ECN Policy Studies

ENERGY MARKET TRENDS IN THE NETHERLANDS 2001

Preface

The Dutch energy sector has never undergone as many changes as in the last few years. Liberalisation of the electricity and gas markets has greatly changed relationships between the relevant actors. This has enormous consequences for energy services – not only for energy utilities, but also to an increasing degree for energy users. One example of this is the fact that consumers can now pretty much choose their green electricity provider.

In 2000 the Energy Research Foundation (ECN) published the first annual issue of *Energy Market Trends in the Netherlands*. By doing so, ECN anticipated the need of market parties, governments and energy customers to obtain a good overview of developments in the Dutch energy market. It can be concluded, based on feedback, that *Energy Market Trends in the Netherlands* is an important source of information for many people. Developments in the energy market, however, follow each other in such rapid succession that the information presented in 2000 has already been partly superseded by current events. ECN's Policy Studies Unit has therefore compiled this *Energy Market Trends in the Netherlands*.

The aim of *Energy Market Trends in the Netherlands 2001* is basically the same as for the first edition. The most important aspects of the energy market are examined in the following four parts:

- Energy policy and market regulation
- Market structure and strategy
- Choice of technology and environmental consequences
- Energy prices

Information about the energy market is presented in each part in two ways. Factual information is first given in *Overview*. This is followed by *Insight,* which presents a further analysis of one or two developments occurring in the energy market. Since the Netherlands is about to introduce the euro, all information about prices and tariffs in this new *Energy Market Trends in the Netherlands 2001* is given in euros.

The free market for green electricity is, in several ways, an example for the entire energy market. In the green energy market, energy suppliers can gain experience by offering new energy products, and consumers, in turn, witness more providers in a free energy market. In addition, extra marketing efforts made by energy suppliers stimulate the use of renewable energy. This *Energy Market Trends in the Netherlands* pays particular attention to this development. Both the demand for green electricity and the supply of renewable energy, especially from biomass and wind, are discussed. Other developments are also examined, such as the implementation of regulations in the gas market and of price formation in the electricity market.

The diverse views in this publication also express expectations about future developments in the energy market. These expectations are based on the situation up to mid September 2001. Unanticipated events can change the course of developments in the Dutch energy market. ECN will continue to follow and analyse these developments, and devote more attention to them in a future edition of *Energy Market Trends in the Netherlands*.

I trust that this *Energy Market Trends in the Netherlands* once again fills a need for comprehensive information about the Dutch energy market. Furthermore, I hope this publication helps give insight into the functioning of a changed energy sector heading towards sustainability.

Prof. F.W. Saris
Director

Energy policy and market regulation

Market structure and strategy

Choice of technology and environmental consequences

Energy prices

ENERGY POLICY AND MARKET REGULATION

The establishment of guidelines for the free energy market in the Netherlands is nearing completion. After the introduction of detailed regulatory procedures for the electricity market in 1999 and 2000, more guidelines have been established for the gas market by the appointed supervisor, the DTe, in 2001. In this same year the market for renewable energy became completely ‘free’. In 2002 the free energy market will be further enlarged because medium-sized customers will then also be free to choose their energy supplier.

It is gradually becoming clear whether regulation of the free energy market is functioning well and whether the promised advantages of liberalisation will be obtained. The government recognises that a liberalised energy market may entail new risks, e.g., regarding supply security and price formation resulting from energy market forces. In the coming years more attention will be paid to monitoring market forces, and if necessary regulatory procedures will be adjusted to counter undesired effects.

The beginning of part one of *Energy Market Trends in the Netherlands 2001* presents an overview of the development of policy and regulatory procedures for the electricity and gas markets. This is followed by an analysis of the problems that need to be surmounted for a properly functioning competitive gas market in the Netherlands.

Phased opening of energy markets

In 1998 the new Electricity Act was put into effect, giving the first tier (large industrial users) the freedom to choose their electricity supplier. The Gas Act, which similarly makes it possible for gas customers to change supplier, came into effect in 2000. With the introduction of the new energy legislation, the Netherlands has satisfied the criteria established in the European energy directives. These directives ultimately require a market opening of 33%. The Netherlands, however, will phase in the full liberalisation of both energy markets (see Figure 1.1). Table 1.1 shows which gas and electricity customers are already free to choose their energy supplier and those who will have this freedom in 2002 and 2004.

Since 1 July 2001 all customers have been free to choose their supplier of green electricity. Suppliers need to purchase green certificates for this green energy. TenneT, the transmission system operator, for the time being, only issues green certificates to producers of renewable-generated electricity. Until 1 January 2001 the actual supply of electricity to captive customers continued to take place via license holders. They send an invoice for the power supplied to the green energy provider. As of 2002 the customer will purchase both the green certificate and the electricity from the green energy provider.

Germany completely opened its electricity and gas markets all at once in 1998 (see Table 1.2). In France, since the beginning of 2000, electricity customers who use more than 16 GWh per year can change supplier. Further market liberalisation is not expected in France. For the gas market, France is following the European Directive.

Belgium obtained a one-year extension from the European Commission to introduce energy liberalising legislation. Since 1 May 2000 customers who use more than 40 GWh per year are free, and as of the start of 2001 the same applies for customers who use 20 GWh or more per year. As of 2006 the electricity market in Belgium will be completely open. The gas market in Belgium will undergo a gradual opening-up, so that ultimately in 2010 all its customers will be free.

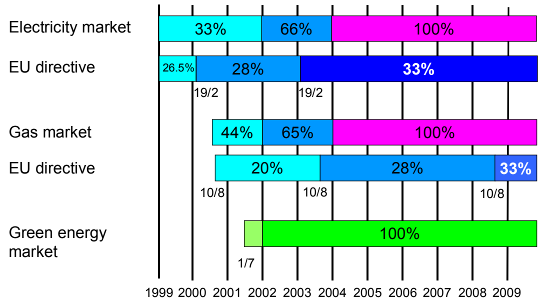


Figure 1.1 Phased opening of energy markets in the Netherlands

Table 1.1 Criteria and number of customers resulting from the opening of the gas and electricity markets in the Netherlands

	Criterion *	Number of customers
Free		
Electricity	> 2 MW	650
Gas	> 10 million m^3	200
Free as of 1-1-2002		
Electricity	< 2 MW, > 3 x 80 Ampere	59.000
Gas	1 tot 10 million m^3	1.900
Free as of 1-1-2004		
Electricity	< 3 x 80 Ampere	7,000,000
Gas	< 1 million m^3	5,664,000

* for electrical connection and for annual gas consumption

Table 1.2 Period and extent of market opening for the gas and electricity markets in Germany, Belgium and France

	Market opening	From	Criterion *
Electricity			
- Germany	100%	1998	
- Belgium	38%	2000	>40 GWh
	45%	2001	>20 GWh
		2003	>10 GWh
	100%	2006	
- France	30%	2000	>16 GWh
Gas			
- Germany	100%	1998	
- Belgium	47%	1999	>25 million m^3
	49%	2003	>15 million m^3
	66%	2006	>5 million m^3
	100%	2010	
- France	20%	2000	>25 million m^3
	33%	2008	>15 million m^3

* customers with an annual consumption larger than the given value

The opening of the gas market in the meantime appears to have been accelerated because, as of 2001, the limit for free customers has been lowered to 5 million m^3, and as of 2006 to a yearly consumption of 1 million m^3.

Energy import and export

The import of electricity has greatly increased since 1999 as a result of differences between prices for generating electricity in the Netherlands and prices in its neighbouring countries. This can be traced to differences in use of fuels and types of power plants. Free import capacity for electricity, the import capacity not used for the former SEP import contracts and UCTE obligations, has been auctioned since 2001: 900 MW for year contracts, 550 MW for month contracts and the remaining portion for day contracts. Auction proceeds are used by TenneT to increase import capacity (see Figure 1.2). On account of DTe guidelines, gas transport companies are obliged to furnish information about available transport capacity. Gasunie Transport Services gives information about the available capacity at a number of cross-border connections for the import of gas for a period of 16 months (Figure 1.3). Within this period a potential of 25.5 billion m^3 gas can be imported. Cross-border capacities can, in principle, be used for both import and export. Figure 1.4 shows the locations where import and export of gas and electricity can take place. Based on the reciprocity clause, the Minister of Economic Affairs can prevent the import of gas or electricity that is intended for free customers who are (still) classified as captive customers in the exporting country.

Grid management and supply to captive customers

In the liberalised energy market, the supply and management of energy grids is carried out by separate companies. The grid operator is appointed by the network owner and requires the approval of the regulator (DTe).

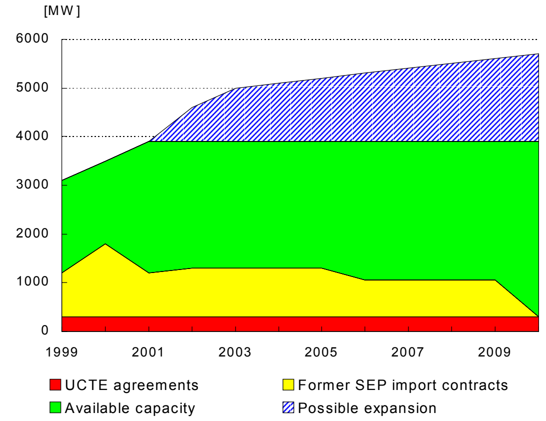


Figure 1.2 Expected development of import capacity for electricity until 2010

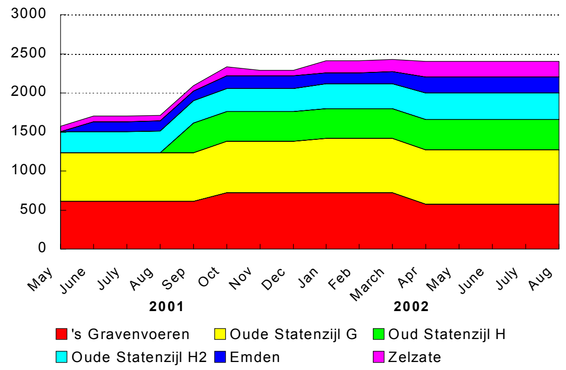


Figure 1.3 Import capacity for gas. At 's Gravenvoeren and Oude Statenzijl G and H2 imports are exchanged with export flows (May 2001)

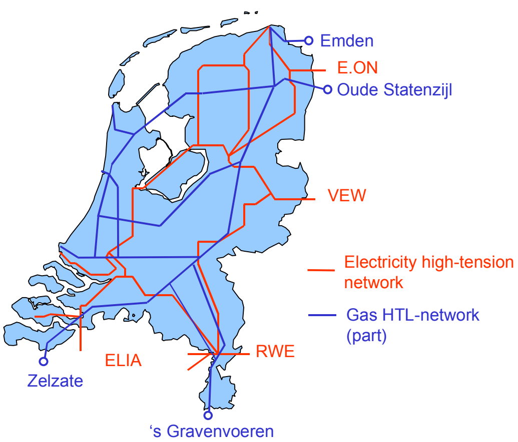


Figure 1.4 Main transmission network for gas and electricity as well as cross-border connections

Besides what is defined in the energy legislation about grid operators, additional rules can be applied to such things as the relationship between network owner and grid operator and the responsibilities of the grid operator. An electricity grid operator has a geographic monopoly: for a specific area there can only be one grid operator. This does not apply to gas networks.

For energy supply to captive customers, a supply license is required. This license is provided to energy utilities that were already supplying energy prior to the liberalisation. The supply license is valid for a specific geographic area, where the license holder has the sole right to supply captive customers up to 2004. Even once the whole energy market is opened, a license will still be needed to supply small consumers. At that stage, however, there will no longer be any area-based restriction. Tables 1.3 and 1.4 give an overview of grid operators and license holders for gas and electricity per province.

