

Iledare (1995) models the effect of the oil price, taxes, depletion, and reserve/production ratio on exploration.

[19] It is not clear to us how there can be any profitable exploration if the discount factor is zero in Pesaran (1990)? Or, in the words of Favero (1992, p.187): "assuming that the future is irrelevant". Any gain from exploration is reaped in the future. (Communicated to the author.)

[20] At page 318 in Favero and Pesaran (1994), below the development equation (27), it says: "We have assumed the latter [the expected shadow price of undeveloped reserve] to depend positively on past exploration effort". Hence γ_6 is negative: more exploration gives less development. This is indeed the result in table 6 at page 324. However, we would expect the reverse: more exploration creates more undeveloped reserve, making the latter less scarce. More directly stated: only with (successful) exploration there is something to develop. (Communicated to the authors.)

Morisset and Pirnia (2000) reviewed empirical studies of the effect of fiscal measures on direct foreign investment. They conclude that "Recent evidence has nevertheless shown that, when other factors such as political and economic stability, infrastructure and transport costs are more or less equal between potential locations, taxes may exert a significant impact." (p.23). See also section 4.2 above.

Kemp and Kasim (2003) estimated a model with many endogenous variables, related to both oil and natural gas. UK time series data are used.

CPB

At the CPB, Van Delft et al. (1981) studied fiscal measures including accelerated depreciation to stimulate investments in general in the Netherlands. They found no (positive) effect of accelerated depreciation on investments in buildings, a small positive effect on investment in equipment and a relatively large effect on investment in lorries. None of the effects was, however, significantly different from zero (but then, of course, they are not significantly different from twice their value either).

The Koyck method or partial adjustment

In some papers an exponential lag was modelled, with the Koyck method. Here the lagged dependent variable is included in the right-hand side of the regression. In a simple form, with one explanatory variable x :

$$y_t = \lambda y_{t-1} + \beta x_t$$

with $|\lambda| < 1$. (Usually $0 < \lambda < 1$.) The steady state (long run) value of β is given by $\beta^* = \beta/(1-\lambda)$, since omitting the time subscript reduces the equation to $y = \lambda y + \beta x$. The equivalent model

$$y_t = \lambda y_{t-1} + (1-\lambda)\beta^* x_t$$

is called the partial adjustment model. In the table below we present both β and β^* , as the short run and long run estimate respectively.

This model is equivalent to the following exponentially declining lag pattern:

$$y_t = \beta\,(x_t + \lambda\, x_{t-1} + \lambda^2 x_{t-2} + \lambda^3 x_{t-3} + ...)$$

The mean lag is equal to $1/(1-\lambda)$. In cases where the regression was estimated on quarterly data, the mean lag in years is found by dividing this result by 4.

Overview

Most papers discussed above include an equation for exploratory drilling. Most of these include the revenue as an important explanatory variable, in the form of the oil price or the gas price, possibly with costs subtracted. In the table below we present estimated elasticities of exploration with respect to this revenue variable.

Estimates of the effect of revenue on exploratory drilling, in the form of elasticities

	Region	Oil or gas	Log	λ	Mean lag	Elasticity SR	Elasticity LR	P–C?	Page	Notes
Fisher (1964)	US						2.5			a
Erickson and Spann (1971)	US	both	yes	-	0.0		0.4	P	104	a,b
Pindyck (1974)	US	gas	yes	-	0.0		– 0.0		640	a,c
Eyssel (1978)		oil					1.8			a
Deacon et al. (1983)		oil				0.4	1.3			a
Griffin and Moroney (1985)		oil				0.1	0.8			a
Pesaran (1990)	UK-CS	oil	yes	0.3	0.4	0.4	0.7	P–C	384	d
Favero (1992)	UK-CS	oil	yes	0.5	0.5	0.1	0.2	P–C	206	d
Favero and Pesaran (1994)	UK-CS	oil	yes	0.6	0.6	1.8	4.4	P–C	326	d
Iledare (1995)	US	gas	yes	-	<2.0		1.0	P	272	e,f
Kemp and Kasim (2003)	UK-CS	gas	no	0.8	4.8	0.0	0.1	P	737	g
the present paper (2004)	NL-CS	gas	yes	-	2.5		0.5	P–C	chaptr 3	

Notes
[a] Included in Walls (1992), p. 298
[b] Shown here is the elasticity of the gas price; the elasticity of the oil price is 1.5
[c] Re-estimation of Erickson and Spann (1971)
[d] Mean lag in years computed from quarters
[e] Mean lag from weighted mean of 1 and 2 years lag (page 270): $P_t = p_{t-1} - a\ (p_{t-1} - p_{t-2}) = (1-a)\ p_{t-1} + a\ p_{t-2}$
[f] The elasticity with respect to P-C is 0.8
[g] The SR elasticity .0 is computed as: $0.0574 \times 10.004 / 29.81 = 0.02$; note that this is no log model.

The region CS indicates the Continental Shelf in the North Sea.

With a λ, both the short run (SR) and the long run (LR) elasticities are given; see the section above about Koyck.

The column "P–C?" indicates if costs are subtracted from price. (Some authors subtract taxes also. Note that in a double log model this does not matter if the tax is a fixed proportion of the revenue.)

Blank cells in the table indicate: unknown to us.

This table has been compiled with care, but some details of the papers might nevertheless have escaped us, as we had limited time.

The long run revenue elasticity (LR) varies widely. It is hard to conclude from this table what its present true value is. Ignoring the extremely high value 4.4 of Favero and Pesaran (1994), one might conclude that it is probably between zero and one.

The lag in the revenue is fairly short in most cases. By far the longest is from Kemp and Kasim (2003): more than four years. However, here the elasticity is practically zero. Next is the lag length in our paper, 2.5 years: a pyramid-shaped lag pattern from zero to five years.

Appendix B Econometric analysis

Model specification

Double log

We have used a double log specification: the log of the number of drilled wells is explained by a linear combination of logs of explanatory variables. This is the form which is used in much of the literature; in particular the recent literature. See the table in Appendix A. For the exploration regression, this is:

$$\log XPL_t = \alpha_0 + \alpha_1 \log REV_t + \alpha_2 \Delta DAW_t + \varepsilon_t \qquad \text{(B.1)}$$

where XPL_t is the number of exploration wells drilled in year t; REV_t is the expected revenue, ΔDAW_t is the value of the DAW variable (the change of the DAW here), and ε_t is a random disturbance, or error term, with expectation zero; all in year t. Taking the exp function of both sides and omitting the error term gives:

$$XPL_t = \alpha REV_t^{\alpha_1} \qquad \text{(B.2)}$$

when ΔDAW_t = 0 and

$$XPL_t = \alpha REV_t^{\alpha_1} e^{\alpha_2} \qquad \text{(B.3)}$$

when ΔDAW_t = 1, with $\alpha \equiv e^{\alpha_0}$. This form shows that the number of wells is a multiplicative function of the contributions of the various explanatory variables. This is intuitively plausible. To take an extreme example, let the expected revenue go to zero; no investment is profitable. With a multiplicative function, the result indeed always goes to zero as well, whatever the value of the other variables.

