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Policy options for improving security of energy supply

Background document

Final report

Delft, August, 2003

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Introduction

Security of the national energy supply has always been high on the Dutch political agenda. While traditionally this has generally implied reducing dependence on energy imports, recent energy crises in the United States and the Russian Federation have shown that energy security may also be jeopardised by poorly conceived privatisation schemes and other imperfections in internal markets.

Against this background the Dutch Ministry of Economic Affairs commissioned the Netherlands Bureau for Economic Policy Analysis, CPB, to review the social costs and benefits of a number of policies to improve the security of the national energy supply. One of the main aims of the envisaged project was to identify policies to mitigate the effects of any future disturbance of energy markets and/or reduce the costs of such disturbance. A second key objective was to assess the benefits and costs of implementing these measures.

In selecting suitable policy options for review and assessing their feasibility in terms of likely public support as well as selected implementation costs, CPB was supported by the independent environmental consultancy CE of Delft. This background document, prepared by CE, looks at some of the policy options available for improving energy security and presents an exploratory cost-benefit analysis of' the six measures selected for further evaluation.

When reading this document two things should be borne in mind:

1. The six policies selected are not representative of the full range of policies that might be implemented to improve energy security. These specific options were selected for further study after extensive discussions and consultation with the Dutch Ministry of Economic Affairs and CPB. The selection process was oriented, first, towards measures on which relatively little information was available on certain cost categories and, second, towards measures considered intuitively to be reasonably promising.
2. In calculating the costs of implementing the described policies, we have focused on a limited number of direct cost categories, to the exclusion of others. This document does not therefore provide a full cost-benefit analysis of the six policy options reviewed; our chief aim was to provide CPB with information on those cost categories on which little information was available or for which cost estimates were contested. Second, no consideration has been given to indirect costs, such as those associated with loss of jobs, for example.

Policies selected for review

The selection of policy options for review is explained and described in Chapter 1. In all, six measures were selected, geared to minimising three specific risks:

a. General policies to reduce overall risk:
   - designation of seven new wind power sites (implementation of plan for 1,000 MW additional capacity proposed by Dutch political party *GroenLinks*).

b Policies to reduce risks on the oil market:
  - extension of ACEA agreement to trucks and vans to improve CO_2 emission profiles, mainly through fuel savings;
  - mandatory blending of a minimum percentage of biofuels in transport fuels, combined with lower excise duty on biofuels;
  - incentives for use of biofeedstocks by the chemical industry (as a subsidy, for example).

c Policies to reduce risks on the natural gas market:
  - increasing domestic gas production by intensifying the ‘small field’ policy and sanctioning in the Wadden Sea and Biesbosch nature reserves;
  - tightening of the EPC energy performance standards for new buildings and intensification of EPA policy for current housing stock.

Feasibility of selected policies: main conclusions

One of the main aims of the project was to assess the feasibility of the selected policies in terms of costs, anticipated legal procedures and public acceptance. For each of these six options Table 1 summarises the main findings of the present study.

Table 1 Main findings on the six policy measures selected for review

Policy measure	Direct effects	Feasibility	Critical factors	Notable findings
1 Designation of seven new wind power sites (*Groen-Links* plan for 1,000 MW additional installed capacity).	Increased power production in MW.	Fairly good, no social problems anticipated, but possibly technical problems with retuning of overall generating capacity.	1 External costs (visual intrusion and noise), but difficult to quantify. 2 Issue of reserve capacity requirements for fluctuations in wind power is complex and needs further study.	1,000 MW installed capacity at these seven sites is over-optimistic; likely to be 25% lower.
2 Extension of ACEA agreement to trucks and vans.	Improved fuel efficiency per vehicle.km.	Feasibility poor for trucks, as autonomous technical improvements in fuel efficiency are already substantial. More feasible for vans.	Industry has shown no interest in extending agreement to vans.	
3 National implementation of EU Biofuels Directive (blending of biofuels in transport fuels), combined with lower excise duty on biofuels.	Reducted fossil fuel consumption per transport-km.	Good, but uncertainty about potential and costs.	Supply of biomass and production capacity for biofuels.	External cost savings (reduced CO_2 emissions) are somewhat disappointing because of energy needed for biomass harvesting and conversion to fuels.
4 Incentives for use of bio-feedstocks by the chemical industry.	Reduced fossil feedstock input per unit product.	Technically feasible but major uncertainties.		Additional costs difficult to estimate, as biofeedstocks are likely to influence conventional cracking process.
5 Sanctioning drilling in gas fields in Wadden Sea and Biesbosch national parks.	Additional m^3 of gas extracted.	Technically feasible, but legal and social problems anticipated.	Strong public opposition to such plans.	Social external costs and benefits of exploiting Wadden Sea field are hotly debated and require further study.
6 Tightening of EPC energy performance standards for new buildings and intensification of EPA policy for current building stock.	Reduced natural gas consumption.	Good, but overall impact only small.	Labour market for EPA advisors.	Additional studies presently underway to evaluate this option.

Costs of policy implementation

As different cost categories have been estimated for each of the six policies reviewed, this background document contains no appraisal of how the policies compare in terms of cost-effectiveness.

The costs estimated can be divided into the following broad categories:

1 Additional investments and operating costs.
2 Government implementation costs, including transaction costs associated with planning procedures and the like.
3 Government administrative costs and loss of tax revenue.
4 External costs.

Table 2 shows the cost categories assessed for each of the measures reviewed.

Table 2 Cost categories estimated in this study (NA = not applicable)

Policy measure		Investments and operating costs	Implementation costs	Administrative costs and tax revenue losses	External costs
1	Designation of new wind power sites (*GroenLinks* plan for 1,000 MW installed capacity at seven sites).	NA	Estimated costs of spatial planning procedures.	NA	Costs of noise and visual intrusion.
2	Extension of ACEA agreement to trucks and vans.	Little scope for improving on autonomous technological improvements.	NA	NA	NA
3	EU Biofuels Directive (blending of minimum % of biofuels in transport fuels), combined with lower excise duty on biofuels.	Additional costs per vehicle kilometre.	Unknown.	Loss of excise duty revenues due to tax exemptions.	Reduced external costs of CO_2 emissions.
4	Incentives for biofeedstocks in the chemical industry.	Additional investments and operating costs for various organic chemicals.	NA	Unknown.	NA
5	Gas recovery in Wadden Sea and Biesbosch national parks.	Additional cost of diagonal drilling (negligible).	Unknown.	NA	Social external costs and benefits of exploiting Wadden Sea field.
6	Tightening of EPC energy performance standards for new buildings and intensification of EPA policy for current building stock.	Costs of EPC measures.	NA	Costs of EPA assessments.	NA

The benefits accruing from each of these policy measures were estimated in terms of the potential fuel savings to be achieved. To keep the calculations as transparent as possible, reported estimated fuel savings have not been converted to a common unit such as PJ[1].

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[1] Recalculation to a common denominator runs the risk of savings having to be compared with a reference scenario, not always straightforward (what type of generating capacity will be substituted by new wind farms, for example?).

1 Introduction

1.1 Introduction

The Dutch Ministry of Economic Affairs has commissioned the Netherlands Bureau for Economic Policy Analysis (CPB) to analyse the social costs and benefits of several policy options for improving the security of the Netherlands' energy supply. One of the key aims of the envisaged project was to identify policies that might be implemented to mitigate the effects of any future disturbance of energy markets and/or reduce the costs of such disturbance. A second key objective was to assess the benefits and costs of implementing these measures[2]. In answering these two key questions, CPB asked the Delft-based independent environmental consultancy CE for assistance. This background report to the CPB study presents the results of the work by CE.

1.2 Goal of this study

The goal of this study can be summarised as follows:

> *To develop and assess the feasibility of several policy options to improve the security of the Dutch energy supply, and to analyse the direct costs and benefits of these policies.*

Two initial remarks should be made:
- the selection of policy options for review in this study took place after extensive discussions and consultation with the Dutch Ministry of Economic Affairs and CPB;
- our analysis of the costs and benefits of the selected policies is restricted to *direct* costs and effects. These results are to serve as input for the energy and macro-economic models to be run by CPB.

1.3 Matching risks and policy interventions

Risks
Before promising policies to improve energy supply security can be short-listed, it must first be clear what risks and causes are to be addressed. CPB (2003) has identified the following risks:
1. Risks associated with disruption of supply and price volatility due to increasing dependence on Middle East oil exporters.
2. Ditto, due to increasing dependence on gas supply from Russia and the Middle East.
3. Ditto, due to insufficient investments in reserve power generating capacity.
4. Ditto, due to inadequate investments in power or gas grids (capacity and quality).

This risk classification scheme provided a framework for analysing potential policy interventions, as set out below.

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[2] Energy Policies and Risks at Energy Markets; a Cost Benefit Analysis (CPB, 2003).

Analytical framework for policy interventions

Policies to improve security of energy supply can be shaped in many ways and be applied at many different points in the respective supply chains. For example, they may be geared to preventing potential disturbance of the energy supply. Alternatively, the aim may be to mitigate the economic damage accruing from any disruption of supply, due to an international oil crisis, say. In order to structure the various policy goals and tools for improving supply security, in this section we outline an analytical framework.

Government intervention to improve energy supply security can be geared to three main objectives:

A To prevent disturbance of supply lines.
B To reduce the vulnerability of the economy to such disturbance.
C To mitigate the negative impact of any energy disturbance (response measures).

Policies in category A seek to address the *causes* of disturbance of the energy supply and include policies addressing political causes, to avoid a crisis between the EU and OPEC, for example, or addressing economic causes, such as poorly functioning or failing markets.

Category B policies aim to reduce the *vulnerability* of the economy to disruptions in the supply of one or more energy sources. A possible key to reducing vulnerability on the demand side is to reduce the energy intensity of the economy, through direct regulation (e.g. tightening energy performance standards) or using market-based instruments (e.g. energy taxes).
Another option for reducing the vulnerability of the economy is to seek diversification of both the fuel mix and the firms and countries supplying energy to the Netherlands. An important question with respect to this policy intervention is to what extent governments still have tools to intervene, given the present liberalised energy market in which industries themselves decide on fuel mix and number of suppliers.

Category C, finally, covers policies seeking to reduce the negative social and economic *effects,* for society as a whole, should an energy crisis actually occur. One such *response measure* would be a government decision to utilise strategic oil stocks to soften price shocks on the oil market.

Within each of these three categories the government can pursue its goals by means of *national* or *international* policies. We distinguish three types of national policy that might also be implemented through the EU: (i) regulation, (ii) market-based instruments, and (iii) voluntary agreements and information campaigns.

Table 3 Policy interventions for improving security of energy supply

	National policy			International policy
Main aim of intervention	*Regulation*	*Market-based instruments*	*Voluntary agreements, information*	
Preventing disturbance				
Reducing vulnerability				
Mitigating effects (response measures)				

For each of the five types of risk identified above, Annex A identifies a number of policy options for preventing disturbance, reducing vulnerability and mitigating the impacts. For this purpose the structure of Table 1 was used.

1.4 Policy options considered in this report

Table 4 presents the main goals of the six policy options reviewed in this report and the direct effects and costs assessed for each. The chapter in which the respective policies are reviewed is also indicated.

Table 4 Main aim, direct costs and effects of policy options reviewed in this study

Main aim of policy	Policy measure	Direct effects	Direct costs
A General policies addressing all risks			
1 To reduce risk by increasing the share of renewables in power generation (Chapter 2).	Designation of seven new wind power sites.	– Increased production in MW. – Risks for security of supply. – Growing profitability of wind power production.	– Average cost of spatial planning procedures per site. – External costs per site.
B Policies addressing risks on the oil market			
2 To reduce risks by reducing the oil intensity of the economy (Chapter 3).	Extension of ACEA agreement to trucks and vans.	Improved fuel efficiency per vehicle.km, including rebound effect of more efficient engines.	– Additional costs per vehicle.km. – Government implementation costs.
3 To reduce risk by increasing the share of renewables. Here: transport biofuels (Chapter 4*)*.	Mandatory blending of minimum % of biofuels in transport fuels, combined with lower excise duty on biofuels.	Reduced fossil fuel consumption per vehicle.km.	– Additional costs per vehicle.km. – Government administrative costs. – Reduced government revenues due to tax exemption. – Change in external costs per vehicle.km.
4 Idem, use of biofeedstocks by chemical industry (Chapter 5).	Subsidy for additional investment costs.	Reduced fossil feedstock input per unit product.	Additional costs of products made to x% from biofeedstocks.
C Policies addressing risks on the natural gas market			
To increase domestic production capacity by intensifying the 'small field' policy (Chapter 6).	Exploitation of Wadden Sea and Biesboch gas fields.	By NATGAS (CPB).	Social external costs and benefits of gas recovery from these fields.
To conserve natural gas (Chapter 7).	Tightening of EPC energy performance standards for new buildings and intensification of EPA policy for current building stock.	Reduced consumption of natural gas.	Costs of implementation

Specification of individual policy measures

Intensification of government policy on renewables

This policy option was elaborated as a government decision to designate a number of new wind power generation sites. For this purpose we took the seven sites described in a plan proposed by the Dutch political party *GroenLinks,* who estimate this will provide an additional 1,000 MW installed capacity.

ACEA voluntary agreement

This policy option comprises extension of the ACEA voluntary agreement on vehicle CO_2 emissions to include vans and trucks. We also indicate how such a move might be backed up by new fiscal policy.