Regulation of electricity tariffs

In 1999 DTe established the structure for electricity grid tariffs. Customers pay for transmission of electricity (transmission services), for a guaranteed supply (system services) and for connection and metering (connection services). For transmission services, the cascade principle applies: customers pay for the (voltage) level at which they are connected and all the levels above that. Electricity generating companies connected to the two topmost levels pay 25% of the costs of these high-voltage grids. As of 2001 this no longer applies to electricity imported via high-voltage grids. This is linked to agreements made between grid managers and energy regulators in different European countries concerning a uniform regulation (the Florence Agreement) for electricity transmission between countries. Another change affects customers who only buy a limited number of hours per year of electricity (a load factor of less than 600 hours). For these customers, including many with their own generating capacity, a reduced transmission tariff applies. Tariffs for

Table 1.3 Gas grid operators and license holders

Province	Gas grid operator	Disrtibution company (gas license holder)
Groningen	Essent Netwerk Noord N.V.	Essent Energie Noord N.V.
Friesland	Essent Netwerk Friesland NW-ZO N.V.	Essent Energie Friesland NW-ZO
		Essent Energie Friesland ZW BV
	N.V. Continuon Netbeheer	N.V. NUON
	N.V. Gasbedrijf Noord-Oost Friesland	N.V. Eneco Energie Noord-Oost Friesland
Drenthe	RENDO Netbeheer B.V.	N.V. RENDO
	Essent Netwerk Noord N.V.	Essent Energie Noord N.V.
Overijssel	Netbeheerder Centraal Overijssel B.V.	Centraal Overijsselse Nutsbedrijven N.V.
	Essent Netwerk Noord N.V.	Essent Energie Noord N.V.
Flevoland	N.V. Continuon Netbeheer	N.V. NUON
Gelderland	N.V. Continuon Netbeheer	N.V. NUON
Noord-Holland	N.V. Continuon Netbeheer	N.V. NUON
	B.V. Netbeheerder Haarlemmermeer	N.V. Nutsbedrijf Haarlemmermeer
	Nutsbedrijf Amstelland N.V.	Nutsbedrijf Amstelland N.V.
	NV. Energiebedrijf Zuid-Kennemerland Netwerk	N.V. Energiehandel Zuid-Kennemerland
	Gasbedrijf Midden-Kennemerland N.V.	Gasbedrijf Midden-Kennemerland N.V.
Zuid-Holland	Energie Delfland N.V.	Energie Delfland N.V.
	EMH Gas Assets B.V.	Energiebedrijf Midden-Holland N.V
	Westland Energie Infrastructuur	N.V. Nutsbedrijf Westland
	Eneco Gasnetwerk B.V.	N.V. Eneco
	ONS Netbeheer B.V.	N.V. ONS Energie
Utrecht	Elektriciteitsnetbeheer Utrecht B.V.	Remu Levering B.V.
	Eneco Zeist en Omstreken B.V.	Gasdistributie Zeist en Omstreken
Zeeland	DELTA Netwerkbedrijf Gas	N.V. DELTA Nutsbedrijven
Noord-Brabant	Gnet Eindhoven B.V.	N.V. Nutsbedrijf Regio Eindhoven
	Essent Netwerk Brabant B.V.	Essent Energie Brabant B.V.
	Intergas Netbeheer B.V.	Intergas N.V.
	Obragas Net B.V.	Obragas Energy Distribution B.V. i.o.
Limburg	InfraMosane N.V.	EnerMosane N.V.
	Essent Netwerk Limburg B.V.	Essent Energie Limburg B.V.
	Eneco Energie Weert N.V.	Eneco Energie Weert N.V.

Table 1.4 Electricity grid operators and license holders

Province	Electricity grid holders	Distribution company (electricity license holder)
Groningen	Essent Netwerk Noord N.V.	Essent Energie Noord N.V.
Friesland	Essent Netwerk Friesland NW-ZO N.V.	Essent Energie Friesland NW-ZO N.V.
	NuonNet i.o.	N.V. NUON Energielevering i.o.
Drenthe	RENDO Netbeheer B.V.	N.V. RENDO
	Essent Netwerk Noord N.V.	Essent Energie Noord N.V.
Overijssel	Netbeheerder Centraal Overijssel B.V.	Centraal Overijsselse Nutsbedrijven N.V.
	Essent Netwerk Noord N.V.	Essent Energie Noord N.V.
Flevoland	NuonNet i.o.	N.V. NUON Energielevering i.o.
Gelderland	NuonNet i.o.	N.V. NUON Energielevering i.o.
Noord-Holland	NuonNet i.o.	N.V. NUON Energielevering i.o.
		Energie Noord West N.V.
	B.V. Netbeheer Zuid-Kennemerland	Eneco Energie Zuid-Kennemerland
Zuid-Holland	EdelNet Delfland B.V.	Energie Delfland N.V.
	Netbeheer Midden-Holland B.V.	Eneco Energie Midden-Holland N.V.
	Westland Energie Infrastructuur B.V.	N.V. Nutsbedrijf Westland
	Eneco NetBeheer B.V.	N.V. Eneco
	ONS Netbeheer B.V.	N.V. ONS Energie
	B.V. Transportnet Zuid-Holland	
Utrecht	Elektriciteitsnetbeheer Utrecht B.V.	REMU Levering B.V.
Zeeland	DELTA Netwerkbedrijf B.V.	N.V. DELTA Nutsbedrijven
Noord-Brabant	ENET Eindhoven B.V.	N.V. Nutsbedrijf Regio Eindhoven
	Essent Netwerk Brabant B.V.	Essent Energie Brabant B.V.
Limburg	InfraMosane N.V.	EnerMosane N.V.
	Essent Netwerk Limburg B.V.	Essent Energie Limburg B.V.
	Netbeheer Nutsbedrijven Weert N.V.	Eneco Energie Weert N.V.

electricity grids prior to 2000 were based on the costs of energy distribution networks in 1996. In accordance with legislation for liberalisation, besides a cost increase based on the consumer price index, an efficiency discount needs to be applied as of 2001. This efficiency discount for 2001, 2002 and 2003 is determined by DTe to average 5.9% per year. The imposed discounts show a large variation because of large cost differences between the network companies (see Figure 1.5).

Regulation of tariffs for gas transport and storage

After the preliminary guidelines for 2001, DTe has developed definitive guidelines for gas transport and storage. In the guidelines for gas transport that are in effect up to 2002 a distinction is made between Gasunie, which manages the national gas transmission network, and the regional gas distribution companies. The fee for transport services offered by Gasunie should be based on an ‘entry-exit-point’ system. This includes a tariff calculated for both point of entry into and point of exit from the gas transport network. The Commodity Service System (CSS), which Gasunie is continuing to use until the end of 2001, is based on a ‘point-to-point’ system where the distance between entry and exit points determines the level of the tariff. For ‘backhaul’, the transport of gas against the physical gas flow, a lower tariff will need to be applied. Daily balancing will apply to both transport services and backhaul. In other words, the in- and out-flowing volumes must be equal within a 24-hour period. These volumes are not allowed to differ by more than 25% during this period (there is less tolerance in extreme cold weather). Hourly balancing needs to be offered when requested by network users. A flexibility service also needs to be offered by Gasunie for excesses of the daily and hourly balancing and to balance the position of the network user. Another basic service that Gasunie needs to offer is quality conversion, blending to make gas suitable for end users.

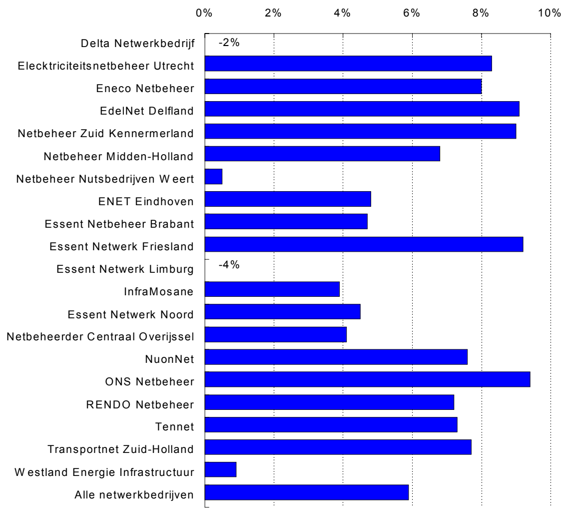


Figure 1.5 Annual efficiency discounts for electricity grid companies for 2001 through 2003

Transport tariffs of the regional gas companies need to be based on the cascade principle, so the different pressure stages in the gas network are taken into account.

The guideline for gas storage stipulates that, with the exception of the LNG plant on the Maasvlakte, in 2002 two thirds of available volume must be considered as storage capacity, and 50% of that has to be accessible to third parties (see Figure 1.6). After 2002 the storage volume available to third parties needs to be increased. The remaining volume will continue to be used to meet gas production objectives.

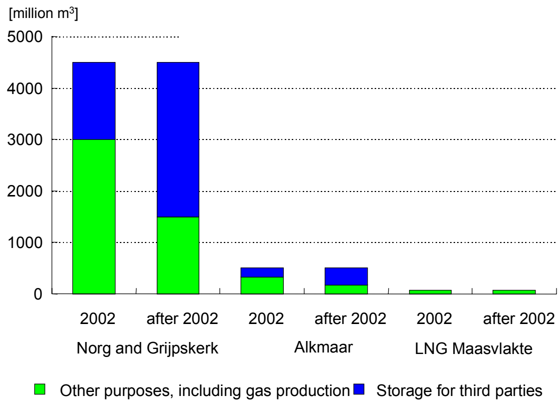


Figure 1.6 Available storage capacity for third parties in 2002 and thereafter

Supply tariffs for captive customers

Energy prices for captive customers are determined until 2004 by DTe *(see also Overview: Energy prices).* To establish supply tariffs for electricity, use is made of the valuation principle. The purchase price for a supply company is established based on 50% of the purchase price for the license holder and for the other part based on the average purchase price for all license holders together. Since tariffs are established in the same way every three months, differences between supply tariffs charged by the different energy suppliers are rapidly becoming less.

The purchase price for a license holder, who supplies gas to captive customers, is comprised of a commodity price and the transport tariff for national gas transport. The license holder raises this purchase price with a surcharge, which is established by DTe. DTe has determined that no efficiency discount applies for 2002 and 2003 for the surcharge on the purchase price. However, there is an efficiency discount for the transport tariff that regional grid operators charge to captive customers. This discount is 9% for both 2002 and 2003 for most gas grid operators. A few grid operators have had a lower efficiency discount imposed.

Ending of Protocol and Co-operative Agreement

To foster a gradual transition to an open electricity market, there was an agreement up to the end of 2000 between large-scale producers (UNA, EZH, EPON and EPZ) and energy distributors. It was agreed in this Protocol that producers would not supply electricity to third parties between 1997 and 2000. Since 2001 this agreement no longer applies, and large-scale electricity producers can also sell their electricity directly to free customers. The Co-operative Agreement that regulated co-operation between the four large-scale electricity producers was also ended at the beginning of 2001.

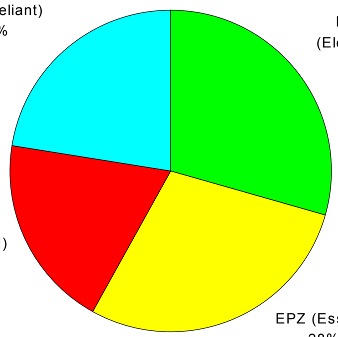


Figure 1.7 Distribution of collective obligations between the four large-scale producers

The apportionment of the remaining stranded costs is regulated (see Figure 1.7) in the Electricity Production Sector Transition Act. Table 1.5 gives an overview of the costs to be shared. Based on advice from the Herkströter Commission, compensation arises for two types of costs (maximum of 1.3 billion NLG). Initially the intention was that compensation costs would be covered by a surcharge on transmission and system services. The European Commission, however, has not given permission for this. The Transition Act also prescribes that the Dutch government is owner of the national high-voltage grid, which means the government purchases shares of TenneT from the production companies.

Table 1.5 Stranded costs to be shared and eventual compensation

Costs resulting from:	To be shared	Compensation
Exploitation of coal gasification Demkolec	•	•
Loan for nuclear power plant Dodewaard	•	
Import contracts for electricity and gas	•	
Construction of electricity connection with Norway	•	
Fuel price risk of district heating contracts		•

Privatisation

For the privatisation of energy utilities, approval is needed from the Minister. A distinction is made between grid management and the other activities of an energy utility. Financial ownership of grid management should lie with the grid operator, because the economic value of the network appears on the grid operator's balance sheet. Legal ownership of the energy networks remains in the hands of public shareholders (provincial and local governments). Economic exploitation of the network is given by the public shareholders to the grid manager by way of an agreement or concession. As of 2002, 49% of shares can be sold directly or via a (partial) stock-market-quotation application to private parties. However, consent from the Minister is still required. As of 2004, it is expected that complete privatisation will be possible.

Renewable energy supply

In addition to directives for the liberalisation of energy markets, agreements have been made within the European Union about making the energy supply more renewable. There are, for example, EU agreements, based on the Kyoto Protocol, to reduce greenhouse gas emissions. The average emission in the period from 2008 to 2012 must be reduced to the corresponding percentage (shown in Figure 1.8) of 1990 emissions. Most EU countries are stimulating electricity generated from renewable sources. Within the EU, agreement has been reached on objectives for each EU member state regarding the share of electricity that must originate from renewable sources in 2010 (Figure 1.9). Electrical generation from renewable sources includes large-scale hydropower. Since countries with hydropower have mostly already realised their available potential, the objective for exclusively large-scale hydropower is also included in Figure 1.9. If the Netherlands realises its agreed-upon share of 9% renewable electricity, the objective for renewable energy by 2010 – a share of 5% renewable energy in terms of total energy consumption – can be achieved. By 2020 the Dutch government has set an objective that is twice as high. The share of renewable energy in terms of total energy consumption must then be 10%.