Note that the regression coefficient α_1 is an elasticity. Hence its magnitude can be appreciated immediately, without extra computations. The effect of the (change of) DAW is $e^{\alpha_2} - 1$. For small values of α_2 this expression is approximately equal to the coefficient itself, but since the estimate of this coefficient is not small at all, we have printed the value of $e^{\alpha_2} - 1$ in the regression results in table 3.1 above, indicated as “transformed to a relative change”. The coefficient α_2 itself is indicated as the “raw” result. Likewise in the tables of the development regression.

Interaction

With an interaction term, equation (B.1) is as follows, where the equation is somewhat simplified with the Δ and the ε_t omitted and with Y_t as the dependent variable:

$$\log Y_t = \alpha_0 + \alpha_1 \log REV_t + \alpha_2 DAW_t + \alpha_3 DAW_t \log REV_t \tag{B.4}$$

The α_3 is the "raw" coefficient of the interaction between the DAW and the revenue. The total effect of the DAW (being 1 instead of 0) on $\log Y_t$ is:

$$\alpha_2 + \alpha_3 \log REV_t \tag{B.5}$$

With $\alpha_3 < 0$ we have: an increasing revenue decreases the effect of the DAW. It follows from (B.5) that the total relative change in Y_t due to the DAW is:

$$\mathrm{e}^{\alpha_2} REV_t^{\alpha_3} - 1 \tag{B.6}$$

This formula is used in the table with the interaction in the development regression, in chapter 3 above.

Equating expression (B.5) or (B.6) to zero gives the answer to the question put in section 3.3.4 above: at what long run oil price is the effect of the DAW reduced to zero, due to the interaction between these two variables? The result, used in 3.3.4, is:

$$REV_t = \exp(-\alpha_2 / \alpha_3) \tag{B.7}$$

Modelling count data

For the development regression, we used a so called count data model: the number of developed wells in any particular year in any particular block is an integer random variable, drawn from the poisson probability distribution. The log of the expected value is a linear combination of logs of explanatory variables. This is the appropriate model for small integer counts. In this case most counts are zero; most of the rest are 1, etcetera. The (multiplicative) contribution of block b in year t to the likelihood function is

$$L_{bt} = \text{Poisson}(DEV_{bt} \mid \mu_{bt}) \tag{B.8}$$

with DEV_{bt} denoting the observed number of development wells, and

$$\log \mu_{bt} = \beta_0 + \beta_1 \log REV_t + \beta_2 DAW_t + \beta_3 SXPL_{bt} \tag{B.9}$$

The expression $\text{Poisson}(n \mid \mu)$, as in equation (B.8) above, is the probability that a drawing from a poisson distribution with parameter μ has the value n. The variable $SXPL_{bt}$ is the number of successful exploration wells in block b, as a weighted average over a number of years preceding and including year t. Note the absence of an error term in the above formula. See for instance Maddala (1993, pp. 51-54).[21]

The R^2 in the table of the development regression in chapter 3 above is (as indicated) taken from an OLS regression of the same model, since the poisson count data model does not produce such a statistic between zero and unity.

Lag patterns

The lag pattern of the successful exploration $SXPL_{bt}$ in the development equation was derived from regressions with all lags individually included in the equation. This was possible due to cross section nature of the data, with many observations. The following percentage lag pattern was chosen: 0, 5, 15, 20, 20, 15, 15, 10 for the current value and for the lags 1 through 7, respectively.

The lag pattern of the revenue variable REV_t was empirically determined with the equation for the development wells. We ran several regressions with a pyramid-shaped lag pattern of various lengths. The choice was made on the basis of the likelihood. (Note that the use of the poisson probability model implies a likelihood function.) The log likelihood of a lag up to 5 years was 0.5 larger than for 4 years (data starting in 1981)[22]. Also, the log likelihood for 5 years was 4.0 larger than for 6 years (data starting in 1982). Hence the value of 5 years back was the maximum likelihood estimate.

Varying the lag length of the revenue variable in the *exploration* regression gave another result: longer lag lengths give a better fit here, up to the point where the exploration peak of 1983-1987 has disappeared from the regression (the latter happens because increasing the length of the revenue lag shifts the start of the regression to later years). However, we stay by the result

[21] The Poisson distribution is a one-parameter distribution over the set of nonnegative integers. Its expectation and variance are dimensionless and equal: $E[\text{Poisson}(n|\mu)] = V[\text{Poisson}(n|\mu)] = \mu$. Maddala (1993) states in footnote 8 at page 51 that the usefulness of the poisson model is limited by count data not having mean equal to variance. Indeed our count data have a variance which is much larger than its mean. However, this is the "marginal" distribution over all data, while the model assumes only that the probability distribution of any particular count, conditional on the explanatory variables, is poisson. With an arbitrary distribution of the explanatory variables, the marginal distribution of the counts is not poisson.

[22] A difference in log likelihoods (or "log likelihood-ratio") of 0.5 is not large. For the comparison of the likelihoods of non-nested models, see for instance Edwards (1976, p.31) and Berger and Wolpert (1988). A log likelihood difference of 2 might be used as a reference. This is the log likelihood difference between $\mu=x$ and the familiar significance threshold $\mu=x\pm2\sigma$, when drawing a stochast x from a normal distribution with known variance σ and unknown mean μ. The log likelihood is $L(\mu) = -(\mu-x)^2/2\sigma^2 + \text{constant}$.

mentioned above of the development regression, with a lag length of 5 years back: the exploration regression is a meagre model with up to 1995 only the revenue as an explanatory variable. In the development regression the revenue variable is the economic element of the model beside a “geological” element in the form of the previous successful exploration in the same block.

We have considered using a Koyck lag, or partial adaption model: including the lagged dependent variable among the regressors. This has been used in the various papers of Favero and Pesaran, and in Kemp and Kasim (2003). See Appendix A above. This model implies the same lag pattern for all explanatory variables: an exponentially declining pattern. However, we assumed and estimated different lag patters for different variables. For instance, the lag between the oil price and development might be longer than the lag between the introduction of a fiscal measure and its effect on development.

For the exploration equation, we present a version with the Koyck lag below. This shows that the choice of the lag pattern can make quite a difference.