National implementation of EU Biofuels Directive

In this option we consider the costs and effects of full national implementation of the EU Biofuels Directive, embracing mandatory blending of a minimum percentage of biofuels in transport fuels, together with part-exemption from excise duty for biofuels. On the latter point we also followed the Biofuels Directive.

Subsidising the extra cost of biofeedstock use by the chemical industry

This policy option was elaborated as an incentive for the chemical industry to use biofeedstocks as a substitute for conventional oil feedstocks. We first assessed how realistic the option is regarded by the industry itself and the likely lead time before any substantial substitution is achieved before going on to estimate the additional cost of one-off modifications to plant and equipment.

Intensification of ‘small field’ policy

In this option the government intensifies its long-standing ‘small field’ policy, sanctioning gas exploration and in sensitive areas like the Wadden Sea and Biesbosch national parks as a means of reducing the risks of supply disruption and price volatility associated with (growing) dependence on imports from Russia and the Middle East. Intensifying the ‘small field’ policy would allow the Groningen gas reserves to be used as a buffer for longer, thus reducing the risks in question. For this option we estimated the external costs of gas recovery in these sensitive areas. The effects of such recovery will later be calculated by CPB using the NATGAS model.

Tightening of EPC energy performance standards for new buildings and intensification of EPA policy for current building stock

This option embraces two policies for reducing natural gas consumption in residential dwellings: tightening the EPC energy performance standards for new buildings from 1.0 to 0.9 or 0.8 and intensifying EPA policy for the current building stock.

2 Designation of seven new wind power sites

2.1 Description and background

The Ministry of Economic Affairs has set a target of 10% for the share of renewables in the Dutch energy supply by 2020, to include 1500 MW installed capacity on land. Over the past 12 years Dutch output of renewable energy has risen from 50 MW to 500 MW. Increasing the amount of wind power is one option for improving overall security of security, and this chapter examines the policy option of designating a number of new wind power sites in order to accelerate that process.

To this end seven new wind power locations were identified, from a plan drawn up by the Dutch political party *GroenLinks*. These are:

1. Highway A6, Almere-Lemmer.
2. North Holland Canal.
3. Highway A7.
4. Eemshaven industrial estate, Groningen.
5. Highway A9, Alkmaar-Badhoevedorp.
6. North Sea Canal, south bank.
7. Corus industrial estate, IJmuiden.

According to *GroenLinks* this will provide an additional 1,000 MW installed capacity. The following analysis assumes that the generating plant will be on stream at all seven locations in three years' time.

2.2 Feasibility

Political feasibility

Public attitudes toward wind power, particularly in terms of its perceived visual impact ('horizon pollution'), are the main factor influencing practically every wind project. Although noise nuisance is also important, it may be more of a technical problem amenable to technological progress. So far the impact on bird life has been minimal (see: www.duurzame-energie.nl)

Public perception is shaped at least as much by attitude as by fact. Poeple's responses to the sight of a wind farm are highly subjective. Many people see them as a welcome symbol of clean and sustainable energy, while others regard them as an unwelcome intrusion.

However, independent surveys of people living near wind farms, or visiting, show that the majority tend to be favourably disposed. Objections to wind farm development usually stem from a relatively small number of neighbours or organisations (CEA, 2002).

Although such objections may prolong the planning procedure, they do not affect the rate of success. CEA concludes that the probability of a project being successfully implemented once the planning permission process is underway is very high: 93%. The average total duration of the permit procedure is 46 weeks, with a variation of about 36 weeks. It is to be concluded, then, that a negative response on the part of neighbours or environmental organisations may affect overall project duration, but probably not the success rate.

It was beyond the scope of this study to undertake a detailed feasibility study for each of the cited wind power locations. Instead, we distinguished between (the estimated feasibility of) sites along line infrastructure like roads and canals and industrial sites like the Corus and Eemshaven industrial estates (see Table 1). It is anticipated that wind turbines installed along line infrastructure will generally meet with less opposition from organisations and neighbours, because of the comparatively minor impact in terms of visual intrusion and noise and the greater distance from residential areas. At industrial sites we predict a lower rate of success, because the turbines might be seen as competing with other on-site industries in terms of the noise nuisance allowed within the 'permit bubble'. In addition, some companies judge wind turbines to be an additional risk factor in terms of potential accidents. This is certainly likely to reduce the feasibility of large-scale wind farm development at such locations. This is especially true of the Corus site, where earlier initiatives to install wind capacity failed because of the supposed risk of damage and personal injury. In reality, it should be added, this risk is to be deemed negligibly small.

The *GroenLinks* document describing the wind power proposal mentions that the cited locations all have the support of Dutch environmental organisations.

Technical feasibility
There appear to be no technical bottlenecks for developing wind farms at the seven cited locations. Wind technology is moving very fast in term of maximising capacity and minimising environmental impacts (i.e. noise, risk of damage and visual integration in the landscape). New technology is continuously being introduced as new turbines are installed. This is sure to improve public acceptance of large turbines.

Manufacturers can now supply turbines of up to 2.5 MW capacity, with a hub height of up to 80 or 100 metres. The average size of new turbines is steadily increasing; in 2002 it was 1,250 – 1,500 kW. Within two or three years, the expected project realisation date, it is assumed that 2-MW turbines will be installed at all these sites.

Installing a substantial amount of new wind power capacity will have an impact on the productivity of the current electricity park. The dependence of turbine output on meteorological conditions means that the electricity production park as a whole must be operated more flexibly, to avoid shortfalls on days with unexpectedly low wind yields.

Legal aspects
There are several legal issues having a major bearing on the feasibility of wind power projects. Wind farm construction is subject to several statutory procedures, viz.:

1 Environmental permit procedure (Environmental Impact Statement).
2 Construction permit procedure.
3 Spatial planning procedures.

It can be concluded from the CEA study that legal procedures do not often lead to major delays in project execution. Such delays certainly cannot be excluded, however, for environmental organisations and neighbours may object to presumed noise nuisance and/or impacts on the landscape or bird life. In terms of these legal aspects, there is no reason to assume that different locations will score differently.

Conclusions regarding feasibility

We conclude that project feasibility is moderate to good at all the wind power sites considered; Table 1 provides a summary. As already mentioned, one caveat should be borne in mind here: that installation of 1,000 MW additional wind power may impose additional requirements on the flexibility of the current generating park.

Table 5 Feasibility of wind farms at the individual sites

Site	Configuration	Estimated feasibility
Highway A6, Almere-Lemmer	Line	++
North Holland Canal	Line	++
Highway A7	Line	++
Eemshaven industrial estate, Groningen	Industrial site	+
Highway A9, Alkmaar-Badhoevedorp	Line	++
North Sea Canal, south bank	Line	++
Corus industrial estate, IJmuiden	Industrial site	+

Feasibility as estimated by CE

++ = good

\+ = moderate

2.3 Effects

Electrical power output

For each of the seven wind farm sites, Table 2 shows the number of turbines, installed capacity (MW), estimated annual output (mln. kWh) and number of households supplied.

One key assumption here is that the turbines will have 2 MW average power capacity. Turbines this size must be spaced at least 400 metres apart when installed ‘in line’, with lines also separated by at least 500 metres in full ‘farm’ configuration. Such spacing is essential to prevent inter-turbine disturbance of wind flow. To ensure the available wind is used efficiently, then, it is essential that turbines always be prudently spaced and sited.

These considerations permit calculation of a maximum feasible number of turbines at each site, leading to an estimated figure of 783 MW for aggregate installed capacity. This is almost 25% less than the capacity estimated by *GroenLinks*. Our estimate may even be deemed somewhat optimistic, as we assume optimum use of the available space at the respective sites.

Table 6 Number of turbines, installed capacity, annual output and number of households supplied at selected wind farm sites

	Number of turbines	MW	Mln kWh	Households Supplied
Highway A6, Almere-Lemmer	125	250	614	186,113
North Holland Canal	50	100	246	74,445
Highway A7	50	100	246	74,445
Eemshaven industrial estate, Groningen	48	96	236	71,467
Highway A9, Alkmaar-Badhoevedorp	75	150	369	111,668
North Sea Canal, south bank	38	75	184	55,834
Corus industrial estate, IJmuiden	6	12	29	8,933
Total	**392**	**783**	**1,924**	**582,906**

The energy output of a wind farm - shown in the fourth column of Table 4 – is governed by three factors: the turbines (in particular, rotor diameter), the wind and the site, the latter being as important as the technology to actual energy output.

The energy content of the wind varies with the third power of the wind speed: twice as much wind thus yields eight times as much energy and vice versa. For each of the seven sites we have assumed an annual average wind speed of 6.6 m/s at hub height (60-80 metres), somewhat less than the annual average measured at the same height in coastal regions (see box).

The formula is as follows:

$$\mathbf{E_{jr} = C \times V^3 \times A}$$

E_{jr} = average annual output in kWh
C = a measure of turbine yield, decreasing in value with increasing average wind speed and varying in the Netherlands from 2.8 at inland sites to 3.6 on the coast. For an average site and turbine, 3.4 is a legitimate estimate.
V^3 = annual average wind speed at hub height in m/s, varying in the Netherlands from 8.5 m/s at 60-m height on the coast to 3 m/s at 30 m inland. We have assumed an annual figure of 6.6 m/s for the seven sites, somewhat less than the coastal figure of 8.5 m/s.
A **=** area swept by rotor in m^2 (PI * 1/2 * rotor diameter^2).

In general, the effective power of a modern wind turbine is typically around 20-40 % of maximum power, the exact figure of course depending on the actual wind regime.

Table 7 presents the results of a sensitivity analysis with different wind regimes assumed. As can be seen, energy output is very sensitive to wind speed (third power). Figure 1 shows the variation in the energy of the wind in two extreme years, 1988 (14% above average) and 2002 (14% below average)[3]. As the figure shows, the monthly average exhibits varies much more than the annual average.

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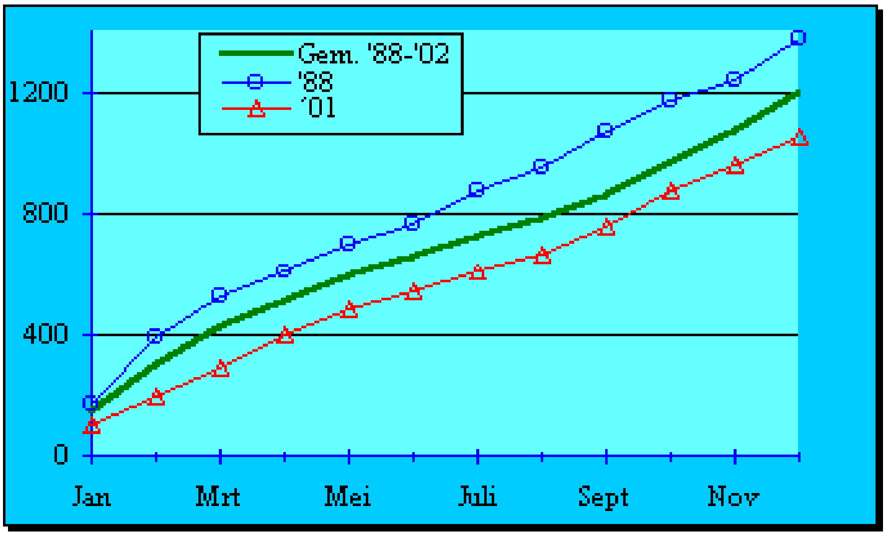
[3] This so-called wind index gives the monthly energy content relative to an average figure.

Figure 1 Total available wind energy in two extreme years relative to an average year



Source: WHS website: Gem. '88-'02 indicates the average value between 1998 and 2002.

Table 7 Sensitivity analysis of annual power output (mln kWh) under five different wind regimes

Wind force (Beaufort) **Wind speed (m/s)**	**0-2** **0-3 m/s**	**4** **5.5 m/s** **-14%**	**4** **6.6 m/s** **average**	**4 tot 5** **7.5 m/s** **+14%**	**> 9** **> 20m/s**
Highway A6, Almere-Lemmer	0	375	614	901	0
North Holland Canal	0	150	246	360	0
Highway A7	0	150	246	360	0
Eemshaven industrial estate, Groningen	0	144	236	346	0
Highway A9, Alkmaar-Badhoevedorp	0	225	369	541	0
North Sea Canal, south bank	0	113	184	270	0
Corus industrial estate, IJmuiden	0	18	29	43	0
Total	**0**	**1,175**	**1,924**	**2,823**	**0**

As can be concluded from Table 7, wind turbines start to produce electricity at wind speeds above 3 m/s. With the annual average wind speed assumed, the seven locations are together anticipated to generate 1,924 mln kWh of electricity a year. From year to year the amount of wind can vary from +14% to -14% relative to the average, which will significantly affect the total amount of power generated (2,823 mln kWh and 1,175 kWh, respectively). Above wind force 9 (over 20 m/s) turbines will be taken off line, cutting energy output to zero.

From Table 4 it follows that on average a wind farm will generate electrical power on 92% of the days of a year.

Table 8 Estimated distribution of wind regimes in the Netherlands at 60-m height

Wind speed (m/s)	Distribution
0-3	8%
3 tot 5.5	**31%**
5.5 tot 7.5	**32%**
7.5 tot 9	**11%**
9 to 15	**18%**
15 to 20	**1%**
Over 20	0.1%

Note: Based on average daily wind speed from 1991-2000 (as recorded at KNMI meteorological station De Bilt) and assuming the average figure of 6.6 m/s at 60-m height is the same as the average measured wind speed at De Bilt (at 1-m height).