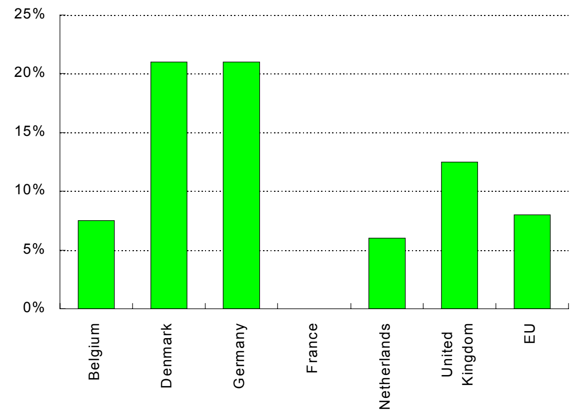


Figure 1.8 Reduction percentages of greenhouse gases from 2008 to 2012 relative to 1990 according to the Kyoto agreements for the entire EU and some member states

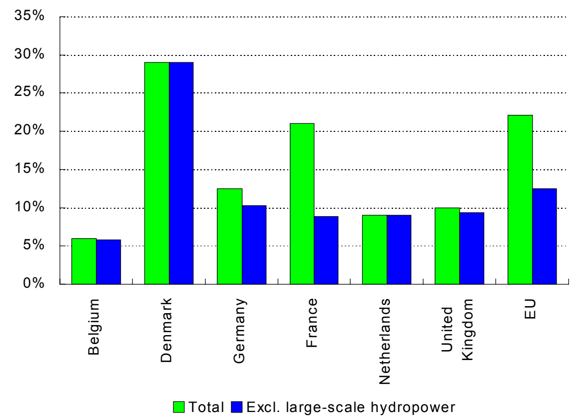


Figure 1.9 European targets for the share of renewable electricity in total electricity consumption in 2010 for the entire EU and some member states

Difficult implementation of the Gas Act

The Gas Act alone does not yet ensure the existence of competition in the Dutch gas market. The organisation of gas infrastructure management, which makes the market accessible so new providers and customers can easily change their supplier, requires extra regulation. Various market parties point out that Gasunie's dominant position is an obstacle to a properly functioning market. The guidelines developed by the supervisor DTe for the transport and storage of gas appear intended mostly to regulate Gasunie's activities with mandatory instructions. Gasunie opposes the guidelines, primarily because they seem to be at odds with the principles in the Gas Act. The position taken by DTe is also subject to criticism. It remains to be seen whether the objectives of the Gas Act can be achieved within the established time frame.

Introduction of competition in the gas market

With Senate approval of the Gas Act on 20 June 2000, the Dutch government succeeded in implementing the EU Gas Directive (98/30/EC) by 10 August 2000. Core themes of the Gas Act include the gradual opening-up of the market and regulation of access to the gas network. Ideally, once full liberalisation of the gas market is achieved, every customer will be able to switch their gas supplier quickly and easily whenever they want (e.g., because of lower prices), and gas suppliers will be able to freely access the Dutch market (and infrastructure), while gas supply is guaranteed and safe at all times. Competition should stimulate gas companies to become more efficient and lower their costs.

Because of the gradual market opening, a declining number of captive customers will coexist with a growing number of free customers in the coming years. Regulation is geared to protect captive customers by subjecting supply licence holders and network companies to maximum tariffs for the supply and distribution of gas. For the supply of gas to free customers, the appointed regulator of the gas market (DTe) has established guidelines (similar to the Tariff Code for the supply of electricity). Based on these guidelines, transmission companies, including Gasunie, have to submit indicative tariffs and conditions for the transport and storage of gas to DTe. The managers of gas pipelines (transmission companies) are obliged to negotiate with those who want their gas transmitted by way of the network concerned. Meanwhile, the 'Platform Versnelling Energieliberalisering' (PVE, a co-operative association between government, the energy sector, industry and other relevant parties, and established by the Minister of Economic Affairs to accelerate energy liberalisation) has developed a model for the wholesale of gas in the Netherlands. This model should create a framework for market players to pursue their commercial activities in a liberalised gas market.

Network management and negotiated access for third parties

To provide third parties with free access to the network, the Dutch government has decided on negotiated third party access (nTPA). For nTPA, to start with, network managers will determine tariffs and conditions. Intervention will only occur when DTe disapproves of these tariffs and conditions. In order to avoid discrimination, cross-subsidisation and other improper competition, former integrated undertakings in the gas sector had to transfer their gas transmission, distribution and storage activities (i.e. ownership and operation of the network) to a separate company as of 1 January 2001. The appointment of network managers requires the approval of the Minister. A listing of approved network companies can be found in Table 1.3.

According to Article 2 of the Gas Act, Gasunie is exempt from having to appoint a separate manager for its transmission network. However, Gasunie has built internal 'firewalls' (administrative separation between network and supply), and announced that it intends a legal separation between NV Gasunie and Gasunie Transport Services.

Different roles of Gasunie

Gasunie has an unusual position in the Dutch gas market, mainly attributable to historical developments. Gasunie fulfils different and sometimes conflicting roles. On the one hand, Gasunie is a commercial party in the liberalised market. On the other hand, it has the responsibility of safeguarding government and public interests.

Purchaser of gas from small fields

The Gas Act obliges Gasunie to purchase gas, under reasonable conditions and at fair prices, from producers who exploit "small fields" in the Netherlands, i.e. all fields, onshore and offshore, except the Groningen gas field (see also *Overview: Market organisation and strategy*). Such a strategy ensures a rational use of Dutch gas reserves and avoids rapid depletion of the Groningen field. As a result, a constant flow of gas from the small fields is made available in the market, which makes exploitation of these fields more attractive, and leaves Gasunie to deal with fluctuating gas demand with its production from the Groningen field.

Provider of a guaranteed and safe supply for captive customers

The Gas Act also obliges Gasunie to ensure a guaranteed and safe gas supply for captive customers until 2004. This supply obligation is defined in Article 87 of the Gas Act, which states that Gasunie is obliged to supply gas to license holders (gas distribution companies), who are in turn obliged to purchase this gas from Gasunie.

National grid owner and operator

Gasunie remains the sole owner and operator of the national gas infrastructure (pipelines, compressing stations, blending stations, measuring and regulating stations, export stations, receiving stations, storage, etc.). Negotiated access applies to the transmission grid and storage facilities. Gasunie Transport Services, a new department at Gasunie, is therefore also responsible for transport and other services to customers who obtain gas from suppliers other than Gasunie. Indicative tariffs, conditions and available transport capacity at 'entry points' have been published.

Gas importer and exporter

Historically, Gasunie, on behalf of the government, was the watchdog of the natural gas supply in the Netherlands. They bought domestically produced gas and some imported gas. Gasunie was also responsible for the export of Dutch gas. This monopoly ended with the liberalisation of the gas market, since other gas companies are now also able to import and export gas, and purchase gas from Dutch producers.

Guidelines

At the end of August 2001 DTe established new guidelines for the Dutch gas market. DTe's guidelines determine how indicative tariffs and conditions for the transport and storage of gas should be established. These guidelines apply to transmission companies, as well as storage companies with a dominant market position, which includes Gasunie, NAM and Bergen Concession (BP Amoco and others). These companies have to comply with the guidelines for 2002 concerning transmission, storage and related services. Once the indicative tariffs are established (published by 1 October 2001), transmission companies are obliged, if the customer so wishes, to negotiate the specific conditions of the transmission services. The guidelines for 2002 are a follow-up to earlier established preliminary guidelines for 2001.

In 1998 Gasunie published its Commodity Services System (CSS) tariffs. CSS is comprised of an integrated tariff structure for the supply and transmission of gas to very large customers. The opening of the gas market necessitated the creation of the CSS, while regulatory principles, such as the DTe guidelines, were not yet available. It was not surprising that Gasunie and other gas companies strongly opposed the guidelines. First of all, DTe did not consult the gas companies when preparing the preliminary guidelines, so filing an objection to these guidelines was impossible. DTe learned from this experience, because while preparing the guidelines for the transmission and storage of gas for 2002, they organised an open consultation procedure. However, gas companies doubted DTe's ability to process all the comments and write well thought-out guidelines within a week after the consultation. Secondly, the imposed time frame, which gives companies only one month to publish their tariffs, is considered impossible. The same problem arose in 2000, but at that time DTe conceded to the gas companies' objections and granted them an extension to 15 December 2000 to publish their tariffs.

Hybrid TPA

The strongest objections to the guidelines, however, concern the de facto establishment of regulated TPA, instead of nTPA as envisaged in the Gas Act. The guidelines depict DTe not as supervisor of the gas market, but as 'market-maker'. DTe itself now even speaks of 'hybrid TPA' in which negotiated access is based on DTe guidelines. This means the guidelines serve as a clear framework within which gas companies offer basic services with standardised conditions and tariffs. Other services (or 'specials') are negotiable between gas companies and grid users.

Operators of gas transmission networks are strictly regulated by the guidelines. Tariffs for gas transmission should be based on an 'entry-exit-point' system and not a 'point-to-point' system, as Gasunie used in past years. Transmission companies are obligated to offer short-term contracts. A minimum of one day applies in 2002, and one-hour contracts should also be available the following year. Gasunie has declared that it will only be able to offer one-week (or shorter) contracts as of mid 2002. Third parties do not need to present a gas contract in order to reserve capacity. Balancing the supply and demand of gas is a controversial issue in terms of regulations. The guidelines now prescribe that guaranteed transport and backhaul should be supplied on a daily balancing basis with a maximum tolerance of 25% (at -5^{o}C). A 'shipper' arranges transport contracts with the relevant network managers. He keeps an eye on the contracted transport capacity and maintains the balance between gas demand and supply. Producers, traders, suppliers, as well as large users can act as shippers in the gas market.

DTe guidelines

The general principles of the guidelines are intended to encourage trade (gas-to-gas competition), an efficient use of services, to avoid discrimination and ensure a fair allocation of costs for basic services. The following basic services are defined in the guidelines:

- *Guaranteed transport*: offers available capacity on a continuous basis, as opposed to interruptible transport. Information on available transport capacities will be published.
- *Backhaul*: makes it possible to contract capacity at an entry or exit point for the transport of gas against the physical gas flow.
- *Flexibility*: enables grid users to hedge against imbalances and to exceed contracted deviations (tolerance values for balancing).
- *Quality conversion*: produces the appropriate gas quality (i.e. calorific content of gas) and composition by blending.
- *Gas storage for third parties:* makes a further distinction between guaranteed injection, volume and production service. This means the relevant capacities are available for those who want to make use of these services. Information on available capacities for injection, volume and production is published.

The guidelines prescribe that Gasunie must use the entry-exit-point system for transport, although nodes (combined entry-exit points) can be built into the gas network. The user of the network pays an entrance fee when gas enters the network and an exit fee when it leaves. Indicative tariffs for guaranteed transport and backhaul should be based on cubic metres per hour for each entry and exit point. This means that the load factor for the user is the determinant for transport prices. In addition, daily balancing of the capacity applies to these basic services, which means that gas volumes going in and coming out over a 24-hour period have to be in balance with each other. If requested, the network operator should offer hourly balancing.

In order to encourage gas-to-gas competition, part of available transport capacity should be reserved for short-term contracts. Short-term contracts are a minimum of one day, while a maximum contract term for basic services is five years. It is prohibited to ask for a supply contract ('show of contract') when capacity is reserved. Clients may exchange imbalances or contracted volumes among each other. Discrimination (e.g. timing and information advantages) between third parties and companies affiliated to transport or storage companies is not allowed.

Another grievance is that indicative tariffs for transport should be based on economic costs according to the guidelines, which include a 'reasonable return on investments' and depreciation based on historical costs. This may discourage gas companies from investing in new transmission facilities such as pipelines, especially when such networks are privatised. In contrast with electricity regulation, network managers have no obligation to connect producers or end users to their network. The network manager will offer a new or heavier connection according to approved tariffs (a one-off tariff plus a fixed annual tariff). However, this offer will not be made if the network company foresees that its tariff-generated income is not able to cover the required investment costs.