Data

Number of wells by block

We obtained data on exploration and development from TNO-Netherlands Institute for Applied Geo-science (NITG), in the form of a long list of wells. For each well we have the year of completing the well, the type of activity (exploration, development, etcetera), the operator company, and the license block on the Dutch Continental Shelf (K1, K2, etcetera).
These TNO-NITG data give no information about production; development results in a production well. We used the 515 wells which are labelled “development” and are located on the Dutch part of the Continental Shelf.

Similar data about exploration wells on the Dutch part of the Continental Shelf were received from EBN. These data also included the exploration result: oil (21 wells), gas (230), or dry (390). The latter category was excluded where successful exploration was used as an explanatory variable in the development equation.

These EBN data on exploration were used not only in the development equation, but also (in aggregated form) in the exploration regression. In the graphs in chapter 3 above, however, published data from Ministry of Economic Affairs (2004) were used. The latter differ slightly from the individual well data, due to small differences in definition (for instance, extra sideway drillings may or may not be counted).

Revenue

The revenue variable was defined as follows. Start with the oil price in dollars per barrel. Deflate with a price index. This gives the real oil price. Subtract a series of deflated running production costs; see section 4.2 above. This gives the real revenue. Divide by the value of the euro (dollars per euro). This gives the revenue in euros per barrel, which is relevant for the gas produced at the Dutch Continental Shelf. Finally, multiply with the value of the euro in 2004. This gives the real revenue in dollars per barrel, corrected for the dollar/euro exchange rate. The 2004 values were taken from the outlook in CPB (2004).

Sensitivity analysis

We have computed several variants of the regressions in chapter 3. They show that some results are indeed sensitive to changes in the specification. Only the "raw" results are shown.

Exploration

For the exploration equation, we present three variants: (a) with the other tax measures included, (b) with the DAW variable itself, instead of its change, and (c) with the lagged dependent variable included at the right hand side (“Koyck”).

Estimation results of variant exploration equation (a): the EBN participation measure added

	Coefficient	Standard error
(Constant term)		
Revenue: long run deflated oil price minus costs	.3	.1
Change in the DAW	.6	.3
The EBN participation measure	− .4	.2

Note: Time period = 1981-2003; R^2 = 0.52

Regression (a) gives a negative effect for the other government measures. The standard error is about the same size as the coefficient. We have concluded that this is not a good specification.

Estimation results of variant exploration equation (b): with the DAW itself

	Coefficient	Standard error
(Constant term)		
Revenue: long run deflated oil price minus costs	.3	.2
DAW	− .1	.3

Note: Time period = 1981-2003; R^2 = 0.25

Regression (b) gives a negative effect for the DAW, with large standard error and a low R^2. We concluded that this is not a good specification.

Estimation results of variant exploration equation (c): with the lagged exploration	Coefficient	Standard error
(Constant term)		
Revenue: long run deflated oil price minus costs	.3	.1
Change in the DAW	1.0	.3
Exploration in previous year	.4	.2

Note: Time period = 1981-2003; R^2 = 0.57

Regression (c) was computed to show the sensitivity of the results to the adding of a dynamic element, the Koyck lag. The above table gives coefficient $\lambda = 0.4$. Hence, here the one-time "raw" effect of the change of the DAW is in the long run equal to $1.0/(1-\lambda) = 1.7$. (For an explanation of λ, see the introduction to the table in Appendix A above.) Recall from the "Lag patterns" section above that a priori we have not chosen this specification, but instead tried to model the dynamics for each explanatory variable separately.

Development

For the development equation, we present one variant: with the change of the DAW instead of the DAW variable itself. See the table below. The change in the DAW has a negative effect. We concluded that this is not a good specification.

Estimation results of the variant development equation	Coefficient	Standard error
(Constant term)		
Revenue: long run deflated oil price minus costs	.6	.1
Previous successful exploration in the same block	1.0	.1
Change in the DAW	– .2	.2

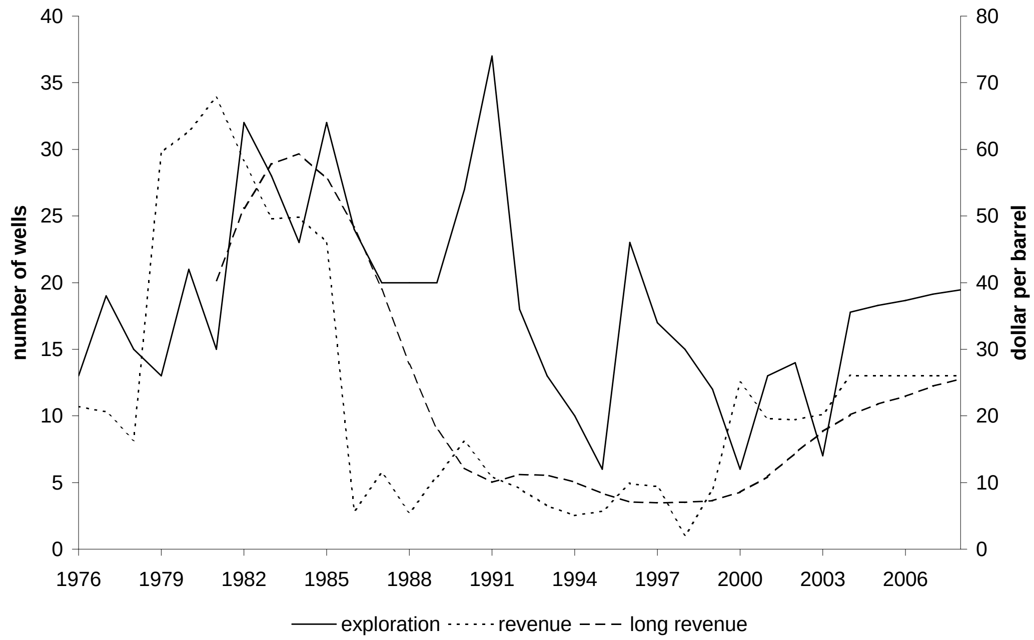
Note: All blocks; Time period = 1981-2003; Used data of years $\times$ blocks = 769; R^2 (from OLS) = 0.13

The future

We have used the regressions of chapter 3 to show the effect of the oil price on exploration up to 2008, using a forecast of the oil price. (Note that the model is not meant to make forecasts, and this exercise is only meant to show the effect of the oil price in the model.)