2.4 Costs

Land use

As less than one per cent of the total area of a typical wind farm is occupied by wind turbines and access roads, the remaining 99 per cent of the land can be used for farming or grazing. As turbines extract energy from the wind, there is less energy in the wind shade of a turbine (and more turbulence) than in front of it.

For its foundations each *turbine* requires an area of about 10 by 10 metres (see WHS). This area cannot be used for other functions. In addition, each *wind farm* needs about 4,500 m^2 of land for an access road.

In the case of agricultural sites, the opportunity costs of alternative land use can be calculated by multiplying the net area utilised by the average price of farmland, € 4 per m^2 in 2002 (CBS). For industrial sites the net area utilised is multiplied by the estimated average price of industrial land. As the average price of industrial estate is not registered by Netherlands Statistics (CBS), we took an estimate of € 66 per square metre[4]. Furthermore, since most industrial sites already have extensive infrastructure, we assumed that the space required for an access road will be only half that at a farmland site.

Table 9 shows the calculated opportunity costs of alternative land use.

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[4] Alternatively, it may be argued that turbines installed at industrial sites will be sited in such a way as to leave the space available for business location unaffected. The opportunity costs of alternative use of the land will then be zero. On the other hand, the noise of the wind might have indirect effects on the space available for new companies, pushing up the opportunity costs. For the purpose of our analysis these two effects were assumed to cancel one another out. Price data were taken from: www.zakensteden.nl, which cites an average price for industrial estate of € 42 in the province of Limburg and € 90 in the Randstad conurbation. We assumed an intermediate value.

Table 9 Opportunity costs of land use

	Type of site	Number of turbines	Land use (m^2)	Cost of land use (€)
Highway A6, Almere-Lemmer	Linear	125	17,000	68,000
North Holland Canal	Linear	50	9,500	38,000
Highway A7	Linear	50	9,500	38,000
Eemshaven industrial estate, Groningen	Industrial	48	9,300	465,300
Highway A9, Alkmaar-Badhoevedorp	Linear	75	12,000	48,000
North Sea Canal, south bank	Linear	38	8,250	33,000
Corus industrial estate, IJmuiden	Industrial	6	5,100	188,100
Total		**392**		878,400

Land ownership may not necessarily be transferred to the wind project developer. Developers in fact usually pay the landowner a certain fee for using the plot of land, which at present averages about 10,000 euro per MW. Based on this figure, Table 5 shows the calculated fee for each of the sites examined.

Table 10 Cost of fees

	Type of site	Number of turbines	Total fee (euro)
Highway A6, Almere-Lemmer	Linear	125	250,000
North Holland Canal	Linear	50	100,000
Highway A7	Linear	50	100,000
Eemshaven industrial estate, Groningen	Industrial	48	96,000
Highway A9, Alkmaar-Badhoevedorp	Linear	75	150,000
North Sea Canal, south bank	Linear	38	75,000
Corus industrial estate, IJmuiden	Industrial	6	12,000
Total		**392**	**783,000**

Cost of additional changes to the generating park
Installation of new wind power capacity places additional demands on standing generating capacity, which must operated more flexibly to avoid capacity shortfalls due to fluctuations in the wind. According to one expert, a total of around 1,000 MW new wind capacity can be incorporated in the Dutch grid without too much problem[5]. Given that there is currently 600-700 MW installed wind power capacity in the Netherlands, installing a further 762 MW will mean that dovetailing it into the overall supply grid becomes crucial.

Sometimes referred to as the ‘hidden costs’ of wind power, these indirect implementation costs arise from the reduced efficiency with which conventional power plant can be operated, because of it having to be taken on and off stream more often. There is considerable scope for handling this problem, moreover. One option is to use cogeneration (combined heat and power) plant to balance any power shortfalls. However, this may mean gearing plant operation more towards power production in times of wind

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[5] Source: Eppie Pelgrim, Tennet.

shortfall, implying relative loss of heat output and an overall reduction of plant efficiency.

The associated costs are generally estimated using probabilistic accounting methods. As far as we know there have been no recent studies on this topic, although some calculations have been reported in older studies. It is a time-consuming exercise, however, as calculations depend on the precise distribution of power plant in the Netherlands today. There are, in other words, no simple rules of thumb for estimating the magnitude of these costs.

Additional costs may also accrue from the need for the power grid to be renewed, as wind turbines require a higher-voltage grid. Again, little is known about these costs, which are very much site-specific. In certain remote areas, for example, it is known that the existing grid had to be replaced. Neither of these cost categories has been included in the analysis reported here, however.

Cost of spatial planning procedures (estimated)
The costs associated with spatial planning procedures are difficult to assess, there being no official data available on the subject. As it takes an average of 46 weeks to go through the legal procedures required of wind power projects, these costs may be assumed to be significant. For wind farm developers, the costs in question accrue mainly from the man-hours devoted to such proceedings. Based on several brief interviews with developers, we arrive at costs ranging from 50,000 Euro for a straightforward procedure up to 350,000 Euro for a more complex one (a hearing before the Council of State) per wind farm. An average value of 200,000 Euro per project therefore seems an appropriate estimate. To some extent these costs are independent of project size, though high costs will obviously mean a greater risk of a small project having to be cancelled.

The costs include:
- cost of external legal assistance;
- project developer man-hours;
- cost of external MER studies;
- cost of advice on spatial zoning plans.

Not included are the cost of the man-hours devoted by municipal and provincial agencies to statutory procedures. This item is hard to estimate, as most government organisations keep no record of the time assigned to individual projects.

External costs (estimates)
In Denmark AKF have carried out by a survey to estimate the external costs of noise nuisance and visual impact of wind turbines. They concluded that these costs were minimal: less than € 0.0012 per kWh of electrical output. The survey was based largely on interviews with 342 people living near wind generators who were asked how much they would be willing to pay to have the units removed. The results were validated by comparing the prices of 74 houses located near turbines with those of similar houses elsewhere.

2.5 Overall cost estimate

Based on the above analysis, we can now arrive at a final estimate of the cost of developing wind farms at the seven sites taken from the *GroenLinks* proposals. We thereby distinguish the following costs:

1. The opportunity costs of land use. For these we take the values from Table 9. These opportunity costs are much lower for agricultural land along roads than for industrial sites.
2. The external costs. These are based on two calculations: a minimum figure, taken from the AKF survey, and a figure based on the fee paid to landowners (see Table 10). We thereby assume that the price differential between the fee paid and the costs of land use (excluding opportunity costs) can be regarded as a reimbursement to landowners for the nuisance caused by the installed turbines. The reasoning here is that in a competitive market the fee for land use should be equivalent to the external costs accruing to the landowner. Note that this calculation assumes both competitive markets and no external costs to any other parties. Both these assumptions are questionable, of course[6].
3. The cost of spatial planning procedures; here we take a mid-range value of around 200,000 Euro per project.

A total estimate can now be given of the cost of implementing each of these seven wind power projects (Table 11).

Table 11 Site-specific cost of implementing the *GroenLinks* wind farm plan in the Netherlands (in 1,000 Euro)

	Annual output (million kWh)	Opportunity costs	External costs, low (AFK)	External costs, high (fees)	Procedures
Highway A6	614	68	0.7	200	200
NH Canal	246	38	0.3	80	200
Highway A7	246	38	0.3	80	200
Eemshaven	236	465	0.3	77	200
Highway A9	369	48	0.4	120	200
NZ Canal, south bank	184	33	0.2	60	200
Corus	29	188	0.0	10	200
Total	**1,924**	**878**	**2.3**	**626**	**1,400**

Note: this ignores the difference in operating costs between wind and conventional power generation.

Using the figures of Table 11 we can now assess the overall annual additional costs of implementing the *GroenLinks* proposals. Assuming a 15-year depreciation period for the turbines, a discount rate of 4% and a depreciation scheme based on constant annuities, we come to the following additional costs, summarised in Table 12. The column 'annual costs LOW' gives the additional costs according to the lower AFK estimate of external costs. The column 'HIGH' gives our estimate based on the assumption that the price differential between the fee and the external costs can be seen as an indication of the external costs of wind power. It should be noted that Table 12 again ignores any additional operating costs of wind power compared to

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[6] Moreover, we have here calculated only the external costs due to building the wind farm itself, i.e. not including any access road. The external costs reported here thus refer only to the price difference between the cost of land use due to the turbines themselves and the reimbursement per MW installed capacity.

conventional generating units; neither does it include the cost of any operational changes to the current generating park or power grid.

Table 12 Annual additional costs of implementing the *GroenLinks* plan

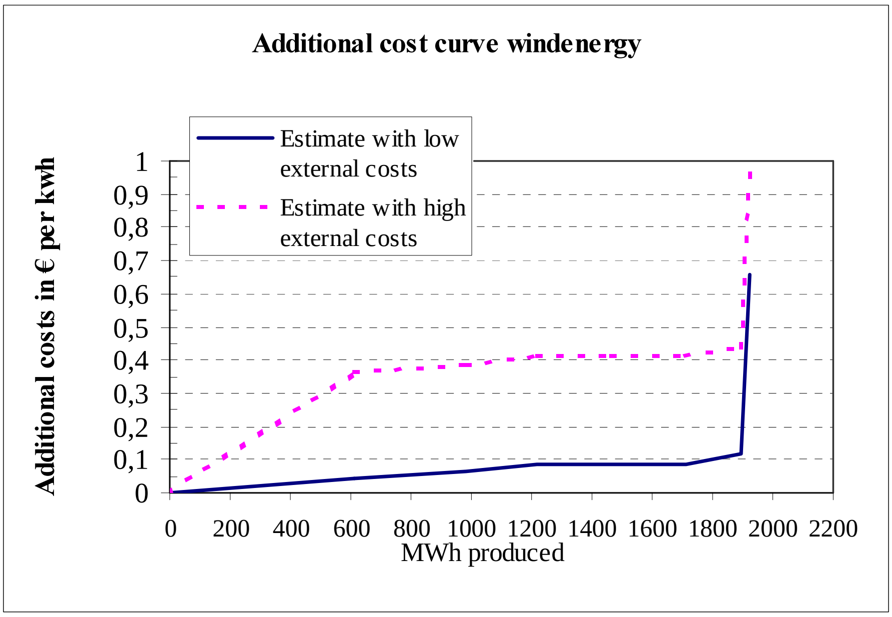
Total costs	Annual costs (Euro)		Annual costs (Euro/kWh)	
	LOW	HIGH	LOW	HIGH
Highway A6	24,841	224,104	0.04	0.36
NH Canal	21,701	101,406	0.09	0.41
Highway A7	21,701	101,406	0.09	0.41
Eemshaven	20,808	97,325	0.09	0.41
Highway A9	22,748	142,305	0.06	0.39
NZ Canal, south bank	21,177	80,956	0.12	0.44
Corus	19,048	28,614	0.66	0.99
Total / average	152,025	776,116	0.08	0.40

Note: this ignores the difference in operating costs between wind and conventional power generation.

As Table 12 shows, the lowest annual costs per kWh output are anticipated at the sites along highways A6 and A9. Along the A7 and the North Holland Canal and at the Eemshaven industrial site the costs are average. The highest costs are expected on the south bank of the North Sea Canal. The costs of building a wind farm at the Corus site are excessive.

Based on this table we can construct the following general cost curves for implementing the *Groen Links* proposals for wind farms at these seven locations. In the end the marginal costs obviously become very high. Installation of wind turbines on industrial sites, in particular, proves to be less cost-effective, for here the opportunity costs for alternative land use are relatively high.

Figure 2 Additional cost curve for implementation of the *Groen Links* wind power plan



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- Julliëte Koeslag, CEA;
- Kees Bakker, Energy Coördinator, Heerhugowaard, Chairman, Vereniging Kennemerwind;
- Eppie Pelgrim, Tennet.

3 Extension of ACEA agreement to trucks and vans

3.1 Description of the measure

This policy option for improving security of supply consists of extending the ACEA agreement on motor vehicle CO_2-emissions to include trucks and vans.

The thinking behind this is that one way to reduce national dependence on imports of foreign oil is to improve vehicle fuel consumption. The European Commission and ACEA, JAMA and KAMA have agreed that CO_2-emissions from individual passenger cars sold on the European market, which correlate closely with fuel consumption, are to be cut back to 140 grams per km by 2008 (ACEA) or 2009 (JAMA, KAMA). For the automotive sector this ‘ACEA agreement’ is now a key policy cornerstone.

Between 1995 and 2001 vehicle-specific CO_2 emissions from cars (‘category M1 vehicles’) decreased from about 186 to 167–170 g CO_2/km. In its 2002 progress report the Commission concluded that the industry was making good progress on implementing its comitments (COM 2002/693).

One way to achieve further cuts in fuel consumption and CO_2-emissions after the current policy period is to extend and widen the ACEA agreement to include both vans and trucks. Because these two vehicle categories are used in an economic context, though, economizing on fuel is already important in the industry.

3.2 Extension to trucks

The truck market is very different to that for passenger vehicles. In the first place, cars are mass-produced. They also have a single, homogeneous function - transporting a maximum of nine people - and fuel consumption per vehicle-kilometre is therefore a simple and workable indicator for monitoring progress on fuel efficiency. There is relatively wide scope for achieving such progress, moreover, for within any given segment of the market fuel consumption can vary substantially. Finally, consumer vehicle choice is by no means purely rational, but based equally on design preferences and personal driving style.