Despite its objections to preliminary guidelines for 2001, Gasunie lowered its tariffs for transmission, quality conversion and hourly balancing by 6.5% as of 1 January 2001. Gasunie's CSS will be replaced by separate tariff systems for transmission and supply. Gasunie also started publishing its available gas import capacity for 2001 and a protocol for assigning transport capacity. Rumour has it that Gasunie's concessions are part of a secret deal with DTe. In reply to questions on this matter, however, the Minister made it clear that there is nothing secret or illegal about the agreement between DTe and Gasunie. The agreement was made in anticipation of guidelines being completed for the year 2002. In return, DTe agreed not to impose a mandatory instruction on Gasunie. Nevertheless, it shows that DTe is receptive to bilateral agreements, suggesting that DTe is not the independent supervisor it is supposed to be.

Several organisations, including VOEG (energy traders), VEMW (large energy users), VNCI (chemical industry) and Productschap Tuinbouw have officially requested DTe to issue Gasunie with mandatory instructions because, in their opinion, Gasunie does not comply with the guidelines for indicative tariffs and conditions. Gasunie, however, claims that its transmission tariffs (including the 6.5% reduction) are among the lowest in Europe.

Gas storage

The guidelines define gas storage and quality conversion as two basic services that should be offered to third parties in the gas market. It is generally expected that access to gas storage facilities will play an important role in the liberalised gas market. Easy and affordable access to storage increases the flexibility to meet the demand for gas at any given time (see box *Gas storage in the Netherlands*).

DTe's guidelines for gas storage are intended to stimulate gas trade, which means that storage facilities should be made available for trading purposes. The Gas Act stresses that DTe guidelines for determining tariffs and conditions only apply to gas storage companies that hold a dominant position, i.e. Gasunie, NAM and Bergen concession holders (BP Amoco). For the time being, however, Gasunie's storage facility, an LNG plant on the Maasvlakte, is not suited to be used for trading purposes. Of the underground storage in Norg, Grijpskerk and Alkmaar, it is assumed that one third of storage capacity is needed for gas production and two-thirds is available for trading. Of this latter portion, only half needs to be offered to third parties in 2002. This share will gradually increase in the following years. The availability of gas storage for third parties also depends on the duration of the contract Gasunie has for the storage facilities.

Quality conversion

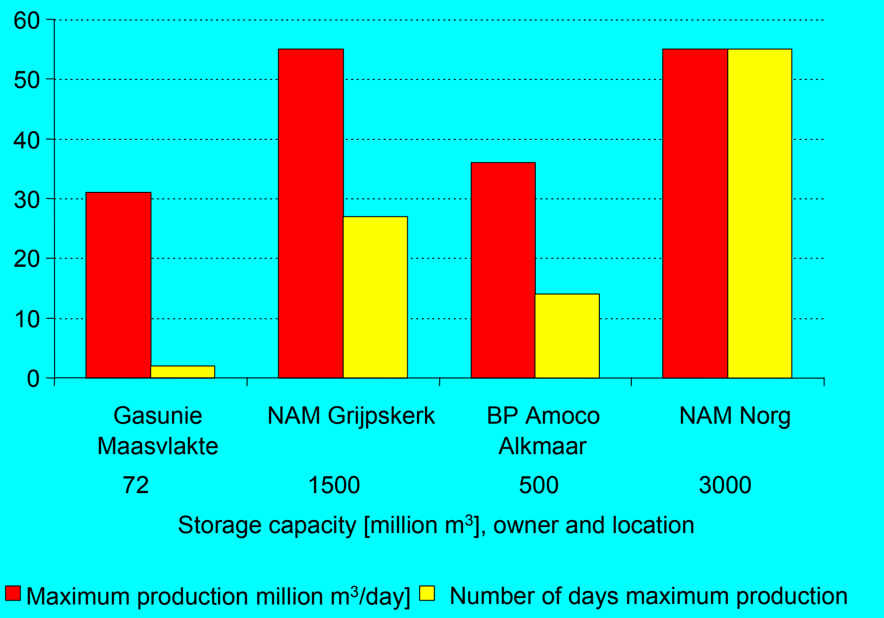
Gas appliances in the Netherlands are adapted to the typical qualitative characteristics (including calorific value) of Dutch (Groningen) gas. Natural gas from other gas fields often varies in quality. Mixing gases from different sources will level out variations in calorific values. In order to reduce the heat content of high calorific gases to that of Groningen gas, high calorific gas is blended with low calorific gas or nitrogen. Liberalisation of the gas market has led to an increase in the import of foreign high calorific gas, and therefore blending becomes more important. Since the import and export of natural gas, along with ensuring gas quality for transmission, have historically been the responsibilities of Gasunie, the company also traditionally operates quality converting or blending stations. However, the Gas Act and guidelines prescribe that, like storage facilities, quality conversion plants can be built and operated by anyone, i.e. quality conversion is not a legal or natural monopoly. Delta Nutsbedrijven, a distribution company in Zeeland (Southwest Netherlands), has been importing British gas for two years now. Delta proves that distribution companies are also able to blend and convert gases, by building a nitrogen plant for quality conversion.

Gas storage in the Netherlands

Storage plays a role in bridging (temporary) gaps between gas supply and demand. There are two types of storage: seasonal and peak. Seasonal storage facilities are able to store large volumes of gas during periods of low demand (e.g. summer) for slow release during periods of high demand (e.g. winter). Seasonal storage generally takes place in depleted oil and gas fields and in aquifers. Peak shaving facilities, such as salt caverns and LNG tanks, store smaller quantities of gas to meet fluctuations in demand over short time periods (e.g. during a day). Oversized transmission pipelines can also be used for storage purposes by compressing the gas, which increases the quantity that can be stored in the pipeline ('linepack').

There are currently only four gas storage facilities in the Netherlands (see figure below). They are all onshore and contracted to Gasunie. Three of the facilities are depleted underground gas fields, and Maasvlakte is an LNG plant. Besides these facilities, Gasunie also has the Groningen field where production can be relatively easily and quickly adapted to changes in demand.

BP Nederland Energie, as an operator of the P15 and P18 offshore gas fields, is developing plans to use these fields for third party storage services. The P15-P18 fields are comprised of eight gas fields, located 40 km off the Dutch coast. BP initially intends to convert one or a few of the fields for storage, with year-round storage (as opposed to seasonal storage) and withdrawal capacity. It has indicated several storage possibilities it could handle and applicable tariffs. BP has also asked for 'expressions of interest' for the planned services.



Supply to captive and small gas users

A guaranteed supply to captive customers is ensured by Article 87 of the Gas Act, which obliges Gasunie to supply gas to license holders, who are in turn obliged to purchase gas from Gasunie. This provision is similar to the Protocol that applied until the end of 2000 in the electricity market. Additionally, consumer protection is ensured by Article 80 of the Gas Act, which mentions maximum transport tariffs for captive and small gas users (who consume less than 170 thousand m^3 annually).

It is, however, questionable whether these provisions actually protect residential customers. The bulk of the gas price that households have to pay is determined by the commodity price and by governmental taxes (see *Insight: Energy Prices)*.

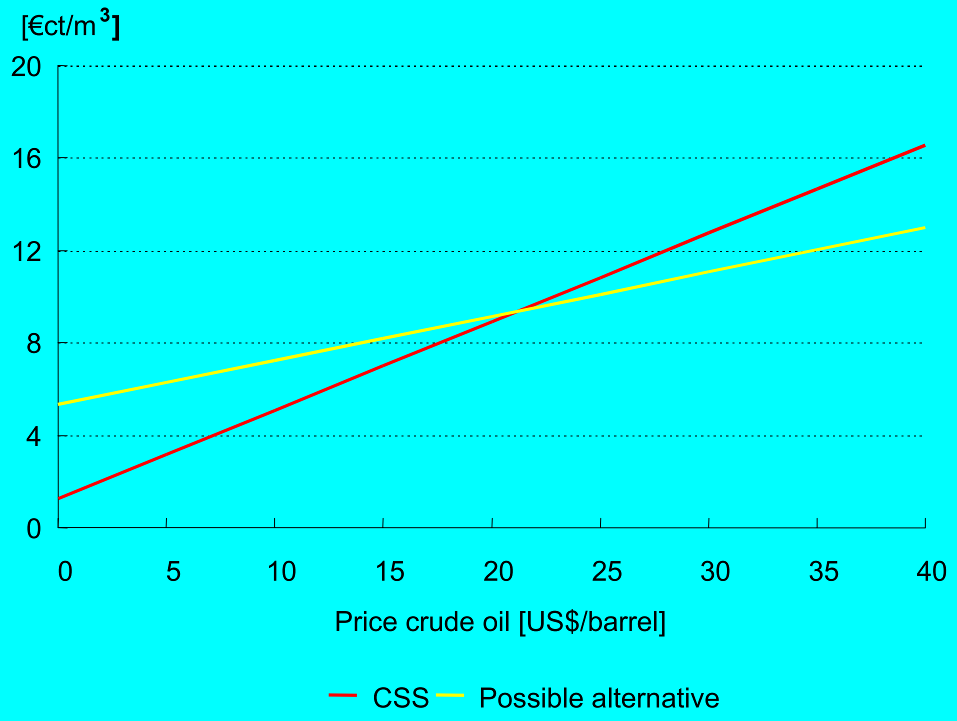
Because supply companies are obliged to purchase from Gasunie, costs are determined by the commodity price charged by Gasunie. This commodity price is not based on the '1999=2001 principle' that applies to maximum transport and supply tariffs, but on the price of oil. The exact price levels at which Gasunie sells gas to supply companies are not made public. DTe had intended to publish these prices, but Gasunie considered them a trade secret and brought the issue before a judge, who ruled in favour of Gasunie.

Oil price link

Gasunie has repeatedly indicated that it would adhere to the link between gas and oil prices. However, the market may force a weaker link with oil prices in the future when gas-to-gas competition gains ground. The recent establishment of an OPEC gas cartel also indicates a more independent price formation for gas as being realistic. It is therefore possible that Gasunie will adapt the formula to determine the commodity price, such that the link with the price of oil is weakened (see box: *Alternative to oil price link*). Whether (gas) price determined by gas-to-gas competition becomes a reality depends not only on developments in the Dutch gas market, but also on what happens in the rest of Europe. Gas is continuing to grow as source in Europe's energy mix; gas-fired electricity production is greatly increasing. At the same time the demand for oil production is declining. Moreover, oil demand is increasingly being determined by the transport sector.

Substitution possibilities between oil and gas are the basis for an oil-related gas price. However, dual and multi-fuel facilities in industrial and electricity production are not as common as they used to be. New facilities in the Netherlands are generally only capable of being heated with natural gas. Oil is only used for electricity generation as a back-up fuel, and fuel oil is no longer a substitute for gas in Dutch households. Hence, demand for gas is growing, while real substitution possibilities between oil and gas are decreasing. Thus, an oil-related gas price seems outdated.

Alternative to oil price link



The figure above compares the relationship between oil price and gas commodity price according to the CSS and a possible alternative formula. The commodity price in CSS is determined by the formula (37.4/500)*(P+48)-0.8, where P is the average value of fuel oil with 1% sulphur over six months, directly preceding the quarter in which the commodity price is charged. For the alternative formula, 500 and –0.8 are replaced by 1000 and 10 respectively. Within the relevant oil price range, the gas commodity price is levelled out. By choosing a different slope in the commodity price formula, Gasunie can easily modify the dependency on the oil price. While the gas price is still linked to the oil price, it follows oil price fluctuations to a lesser extent.

Privatisation of the gas distribution network

In the 'pre-liberalisation' era, it was common for provinces and larger municipalities to hold shares in, or fully own energy utilities (production, supply and networks), in order to protect public interests such as supply security and environmental protection. With the changing market conditions, the question is whether the advantages of public ownership of energy outweigh the disadvantages (see box: *The pros and cons of network privatisation*). Public utilities feel constrained in terms of becoming competitive and market-oriented. As a result, many local governments sold, or are willing to sell their shares, and a few Dutch energy utilities have thus become (partly) privatised. Until 1 January 2003 privatisation is only possible under certain conditions and requires the explicit approval of the Minister.

After the decision to nationalise the ownership of TenneT, the power crisis in California caused reluctance in the Dutch parliament to privatise regional gas and electricity networks. Because network companies, although legally separated, are still part of energy holdings, selling the holding to a private and possibly foreign company normally also means selling the 'natural monopoly' of the network to the same buyer. The value of the total holding is more than the sum of the separate supply and network companies. Furthermore, it is estimated that the network represents about 80 per cent of the total value of the holding. Thus, privatisation of just the supply company, which is preferred by the government, is not interesting enough for private parties. At the same time, privatisation of the network company is favoured by private parties but meets political opposition.