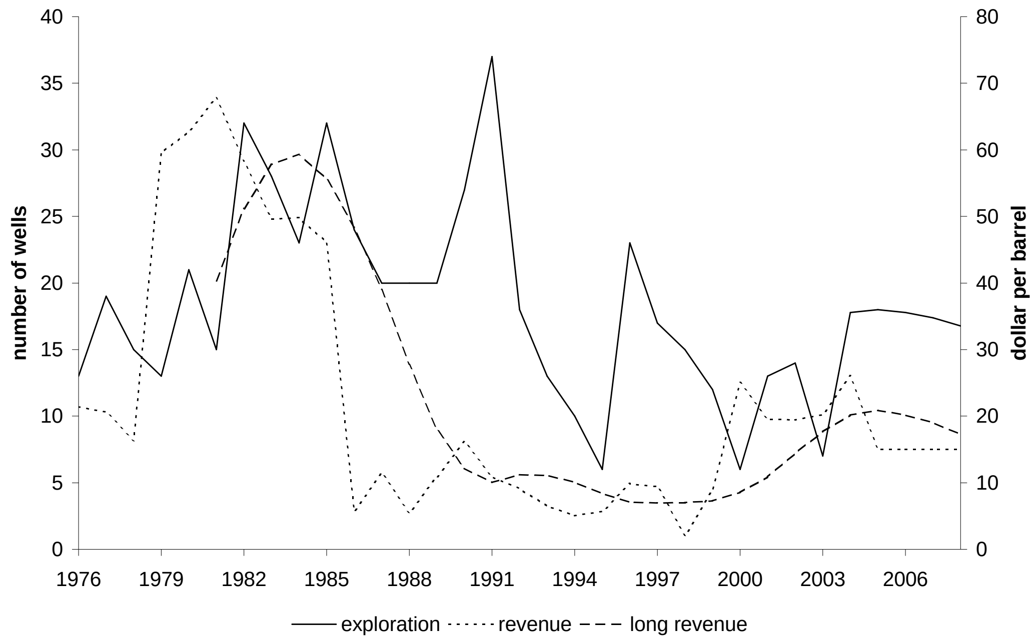
First, assume that the oil price is 36 dollar in 2004 and later. The revenue variable stays at 36 (price) – 10 (costs) = 26 dollar per barrel. The long run revenue series gradually increases to the same level. The result is a small increase in exploration, shown in Figure B.1 below.

Figure B.1 **The number of exploration wells, forecasted over 2004-2008 (oil price 36 dollar per barrel)**



Alternatively, assume that the oil price drops from 36 dollar in 2004 to 25 dollar in 2005 and later years. The revenue variable drops to 25 – 10 = 15 dollar per barrel. The long run revenue gradually moves down; we computed this series up to 2008, where it reached 17 dollar per barrel. The result is a small decrease in exploration, shown in Figure B.2 below.

Figure B.2 **The number of exploration wells, forecasted over 2004-2008 (oil price 25 dollar per barrel)**



Appendix C View of Gaffney, Cline & Associates

This Appendix contains a note written by Gaffney, Cline & Associates (GCA) titled: *'Summary of Views Presented by GCA at Meeting in Bentley with Machiel Mulder of the Dutch Planning Ministry, 26th May, 2004'*

Promoting activity in any country or basin is rarely (if ever) something that can be done, or switched on and off, through a single factor. In this case the question of "Depreciation at Will" is being held as the single factor that makes all the difference between a successful (or acceptable) level of activity offshore the Netherlands, or otherwise.

It is GCA's experience that it is a combination of factors, both hard and soft, that go towards making an area successful. This experience has been built over a number of years, and includes E&P FDI initiatives in countries/states such as Argentina, Brazil, Venezuela, Kuwait, Saudi Arabia, Pakistan, Alaska, Greenland and Timor Leste.

Fiscal structure and government take is undoubtedly an important issue. It is easily measured using cash flow models, and just as easily misinterpreted as to the impact that it might have on activity. It is easy to look at any parameter in isolation and suggest that of all the parameters considered it has the largest impact on rate of return, and therefore if looked at in isolation could create/stifle activity accordingly. However, such an assessment can only truly be made in light of all prevailing factors.

Adverse (from a company's perspective) changes to fiscal structure always raise alarms about the negative impact they are going to have on activity. Such cries will usually come from incumbents, who measure things against pre-existing returns. Prospective entrants are less likely to make the comparison with the previous terms, and are much more likely to see things in the context of all factors, and ask themselves "How do these terms compare with other investment options I have open when considering things like geology, risk, costs, operational "hassle factors", access to acreage/additional opportunities, regulatory oversight and cost, etc".

We have not done an evaluation of the player-universe in the offshore area, the interests they hold, and the cycling of these over time to make any detailed comments with respect to the Netherlands. However, it is a truism that as an area matures, so the appeal changes. While it may attract a particular universe of players at the outset, as opportunity size declines (and player size increases), so the materiality changes. Current opportunities offshore Netherlands will appeal to players of a much smaller size than would have been the case 30 years ago. How have acreage availability, licensing policy, relinquishment requirements, fallow acreage/field initiatives and so forth evolved to cope with this changing landscape?

Countries are very much in competition these days to attract players into their acreage. This means making information available easily available to companies in order that they can assess the potential and its fit with their strategies. It also means appropriate marketing at industry events to ensure people are aware. A walk around the AAPG convention, for example, will see booths from a large number of countries promoting acreage, highlighting the plays, where data can be made available, highlighting farmouts, and generally making people aware. Coupled with a good web site, where key information and statistics can be obtained, this is a relatively low cost means of ensuring that the “we are open” message is fully transmitted.

How much of this is, or may be, appropriate to the Netherlands is also a function of the political and social will of the country and its administration. There are a number of models out there to examine, but briefly it may be helpful to focus on three: the US Gulf of Mexico (GOM), the UK, and Norway.

Both the US and UK have “open market” systems where activity is driven substantially by the rate at which companies are prepared to invest. While this is affected in turn by the key factors of oil/gas price, geology, and infrastructure/costs it is also “managed” from a national perspective by the regulatory and licensing regime. In the GOM, acreage is offered in very small parcels of 5,000 acres. License offerings are typically annual (in any one part of the Gulf), and the entry ticket is a cash bonus. You have no work obligation, but you can only hold after 5 years (10 years for deep water) if you have production. The combination of small license areas and limited life (unless you are producing) provides an incentive for maintaining activity or cycling of acreage. Of course, in the GOM there are a number of other factors that assist, but the basic model is ‘we provide regular opportunities, you get on with it’.

The UK model is based on the same generic philosophy, though with a somewhat heavier hand in the licensing. Instead of cash bonus awards, it is competitive activity bids with a greater potential for discretion to play a hand in the award. Recent innovations have been for the DTI to introduce incentives to activity on fallow acreage or discoveries, and a ‘promote’ license where players can hold for two years to work up a play before committing to drill (and perhaps bringing in a new partner). As with the GOM though, such a system relies on a regular supply of new opportunities other than just through promoted farm outs.