The truck market is very different. In terms of both size and function there is far greater differentiation (3.75 up to 40 tonnes gross vehicle weight; refrigerated trucks, refuse vehicles, etc., etc.). It is consequently very difficult to develop an indicator for measuring (improvements in) fuel economy that can be used for all types of vehicle. Besides, a new fuel consumption test would have to be developed for each and every type of vehicle. Another key difference is that in the highly competitive road haulage industry fuel consumption is a central sales argument for manufacturers. Fuel costs account for some 15% of total haulier costs (CE, 1999). This explains why differences in fuel consumption between trucks used in a given market segment are so small: a few per cent at most (CE, 1999). It also explains why there has been a steady and continuous improvement in truck fuel efficiency, more so than for cars. Between 1980 and 1997 the fuel consumption of a 40-tonne truck decreased by about 20%[7].

Given these considerations, it is doubtful whether extension of the ACEA agreement to trucks is either technically and economically feasible (development of appropriate indicator, costs of testing) or indeed an effective way of cutting truck CO_2-emissions further. In this sector, fuel-based measures or economic instruments like fuel taxes or emissions trading are probably more appropriate instruments.

3.3 Extension to vans

Light commercial vehicles, or 'category N1 vehicles', comprise vans and small trucks with a maximum gross weight of 3.75 tonnes. Like passenger cars, vans are mass-produced and engineering improvements such as direct fuel injection and better rolling resistance are also generally implemented in N1 vehicles, too. A substantial proportion of these vehicles – the small 'car-derived vans' – share their engine and other engineering features with vehicles included in the current ACEA agreement with the EC and will therefore automatically have improved fuel performance. In (RIVM, 2001) it is argued that a 20% increase in fuel efficiency will be achieved between 1995 and 2010 as a result of autonomous technological developments.

In this category there is little scope for improving aerodynamics or weight, moreover, as the vehicles in question are used to carry heavy or bulky loads. Additionally, over 90% of N1 vehicles run on diesel; as fuel costs are already a priority for hauliers, there is only limited scope for improvement on this point. The market will therefore favour fuel-efficient vehicles without any intervention from the EU – a situation very different from that for M1 vehicles, i.e. passenger cars, where fuel economy is often a secondary consideration compared to performance or brand appeal. The sub-category 'small trucks', designed for dedicated jobs, generally benefits from efficiency improvements in the (large) truck industry.

In contrast, however, the Commission is of the opinion that the cost-intensive measures being implemented in the car industry to reduce fuel consumption are *not* being transferred to N1 vehicles, holding that there is no incentive here to (drastically) reduce fuel consumption. There are no quantitative data to support this position, though.

To monitor (improvements in) the fuel economy of N1 vehicles and pave the way for mandatory fuel efficiency labelling, the European Commission has proposed amending Directive 80/1268/EEC, extending its scope from M1 vehicles (passenger cars) to N1 vehicles (light commercial vehicles). In response[8] to this proposal, the European Parliament has outlined a number of reasons why introducing an ACEA agreement for vans and light trucks is technically more difficult and therefore less cost-effective than the current agreement.

The Directive is expected to come into force at the end of 2003. The Commission is currently preparing a Communication outlining the policy scope for limiting the emissions of N1 vehicles. Judging from contacts with the Com-

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[7] EA: http://www.acea.be/ACEA/tr/index.html.

[8] 5-0232/2002.

mission[9], extension of the agreement to vans seems unlikely, the industry having shown no interest. Flexibility is deemed less important than in the passenger car market, purchases being affected far less by considerations of comfort, design or driving style. Separate legislation may possibly be introduced for the two sub-categories of N1 vehicle.

In view of the above, it might well be concluded that there is relatively little to gain from a voluntary agreement to reduce the CO_2-emissions of these vehicles. Nonetheless, the Commission estimates, on the basis of ‘expert judgement’[10], that a fuel economy improvement of 10-15% can be achieved at a cost of 50 – 100 Euro per tonne CO_2, equivalent to about 0.015 to 0.03 Euro cent per vehicle-kilometre.

A different option for reducing the fuel consumption of light commercial vehicles is to extend statutory speed limitation to this vehicle category. Depending on the maximum speed set, savings of the same order of magnitude would be achievable. Besides the savings on fuel, road safety would also be improved, moreover. However, the Commission does not expect the Transport Council to support speed limitation for this vehicle category.

3.4 References

Literature

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- K.H. Zierock, European Commission, DG Environment;
- L.H.M. Schlosser, Dutch Transport Research Centre (AVV).

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[9] Telephone conversation with Mr Zierock, DG ENV.

[10] No specific studies have been done on this issue.

4 Transport biofuels

4.1 Description of measure

This policy option consists of prescribing a mandatory minimum percentage of biofuels to be blended in transport fuels, combined with a reduced rate of excise duty on biofuels.

In November 2001 the European Commission proposed two directives to the European Parliament and the Council on use of biofuels in the transport sector. The first directive seeks to promote use of transport biofuels, while the second amends Directive 92/81/EEC, on the scope for applying a reduced rate of excise duty on certain mineral oils containing biofuels and on biofuels themselves.

Since then these proposals have been discussed and amended in a first hearing by the European Parliament and in a common position by the Council. The revised proposal for promoting biofuels was recently discussed in a second parliamentary hearing, with agreement being reached on a revised draft directive to be put to the Council[11].

The main thrust of the two directives can be summarised as follows:

1 Promotion of transport biofuels
  - a Motives:
    - to reduce over-dependence on oil-based fuels;
    - biofuels are environment-friendly and help fulfil commitments under the Kyoto Protocol;
    - biofuels can provide new sources of farm income.
  - b Indicative targets for minimum proportion of biofuels sold[12]:
    - 2% of all petrol and diesel sold for transport purposes on national markets by 31 December, 2005 (calculated on the basis of energy content);
    - 5.75% by 31 December, 2010.
  - c Member states are to set national targets and report on their progress in meeting these targets. Any differences between national targets and the cited indicative targets must be duly motivated (because of limited domestic biofuel production potential, for example, or allocation of biomass resources to energy uses other than transport fuels).

2 Amendment of the directive on excise duties on mineral oils:
  - a Member states may reduce excise duties on pure biofuels or biofuels blended into other fuels, to the extent that these are used for heating or transport purposes.
  - b Excise duty may be reduced by up to 50% of the rate for conventional fuels.
  - c If the fuel is used for local public passenger transport, including taxis, an additional tax exemption of up to 100% is permitted[13].

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[11] Between writing and issuing of this report, this Directive of the European Parliament and Council (2003/30/EG) has been agreed upon and has come into force.

[12] In the Commission's original proposal, mandatory targets were set. In the common position these were replaced by indicative targets, however.

[13] Such tax exemption to be valid for the period from January 2002 to December 2010.

d These tax exemptions may not overcompensate the additional cost of biofuels.

There are various ways and means of implementing this policy measure, member states having some freedom as to how they achieve the indicative targets set for the minimum proportion of biofuels. In this section we focus on one possible policy option: mandatory blending of a minimum percentage of biofuels in transport fuels, combined with a reduced rate of excise duty on biofuels[14]. Oil companies would thus be obliged to blend a minimum of 2% biofuels in their transport fuels by 2005 and a minimum of 5.75% by 2010. In this option excise duty on these biofuels would also be reduced, by an amount equivalent to the additional cost of biofuel compared with fossil fuel production.

The precise amount by which excise duty is reduced will obviously have a major impact on the cost of the measure to the (Dutch) government. In the analysis below we assume the following reductions: € 0.005 in 2005 for diesel and petrol with 2% biofuel (based on energy content) and € 0.0143 in 2010 for diesel and petrol with 5.75% biofuel. These cuts are expected to be roughly equivalent to the additional cost of the biofuel blended into the regular fuel, as will be shown below.

In practice it is also possible to implement just one of these policies, that is, either make a minimum biofuel blend mandatory or reduce excise duty.
The first of these measures would ensure that European targets are met, but has the disadvantage of embodying no form of cost control: if the supply of biofuels does not keep up with growing demand, the costs of the measure may rise substantially. As the EU targets are merely indicative, there is no legal obligation to meet them.

The second instrument is more market-oriented. The reduction in excise duty will promote the use of biofuels only to the extent that such fuels can be produced at limited additional cost compared to fossil fuels. The volume of biofuels can then be controlled by regularly evaluating the policy's effectiveness, with excise duty dates being adjusted further as necessary and desirable.

Simultaneous implementation of both measures retains the features of a mandatory minimum blend but with the additional advantage of reducing the additional cost to consumers and the road haulage sector, although at the expense of reduced tax revenue.

It is not as yet clear which vehicle categories would be encompassed by these measures. Here we have assumed they would apply to all transport fuels currently subject to the higher excise duty rate, i.e. diesel and petrol for passenger cars, small vans, heavy goods vehicles and buses.

4.2 Feasibility

We now turn to a brief discussion of the feasibility of the dual policy measure in terms of legal issues, technical issues and political support.

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[14] In earlier versions of the biofuel Directive, mandatory blending of a minimum percentage of biofuels was proposed as a possible policy option. However, this has not been included in the final Directive (issued after writing of this report).

Legally, the mandatory blending of biofuels that we consider in this measure is not likely to be allowed by the EU (contrary to provisions made in the earlier versions of the proposals). The second part of this policy option, reduction of excise duties, can be implemented as soon as the proposed directive on excise duties comes into force (scheduled for the coming year). The reductions in excise duty cited above are generally considered to be in line with this proposal.

Technically, the main uncertainties relate to potential biofuel production capacity and costs. Once EU member states have policies in place to increase biofuel production and sales, in line with the directive, demand for these fuels can be expected to increase significantly. At the moment there are only a few EU countries where biofuels are marketed on any scale at all. In France, the European frontrunner in this area, the total share of biofuels in transport sector fuel consumption is a mere 0.7% of aggregate fossil fuel consumption. The proposed (indicative) expansion of biofuel production will therefore cause a very marked increase in biofuel demand. This must be mitigated by the growth of biomass supply (from dedicated agricultural and organic waste products) and biofuel production capacity. As in any market, biofuel prices will rise if there is insufficient supply.

Politically, it is not yet clear whether there will be sufficient support for the envisaged policy. The Dutch environment Ministry is carrying out a study on the feasibility and impact of various options for implementing the Directive. Based on the outcome of this study, the Ministry is to advise the Dutch Parliament this summer; it is then up to Parliament to pronounce on the policies to be implemented.

4.3 Costs

The main costs of the measure accrue from the higher production costs of biofuels compared with fossil transport fuels. Estimates of these costs depend very much on the assumptions made with respect to a variety of issues, in particular:

- the type of fuel;
- the size and type of production facility;
- the cost of biomass feedstock, and
- the price of fuel production by-products (e.g. glycerine).

At present it is difficult to make hard and fast predictions on any of these issues.

As things stand at the moment, production costs are generally estimated at approx. 500 Euro/1,000 litre for biodiesel - the most common biofuel today – and approx. 430 euro/1000 litre for bioethanol from sugarbeet and cereals. Taking a figure of 340 euro/1000 litre for the cost of fossil fuel production (the average reported for 2001 and 2002) and correcting for the lower energy content of the biofuels[15], the additional cost of biofuels amounts to about 200 - 300 euro/1,000 litre of replaced fossil fuels. Biodiesel is (currently) at the lower end of this range, bio-ethanol at the upper end.

Assuming an average cost increase of 250 euro/1,000 litre of replaced fuel, the excise duty reductions cited earlier equal the additional production costs

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[15] The (volumetric) energy content of biodiesel is 8% less than that of diesel, the energy content of bioethanol is 32% less than that of the petrol that it may replace.

per litre € 0.005 in 2005 for diesel and petrol with 2% biofuels and € 0.0143 in 2010 for diesel and petrol with 5.75% biofuels (calculations based on energy content).

These cost estimates and projected cuts in excise duty were fed into the Global Competition (GC) scenario used in the National Institute of Public Health and Environmental Protection's 5th National Environmental Outlook (RIVM, 2000) to estimate the resultant costs to the various parties concerned. The results are shown in Table 13 and Table 14, reporting:

- estimated total macro-economic costs, i.e. the additional production cost of biofuels compared to fossil fuels, and
- the increase in fuel production cost per kilometre due to the increase in fuel cost, for several vehicle categories.

The loss of government revenue due to reduced excise duties is equal to the total macro-economic costs, as the measure has been designed such that that the additional production costs are fully compensated by cuts in excise duty[16]. For the same reason the costs of this measure to consumers and road hauliers are deemed to be negligible.

Table 13 Costs of the measure: total annual macro-economic costs in 2005 and 2010

	Marco-economic costs, i.e. loss of excise duty revenue (million euro per annum)	
	2005	2010
Total	56	170

Table 14 Costs of the measure and costs per kilometre driven, in 2005 and 2010, for several types of vehicle

	Additional cost of fuel production			
	Euro cent per kilometre		percentage of fuel production costs	
	2005	2010	2005	2010
Passenger car, petrol	0.04	0.10	1.5	4.2
Passenger car, diesel	0.03	0.08	1.5	4.2
Small vans, petrol or diesel	0.04	0.12	1.5	4.2
Trucks	0.17	0.50	1.5	4.2

The enforcement costs of this measure are unclear as yet. However, as there is already a system in place for enforcing excise duty payment, with sales of different types of fuel being accurately monitored, we estimate there will be little additional cost.