The main argument against distribution network privatisation is the fear that private companies are not inclined to invest in production and grid capacity (including grid maintenance). Advocates of privatisation, however, claim that proper regulation of (private) network companies will prevent the network from solely being used as a 'cash cow' for the energy company. The central question in the privatisation debate is whether a supervised private company is more reliable than the government as shareholder.

The political debate concentrates primarily on privatisation of electricity distribution, however, it is also a relevant issue for gas distribution, although in reality the parallel is not complete. At the level of the national transmission grid, the Dutch state currently owns 100 per cent of TenneT and 50 per cent of Gasunie (the remaining shares of Gasunie are owned by Shell and Esso). Gasunie together with the Ministry of Economic Affairs are examining the possibility of splitting Gasunie into two companies, i.e. trading and transport. When the split occurs, the trading company will be completely privatised and the transport company will be completely state-owned.

There are also a number of differences between gas and electricity at the level of the distribution network. Expansion of the electricity grid is part of the liberalisation regulation (i.e. the Electricity Act), whereas investments in gas distribution networks are not included in the Gas Act. Every region has but one electricity grid, while for gas the possibility exists for pipeline-to-pipeline competition.

The pros and cons of network privatisation

Advantages of network privatisation

- Supplying and trading gas and electricity are risky activities. Profits are no longer predictable as they were in the past, so energy utilities are also susceptible to losses. Public shareholders would bear the risks of investments in the networks and finance the possibility of acquisitions.
- Public and private interests collide. Strategic decisions necessary in a market environment cannot be made by the government, because it incorporates public interests in its decisions. History shows that the Dutch government is often not capable of making economic decisions. For example, in times of overcapacity the government supported the construction of new production plants.
- The money spent by (local) governments for energy utilities could be used otherwise. Public money would then no longer be tied to energy services.
- The power of provinces and municipalities as shareholders to influence energy utility prices is declining because prices and tariffs will increasingly be determined by the spot market and by DTe respectively.

Disadvantages of network privatisation

- Investments in networks (new capacity, maintenance and safety) are in jeopardy. The network is an 'easy' asset that will only be used to generate a stable, albeit low, profit.
- Safe and stable supply of energy is in the public interest.
- Supply to some groups can no longer be guaranteed, at least not at low prices.
- The network can be regarded as a natural monopoly, which entails the danger of an improper advantage for energy producers and suppliers.

In July 2001, the Minister established new rules for the privatisation of energy utilities. Legal ownership of energy distribution networks should be in the hands of regional and/or local governments (current shareholders), while the financial owner of the network should be the grid operator (which is currently not the case). The economic value of the network should be included on the grid operator's balance sheet, in order to ensure that the full value of the energy company is maintained when privatisation of the minority of shares (49%) is made possible as of 1 January 2002. In 2004, after an evaluation, it will be decided whether a transition to full privatisation of energy utilities can take place. Legal ownership of the energy networks in the future will remain completely in the hands of regional and local governments. It is striking that Gasunie is also included in the group of public shareholders, because for a long time it has held a minority interest in a few gas distribution companies.

DTe reconsiders its position

Criticism of DTe's somewhat disputable position in gas regulation may lead to some change. DTe overruled the claim by large users to issue Gasunie with mandatory instructions in May 2001. This decision was inevitable because, already in January, when the public hearing for the claim was to take place, DTe announced it would not proceed with the claim, as part of the deal between DTe and Gasunie. DTe lost touch with the interests of large gas consumers, and will find it difficult to regain their confidence. Nevertheless, DTe changed its attitude when a decision had to be made about definitive guidelines for 2002. An open consultation procedure for these guidelines and overseeing strict compliance by Gasunie are essential to reconfirm DTe as an independent regulator of the gas market. The effect might be, that DTe will occupy a much stronger position than before. This can already be seen by the definitive establishment of the guidelines for 2002.

By publishing the consultation and information document for definitive guidelines, DTe has shown its willingness to involve the relevant parties in the procedure. However, the time frame is still rather tight. Based on these guidelines, gas companies should publish their indicative tariffs and conditions for gas transport and storage for 2002 by 1 October 2001. Until that time, (large) gas users are unclear about these tariffs and conditions. Back in June 2001, horticulturists issued complaints about the lack of information. Some horticulturists will become free (or eligible, as opposed to captive) consumers in 2002. They need to know gas transport and capacity tariffs in order to be able to decide which plants to grow next year, and October is too late to order new plants.

Meanwhile, Gasunie has begun to inform its clients about new transport tariffs. These new tariffs should be established in the autumn of 2001. The first ideas regarding the structure of Gasunie's new transport tariffs conflict with DTe's guidelines. For example, the notion of hourly balancing and the limited possibility of hourly flexibility services are once again issues. Other potentially conflicting issues concern, e.g., 'point-to-point' system of the transport tariffs and the 'show of contract'. Gasunie has once again gone to court to have DTe's guidelines declared invalid, a strategy that has worked for them before. It looks as though DTe will find it very difficult to have Gasunie operate according to the guidelines.

Reliable policy and regulation is essential

The above example of the horticulturists shows the importance of proper and early information. When firms do not know what to expect, investments are likely to be postponed or poorly made. This applies for free gas customers, as well as for distribution companies, e.g., in order to decide on investments in pipeline capacity. Other signals come from the regulations about privatising gas distribution networks. The uncertainty of the privatisation regulation slows the development of gas companies and has already resulted in threats of compensation claims.
The rush to regulate the gas market has spurred DTe to publish the preliminary guidelines for 2001 without consulting the relevant parties. Although the follow-up procedure seems better, there are still problems. It has resulted in conflicts and uncertainties about the future structure of the gas market. The conclusion might be that the Dutch gas liberalisation process has been too hasty. Market opening, especially for the middle group, seems to be happening too soon, and it is questionable whether opening the market to the remaining gas consumers (including households) in 2004 will be properly implemented. In any case, the objective of PVE to accelerate the liberalisation process seems impracticable.

Gradual price reform

The commodity price of gas is not regulated, so in principle Gasunie and other gas suppliers are free to set their own commodity price. Gasunie will replace its price and tariff system, CSS. In the years to come, Gasunie's commodity price will probably remain based on the price of oil. Nevertheless, the changing structures in the European gas market and upcoming gas-to-gas competition will undoubtedly force Gasunie to (gradually) abandon the oil-price link. Gasunie's declining market share and the increase in gas imports already indicate that the price of gas is more influenced by competition. However, the obligation for distribution companies to purchase from Gasunie until 2004 will, for the time being, preserve Gasunie's market share somewhat.

Gasunie's declining market share is not to be expected in transport and auxiliary services, such as storage and quality conversion. These tariffs are regulated by DTe's guidelines and should, in principle, be based on costs. Non-exclusivity of auxiliary services supply is good for competition when profitable alternatives are offered for storage and quality conversion. However, because of Gasunie's advantaged (former monopolistic and incumbent) position, it can be expected that Gasunie will set tariffs in such a way that they will not stimulate the development of any alternatives. This in no way diminishes the possibility for gas distribution companies to reconsider their activities and focus more on certain aspects of the supply chain. An example is Delta Nutsbedrijven investing in a quality converting facility. Thus, Gasunie cannot afford to diverge too much from possible alternative prices and tariffs.

MARKET STRUCTURE AND STRATEGY

Liberalisation of the electricity and gas markets has led to mergers and acquisitions in the energy sector, both in electricity production and energy distribution. There appears to be a certain consolidation. The relative quiet is probably also a result of the conditions set by the government on the privatisation of Dutch energy companies. Energy companies, however, are expecting scale increase. The electricity production sector is already dominated by foreign energy companies, and in energy distribution the expectation is that the role of foreign companies will also become greater.

Meanwhile, energy suppliers are preparing themselves for the next fase of the liberalisation: in 2002 a second group of large users will be able to choose their own energy supplier. In 2001 the market for green electricity has become free. Large energy suppliers have launched public campaigns in which they seem to use the image of renewable energy to gain public favour.

This part of *Energy Market Trends in the Netherlands 2001* further describes the way in which energy suppliers are preparing themselves for competition in the retail market. Two analyses in *Insight* examine, in succession, competition in the green electricity market and competitive strategies of existing energy suppliers in a free retail market. *Overview*, which precedes the two analyses, presents the current structure in the markets for electricity, gas and green electricity.

Structure of electricity production

Electricity demand in the Dutch electricity market is mostly met with large-scale generating plants (see Figure 2.1). Until 1998 the share of centralised production amounted to almost 60%. Once the electricity market was liberalised, the share of centralised production fell to a bit over 50%. In the same period the import of electricity increased from about 11% in 1998 to 18% in 2000. The growth of local production since 1998 is level with the growth of total electricity demand. The share of local production since then is about 30%.

Figure 2.2 shows that the four large-scale producers (E.ON Benelux, UNA/Reliant, Electrabel, EPZ) account for two-thirds of domestic electricity production. Waste heat from 13 of the 25 power plants is used to heat homes, commercial and industrial buildings, and greenhouses. Cogeneration plants (CHP) are also used by energy suppliers, customers or joint ventures. Together in 2000 they had a 29% share of domestic electricity production. The remaining electricity comes from incineration plants and renewable sources (wind, sun, hydropower and biomass).

Three of the four large-scale electricity producers have been acquired by foreign energy companies. E.ON, the product of a merger between two German electricity companies, PreussenElektra and Bayernwerk, acquired EZH. EPON has been acquired by Electrabel (Belgium). Figure 2.3 shows both companies' share of electricity generated in the Netherlands as part of their total production. The figure also shows the production volumes of EPZ, which is a subsidiary of Essent, and UNA, which was acquired by Reliant (USA). Reliant is, two years after the acquisition, planning to sell UNA. EDF is the largest electricity producer in Europe and also the biggest exporter of electricity, to the Netherlands, etc.

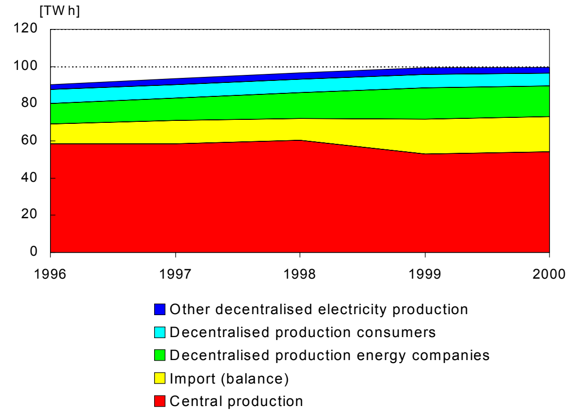


Figure 2.1 Development of electricity supply in the Dutch electricity market

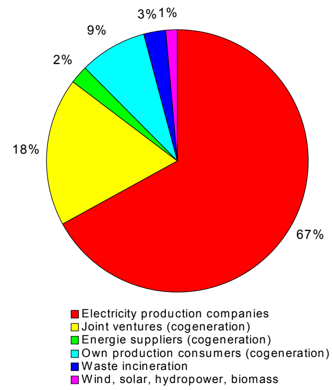


Figure 2.2 Distribution of Dutch electricity production in types of producers in 2000

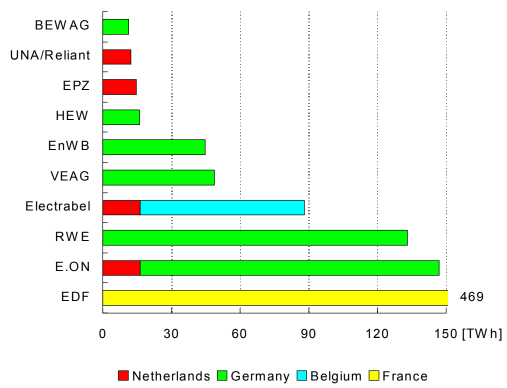


Figure 2.3 Electricity production of large-scale electricity producers in the Netherlands, Germany, Belgium and France based on data from 1999

Figure 2.4 shows the distribution of electricity production capacity among the most important players in the Dutch electricity market. From the figure it appears that three electricity suppliers, Essent, Nuon and Delta Nutsbedrijven, control a considerable share of the production capacity. Essent's position is determined by vertical integration with EPZ. Nuon and Delta Nutsbedrijven have a relatively strong position in local cogeneration, including joint ventures with industry. Nuon's acquisition of the coal-gasification plant in Buggenum is incorporated in Figure 2.4.