At the other end of the spectrum, the classic Norwegian system has been through tightly regulated licensing awards, allowing in just a select group of companies. While exploration activity has not actively been discouraged, development approvals have been subject to heavy oversight, which has an overall governing effect on activity. This approach has lightened slightly in the S of 62 area of the North Sea, but it is still not “open season” for companies to come in explore/deal. None of this is to suggest that Norway has got it wrong. It has a small population and a lot of resource; if they had tried to develop it at the same pace as the UK (which is about 10-15 times larger as an economy) then it would have had significant economic consequences. Norwegians saw this as a policy that was right for them.

In summary, there is no absolute 'right' or 'wrong' in this matter. You first have to establish your objectives and any limitations that you are going to impose in reaching them. Within such confines, you can then plan a resource exploitation policy that you hope is optimised within that. It will not be just one factor that you are setting, but a complete system of regulation and promotion that suits.

As such, we had suggested that it might be helpful to have a one-day workshop that looked at all the factors that might affect E&P activity in the country, and see what range of alternatives might theoretically and practically be possible. We also suggested that in the first instance this might best be done without the participation of industry lobby groups. However, that workshop should seek to reach a conclusion as to the next step which would involve consultation with the industry on what broader set of changes might be made to reinvigorate the sector.

Appendix D Financial analysis on project level

Data and model of TNO-NITG

In analysing financial restrictions on project level, we received cooperation from the Netherlands' Institute of Applied Geoscience (TNO-NITG), the leading Dutch geological research institute, and Energie Beheer Nederland (EBN), the government agency participating in mining activities of gas firms. The financial analysis on project level is primarily based on two components: geological data and a financial-economic model.

TNO-NITG collects, on a regular basis, geological data on the Dutch part of the Continental Shelf. These data, produced by seismic and geological studies, include information about what are called 'prospects'. A prospect is an area of which geologists suspect oil or gas is present. A prospect is generally characterised by the magnitude of the oil or gas reserve and the probability of a successful exploration. Currently, the TNO-NITG database includes 974 prospects. The total expected volume of these prospects is 376 billion m^3. However, many of those prospects are only economically viable for drilling, if economic conditions strongly improve.

In order to assess the number of projects which are economically viable, TNO-NITG, in cooperation with EBN, has developed a financial-economic model. In that model, the key parameter is the Expected Monetary Value (EMV). EMV is defined as:

$$EMV = POS \times NPV_{success}^{AT} - (1 - P) \times DC^{AT} \qquad \text{(D.1)}$$

in which:

POS = probability of success of finding gas

$NPV_{success}^{AT}$ = net present value (after tax) of the gas reserve in case of a successful exploration

DC^{AT} = dry hole costs (after tax): the net costs of the exploration drilling

The probability of finding gas (P) depends on geological, geochemical and geophysical characteristics of the area. The net present value (NPV) depends on the (expected) future gas price, capital expenditure, operational costs, magnitude of the reserve, discount rate and taxes. The dry hole costs (DC) depend on, among others, the rig rate, depth of the well and taxes.

A project is economically viable if the EMV is positive. A positive EMV, however, does not always imply that a prospect will be drilled. If firms have a portfolio of several prospects, they will prefer (to start with) projects with the highest expected profitability. In order to simulate the ranking process, TNO-NITG in her model uses Risked Value to Investment Ratio (RVIR) as an additional financial-economic criterion. This criterion is defined as:

$$\text{RVIR} = \frac{\text{EMV}}{P \times I^{BT} - (1 - P) \times DC^{BT}} \qquad \text{(D.2)}$$

in which:

I^{BT} = investments before tax

DC^{BT} = dry-hole costs before tax

This ratio relates the size of the EMV to the magnitude of the investments. If two projects have the same EMV, a firm would choose to start with the project with the lowest level of capital requirements. This RVIR criterion holds when the availability of capital is restricted. In that case, the larger the RVIR, the higher its ranking in a firm's portfolio of investment projects. According to TNO-NITG's information, most firms are using an RVIR or equivalent approach. The range of RVIR thresholds actually applied is believed to be between 0.1 and 0.2. See further on the choice of the financial-economic criterion the main text in Chapter 4.

Sensitivity analysis

In order to test the sensitivity of the model outcomes to its assumptions, we asked TNO-NITG to conduct a sensitivity analysis. This analysis was directed at:

- The discount rate (both for the project cash flow of firms and for the cash flow of the government),
- The future oil price (to which the gas price is still strongly related) and
- The financial criterion used to select a project.

Below, we depict the results of this analysis. The main text in Chapter 4 discusses these results. As said in that chapter, these results are based on the assumption that only financial criteria determine whether an investment is done or not. In particular when financial restrictions are relatively weak, this assumption strongly affects the results. In that case improving financial conditions for investment projects could have no effect on investments at all as they could be hampered by other restrictions. In chapter 4 we show that especially characteristics of the physical infrastructure constitute a restriction on the annual level of mining activities on the Continental Shelf.

Sensitivity of the results to the discount rate						
EMV> 0	10%		12%		15%	
Oil price: 25 dollar						
	DAW	No DAW	DAW	No DAW	DAW	No DAW
Number of projects	357	258	334	199	287	152
Total expected reserves (billion m^3)	299	257	291	226	271	192
State revenues (discounted value in billion euro)	4.86	5.06	4.84	4.68	4.72	4.15

Source: TNO-NITG

Sensitivity of the results to the oil price (used for screening)				
EMV> 0	25 dollar		20 dollar	
Discount rate:				
- firms: 10%				
- government: 6%				
	DAW	No DAW	DAW	No DAW
Number of projects	357	258	201	98
Total expected reserves (billion m^3)	299	257	233	162
State revenues (discounted value in billion euro)	4.86	5.06	2.43	2.30

Source: TNO-NITG

Sensitivity of the results to the financial criterion						
Discount rate:	EMV>0		RVIR > 0.1		RVIR > 0.2	
- firms: 10%						
- government: 6%						
Oil price: 25 dollar						
	DAW	No DAW	DAW	No DAW	DAW	No DAW
Number of projects	357	258	204	121	108	73
Total expected reserves (billion m^3)	299	257	235	180	171	139
State revenues (discounted value in billion euro)	4.86	5.06	4.39	3.98	3.57	3.22