There may be additional costs to government, though, in the form of new subsidies that may have to be paid to the agricultural sector. This potential cost item cannot yet be estimated.

One of the motives for promoting transport biofuels is the positive environmental impact this will have; it will lead to a certain reduction in the overall external costs of land vehicle transport. The main impact will be a reduction

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[16] This loss of government revenue might be offset by a (slight) increase in excise duty on fossil fuels. This has not been assumed here, however.

of greenhouse gas emissions, from 'well to wheel'. However, the actual reduction achieved in practice depends very much on two factors:

– the kind of biomass used as a feedstock, especially the amount of N_2O emitted during cultivation due to use of nitrogen fertilisers[17], and
– the production process used, in particular the energy required for converting the biomass into high-quality transport fuel.

The range of estimates reported in the literature for effective improvements in greenhouse gas efficiency is fairly large. For both biodiesel and bioethanol a 30-50% reduction of CO_2-equivalents seems a reasonable estimate. The reductions likely to result from implementing the policy measure are shown in Table 15 below (for comparison: combustion of 1 litre of fossil fuel emits 3.2-3.3 kg CO_2-equivalents). The table also gives figures for the estimated reduction in external transport costs, using a price of 50 Euro/tonne CO_2-equivalents.

Table 15 Reduction of CO_2-equivalents due to the measure, in kg/km and as a reduction in external costs (assuming 50 Euro/tonne CO_2-equivalents)

	Reduction of CO_2-equivalents			
	in kg/km		in Euro ct/km	
	2005	2010	2005	2010
Passenger car, petrol	0.0014-0.0024	0.0038-0.0064	0.0071-0.012	0.019-0.032
Passenger car, diesel	0.0011-0.0019	0.0029-0.0049	0.0057-0.0094	0.015-0.025
Small vans, petrol and diesel	0.0017-0.0028	0.0045-0.0075	0.0084-0.014	0.022-0.037
Trucks	0.0065-0.011	0.019-0.032	0.033-0.054	0.093-0.15

4.4 Effects

Assuming the indicative targets for minimum biofuel blends are met for both diesel and petrol, there will be 2% substitution of fossil fuels in the transport sector in 2005 and 5.75% substitution by 2010.

As mentioned, though, biofuel production requires energy, and this is likely to be of fossil origin[18]. Depending on the biofuel in question, there may be major variation in 'well to wheel' energy efficiency, expressed as the overall energy output/input ratio: a ratio of 2 means that in terms of the resultant energy content, production of 2 units of the biofuel requires 1 unit of fossil fuel. Output/input ratios in the following ranges are reported in the literature[19]:

– biodiesel (Rapeseed Methyl Ester, RME): approx. 2.5-3.0;
– bioethanol from sugarbeet: approx. 2.4;

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[17] N_2O is a very powerful greenhouse gas, with 1 unit of N_2O equivalent to 270 to 290 units of CO_2.

[18] Even if renewable energy is used for biofuel production, this energy cannot then substitute for fossil fuels elsewhere. Under the reasonable assumption that renewable energy will remain scarce in the coming years, this use will therefore have a negative impact on efficiency.

[19] Source: EEB background paper, 2002.

- bioethanol from tree residues may be far more efficient, with a ratio of up to 17.

In the short and medium term it is expected that biodiesel and sugarbeet bioethanol will mainly be used to comply with the biofuels Directive, as these can probably be produced at lowest cost. An output/input ratio of 2.4 therefore seems a reasonable assumption, corresponding to an efficiency of 58%. The results are shown in Table 16, with and without a correction for efficiency.

Table 16 Projected fossil fuel consumption per vehicle kilometre without the policy and reductions achievable with the policy, in 2005 and 2010 (with and without correction)

	Vehicle fossil fuel consumption without this policy [litres/kilometre]		Reduction of vehicle fossil fuel consumption with this policy, *uncorrected* [litres/kilometre]		Reduction of fossil fuel consumption after correction for energy required for biofuel production [litres/kilometre]	
	2005	2010	2005	2010	2005	2010
Passenger car, petrol	0.073	0.068	0.0015	0.0039	0.0009	0.0023
Passenger car, diesel	0.058	0.053	0.0012	0.0030	0.0007	0.0018
Small vans, petrol and diesel	0.087	0.080	0.0017	0.0046	0.0010	0.0027
Trucks	0.347	0.346	0.0069	0.0199	0.0040	0.0116

There are other categories of external costs arising through the use of biofuels, for example those due to pesticide use in biomass cultivation. These issues are not yet well understood, though, and have therefore been ignored here. Besides, fossil fuel consumption is also associated with various external costs of its own, such as those of SO_2-emissions. A full external cost-benefit analysis of biofuels versus fossil fuels is yet to be undertaken[20].

4.5 Literature

European Environmental Bureau, *EEB background paper 18-03-2002, on the use of biofuels for transport.*

European Parliament, A5-0057/2003 Final, *Recommendation for second reading on the Council common position for adopting a European Parliament and Council directive on the promotion of the use of biofuels for transport*, Committee on Industry, External Trade, Research and Energy, February 2003.

European Commission, COM(2002) 508 final, *Amended proposal for a Directive of the European Parliament and of the Council on the promotion of the use of biofuels for transport*, September 2002.

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[20] At the moment of writing, a study is undertaken by Ecofys investigating the consequences from implementation of the Directive.

European Council, 6795/03, *Common position adopted by the Council with a view to the adoption of a Directive of the European Parliament and of the Council on the promotion of the use of biofuels for transport*.

RIVM, *Scenario's voor duurzame energie in verkeer en vervoer, Beoordeling op verschillende criteria voor duurzaamheid*, RIVM report 773002025/2003

RIVM, National Environmental Outlook 5 2000-2030, RIVM, Bilthoven, 2000.

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5 Biofeedstocks in the chemical industry

5.1 Introduction: biomass as a chemical industry input

This chapter focuses in more detail on the main technological opportunities for converting biomass into chemical products, either directly or via chemical intermediates. Although in theory there are various possible routes to biofeedstock-based chemical production (see Box 5.1), our sole focus here will be on the use of biomass as a resource for synthesising chemical building blocks which can then be converted to marketable products. In principle, this biomass will be used partly as a substitute for fossil fuel inputs to current chemical production technologies, thus helping to reduce dependence on foreign fossil imports.

Box 5.1 Biofeedstocks for chemical production: two approaches

In theory there are two distinct paths to establishing a bio-based chemical industry: an 'integrated process chain' approach and a 'value chain' approach. The **integrated process chain approach** is analogous to that currently adopted by the petrochemical industry, with a 'universal substrate' (prepared from biomass rather than naphtha, say) being first converted into a number of universal building blocks, from which specific chemical products are then produced. In this approach it is taken to be economically and technologically advantageous to synthesise chemicals in tightly integrated production facilities. In this case the main technological challenge is therefore to convert biomass into the familiar building blocks already used by the petrochemical industry.

In the **value chain approach** valuable compounds in biomass feedstocks are identified and isolated in specific processing and (bio)conversion steps. The *remaining* biomass is then transformed into a 'universal substrate' from which chemical products can be synthesised. In this approach the technological and economic advantage is seen as lying in direct extraction of valuable chemicals and polymers from bioresources rather than synthesis from universal building blocks.

Although the second approach is generally held to be more cost-effective, the lock-in effect of the petrochemical industry's current infrastructure means the integrated process chain approach at present seems to be the only feasible option.

Figure 3 provides a schematic representation of the possible pathways for converting biomass to chemical products using the integrated process chain approach[21].

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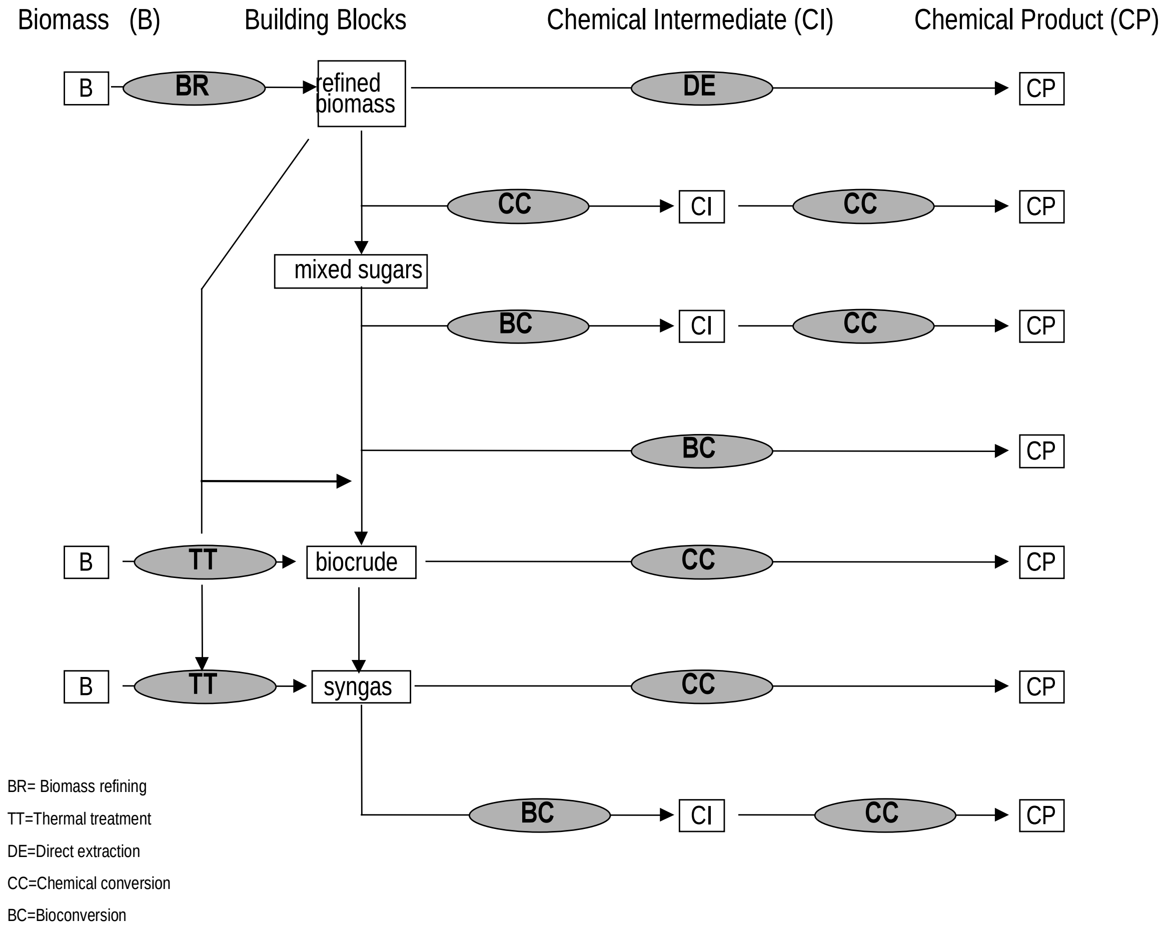
[21] R. van Tuil, I. de Keizer e.a.; *Biomass for the chemical industry*; ATO, CE; Wageningen; 2002.

Figure 3 Schematic representation of chemicals production from biomass in the integrated process chain approach



This arrangement is thus very similar to the traditional chemical processes in which fossil feedstocks (natural gas or naphtha) are chemically reacted in a cracker. The process of cracking (i.e. breaking larger molecules down into smaller ones) produces the basic chemicals, often termed 'building blocks'.

Technologies

The main technologies available for synthesising building blocks from biomass are:

- biomass refining or pre-treatment;
- fermentation and bioconversion;
- thermo-mechanical treatment (HTU);
- gasification.

Building blocks

The figure also shows that four main categories of building blocks can be identified as intermediates for the production of chemicals from biomass:

- refined biomass: biomass in which valuable components have been freed up by physical and/or mild thermo-chemical treatment for further conversion;

- mixed sugars (C5 and C6 sugars): a more refined feedstock for biological or chemical conversion originating mainly from food industry by-products and potentially from lignocellulosic biomass;
- biocrude: a petroleum-like mixture of hydrocarbons with a low oxygen content produced by severe thermo-mechanical treatment of biomass (waste); like its petroleum analogue, it can be used for producing electricity, fuels, chemicals and materials;
- syngas: a gaseous mixture consisting mainly of CO and H_2 produced by gasification of biomass; again it is a universal feedstock for energy, fuel, chemicals and materials.

Chemical intermediates and products
The chemical products synthesised from the building blocks can be divided into several generic categories, each of which can be used to produce a wide range of specific products. Table 17 summarises the main categories and some of the typical products.

Table 17 Main categories of chemical building block and products synthesised from them

Category	Typical products
Naturally occurring carbohydrate polymers	Mainly cellulose-based products such as paper, textile fibres, water-soluble gums, etc.
Fats and oils of vegetable origin	Soaps, lubricants, cosmetics, surfactants, pharmaceuticals
Terpene-based materials	Cleaning products, chewing gum ingredients, food packaging coatings
Chemical products from carbohydrate-containing sources	Solvents, oxalic acid (used in the leather industry), biodegradable polymers (based on lactic acid)
Fermentation products from carbohydrate-containing sources	Bioherbicides, biopesticides, pharmaceuticals, biopolymers, flavours (e.g. ethanol)

5.2 Description of measure

One means of encouraging greater use of biofeedstocks by the chemicals industry would be for the government to provide an investment subsidy to chemical operators for converting production facilities.