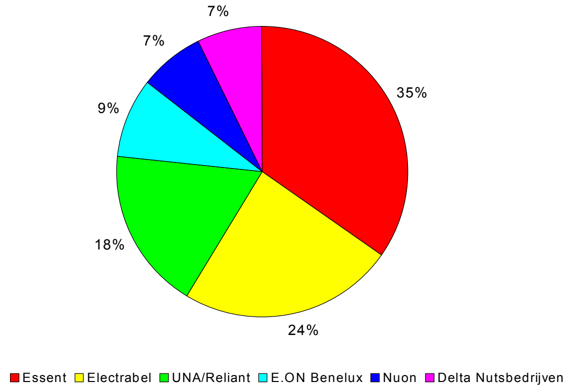


Figure 2.4 Distribution of electricity production capacity (total of 19,400 MW)

Electricity trading

Electricity in the liberalised electricity market is traded by energy traders with bilateral contracts (over the counter market) and via the Amsterdam Power Exchange (APX). In addition to trade in physical volumes, there is also trade in financial derivatives such as 'futures' and 'forwards'. Figure 2.5 shows that the volume of these forms of electricity trade can exceed the physical consumption by several times. This is not yet the case in the Netherlands, though the growth between 1999 and 2000 was considerable. Part of the electricity trade takes place at the APX. In March 2001 the trading volume was equal to 7% of the volume that was distributed via the electricity grid that month (see also *Energy prices*).

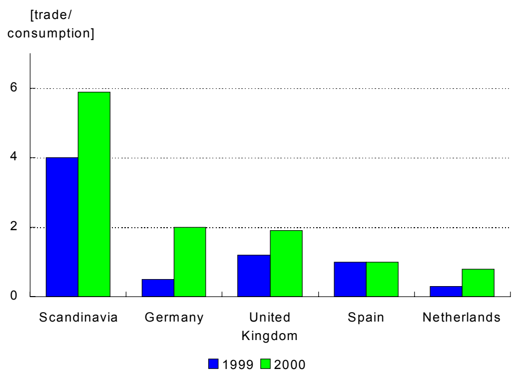


Figure 2.5 Total volume of electricity trade in relation to physical consumption

Electricity consumption

Since 1998 a group of about 650 large consumers has the possibility to choose their electricity supplier. As of 2002 a second group of about 59,000 customers will have the same freedom of choice (see also *Overview: Energy policy and market regulation*). Figure 2.6 shows the development of electricity demand distributed among four customer groups. The customer group that will be free as of 2002 has a 66% share of Dutch electricity consumption, which nearly corresponds to the categories 'industry' and 'other large-scale consumers' in Figure 2.6. Customers in the categories 'households' and 'other small consumers' become free as of 2004.

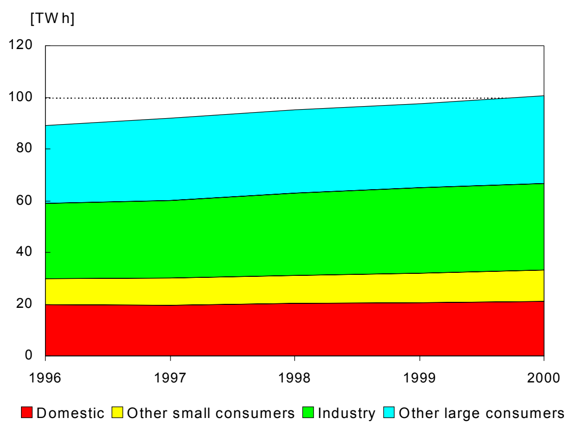


Figure 2.6 Development of electricity consumption distributed over four consumer categories

Gas market

The natural gas traded in the Dutch gas market comes from the Groningen gas field, other smaller gas fields (on land and in the North Sea) and from gas fields abroad. Figure 2.7 shows that the total volume in the Dutch gas market for the last three years has remained nearly unchanged, although the origin has changed. Domestic gas production in 2000 was 7.5 billion m^3 less than in 1998. Production from the Groningen field has declined somewhat faster relative to production from the smaller gas fields. The import of natural gas, conversely, has practically doubled in the last three years to 13.4 billion m^3 in 2000.

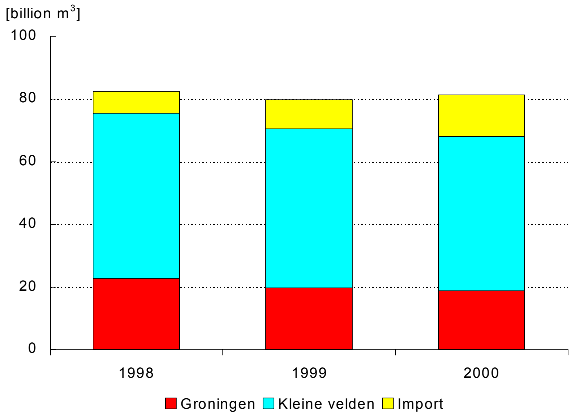


Figure 2.7 Source of gas in the Dutch gas market

Figure 2.8 shows that a large portion of natural gas produced in the Netherlands is exported abroad (Germany, Belgium, France, Italy and Switzerland). Export volume has virtually remained the same in the last three years. The same is true for domestic gas sales. Gas sales to electric power plants, however, have decreased to 26% of domestic gas sales (in 1998 it was 30%). This can be attributed to the sharp increase in the price of gas and competition in the electricity market. Gas sales to large customers (industry, horticulturists and others) have fallen slightly, while gas consumption in the 'small consumer' category was 3.6% higher in 2000 than it was in 1998. The volume supplied to free customers (electric power plants and large industrial consumers) in 2000 amounted to approximately 23 billion m^3. As of 2002 there will be approximately 1500 additional large customers, so the supply to free customers will then be around 25 billion m^3.

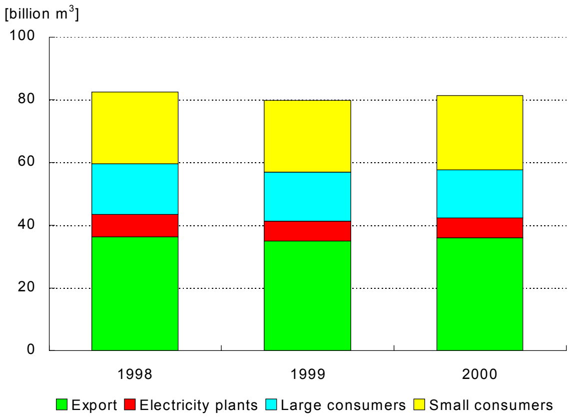


Figure 2.8 Allocation of gas in the Dutch gas market

Gasunie still holds an important position in the Dutch gas market (see also *Insight: Energy policy and market regulation*). Figure 2.9 shows that Gasunie's share of domestic gas sales is decreasing. This includes Gasunie's supply to electric power plants, industry and regional energy suppliers (62% for industry and electric power plants in 2000). Although gas imports are sharply increasing – to Gasunie too – Gasunie's share of total gas import is decreasing. The annual import of

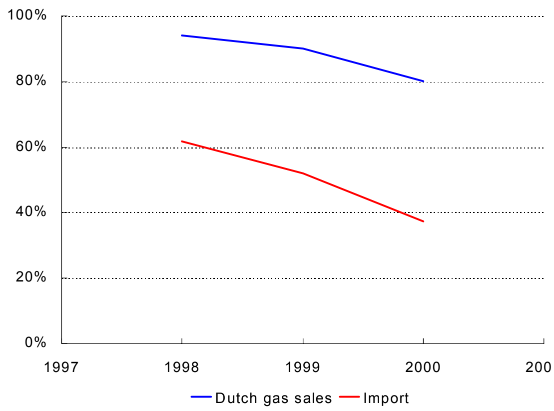


Figure 2.9 Share of Gasunie in Dutch gas sales and import of gas

4 billion m^3 of Russian gas as of October 2001 will cause this situation to change.

Energy suppliers

The number of free customers in the energy market is still relatively small (about 650 for electricity and 150 for gas). The majority of customers in 2001 are still 'captive', meaning that they obtain electricity from a licensed supplier. The energy supplier of captive customers is part of the same group as the grid manager. Therefore, the market shares of energy suppliers nearly correspond with the number of connections. Figures 2.10 and 2.11 show the market shares of the energy suppliers in the electricity and gas markets based on the number of connections. Although some energy companies still operate independently, the mergers and acquisitions are fully incorporated in these figures. Remu and Nutsbedrijven Regio Eindhoven (or NRE) have been acquired by Endesa (Spain), and Nutsbedrijven Haarlemmermeer and Intergas by RWE (Germany).

Figure 2.10 shows that, based on number of customers, the three largest energy suppliers Nuon, Essent and Eneco in the electricity market have a combined market share of 87%. By having acquired Remu and NRE, Endesa is the fourth player in the Dutch electricity market. The 'others' category includes Cogas, Rendo, ONS Energie and Westland Energie, each having a market share of 0.4% to 0.6%.

As gas supplier to end users, Gasunie is still the biggest player in the gas market. In 2000 Gasunie supplied 13.8 billion m^3 to industry and electric power plants. In the same year regional energy suppliers provided approximately 23 billion m^3 to captive customers. Figure 2.11 shows market distribution of energy suppliers based on number of connections. The three biggest players, Nuon, Essent and Eneco, supply over three-fourths of all gas customers. The two foreign players, Endesa and RWE, together serve 14% of the gas customers. The group 'others' includes Cogas, Rendo,

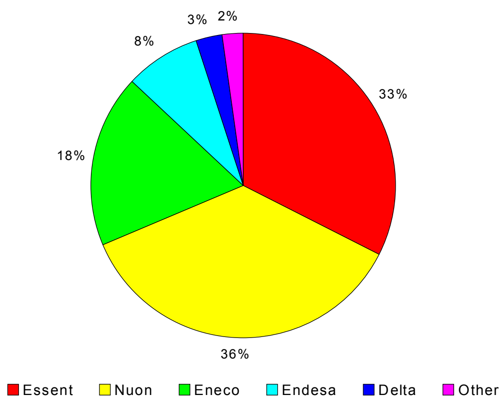


Figure 2.10 Distribution of market share of energy suppliers in the electricity market based on the number of consumers

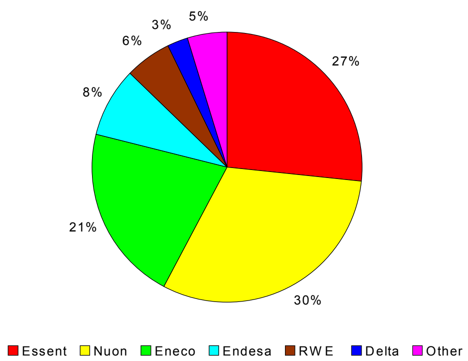


Figure 2.11 Distribution of market share of energy suppliers in the gas market based on the number of consumers

ONS Energie and Westland Energie, with market shares from 0.5% to 2%. Because Westland Energie provides gas to a large number of horticulturists, its market share based on volume compared to its number of connections is considerably larger (about 3.3% of domestic gas sales).

Green electricity market

Because of an increase in the Regulatory Energy Tax (REB) and an exemption for renewable electricity, the price of green electricity has become almost the same as conventional electricity. With the prospect of a free green electricity market, many energy suppliers in the first half of 2001 were able to increase the number of green electricity customers. Figure 2.12 shows the growth in the number of green electricity customers. Since July 1st the market for green electricity has been free, so customers can also obtain green electricity from other suppliers. Moreover, new suppliers have entered the green electricity market. Figure 2.13 shows an estimated distribution of the green electricity market among its most important players. The market distribution is similar to the one for conventional electricity (see Figure 2.10). New players such as Echte Energie and Energie Concurrent still have a modest market share. This is because the growth in the number of green electricity clients in the first half of 2001 represents those clients who were already using the same energy suppliers.

Energy suppliers attempt to differentiate themselves from one another in the green electricity market by offering variations in quality and price. Table 2.1 gives an overview of green electricity offered by the most important players in this market. The quality of the product is determined by the renewable energy sources used and where the green electricity is generated. Green electricity is provided at a higher, a lower and the same price as conventional electricity. In addition, until 1 January 2002, there are price differences between the different regions (see also *Insight: Energy prices*).