Source: TNO-NITG

Cumulative sensitive to combined changes in discount rate, oil price and financial criterion						
	EMV > 0		RVIR > 0.1		RVIR > 0.2	
Discount rate government: 6%	Discount rate firms: 10%		Discount rate firms: 10%		Discount rate firms: 15%	
	Oil price: 25 dollar		Oil price: 20 dollar		Oil price: 20 dollar	
	DAW	No DAW	DAW	No DAW	DAW	No DAW
Number of projects	357	258	91	48	23	2
Total expected reserves (billion m^3)	299	257	156	102	65	8
State revenues (discounted value in billion euro)	4.86	5.06	2.00	1.60	1.00	0.17

Source: TNO-NITG

Sensitivity of the calculated state revenues to the discount rate for government cash flows (in billion euro)				
EMV> 0; Discount rate firms: 10% Oil price: 25 dollar	0%	6%	9%	12%
DAW	11.21	4.86	3.00	1.68
No DAW	10.21	5.06	3.52	2.39

Source: TNO-NITG

Sensitivity of the calculated state revenues to the discount rate for government cash flows (in Billion euro)				
RVIR > 0.1; Discount rate firms: 10% Oil price: 25 dollar	0%	6%	9%	12%
DAW	9.54	4.39	2.89	1.81
No DAW	7.74	3.98	2.87	2.05

Source: TNO-NITG

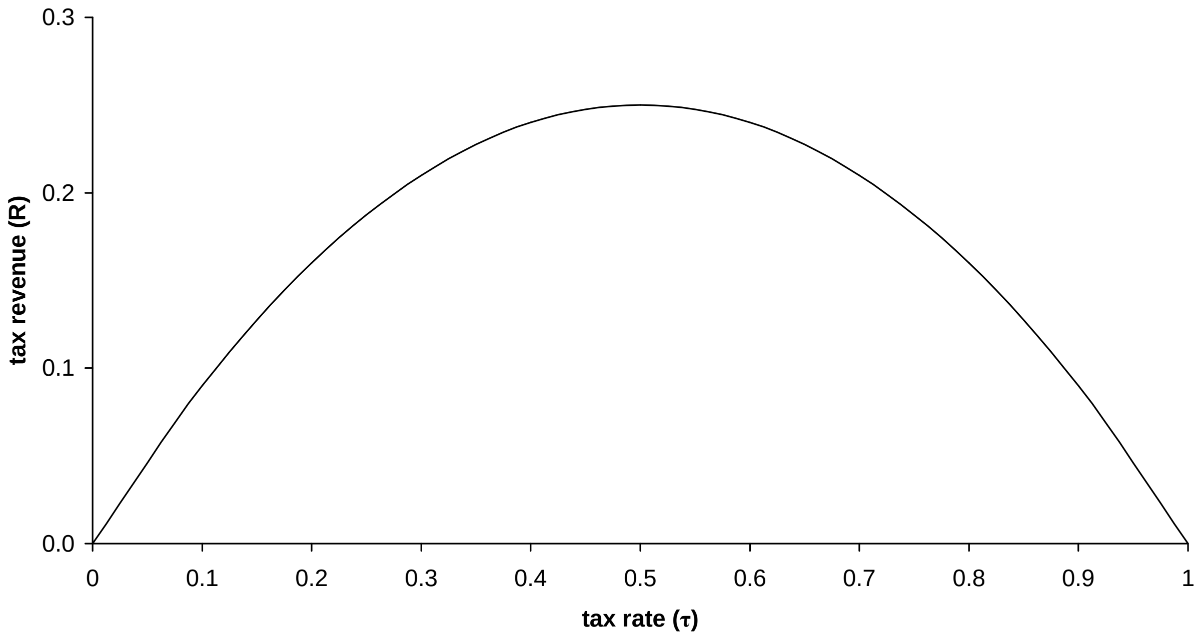
Appendix E The Laffer curve

This appendix contains a 'back of the envelope' calculation that gives us guesstimates of our position on the Laffer curve. If we are right from the top, decreasing the tax burden increases tax revenue; if we are left from the top, the reverse is true. We have used a method that is consistent with mainstream economic theory. Furthermore, we have used the available empirical evidence on taxation and behavioural responses in a manner that brings us closest to the actual situation of The Netherlands in general and the gas industry in particular. We conclude that in all likelihood decreasing the tax rate decreases tax revenue as the responsiveness of investment to variation in tax rates is insufficient to make up for the direct loss of revenue. The caveat is nevertheless that uncertainty remains.

Theory

The Laffer curve depicts the relationship between tax revenue (R) and the tax rate (τ). It starts from the origin, moves upward, then downward, and returns to the τ-axis for τ=1. The reason is that a 0% tax rate never yields revenue, nor does a 100% tax rate. In between these two extremes, increasing t only increases R for as long as the narrowing of the tax base (B) does not take the upper hand. Figure E1 displays a hypothetical example.

Figure E1 Laffer Curve: relationship between tax rate and tax revenue



In the example the relation between R and t is well-behaved, with a revenue maximising government wanting to set the tax rate at 50%. Real world Laffer curves are more erratic. Nevertheless, by assumption they all have the following mathematical properties:

$$R(\tau) \equiv \tau B(\tau)\ ,\ B(1) = 0 \ \text{and}\ \frac{dB}{d\tau} < 0 \tag{E.1}$$

Differentiating with respect to τ and rearranging of terms yields:

$$\frac{dR}{d\tau}\frac{\tau}{R} = 1 + \varepsilon \tag{E.2}$$

where $\varepsilon = dB/d\tau \cdot \tau/B$ denotes the tax rate elasticity of the tax base. At the top of the Laffer curve, the increase of R due to a higher τ exactly balances the decrease of R due to a narrower B. Thus, we are to the right (left) of the top if ε<–1 (ε>–1). The intuition is straightforward: if B is sufficiently responsive to τ, decreasing the tax rate will increase tax revenue; if it is not, decreasing the tax rate will decrease tax revenue, albeit less than proportionally.

In short, in order to be able to say whether a decrease of the tax rate increases or decreases tax revenue, having an estimate of the tax base elasticity ε is sufficient. In the empirical literature, one finds, however, only estimates of the tax base *semi*-elasticity $\varepsilon' = dB/d\tau .1/B$, to be proportional change of the tax base per percentage point change of the tax rate. Since the relation between ε and ε' is by definition ε=ε'τ, we also need τ. This could be simply the statutory corporate income tax rate. Better is to use the marginal effective tax rate since this rate governs the impact of taxation on the investment behaviour of a wealth maximising firm in a competitive environment.