5.3 Feasibility

Technically, there is a great deal of uncertainty regarding the quantity of biofeedstocks available as an input to the production process. However, the most serious bottleneck is not technical in nature: technically speaking, there is little reason why biomass should not be used as a basic feedstock for chemical production. It is on the supply side, rather, that the main problems are anticipated.

The feasibility of the various conversion processes is particularly dependent on the wide variation in the quality of the biomass potentially available as a raw material. It is estimated that the total quantity of suitable feedstock is about 12 million tonnes (dry weight) a year, excluding imports. However, the precise supply available at any one time is highly variable, a mix mainly of agro-industrial residues, agricultural wastes, forestry residues and other wastes. Since most of these streams are dispersed widely over the country and many would also have other possible useful applications (to produce biofuels, for example), large-scale chemical producers would have to use a variety of feedstocks to ensure continuity of supply ('multifeedstock plant'). There should also be due scope for importing biomass from further afield.

For the medium-term (< 10 years) the focus should be on biofeedstocks with desirable properties (homogeneous streams low in lignin and/or low in ash, for example). For the longer term (> 10 years), as the scale of production grows, the range of feedstocks should be broadened to include additional residues and (imported) woody energy crops (e.g. willow).

Costs
The cost factor is another important reason why biomass does not currently play any significant part in chemical production. The main factor here is the 'lock-in effect': the entire chemical infrastructure is presently locked into using naphtha as its basic feedstock, and the use of biofuels is in this case limited to use as additional building block for conventional products.

5.4 Costs

The production costs of the chemicals made from biofeedstocks will depend on several factors:
- the type of biomass used as a feedstock;
- the type of conversion process applied;
- the type of chemical product ('intermediate' or 'end product specialty').

Given the range of parameters involved, actual production costs will clearly vary widely. On the other hand, though, biofeedstock use by the chemical industry is still in its infancy. As yet, then, no really reliable or complete cost review can be undertaken.

By way of orientation, though, we shall briefly review the production costs typically quoted at present for the main technologies for converting biomass to useful chemicals (cf. Figure 3):
- biomass refining or pre-treatment;
- fermentation and bioconversion;
- thermo-mechanical treatment (HTU);
- gasification.

Table 18 reviews the production costs of key products and conversion processes. These can be compared with market prices, also shown in the table.

Table 18 Production costs of principal biofeedstock conversion processes and products, with market prices[22,23]

Conversion process	Product	Production costs (/GJ)	Market price (/GJ)
Biomass refining or pre-treatment	Various products	High	-
Fermentation and bioconversion	Ethanol from melasses	16	7 – 25
	Ethanol from grain	16	
	Ethanol from cellulose	35	
	Other products	unknown	
Thermo-mechanical treatment (HTU)[24]	Biocrude	7[25]	4[26]
Gasification	Methanol	8 – 20	10
	Hydrogen gas	8 – 15	7
	FT products[27]	20	3 – 6
	Other products	unknown	NA

It can be concluded from Table 18 that production costs generally exceed market prices (by far) at present. Again, though, it should be stressed that prices may vary widely, depending on process conditions and other factors. Some conversion processes, such as fermentation or HTU, already appear to be competitive with conventional processes under specific conditions.

In the case of biomass refining or pre-treatment, the variation is enormous. Potential feedstocks are highly variable and most streams are dispersed widely over the country. As a result, costs and market prices may extend across a wide range.

5.5 Effects

In 2001 almost 3.4 Mtonnes of naphtha feedstock was consumed by the petrochemical industry. Table 19 provides a crude estimate of the consequences of replacing a percentage of this naphtha by biomass.

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[22] R. van Tuil, I. de Keizer et al., *Biomass for the chemical industry*; ATO, CE; Wageningen; 2002.

[23] M.M.G. Fase, C.K. Folkertsma, *Biobrandstoffen: milieueffecten en toekomstperspectieven in het licht van de komende WTO besprekingen*, WO&E report no. 598; De Nederlandsche Bank, Afdeling Wetenschappelijk onderzoek en econometrie, 1999.

[24] TNO MEP, press release, *Nieuwe onderzoeksfase HTU®-technologie voor olie uit biomassa gericht op bedrijfszekerheid;* 08-10-2002.

[25] This price is based on biocrude made from negatively priced waste: - 1 €/GJ.

[26] Biocrude competes with naphtha, the estimated future price of which has been taken to be $200/tonne (source: www.hcasia.safan.com/mag/hcmar02/r14.pdf).

[27] FT = Fischer Tropsch; the FT process may be part of the gasification process.

Table 19 Biomass requirements for part-substitution of naphtha feedstocks[28]

Apparent naphtha consumption, 2001[29]	3.35 Mtonne	
Tonne biomass per tonne product[30]	2.5[31]	
Naphtha replaced by biomass	**Biomass required (Mtonne)**	**Oil saved (PJ)**
1%	0.084	1.53
5%	0.42	7.65
10%	0.84	15.30
50%	4.2	76.50

For comparison, a reduction in oil demand of 15.3PJ (10% substitution of biomass) represents about 1.5% of annual Dutch consumption of oil and oil products.

A crucial assumption in Table 3 relates to the amount of crude oil saved through reduced demand for naphtha with growing use of biofuels. In technical terms this is a tricky issue, as some 26% of aggregate crude oil inputs are cracked into naphtha at refineries, other key fractions being kerosene and petrol. This figure of 26% is flexible, however, there being some degree of engineering scope for optimising the cracking process. Reduced demand for naphtha cannot therefore simply be translated to a fourfold reduction in demand for crude oil, as the other fractions still need to be produced. The assumption made here, then, is that 1 Mtonne less demand for naphtha implies 1 Mtonne less demand for oil. Given the flexibility in the cracking process, this is a fairly safe assumption for small reductions in demand: for more substantial reductions, however, this assumption fails because of the above reasoning.

5.6 Matching costs and effects

If the products in Table 18 are synthesised from biomass, naphtha will generally be saved. Because these products are elements of a large and complex process chain, however, the actual amount of naphtha saved is very difficult to calculate.

For example, biomass can be used to produce ethanol. This ethanol can be burned as a biofuel, but it can also be used to produce the chemical (intermediate) ethene. In this case, part of the conventional crude oil chain will be replaced; *which* part is unknown, however. Naphtha is typically cracked in multiple units, with the cracking process being optimised for certain products (ethene, propylene, methane, benzene, toluene, hydrogen, heavy oil fractions and so on). How ethene output relates quantitatively to naphtha savings therefore generally depends on the particular cracker optimisation procedure applied.

It is also important to note that substituting part of a given production chain will have major implications for the rest of the chain and for the entire mar-

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[28] These calculations are based on apparent naphtha consumption (3.35 Mtonnes in 2001), 1 tonne of naphtha being taken as equivalent to 45 GJ.

[29] *Oil, gas, coal & electricity*, International Energy Agency, Quartely Statistics.

[30] GAVE, *Beschikbaarheid biomassa voor energie-opwekking*; GAVE00.01-9922; Utrecht; 2000.

[31] This factor indicates how much primary biomass is needed *on average* to produce 1 tonne of product.

ket. If all ethene were to be produced from biomass, optimisation of the conventional crude oil refinery process would have to be changed accordingly, leading in turn to other changes in the market and in product prices. Although details will differ, there will be similar knock-on effects for all the products in question.

The costs shown in Table 18 are typical, average costs under present circumstances, moreover, and will not reflect actual trends as biofeedstocks achieve penetration in chemicals production. There are strong reasons to believe that substantial cost savings can be achieved as biomass is used more and more for chemicals production. However, such declines in the marginal costs of production cannot be estimated on the basis of current literature.

Table 20 presents a very crude estimate of the expected additional costs of 10% biomass input for chemicals production. A crucial assumption here is that all the biomass is used to produce ethene, methanol, etc. There is no information available on the likely ultimate mix between these end products. We have assumed, furthermore, that the market prices represent roughly 80% of production costs, as given in Table 18. The additional costs given in Table 20 are expressed in Euro per GJ oil saved.

Table 20 Estimated cost of substituting 10% of naphtha feedstock for chemicals production by biomass

10% biomass		Total cost (million Euro)			Additional cost (€/GJ)		
	Oil saved (PJ)	Minimum	Average	Maximum	Minimum	Average	Maximum
Ethene	15.3	-61	194	450	-4	12.7	29.4
Methanol[32]	NA	0	92	184	0	6	12
Biocrude	15.3	NA	58	NA	NA	3.8	NA
Hydrogen	15.3	37	90	144	2.4	5.9	9.4
FT products	15.3	233	251	269	15.2	16.4	17.6
Average	15.3	*41.6*	*137.1*	*209.3*	*2.72*	*8.96*	*13.68*

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[32] Methanol is produced from natural gas rather than crude oil; synthesising methanol from biomass will therefore not save naphtha but natural gas. The precise savings will of course be roughly similar to the case of oil products.

6 Intensification of ‘small field’ policy

6.1 Description of measure

In 1974 the Dutch government instigated what is known as the ‘small field’ policy (*Kleine Velden Beleid*) with a view to conserving the reserves of the Groningen gas field as far as possible for future generations This policy has been successful, in the sense that many smaller fields have subsequently been taken into production. The supply security policy reviewed in this chapter consists of a further intensification of this policy.

Such a move could in principle take one of two forms:
a Increasing the fixed supply price of gas, i.e. the price paid by distributors (Gasunie) to producers, which would allow exploitation of marginal fields and stimulate exploration of new fields.
b Allowing production company NAM to drill for gas in fields in protected areas such as the wetlands of the Biesbosch and the Wadden Sea.

We have chosen option (b) for review here, as this would address what is currently regarded as the main bottleneck of the ’small field’ policy.

Box: A short history of Dutch gas exploration

On 7 December, 1999 the Dutch Cabinet announced its current position on natural gas recovery from the Wadden Sea field, as requested by the Second Chamber of Parliament in anticipation of a major physical planning exercise scheduled for this contested issue (*Planologische Kernbeslissing Waddenzee*). Having reviewed the available information – including EIA reports on drilling in the North Sea Coastal Zone and Ameland and Wadden areas, the Integrated Study on Soil Subsidence of December 1998 and advice from various experts – in November 1999 the Cabinet concluded that the uncertainties and doubts regarding potential irreversible damage had not been adequately dispelled. It was consequently judged that there were insufficient grounds for granting the licences applied for. These were for exploratory wells in the North Sea Coastal Zone and on the Island of Ameland (Ballum) and production wells at the Paesens/Moddergat and Lauwersoog sites. These sites are all situated in the Noord-Friesland and Groningen concessions.
(From: Oil and gas in the netherlands exploration and production 1999: A review of oil and gas exploration and production activities in the Netherlands and the Netherlands sector of the Continental Shelf)

6.2 Feasibility of the measure

6.2.1 Political feasibility

According to a survey conducted in 1999 by national pollsters NIPO and financed by NAM, only 20% of the population is opposed to drilling for gas in the Wadden Sea under all circumstances. Around two-thirds of the population might be prepared to support such plans if there was no irreversible damage to the natural environment. Environmental concerns are indeed the main issue standing in the way of a decision to sanction such drilling, and at present the political feasibility of such a move is to be deemed rather low. The experts, who also cite political feasibility as the main obstacle, advocate allowing exploitation of just one field, subsequently monitoring the impact on land subsidence and the environment.

6.2.2 Technical feasibility

Technically speaking, no bottlenecks are to be expected. Once exploratory drilling has been carried out, the technique of diagonal drilling is well enough established to start production operations almost immediately. Exploratory drilling will have to take place within the Wadden Sea, however, which may have a temporary impact on tourism and other sectors of the local economy. In both the Wadden Sea and Biesbosch the exploratory phase should take no more than two months, after which the site can be cleaned up. The need for diagonal drilling will have hardly any influence on the cost of gas recovery[33].

6.2.3 Legal aspects

The legal framework for the envisaged policy is provided by three documents: the Dutch government's decisions on development of the Wadden Sea region (*Nota Waddenzee*) and structural protection of 'green areas' (*Structuurschema Groene Ruimte*) and the European Bird and Habitat Directive. The first two, national documents would have to be amended to allow gas recovery in the Wadden Sea. The third may pose more structural problems, however, being beyond the scope of Dutch political influence. In the past, environmental NGOs have successfully fought government decisions on infrastructure projects with reference to the Bird and Habitat Directive. According to experts, subsidence due to gas drillings would fall under the Habitat Directive (article 6) and a lengthy legal procedure is therefore to be expected if the government were to sanction extraction beneath the Wadden Sea (Waddenadviesraad, 1999). In addition, the mining activities would require an Environmental Impact Assessment, also subject to legal procedures[34].

We conclude here that the legal aspects are far from clear. Intensifying the 'small field' policy will involve costs arising from the lengthy legal procedures that are sure to be initiated if the go-ahead is given for exploitation of the Wadden Sea gas field.

6.3 Effects on supply and security

6.3.1 Effects on gas supply

Authorising extraction from under the Wadden Sea implies recovery of an additional 70-220 billion m^3 of gas. The uncertainty in this range is due to the fact that the precise extent of these reserves is at yet unknown, because so little exploratory activity has been allowed under standing government policy.

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[33] Personal communication, Martien Visser, Gasunie.

[34] As was pointed out by several people, moreover, NAM already basically has a concession for exploitation in the Wadden Sea; the only reason such activities have been consistently postponed is through lack of public and political support for exploration and recovery in this sensitive area.