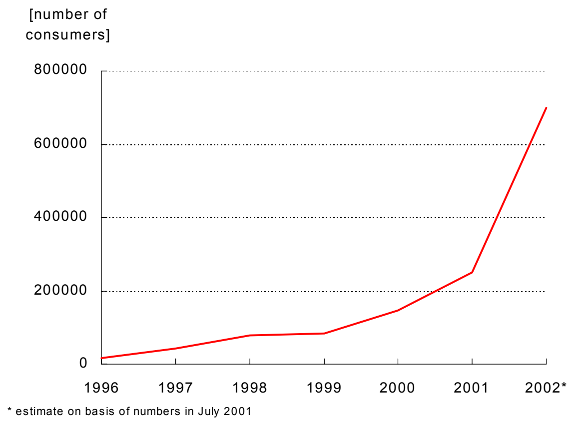


Figure 2.12 Growth of number of consumers of green electricity

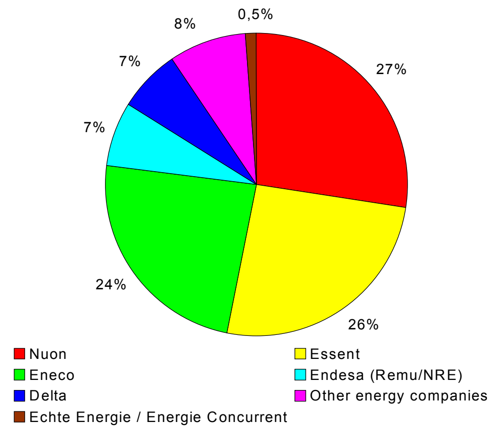


Figure 2.13 Distribution of market share of energy suppliers in the green electricity market based on the number of customers (July 2001)

Table 2.1 Supply of main green electricity suppliers

Supplier	Product name	Price	Renewable energy sources	Origin
Nuon	Natural electricity	supplemental price	solar, wind and water	Netherlands and abroad
Essent	Green electricity	no price difference	solar, wind, water and biomass	Netherlands only
Eneco	Eco electricity	supplemental price	solar, wind, water and biomass	Netherlands and abroad
Delta	Zeeuws green	no price difference	wind and biomass	Netherlands for the time being
Remu	Eco electricity	supplementary price	solar, wind, water and biomass	Netherlands for the time being
Echte Energie	Clean electricity	supplementary price	solar, wind and water	Netherlands for the time being
Energie Concurrent	Green electricity	lower price	wind	Netherlands only

Competition in the retail market begins with green electricity

As of July 2001 the green electricity market is the first segment of the retail market to be opened to competition in the Netherlands. This forms a critical test case for incumbents and new entrants in the energy market, both from the point of view of marketing green energy products, and of an efficient switch for customers to another energy supplier. Energy suppliers import green electricity from abroad in order to satisfy the sharp increase in demand. There is, however, still no agreement between the different European countries on regulations to promote renewable energy and green certificates, which verify the source of the green electricity. Because European regulatory procedures are still expected, there remain uncertainties about the international market for green energy.

Supply and demand

The production of renewable electricity in the Netherlands is sufficient to supply approximately 500,000 to 600,000 households. As of 1 July 2001, when the green electricity market was opened, there were already more than a half million green electricity customers. Because end-user prices for green electricity are comparable with those for conventional electricity, demand is expected to rapidly grow beyond current supply. With the competition ready to pounce, customer waiting lists are not an attractive option for energy suppliers. Therefore, most energy suppliers are looking abroad for a solution and have secured extra green electricity by signing import contracts. Nuon is even actively developing its own renewable production capacity. It has developed wind parks in Germany, China and India, and owns shares of different international projects. However, in the expanding internationalisation of the green electricity market, there are companies such as Essent doing the exact opposite by, for example, introducing a “Made in Holland” green electricity label to the market. While traditional suppliers are quickly developing their own green strategies, the green electricity market has already seen some new entrants – mostly Internet companies with a somewhat more sharply focused offer than the traditional suppliers. Examples of these include Energieconcurrent.nl and Echte-energie.nl. It awaits to be seen whether the Internet provides a valuable means of attracting green electricity customers, because it is generally assumed that the true supporters of green electricity have already switched to using the green electricity provided by their existing supplier, irrespective of price. The challenge now is to exploit the large remaining market potential.

Raising customer awareness

Although study after study indicates broad support for renewable energy in the Netherlands – particularly if the price is the same as ‘normal’ electricity – these studies also indicate that there is still a widespread unfamiliarity with this product. A survey by the *Centrum voor Marketing Analyses* of 400 Dutch households shows that 13% were unaware that they could switch to a green supplier as of 1 July 2001. Furthermore, many question the environmental integrity of green offerings. A few people think green electricity could damage their household devices. Most of the people surveyed still have the impression that green electricity is more expensive than conventionally generated electricity, and – a very encouraging - 40% indicate they are considering making a switch to green electricity. Although current ‘switching’ rates lag far behind this number, it nevertheless shows that a considerable potential for green electricity is waiting to be developed. It is up to the energy suppliers to develop effective strategies to transform this potential demand into concrete green electricity contracts. Doing this raises an important dilemma. On the one hand, energy suppliers want to distinguish their products from all the others and attract customers to their own specific (green) products. On the other hand, product differentiation may confuse the public. Why should one mix of renewables be better than the other? Given the current unfamiliarity with green electricity, customers cannot be expected to have an informed opinion about this. The marketing message of all green electricity suppliers should therefore be simple and, at least to some extent, consistent and coherent. As the market for green electricity matures and customers become more familiar with this product, there will be more scope for product differentiation. In fact, differentiation will then be necessary for electricity suppliers to avoid price competition that would destroy their profit margins. This can be seen in other countries where the retail market for electricity has already been opened to competition. In Germany, for example, E.ON offers retail customers their own mix of green energy sources via the Internet. The Netherlands is not yet at this stage.

Educating customers about green electricity is in the public interest and should therefore be the government's responsibility. The Ministry of Economic Affairs, prior to the opening of the green electricity market, organised a publicity campaign in all the major newspapers. This informed customers about the possibility to choose a green electricity supplier as of July 1st. In addition, the 'ins' and 'outs' of green electricity supply are explained on different government-funded websites. The government, however, is not the only one providing information about green electricity. Socially-minded organisations and industry also do their part. An important example is the recent co-operation between the Body Shop and Greenpeace. Each Body Shop in the Netherlands cleared some store space to inform its customers about green electricity and entice them to switch to a green supplier. Greenpeace is collecting the information where customers indicated their interest in switching, and is sharing the list of these potential customers with Echte Energie and Energieconcurrent.

The role of labelling: green is green

In order to distinguish green electricity from ordinary electricity, a green certificate system was created. The government determines which type of power is eligible for a green certificate (see box: *The invisible green hand: trading certificates*). Furthermore, there are quality labels, which are used by some energy companies to indicate special characteristics of green energy products. These quality labels are developed and issued by independent certifying organisations, who establish standards for renewable energy sources and technologies in the green electricity mix. Green electricity suppliers can become eligible for a quality label once a specific product meets these standards. In the Netherlands, the quality label for sustainably generated electricity is issued by the World Wildlife Fund (WWF). As the public generally trusts the WWF, the WWF label is an influential means to communicate the environmental quality of the green product and the credibility of the provider. Up to now all green electricity products in the Netherlands have been given a WWF label.

Green fiscal policy stimulates supply and demand

The regulatory energy tax (REB) on electricity used by retail consumers amounts to 5.83 €ct/kWh. The REB is collected by the electricity supplier and then transferred to the tax authorities. To stimulate the demand for green electricity, there is no REB imposed on the consumption of such (renewably-generated) electricity. This means that the extra costs for end users of green electricity are greatly reduced, and suppliers are thereby able to offer green electricity for the same or even lower price than regular ('grey' or fossil-based) electricity. When the end-user price of 'green' and 'grey' power are the same, the costs to generate renewable electricity can be 5.83 €ct/kWh higher than regular electricity. Alternatively, one could say that if there is sufficient demand for green electricity then the price of green certificates would be at least 5.83 €ct/kWh.

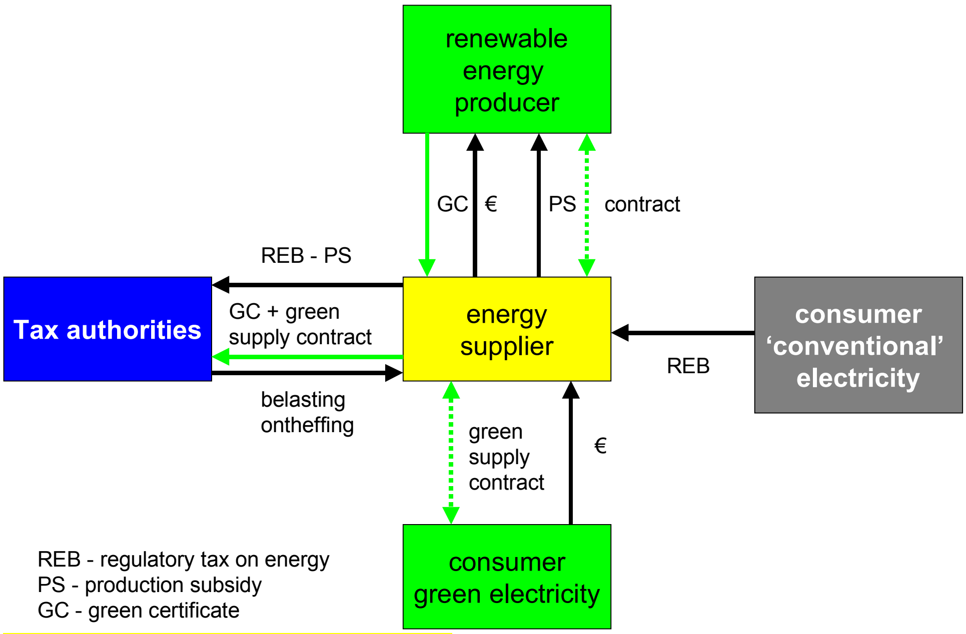
The invisible green hand: trading certificates

Green certificates embody the 'greenness' of renewable electricity and are the unique proof that a certain amount of electricity has been sustainably generated. Green certificates can be traded separately from physical electricity. A producer of renewable electricity sells the electricity in the power market and the green certificates in the green certificate market. To supply green electricity to an end user, a supplier has to purchase a number of green certificates equivalent to the amount of electricity supplied to the end user.

Green certificates are issued for electricity produced from small-scale hydroelectric installations (less than 15 MW), wind and solar energy, and biomass. Waste is not considered a renewable resource. In the Netherlands, a green certificate system is managed by TenneT, the operator of the national grid. Green certificates only exist in electronic form. Producers, traders and suppliers of renewable electricity have an account with TenneT where the certificates are registered. When a supplier purchases a green certificate from a producer two things happen. First, there is a financial transaction between the two parties. Then the producer asks TenneT to transfer the contracted number of green certificates from his account to the supplier's account. Once the consumer has purchased the green electricity, the corresponding green certificates are transferred from the supplier's account to the tax authorities.

In order to stimulate the supply of renewable electricity, Dutch environmental tax legislation also allows the electricity suppliers to grant a production subsidy of 1.94 €ct/kWh to renewable electricity producers. This subsidy is paid out of the REBs (eco-taxes) collected by the suppliers from their non-green customers. The combination of these two tax measures is meant to stimulate demand and at the same time ensure an adequate supply.

Figure 2.14 shows the system of green certificates and regulatory energy tax in greater detail. It is assumed in this figure that the green and regular electricity customers pay the same for electricity (the commodity) and for network tariffs. The only differences between green and regular (fossil-based) electricity are the obligatory energy tax (REB) and the green certificates (GC). Renewable electricity producers have a contract for the supply of GCs to an electricity supplier. This contract includes the price of the green certificates and the production subsidy (PS) received. The electricity supplier receives REB from regular electricity customers. The collected REB minus the disbursed production subsidies (PS) is transferred to the tax authorities. The electricity supplier uses the green certificates to satisfy the demand of green electricity customers with whom it has a green electricity contract. In order to qualify for the green electricity tax exemption, the supplier needs to show its green electricity contract and transfer a commensurate amount of green certificates to the green certificate account of the tax authorities. The green electricity customer thus pays a price (€) for the green certificate instead of paying the REB. For the end user, the combined price for physical electricity plus green certificates is comparable to the price of fossil-based electricity including REB.



[Zijn Eurotekens goed weergegeven?]

Figure 2.14 Schematic view of the system of green certificates and Regulatory Energy Tax

Green electricity market as test case

With the liberalisation of the retail market for green electricity, since 1 July 2001 energy suppliers may solicit green electricity customers in each other's supply area. This not only provides a strong incentive for the development of the green electricity market, but also forms a test case for full competition in the retail market in 2004. In the current green electricity market, mechanisms and qualities that enable retail competition, such as switching, can be tested and expanded. It is therefore interesting to examine in more detail how the retail market for green electricity is organised.

The supply of electricity to households is regulated until 2004. Only licensed suppliers are allowed to supply electricity in an exclusive supply area, for a prescribed price. If a retail customer switches to green electricity from a supplier who is not licensed for the customer's area, the licensed supplier continues to supply the physical electricity. However, the financial relationship now lies between the consumer and the new green supplier. The consumer pays the price of physical electricity and green certificates to their new green supplier instead of the licensed supplier. The green supplier in turn purchases sufficient green certificates to match the demand of the green consumer and compensate the licensed supplier for the physical supply of electricity to the consumer by paying the regulated supply tariff. Under the market rules for 2001, price setting and differentiation can only take place with regard to the green certificate part.