The marginal effective tax rate belongs to the family of *ex ante* effective tax rates. They are defined as the percentage difference between pre and post tax rates of return on hypothetical investment projects. Although the calculation of ex ante rates can be quite involved, their basic idea is relatively simple. A function summarises the tax code by explicitly incorporating its most important aspects, such as the statutory corporate income tax rate, interest deductibility, depreciation allowance, investment credits, and imputation of corporate taxes to shareholders. It maps a given pre tax rate of return to a maximal post tax rate of return, or a given post tax rate of return to a required pre tax rate of return, thus driving a wedge between these rates. The wedge divided by either of these returns is then by definition the ex ante effective tax rate. The method has been developed by King and Fullerton [1984], and has been extended in various directions by Alworth [1988], Chennells and Griffith [1997], Devereux and Pearson [1995], Devereux and Griffith [1999], Jacobs and Spengel [1999], Keen [1990], and the OECD committee on fiscal affairs [1991].

One advantage of ex ante effective tax rates is that they do not directly depend on investment behaviour. Thus, relating investment to ex ante effective tax rates is free from a simultaneity problems. Another advantage of ex ante tax rates is their close correspondence to mainstream economic theory. In particular, the pre and post tax required rates of return correspond to the Jorgenson's [1963] and Auerbach's [1979] user cost of capital that governs investment behaviour of a wealth maximising firm.

In principle we are free to choose any hypothetical investment project as the basis for the calculation of the effective tax rate. We are, however, interested in the investment behaviour of wealth maximising firms, incumbent in a competitive environment. We focus therefore on marginal investment projects with a rate of return that is just sufficient to satisfy financiers and the tax authorities.

Let q denote the real rate of return on investment, δ the depreciation rate of invested capital, π the inflation rate, and t a point in continuous time. In addition, let a be the proportion of the remainder of the initial investment outlay that may be deducted from the corporate income tax base - the depreciation allowance - and b be the proportion of the investment that is financed by debt. Finally, let s be the statutory corporate income tax rate, and r nominal the interest rate. Then, the nominal corporate income tax liability at time t that springs from a one euro investment at time 0 equals:

$$s\left(e^{-(\delta-\pi)t}q - e^{-at}a - br\right) \tag{E.3}$$

The nominal post tax corporate income is the difference between nominal pre tax corporate income and the corporate income tax liability:

$$(1-s)e^{-(\delta-\pi)t}q + s\left(e^{-at}\,a + br\right) \tag{E.4}$$

Multiplying by $e^{-t\pi}$ gives the real post tax corporate income:

$$(1-s)e^{-\delta t}q + s\left(e^{-(a+\pi)t}a + e^{-\pi t}br\right) \tag{E.5}$$

The present value of the stream of real post tax corporate income, discounted with the interest rate, is the sum:

$$\int_0^\infty e^{-rt}\left((1-s)e^{-\delta t}q + s\left(e^{-(a+\pi)t}a + e^{-\pi t}br\right)\right)dt \tag{E.6}$$

which upon integration reduces to:

$$\frac{1-s}{r+\delta}q+A+D \tag{E.7}$$

where $A = as/(r+a+\pi)$ and $D = brs/(r+\pi)$ are the present value of the depreciation allowance and the deductibility of interest payments. Wealth maximisation implies that the marginal unit of capital does not contribute to total profits. In a dynamic framework this is equivalent to the marginal euro of investment just breaking even. In particular, the present value of the future stream of real after tax profits equals unity.

$$\frac{1-s}{r+\delta}q+A+D=1 \tag{E.8}$$

Solving for q yields

$$q=\frac{1-A-D}{1-s}(r+\delta) \tag{E.9}$$

This is the required rate of return, well known from the cost of capital theory. It is just sufficient to cover depreciation, and to pay financiers and tax authorities. Note that in the absence of taxation (τ=A=D=0) the required rate of return reduces to r+δ. Thus, taxation drives a wedge between $(1-A-D)/(1-s)\cdot(r+\delta)$ and r+δ. The marginal effective tax rate τ is then simply the percentage difference between these two rates of return:

$$\tau=\frac{s-A-D}{1-s} \tag{E.10}$$

It is easy to verify that the marginal effective tax rate decreases in the present value of the depreciation allowance, which in its turn increases in a. Thus, the more generous the depreciation allowance, the lower the marginal effective tax rate, as one would expect. Note that the channel through which an increase of a decreases the tax burden is exclusively through postponement of tax payments, since the fiscal book value of the investment goes to zero as time goes to infinity.

Empirics

Now we have set the pieces, the remainder of the exercise consists of empirically filling in the tax elasticity of investment and the marginal effective tax rate in order to arrive at a guesstimate of ε. Unfortunately, there are no rock solid estimates of this elasticity, not even for the US. We have to rely on estimates of the semi-elasticity $dI/d\tau 1/I$, where I denotes investment instead of the capital income that it generates. This is permitted since the relation between B and I is monotonic - on average investment yields capital income.

Ederveen and De Mooij (2003) analyse the existing empirical literature, and come up with a benchmark semi-elasticity of -2.40. The interpretation is that real investment, broadly defined, increases with 2.40 percent per percentage-point reduction of the tax rate.

We can mould this result such that it becomes more appropriate for the question at hand. First, we are interested in real investment, and less in financial transactions such as mergers and acquisitions. For that reason we add -0.43, the estimate of the ‘product, plant, and equipment’ dummy from Ederveen and De Mooij’s meta-analysis. Second, we use the marginal effective tax rate, therefore we add 3.08, the marginal effective tax rate dummy. Third, we have to convert the semi-elasticity - equal to $-2.40+0.43-3.08 = -5.06$ - to a proper elasticity by multiplication with the prevailing Dutch marginal effective tax rate.

Devereux et al. (2003) calculate the marginal effective tax rate for a number of countries. In the Netherlands it equals 24% if the marginal investment is financed with equity (b=0), and -0.33% if it is financed with debt (b=1). An approximation of the average marginal effective tax rate can be obtained by weighting both percentages with shares of equity and debt in the financing decisions of all Dutch firms. Draper and Huizinga (2001) estimate these shares at 0.55 and 0.45. This yields $0.55 \cdot 24 + 0.45(-33) = -1\%$. Depreciation allowances and deductibility of interest makes the Dutch fiscal authorities effectively *subsidise* marginal investment. Alternatively, one could say that -since -1% is close to zero - Dutch corporate income taxation is neutral at the margin.

Clearly, a negative marginal effective tax rate implies that $-5.06 \cdot (-0.01)=0.05>-1$. The conclusion is that for real investment in the Netherlands, the patchy available evidence points in the direction of a decrease of tax revenue for a decrease of the effective tax rate.