Producers NAM assume a figure at the higher end of this range, anticipating extraction of around 200 billion m^3 at reasonable cost. This was also the figure quoted by the Dutch minister of Economic Affairs to parliament several years ago (Proceedings of the Second Chamber 24 889, no. 1, 1996). Most NGOs take the true reserves to be substantially lower, however: around 130 billion m^3 (see Aid Environment, 1999). From the literature alone there is no way to validate either of these figures, and we have therefore taken a range of 130-200 billion m^3 for the minimum gas reserves in the Wadden Sea field.

The reserves beneath the second national park, Biesbosch, are far smaller, but are again essentially unclear, as no exploratory drillings have yet taken place. One source suggests that around 2-3 billion m^3 of gas might be extracted from this field[35].

All in all, then, we have assumed that the total additional output of gas to be expected from intensifying the 'small field' policy in these two protected areas will be somewhere between 132 and 203 billion cubic metres[36].

It is of interest to note, moreover, that according to the NAM around 40-45 billion m^3 of gas can be extracted from the Lauwersoog and Moddergat parts of the Wadden Sea field where wells were already drilled and purification facilities built between 1995 and 1997.

6.3.2 Effects on energy security

Exploiting the Wadden Sea and Biesbosch gas reserves would allow foreign imports to be reduced, particularly those from the Russian Federation. The total estimated reserves in these 'small fields' are equivalent to 3 to 4 years of domestic consumption. The question is what to do with this 'strategic reserve'. Extraction now might allow imports to be cut for a limited period of time, during which energy security would indeed be improved. Alternatively, though, it might be opted to leave the gas where it is, for security of supply at some time in the future. Given the relatively favourable political situation in the Russian Federation at present and the implications for gas exports, it might be wiser to leave the Wadden Sea gas in the ground to serve as a future buffer.

The effects on energy security therefore hinge critically on the assumptions made regarding future political developments in Russia and other important suppiers of gas.

6.4 Costs

The costs of this measure consist of:

1. The direct costs of exploration, study and gas recovery (i.e. normal operating costs).
2. The costs arising through additional constraints such as the need for diagonal drilling.

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[35] See for example: http://www.ikcro.nl/artikelen/ANP-011200-434-anp.html. The exact source of these figures, circulating on Internet, could not be traced.

[36] For comparison: total estimated 'small field' reserves are around 560 billion m^3, annual Dutch production about 80 billion m^3, while the estimated reserves in the Newly Independent States (NIS) stand at around 57500 billion m^3 (source: Waddenadvies, 1999).

3 The external costs of (irreversible) environmental impacts, geohazards, etc.
4 Other costs, such as those of legal procedures.

The first two cost categories are not of particular interest here. In the long run the marginal costs of extraction and resource rents may be expected to equal the (projected) price of gas imports. In other words the 'Hotelling rule' applies: NAM will exploit as much of the Wadden Sea gas as is profitable compared to Russian imports under anticipated market conditions. The producer surplus is the expected benefit accruing from gas recovery in the Wadden Sea compared to Russian imports; under certain assumptions this producer surplus can be taken time in the future[37].

Essential here is the assumption that sooner or later the Wadden Sea gas will be extracted. If not, the economic value of this gas is zero and the producer surplus can be regarded as a *benefit* of intensifying the 'small field' policy. However, here we interpret standing government policy not as a permanent ban on gas extraction in the Wadden Sea but as merely temporary. This would imply that exploitation of this gas field would be possible at some time in the future.

Below we review the other two cost categories in more detail, first considering the external costs of environmental impacts, geohazards and so on. We do so with reference to the Wadden Sea gas field only.

6.4.1 External costs

To date there has been only one real attempt to estimate the external costs of gas recovery from under the Wadden Sea: a study by Aid Environment, commissioned by Greenpeace, entitled 'The downside of Wadden gas' (*De schaduwkant van Waddengas*, Aid Environment, 1999). To our mind this study has succeeded well in assessing the overall economic value of the Wadden Sea ecosystem. The researchers adopted a functional approach, identifying a specific set of functions provided by the Wadden Sea and assigning a value estimate to each[38]. However, the estimated *impact* on these functions of ground subsidence – the main projected consequence of drilling – we consider to be somewhat exaggerated, a view we share with other commentators[39]. For most functions of the Wadden Sea the study assumes that maximum subsidence of about 20 cm around the island of Ameland would lead to an aggregate loss of around 1/3 of productive functions. That this is no more than a blunt overestimate will be clear from the case of tourism, for to assume that tourist revenue will drop by around 1/3 of course neglects the fact that most holiday-makers come to the area to enjoy the sea and sun and not particularly the sand banks or tidal mudflats might be lost to subsidence.

This position is reinforced by a subsequent study on the effects of subsidence on and around Ameland, which concludes on the one hand that subsidence will be greater than first anticipated, but on the other that the impact on the environment and the productive functions of the Wadden Sea will be

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[37] Expected resource rents depend, among other things, on future trends in recovery costs and gas price, combined with discount rate.

[38] This approach originates from de Groot (1994).

[39] This was also the opinion of Marquinee (NAM) and can also be found in the reviews by Oosterhaven (2000) and Davidson (CE, 1999).

less severe because of the resilience of the ecosystem, i.e. its capacity to adapt to changing conditions (WL/Alterra, 2000). The NAM et al. (1998) study *Integrale Bodemdaling Waddenzee* assumes that most detrimental environmental effects can in fact be mitigated.

Without going into complex biological details it is not feasible here to give a better estimate of the external costs of gas recovery from the Wadden Sea. In Table 21 we therefore interpret the results of the Aid Environment study, presenting three estimates in all. The *maximum* cost estimate is that originally reported in the cited study: a total of 1,108 million Euro annually. The *minimum* estimate is made up of costs that seem more or less unavoidable: for higher dykes and compensation to farmers with low-lying land more prone to water-logging and other such damage. We thus assume that the ecosystem will be sufficiently resilient to automatically compensate for any ground subsidence that occurs. Of course this scenario is not particularly realistic either and we have therefore worked with a third estimate in which net damage to nature is set – arbitrarily – at 50% of the Aid Environment figure. In other words, half the impact of subsidence is assumed to be absorbed by ecosystem resilience. In the case of tourist revenue losses we have assumed that around 10% of the tourists visiting the Wadden Sea are interested in exploring the mudflats and other tidal zones. The third of these estimates is a rather arbitrary median value of around 450 million Euro annual costs.

Table 21 Categories of external damage due to gas recovery in the Wadden Sea

Annual expected external costs					
	Annual costs				
Annual damage, in million Euro (1999)	Maximum (Aid Envir)	Minimum	*Adapted (rough estimates)*		Assumptions for adapted estimates:
External costs, private parties	**776**	**39**	***291***	*To sector*	
Reduced water-bearing capacity of dunes	47	NA	*23*	Water supply	See critique by Oosterhaven
Raising of dykes	3	3	*3*	Government	
Additional water-pumping	NA	NA	*NA*	Government	
Additional reimbursement of farmers for water-logging, etc.	10	10	*10*	Government / Agriculture	
General fishery losses due to damage to Wadden Sea breeding grounds	349	NA	*174*	Fisheries	Assumption: only half fishery functions disappear
Losses to local Wadden Sea fisheries	112	27**	*56*	Fisheries	Assumption: only half fishery functions disappear
Tourist revenue losses	257	NA	*26*	Tourism	Only 10% of tourism is related to tidal flats
External costs, environment	**332**	**0**	***166***		
Water-purifying capacity of Wadden Sea	215	NA	*108*	Environment	Assumption: only half purifying function disappears
Loss of land, e.g. tidal marshes	28	NA	*14*	Environment	Sandbanks are half the value of tidal marshes
Loss of habitat function	89	NA	*44*	Environment	Habitats on sandbanks are half the value of tidal marshes
Geohazards	**0.2**	**0.2**	***0.2***		
Risk of blow-out (1 in 2000 drillings)*	0.2	0.2	*0.2*	Environment	
Total	**1108**	**39**	***458***		

Notes: Data from AidEnvironment (1999), own calculations and interpretations.

** Calculated as cost of blow-out (cited as 740 million guilders by Aid Environment) times expected probability.*

*** Aid Environment estimate of 60 million guilders (1999, p.41) for potential impact on local mussel production.*

As can be seen from the table, total anticipated external costs range all the way from 39 to 1,108 million Euro annually. Our own very rough and *by no means scientific* estimate is an average figure of around 450 million Euro a year.

6.5 External costs in relation to gas recovery

The following, crucial question is how these projected impacts relate quantitatively to the amount of gas recovered. This involves two basic questions:
a To what level of gas production do the external costs of Table 21 relate?
b What can be said about the impact of scaled-down recovery operations; will the ensuing cost reduction be linear or non-linear?

Strangely enough, the first question is difficult to answer. The Aid Environment study estimates that the total benefits ultimately accruing from gas exploration and recovery will be an expected 130 billion cubic metres of natural gas. However, the assumed *costs* of extraction are based largely on the maximum case cited by NAM (Chapter 3, 1998), which proceeds from a far larger exploitable reserve of around 220 billion cubic metres[40]. It is this latter figure we take in our analysis below.

The second question is perhaps more important. The external costs are due to the combined impact of subsidence and the knock-on effects of subsidence on the Wadden Sea ecosystem. Both are probably non-linear and will often come in shocks.

The degree of subsidence depends on the type of field being drilled and the amount of gas extracted. Per m^3 gas extracted, larger fields suffer greater subsidence. In the relatively large Groningen (Slochter) field the amount of subsidence virtually equals the compression of the geological strata above the gas field. In smaller fields, though, subsidence is only a fraction of this compression. Compression itself varies almost linearly as pressure in the gas-bearing strata decreases and can therefore be assumed to vary linearly with progress in gas extraction (NAM, 2000)[41].

NAM (1998) and Aid Environment (1999) also assume that gas extraction, subsidence and the impacts of subsidence are related linearly. We therefore recommend that CPB likewise use a linear relationship in modelling the external costs of gas recovery, with a remark to the effect that to mitigate external costs, a policy geared to exploiting the smallest Wadden Sea fields would be preferable. More detailed calculations could be made once the size of the reserves are known more accurately so that the effects between small and bigger fields on subsidence can be taken into proper account. However, this information is unavailable at present and it is beyond the scope of this study to estimate these two parameters.

The following table, then, presents the total estimated costs of gas extraction following intensification of the 'small field' policy to allow drilling in the Wadden Sea.

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[40] These figures are unclear in both reports and none of the authors were able to provide much background on how they were obtained. Based on the references to NAM (1998) in the Aid Environment Report (1999; see for example the subsidence figures on p. 43), we conclude that the latter adopted the Maximum Case from the former. According to Marquinee of NAM, the Maximum Case assumed recovery of 220 billion m^3. This figure was not actually cited in the NAM report, however, presumably for strategic reasons.

[41] The pressure itself also depends on geological conditions, but including this factor here would bring in too much detail.

Table 22 Rough estimate of annual cost of gas recovery in the Wadden Sea due to intensification of the 'small field' policy (million euro per billion m^3)

	Maximum	Minimum	Median
Cost to government	0.06	0.06	0.06
Cost to fisheries	2.09	0.12	1.05
Cost to tourism	1.17	NA	0.12
Cost to the environment	1.51	NA	0.75
Geohazards	0.00	0.00	0.00
Total	**5.04**	**0.18**	**2.08**

Finally, we conclude here that the external costs cannot be satisfactorily estimated from the literature. Only one study has attempted to estimate such costs and although the aggregate economic value of the Wadden Sea was appraised very carefully, the predicted impacts on the ecosystem are to be seriously doubted. Indeed, these estimates are rejected by a number of experts. The figure of 1,108 million Euro therefore appears to be very much an upper limit. The total impact will presumably be less, but cannot be determined without a detailed study of the complex ecosystem dynamics of the Wadden Sea. No such study has yet been undertaken in tandem with a cost estimate of losses of productive functions.

6.6 Other anticipated costs

If gas exploration and recovery in the Wadden Sea are sanctioned, there are likely to be a number of other costs, in particular those of legal procedures.

6.6.1 Costs of legal procedures

For the reasons outlined above, the exact legal scope for gas extraction from the Wadden Sea field is unclear. Given that public opposition to drilling in protected areas is likely to be high and that Wadden Sea NGOs appear to be well organised, great efforts will probably be made to thwart a permit for exploratory drilling, first, and for actual exploitation of the gas reserves, later It is impossible to estimate in advance the total costs of such procedures to the government or to NAM. Similar considerations apply, although perhaps to a lesser extent, to the Biesbosch field.

6.6.2 Opportunity costs

One final category of cost to be included in this exploratory analysis is the cost of not using the Wadden Sea or Biesbosch gas. Two items can be distinguished here: loss of the producer surplus, and the external costs associated with foreign gas imports.

As stated above, the producer surplus can be assumed to be equal to resource rents and is here consequently ignored.

On the second item, let us assume the gas is imported from Russia. This will entail additional environmental problems in the Russian Federation. One study by Pre Consultants (2001) assumes that the external costs associated with Russian gas are generally around 20-25% higher than those of Dutch gas, due mainly to losses during transport, in particular pipeline leakage in the Russian Federation and, above all, the transit countries (Belarussia and the Ukraine). However, these costs do not accrue directly to the Netherlands but to the Russian Federation and, depending on the type of study, a separate decision must be taken whether they need to be taken into account, or not.

6.7 Literature

Waddenadviesraad, 1999. *Advies over de Hoofdlijnenbrief herziening pkb-Waddenzee, gericht aan de Minister van Volkshuisvesting, Ruimtelijke Ordening en Milieubeheer, vastgesteld tijdens de plenaire vergadering van de Waddenadviesraad op 28 april 1999*.

J. Oosterhaven, 2000. *Waddengas: mogelijk geringe schade, in ieder geval hoge baten,* review of*: De Schaduwkant van Waddengas,* AID Environment, for Greenpeace Nederland, Nieuwsbrief Milieu en Economie, 2000-2.

Aid Environment, 1999**.** *De Schaduwkant van Waddengas.* Report for Greenpeace by Jeroen van Wetten, Jose Joordens, Mark van Dorp and Liesbeth Bijvoet.

NAM, 1998. *Integrale Bodemdalingstudie Waddenzee,* (main report).

NAM, 2000. *Bodemdaling door Aardgaswinning: Groningen veld en randvelden in Groningen, Noord Drenthe en het Oosten van Friesland. Status Rapport 2000 en Prognose tot het jaar 2050.*

WL/Alterra, 2000. *Monitoring effecten van bodemdaling op Ameland-Oost: evaluatie na 13 jaar gaswinning* (summary).

Pre Consultants, 2001. *Hoe groen is gas: Vergelijkende milieu- en kostenanalyse van verschillende energiedragers in Nederland.* Study for NAMby Renilde Spriensma, Suzanne Effting and Carmen Alvarado (report version 2.1).

Persons contacted
Interviews were held with:

- Jeroen van den Bergh, VU (in connection with Aid Environment study);
- J. Marquinee, NAM;
- Martien Visser, Gas Unie;
- Liesbeth Bijvoet, Aid Environment;
- Ipo Ritsema, TNO-NITG.

7 Energy Performance Standards for buildings

7.1 Description of measures

In the Netherlands two main policy tools can be distinguished for reducing the energy consumption of buildings:

- the EPA (Energy Performance Advice) policy for *existing* buildings;
- the EPC (Energy Performance Coefficient) standards for *new* buildings.

Energy Performance Advice (EPA)
The aim of the EPA policy tool (for *Energy Performance Advice*) is to increase the rate of energy saving in **existing** building stock. The EPA provides insight into the energy-related quality of buildings and recommends suitable conservation measures. Although subsequent action is in itself voluntary, the EPA can help building owners identify measures that will bring buildings covered by the general administrative orders based on the Environmental Management Act into compliance with the requirements of these orders. It can also be used to bring buildings not covered by such orders up to a comparable performance level. The EPA scheme was started in 2000 as an experimental policy.
The EPA is supported by two tax measures:

- the *Energie Premie Regeling* (EPR), a subsidy related to products or energy saving measures increasing the profitability of such measures;
- the *Regulatory Energy Tax* (RET, *REB* in Dutch) on energy use, with a positive impact on the profitability of energy-saving measures in general.

The option considered here is an *intensification* of EPA policy. Making the EPA compulsory would be difficult at present, given the number of EPA advisors that would be needed to carry out energy performance assessments. Even if there were merely an intensification of the policy, as is assumed here, it is uncertain whether enough EPA advisors would be available (i.e. educated) in time.

Energy Performance Coefficient (EPC)
The *EPC (Energy Performance Coefficient)* policy tool seeks to reduce the energy requirements of **new** buildings, by gradually stepping up mandatory energy performance standards (EPN). As a consequence, new buildings now use considerably less energy than in the past and progressive replacement of the existing building stock is leading to significant energy savings. Since the year 2000 the EPC rate for non-residential buildings has been 1.0. In order to improve security of supply the Dutch government is currently considering a further tightening of the EPC rate. In this chapter we assess the consequences of a tightening to values of 0.9 and 0.8.

The remainder of this chapter reviews the feasibility, costs and effects of the two cited policy measures.

7.2 Feasibility

EPA
As already stated, the scope for intensifying standing EPA policy depends largely on the availability of EPA advisors. Beyond this restriction though, a compulsory EPA would appear feasible at some time in the future, given the

recently published European Directive 2002/91/EC on the energy performance of buildings (16 December, 2002). Article 7 of this Directive states that “Member States shall ensure that, when buildings are constructed, sold or rented out, an energy performance certificate is made available to the owner or by the owner to the prospective buyer or tenant”. A compulsory EPA, including a certification procedure, for the Netherlands’ current building stock would mean compliance with the recent European Directive.

EPC
According to Brouwer (2003)[42] a reduction of the EPC rate to 0.8 is not yet feasible because of the higher costs this would entail (as outlined below) and because it would place further restrictions on building design, seen by the Department in question as a boundary condition that should remain unchanged. In Brouwer’s view reducing the EPC rate to 0.9 is economically feasible. However, given the relatively small gains in energy efficiency that would result, he suggests waiting a few more years. His “strategic argument” is that reaching agreement with the house-building sector now on an EPC rate of 0.9 would slash the possibilities of setting a tighter standard in several years’ time.

7.3 Costs

EPA
In reviewing the costs and effects of intensifying the EPA policy we follow the assumptions of Menkveld et al., 2002):

- scrapping of the requirement that at least one recommended EPA measure is actually implemented for a subsidy to be granted;
- an increase of the current subsidy from € 159 to € 200 per EPA;
- an intensification of the media campaign promoting the EPA;
- continuation of EPR and RET policies until 2010.

A total of about 60,000 EPA assessments are made each year, implying total costs to the government of some € 12,000,000 per annum.

EPC
According to Brouwers (2003) the additional cost arising from a tightening of the EPC rate from 1.0 tot 0.9 will be virtually zero[43]. In other words, reducing the EPC to 0.9 will result in extra energy-saving measures to new houses that are cost-effective. A further reduction to a value of 0.8 will lead to additional costs of € 70 per annum (band width: € 0 to € 170) per house.

7.4 Effects

EPA
Based on (Menkveld et al., 2002) we estimate that intensifying the EPA policy will lead to additional cuts in natural gas consumption of between 0.9 and 3.5 PJ in 2010. The uncertainty reflected by this band width is due mainly to the question of whether sufficient EPA advisors can be made available in time.

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[42] Based on personal communication with Mr. F. Brouwers of the Housing Department, Ministry of VROM, who commissioned a study to DHV on the costs and effects of reducing the EPC to 0.9 or 0.8. The results of the study are not yet available.

[43] Ibid.

EPC

Table 14 gives an indication of the consequences of this measure for the natural gas consumption of a reference dwelling.

Table 23 Estimated energy consumption of a reference dwelling (m^3 natural gas equivalents) as a function of EPC value, based on Kroon et al. (1998)

EPC value	Year of start	Natural gas equivalents in m^3
1.2	1998	1,200
1.0	2000	1,000
0.8	2004	700
0.6	2008	600

A DHV study currently in progress (see above) estimates that tightening the EPC value from 1.0 to 0.9 would lead to total savings of 0.52 PJ (natural gas equivalents) in new dwellings (i.e. excluding commercial and industrial buildings) and further tightening to 0.8 to savings of about 1.5 PJ.

7.5 Literature

EC (2002), *Directive 2002/91/EC on the energy performance of buildings* (16 December 2002).

Kroon et al. (1998), *Extra energiebesparing nader onderzocht, Achtergrond-document bij de energiebesparingsnota 1998,* ECN, Petten.

Menkveld et al. (2002), *Effect op CO_2-emissies van beleid in voorbereiding*, ECN Policy Studies and RIVM Milieu- en Natuurplanbureau.

Persons contacted

- F. Brouwer, Ministry of Housing, Spatial Planning & Environment (VROM, DGW);
- P. Viervijver, DHV.

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Policy options for improving security of energy supply

Background document

Annexes

Final report

Delft, August, 2003

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A Policy interventions for improving security of energy supply

Table 24 Policy interventions to reduce risks associated with disruption of supply and price volatility due to increasing dependence on Middle East oil exporters

Policy goal	National policy instruments			**International policy instruments** (agreements, partnerships)
	Regulation	Market-based	Voluntary agreements / information	
A Preventing disturbance				
A1 Prevent international economic and political crisis				Dialogue with OPEC (through IEA or EU)
A2 Increase domestic oil stocks (reduces impact of OPEC actions)	Strengthening stock oil mechanism, EU and IEA			
A3 Expand oil trade				Open new markets through WTO
A4 Encourage additional oil supply from other regions (e.g. Africa)		Provide development aid to these regions	Promote investments by Western companies in new regions	
B Reducing vulnerability				
B1 Energy saving	Energy efficiency standards (EPN, EPL)	Regulatory Energy Tax, EU energy tax	Negotiated agreements on long-term targets and benchmarking	
B2 Reduce oil intensity	Improve spatial planning procedures for new wind and gas sites	Diversification (e.g. reduced excise duties on biofuels, to increase share of renewables)	Extension or intensification of ACEA convenant	
B3 Increase domestic oil stocks	Strengthening stock oil mechanism, EU and IEA			
B4 Ensure access to external oil supplies				– Partnerships – Conservation and maximum exploration of EU oil resources – Investment in pipelines (e.g. to Caspian Sea)
C Mitigating effects				
C1 Reduce negative socio-economic impacts of international oil crisis	– Demand constraints (e.g. ‘car-free days’) – Use domestic oil stocks			

Table 25 Policy interventions to reduce risks associated with disruption of supply and price volatility due to dependence on gas supply from Russia and the Middle East

Policy goal	National policy Instruments			**International policy instruments** (agreements, partnerships)
	Regulation	Market-based	Voluntary agreements / information	
A Preventing disturbance				
A1 Prevent international economic and political crisis				Dialogue with Russia and Middle East
A2 Conserve domestic natural gas stocks	Reduce national production cap to prolong stock availability		Agreement on minimum underground storage capacity	
A3 Increase competition on international natural gas market / expand trade	Promote harmonisation of gas markets in EU countries			– Open new markets through WTO – Promote liberalisation of Russian gas market
A4 Encourage additional gas supply from other regions (e.g. Africa)		Investment support		
B Reducing vulnerability				
B1 Energy saving	Energy efficiency standards (EPN, EPL)	Regulatory Energy Tax, EU energy tax	Negotiated agreements on long-term targets and benchmarking	
B2 Reduce gas intensity	– Improve spatial planning procedures for new wind and biomass sites – Require minimum share of coal-fired power plants	– Adopt favourable gas prices for agriculture and industry (e.g. aluminium production) – Diversify (e.g. by supporting renewables) – Support hydrogen R&D	– Promote household electrification	
B3 Conserve and manage domestic natural gas stocks	Reduce national gas production		Guaranteed demand from small gas fields	
B4 Ensure access to external gas supplies		– Support to LNG facilities (e.g. harbours) – Support to investments in interconnections		– Partnerships – Maximum exploration of EU gas resources
C Mitigating effects				
C1 Reduce negative socio-economic impacts of international gas crisis	Demand constraints	Price regulation based on gas supply security		

Table 26 Policy interventions to reduce risks associated with disruption of supply and price volatility due to inadequate investment in reserve power generating capacity

Policy goal	National policy instruments			**International policy instruments** (agreements, partnerships)
	Regulation	Market-based	Voluntary agreements / information	
A Preventing disturbance				
A1 Improve market functioning (in EU countries)	– Harmonise policy in EU countries – Create stock market for installed capacity		Create information system for long term demand, supply, import/export (monitoring)	– Dialogue within EU to speed up deregulation in other countries
A2 Ensure minimum reserve capacity	– Capacity requirements	– Reserve capacity payments – Charge on each kWh generated to finance reserve capacity		
A3 Increase interconnections	Promote competition	Charge on each kWh transported to finance reserve capacity on interconnections		Agreements other EU countries
B Reducing vulnerability				
B1 Energy saving	Energy efficiency standards (EPN, EPL)	Regulatory Energy Tax, EU energy tax	Negotiated agreements on long-term targets and benchmarking	
B2 Price differentiation		Allow price differences and guaranteed deliveries		
B3 Promote substitution potential		Support to industry for investments in cogeneration		
B4 Ensure access to foreign capacity		Payments for reserve transport and generation capacity		
C Mitigating effects				
C1 Improve market transparency	Create exchange market (APX) for reserve capacity			
C2 Price regulation				

Table 27 Policy interventions to reduce risks associated with disruption of supply due to inadequate investment in power and gas distribution grids (capacity and quality)

Policy goal	National policy Instruments			**International policy instruments** (agreements, partnerships)
	Regulation	Market-based	Voluntary agreements / information	
A Preventing disturbance				
A1 Improve market functioning (in EU countries)	Harmonise transport tariffs in EU countries	Internalise external costs of disruptions	Create information system for long-term demand, supply, import/export (monitoring)	Dialogue within EU to speed up deregulation in other countries
A2 Ensure minimum reserve capacity and quality	– Capacity requirements – Minimum standard disruptions – Output standard disruptions	– Reserve capacity payments – Congestion charge – Charge on each kWh transported to finance reserve capacity		
A3 Increase interconnections	Promote competition			Agreements with other EU countries
B Reducing vulnerability				
B1 Energy saving	Energy efficiency standards (EPN, EPL)	Regulatory Energy Tax, EU energy tax	Negotiated agreements on long-term targets and benchmarking	
B2 Promote decentralised generation		Support to industry for investments in decentralised generation		
B3 Promote substitution options		– Support to dual-firing industry – Support to household micro-co-generation		
C Mitigating effects				
C1 Improve market transparency	Create exchange market (APX) for reserve capacity			