There may, however, be differences between industries: first, there may be variation in the responsiveness of investment to taxation; second, there may be variation in taxation itself. The latter is important for the gas industry, if only because the statutory corporate income tax rate is not 34.5% but 50%. We make the following working assumptions for the status quo:

$S = 0.50$ (statutory tax rate equals 50%)
$R = 0.10$ (interest rate equals 10%)
$\pi = 0.02$ (inflation rate equals 2%)
$a = 0.12$ (fiscal depreciation rate equals 10% in continuous time, which amounts to a halving of the book value of the initial investment outlay in six years)
$\delta = 0.12$ (economic depreciation rate equals the fiscal depreciation rate)

b=0.15 (the marginal investment is financed for 15% with debt, and for the remainder with retained profits and new stock emissions, which conforms to the debt equity ratio of firms in the gas industry))

This implies that the present value of the depreciation allowance is:

$$A = \frac{0.12 \cdot 0.50}{0.10 + 0.12 + 0.02} = 0.25 \tag{E.11}$$

and the present value of the deductibility of interest payments:

$$B = \frac{0.15 \cdot 0.10 \cdot 0.50}{0.10 + 0.02} = 0.06 \tag{E.12}$$

The marginal effective tax rate then becomes:

$$\tau = \frac{0.50 - 0.25 - 0.06}{1 - 0.50} \cdot 100 = 0.38 \tag{E.13}$$

This rate of course drops with the introduction of the DAW, which is boils down to the alternative assumption: a=1 (DAW is immediate expensing). This implies that the present value of the depreciation allowance becomes:

$$A = \frac{0.50}{0.10 + 1.00 + 0.02} = 0.45 \tag{E.14}$$

while the present value of the deductibility of interest payments remains:

$$B = \frac{0.15 \cdot 0.10 \cdot 0.50}{0.10 + 0.02} = 0.06 \tag{E.15}$$

The marginal effective tax rate then becomes:

$$\tau = \frac{0.50 - 0.45 - 0.06}{1 - 0.50} = -0.02 \tag{E.16}$$

Taking the arithmatic mean of the two tax rates at which the semi-elasticity –5.06 can be evaluated, and putting the elasticity and the mean tax rate together yields:

$$\frac{dI}{d\tau}\frac{\tau}{I} = -5.06 \cdot \frac{0.38 - 0.02}{2} = -0.91 \tag{E.17}$$

Thus, we conclude that $\varepsilon > -1$. In other words, the responsiveness of the tax base is insufficient for the reintroduction of the DAW to be budget neutral. We repeat, however, that the available data are patchy, and that we have made a number of assumptions in order to arrive at this result. Nevertheless, since we have loaded the dice in favour Dutch revenue authorities, for example by abstracting from possible capacity restrictions of the gas industry, the guesstimate -0.91 should be interpreted as an upper bound of the responsiveness of investment to taxation.

Appendix F A simple model of the DAW

In this Appendix we have tried to build a simple analytical toy model of the DAW. This model has not been used in the analysis in this Document. Contrary to the previous Appendix, discrete time is used here.

Consider an investment project which is marginal without the DAW: the present value of its cash flow without the DAW is just zero, using the firm's discount rate. Let:

A = annual revenue of the project: sales minus running costs
I = investment
τ = tax rate
N = duration of the project
r_f = discount rate of the firm
r_g = discount rate of the government
$F = \sum_{t=0}^{N-1} \left(1+r_f\right)^{-t}$
$G = \sum_{t=0}^{N-1} \left(1+r_g\right)^{-t}$

The last two variables are the present value of a constant stream of one unit, discounted with the firm's discount rate and the government's discount rate respectively. Of course we have $0 < F < N$ and $0 < G < N$. Also:

$$\lim_{N \to \infty} F = \frac{1}{r_f} \tag{F.1}$$

and

$$\lim_{N \to \infty} G = \frac{1}{r_g} \tag{F.2}$$

As said above, the present value of the cash flow of our project is zero without the DAW. We write this as the investment being equal to the discounted after-tax revenue:

$$I = \left(A - \tau \left(A - \frac{I}{N} \right) \right) F \tag{F.3}$$

Here the annual tax base is $A - I / N$, where I / N is the depreciation, evenly spread over the years. This can be written as:

$$\frac{A}{I}\left(1-\tau\right) = \frac{1}{F} - \frac{\tau}{N} \tag{F.4}$$

With equation (F.1) we have for projects with a long duration:

$$\frac{A}{I}(1-\tau) \approx r_f \tag{F.5}$$

This is simply the after-tax annual revenue being equal to the discount rate. With the DAW, the present value of the firm's cash flow is:

$$A(1-\tau)F - I(1-\tau) \tag{F.6}$$

The value of A in (F.6) is given by equation (F.4). Using this, we get after some elementary manipulations the following present value of the cash flow with the DAW:

$$\tau\left(1-\frac{F}{N}\right)I \tag{F.7}$$

This is the firm's benefit of the DAW. Since $0 < F < N$, the expression between parentheses is between zero and one. For projects with a long duration, the expression (F.7) is approximately equal to τI .

Next we consider the present value of the tax revenue of the government. If the project would be executed without the DAW, then this present value would be:

$$\tau\left(A-\frac{I}{N}\right)G \tag{F.8}$$

With the DAW, the project is surely executed and the present value of the tax revenue of the government is:

$$\tau(AG-I) \tag{F.9}$$

If the project would have been executed without the DAW, then the "dead weight loss" of the government is expression (F.8) minus expression (F.9):

$$\tau\left(A-\frac{I}{N}\right)G-\tau(AG-I) \quad = \quad \tau\left(1-\frac{G}{N}\right)I \tag{F.10}$$

Since $0 < G < N$, the expression between parentheses in the last member of (F.10) is between zero and one. Note that if $r_g = r_f$ and hence also $G = F$, then the dead weight loss for the government (F.10) is equal to the benefit of the DAW for the firm (F.7). If the project would *not* be executed without the DAW, then the benefit of the DAW for the government is simply expression (F.9).

Finally, assume for example the following parameter values: τ = 0.5; N = 15 years; r_f = 10% per year; r_g = 6% per year. Then F = 8.4 and G = 10.3. Without loss of generality, let I = 1. Using (F.5) we then have A = 0.17 for our marginal project. Using (F.7), the benefit of the DAW for the firm is 0.22.

Using (F.9), the benefit for the government if the project *would not be executed without the DAW* is 0.39. Note that the benefit of the DAW for the government is larger than the benefit of the DAW for the firm. Recall that in this particular case, with a marginal project, it does not matter for the firm's profit whether or not the project is executed without the DAW: the present value of the profit without the DAW is zero in both cases. Hence the benefit of the DAW for the firm is here in fact equal to a postponement of tax payments, while the benefit of the DAW for the government consist of receiving taxes where otherwise no taxes would be received at all.

On the other hand, if the project would be executed without the DAW, the dead weight loss, using (F.10), is 0.16.

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