As of January 2002 green electricity suppliers will also be responsible for the physical delivery of electricity to their customers. This means that green electricity suppliers will no longer compensate the licensed supplier for delivering electricity to their customers, but that they themselves will have to purchase electricity in the electricity market that they consequently sell to their customers. Officially, new electricity suppliers who only offer green electricity in the market would need a supply license, just like the currently licensed suppliers. The Minister is thinking about introducing a 'light' licensing system for these new green suppliers in order not to increase the administrative burden to unreasonable levels. This lighter licensing system would mean that price regulations, which currently apply to traditional licensed suppliers, do not apply to these new green suppliers.

Until 2004 the supply tariff for every licensed supplier is set by DTe, the regulator in the energy market. The amount of this tariff is based on the principle of 'yardstick competition'. Fifty per cent of the purchase price for electricity is based on the average wholesale purchasing cost to the supplier. The other fifty per cent is based on the average purchasing cost for all license holders together. This provides a strong incentive for suppliers to reduce their purchasing costs. As retail prices are set every three months and this regulation is repeatedly applied, supply tariffs converge between the different energy suppliers. The only remaining distinguishing factor for end-user prices in different areas is the cost of transmission and distribution, which remains regulated.

After 2004, when the retail market will be open to competition, prices can be expected to fluctuate as different suppliers segment their customer groups and differentiate their products. However, this will already be possible in the green electricity market as of 2002. Competition will then be possible in terms of the price of both electricity and green certificates, which will give green electricity (supply) an advantage over fossil-based electricity. Licensed suppliers who provide green electricity will thus be able to freely compete in the green electricity market. For these suppliers, all electricity purchased, including the portion supplied to green electricity customers will be used to establish their yardstick for supplying captive customers. This prevents licensed suppliers from subsidising the electricity price for green customers with the one for non-green customers.

Price strategies

If we compare the pricing strategies used by green electricity suppliers in the Netherlands prior to 2001, we see the following patterns (see also *Insight: Energy prices*). Echte Energie and Essent supply green electricity at the same price as the regulated tariff plus REB. Green electricity prices thus vary per area. A similar price strategy is used by Energieconcurrent, which always sets its price at 1 ƒct/kWh below the supply tariff plus REB. As many people are not aware of the amount of their electricity bill, this is an easy way to communicate a cheaper offer. Nuon also varies its price per area, and charges 1.15 ƒct/kWh extra for green electricity, but only because of the larger proportion of solar energy in its green electricity mix.

Eneco, which charges an additional 0.5 ƒct/kWh in its own supply area, charges the same price for green electricity in all other areas. This price is nearly always slightly higher than the supply tariff in the area concerned. Remu also charges a uniform price for green electricity, which is sometimes higher or lower than the supply tariff in a certain area. Thus, there are two main ways of price setting; the same price throughout the Netherlands or the same price difference relative to the price of normal electricity per area. Both have their advantages in providing transparency of supply. As of 2002 there will be competition regarding the price of electricity and of green certificates. It will be interesting to see how different electricity suppliers will respond to this and possibly adjust their pricing strategies.

The renewable European electricity market

A proposal for a Directive to promote electricity from renewable energy sources in the internal European market will be ready for final approval by the European Parliament in September 2001. The Directive aims to increase the entire EU's share of renewable electricity to 22.1% in 2010 and sets indicative objectives for the share of renewable electricity for each member state. Member states are left free to adopt policies they feel are appropriate to reach their target. Possible options include a fixed fee feed-in tariff system (Germany and Spain) or a green certificate system with a consumption or production obligation (Denmark and UK). Four years after implementation of the Directive, the Commission will launch a study of the co-existence and possible conflicts between the different support schemes in the member states. Based on the findings of this investigation the Commission will make proposals to develop the harmonisation of these EU support schemes. The member states will consequently have seven years to adapt their support schemes to the harmonisation standard in order to reassure investors of the certainty of the new standard. The total time needed to reach a harmonised European market for renewable electricity is therefore at least 11 years. Nevertheless, international trade in renewable electricity is already taking place and is likely to increase. The electricity industry in the EU has recognised the benefits of international trade in green certificates, and has established the Renewable Energy Certification System (RECS) to accelerate the introduction of a green certificate system in the EU. Moreover, in 2001 the EU began a test phase for trade between participating countries. This initiative could be a forerunner for a harmonised EU green certificate system.

Problems with international trade in renewable electricity

The REB exemption for renewable electricity and the production subsidy from REB funds determine the minimum market value for green certificates in the Netherlands. In other countries the market value is determined by similar tax measures or, for example, by an obligation to produce or consume a certain amount of renewable electricity, with an associated penalty for not fulfilling the obligation. Because the REB plus production subsidy in the Netherlands is higher than the market value of renewable electricity in other countries, this makes it attractive to export renewable electricity to the Netherlands. The relatively low costs of cross-border transmission form no impediment to this export. Moreover, in the medium term these costs are expected to be reduced even further as European transmission operators and regulators work together towards a harmonised system for setting international tariffs for the whole EU.

In order to avert the consequences of the rapidly approaching limit of the domestic supply, most green electricity suppliers have secured large volumes of import contracts. The production subsidy paid from the REB revenues also applies to imported green electricity. The increasing import of renewable electricity leads to an increasing amount of tax revenues being invested in foreign projects. This does not, however, necessarily lead to an increased supply of green electricity in other European countries. Existing production facilities abroad may choose to supply the Dutch market rather than make use of the support mechanisms in their own countries. They could decide to incur a penalty by not meeting their domestic supply obligations in order to supply green electricity to the Dutch market and still realise a higher profit. The REB therefore makes additionality of the renewable energy supply questionable. The Dutch government has acknowledged this problem and by submitting the guidelines, aside from those for the green certificate system, has refrained from issuing green certificates for foreign import of renewable electricity during the first phase of the green electricity market opening. Nevertheless, import based on the agreed-upon import contracts qualifies for the production subsidy and the REB exemption. Dutch environmental tax legislation after all determines that both production subsidies and the REB exemption based on contracts have to be granted. The Ministry is now studying the possibility of, on the one hand, meeting Dutch renewable energy policy objectives and, on the other hand, preventing the outflow of tax revenues. At the same time EU regulations that forbid discrimination towards foreign sources of renewable electricity should be taken into account, and a longer-term connection should be found for the increasing harmonisation of green electricity markets in the EU as a consequence of the EU Directive for renewable energy being implemented.

Price developments of renewable energy in the Netherlands

Based on the above text it can be concluded that the price development of green electricity is subjected to a number of uncertainties emanating from the policy and regulatory context in which green electricity markets are to develop. In the short term, price regulation of captive customers and the phased opening of the retail market will lead to price differences for green electricity. In the mid to long term the major uncertainties are caused by the development of EU-wide renewable energy support schemes and the way in which the green electricity market will be harmonised in the EU. Once a harmonised green electricity market comes into being around 2010, based on a green certificate system without trade distorting subsidies or support schemes, a uniform price for green certificates can be realised for the whole European Union. Assuming the currently known potential for renewable energy and the costs of renewable energy technology, the market price for green certificates can be calculated to be approximately 6 €ct/kWh. This estimate gives a reasonable reference value for investors and green electricity suppliers to calibrate their strategies. In the short term, suppliers face the formidable challenge of quickly developing a profitable green electricity market while maintaining customer confidence under highly dynamic circumstances.

The new face of existing energy companies

Competition between energy suppliers in the retail market will differ greatly with competition in the commercial market. Existing energy companies will need to build a new relationship with the consumer, based on other arguments than those used by traditional energy companies. Furthermore, supplying energy will no longer be the exclusive right of the existing energy companies. In order to withstand competition, energy companies can choose among different and potentially useful strategies such as differentiation, own identity and new sales channels. Since the green electricity market has been opened in 2001, the existing large Dutch energy suppliers are already beginning to show a piece of what might become their new face.

The consequences of liberalisation

Up to now the effects of liberalisation have been limited to the energy sector itself or the large commercial market. However, the dynamics in the transition phase are considerable and the interest is immense, especially compared to the attention energy companies experienced prior to talk of liberalisation. For the ordinary consumer, however, it remains a distant concern. As of 1 January 2004 this situation will change as small consumers gain the freedom to choose their energy supplier. The green electricity market has already been free for all consumers since 1 July 2001. As a result, energy companies can already gain experience with the required skills for a free consumer market. They have started publicity campaigns to support their future ambitions in the consumer market such as: a handy windmill operator presenting Nuon as a knowledge leader in the area of renewable energy, a group of witty Essent children expressing the 'everything for and around the house' concept, and an attractive woman in a beautiful desert scene proclaiming 'Times are changing' for Eneco. These are just some examples of what awaits the consumer.

Continuous segmentation

Currently the customer base of the Dutch energy companies is divided by region. After the market is opened there will be a shift to a division based on benefits (common physical needs) or target segments (common psychological needs). This shift will entail a partial loss of the existing customer base. These customers, however, do not all represent the same values. Some, for example, are more inclined to pay a price increase, more difficult to win back or more open to additional products and services. To maintain a healthy market, it is important that energy companies not attempt to maximise their customer base at any price. Such a defensive strategy would strongly decrease the attractiveness of the market. By not making clear choices, energy companies would become vulnerable to new entrants who do. Traditional energy companies will have to take a proactive role in the free market to ensure retaining a customer base of loyal, satisfied and definitely not indifferent customers. This is a way to optimise value by means of differentiation of products and services, and not aiming for the lowest price but the most relevant one.

Ability to differentiate

A disadvantage of products such as gas and electricity is that they have a uniform qualitative characteristic: they are commodities. The sale of energy alone will quickly lead to a price war, which will necessitate an increasingly defensive strategy. In such a scenario the profit margins would decrease, and process innovation would compel energy companies to seek economies of scale at an accelerated pace. In theory there can only be one 'cost leader', and if several suppliers seek this position there's a risk the industry will become unattractive. The energy companies agree that it is not worthwhile to sell energy alone. And bargain shoppers, the dynamic segment of the small consumers, are not loyal. There are two main ways to break through the commodity image of energy. The first is an intrinsic differentiation and has to do with the way in which energy is produced. In the future there can, for example, be a labelling system that indicates the source of the electricity. This will increase the possibilities to differentiate the product. There are already several years of experience in separately selling renewable electricity and, since the full opening of the green electricity market, electricity companies have been attempting to differentiate themselves by emphasizing the differences in the source(s) of their green electricity. Recent figures on the different green products indicate that green electricity is extra appreciated by customers. A second way to differentiate the product is bundling. An energy company can offer energy in combination with other products and services (increased turnover through product expansion). Therefore, some energy companies pursue a multi-utility strategy.

Essent

Essent, the biggest Dutch energy supplier, is pursuing a broad multi-utility strategy. In addition to electricity, heating and gas, this company also includes waste treatment and information services in its products and services package. The core of Essent's newly formed retail company is comprised of Essent's supply companies together with 'Inhome', the service organisation. The energy company offers a range of products and services linked together with the theme of 'unburdening' in and around the home or office'. Essent has acquired installation companies to intensify contact with its clients and relinquish its anonymity. Essent is thus attempting to generate more customer loyalty in the retail market; a strategy that can also be applied to the (small) commercial market. Essent has acquired energy companies in Germany with a similar (broad multi-utility) strategy. This fits in with Essent's 'focus and grow' strategy, which means the company is seeking to grow horizontally (increasing scale).

It seems likely that the role of the existing energy companies with a retail strategy in a free market will strongly depend on the extent to which they succeed in differentiating the product energy. If new entrants also compete in the retail market based on price, then the market structure will change to the disadvantage of the traditional energy companies precisely because their strength lies in supplying energy services and offering multi-utility concepts. The existing energy suppliers think differently about how best to shape the relationship with retail customers in the free market, and which accompanying retail strategy would be the most appropriate. The boxes (above and below) provide an overview of the strategies of the three largest energy suppliers: Essent, Nuon and Eneco. Up till now they are the only ones to support their retail strategy with a national campaign.

Role of marketing in the retail market

Retail customers are less rational in their purchasing decisions, which means an important role remains in the retail market for marketing. Creating a strong brand image is an important weapon in competing against retailers from outside the energy sector. A surplus value can be added to the product by linking it to other companies' products or services. Perceptions compete not products. A strong degree of segmentation will take place in the retail sector. The different positioning options of the energy companies are plotted in the Brand Strategy Research grid (BSR grid) in Figure 2.15. The values on the X axis are 'me-orientated' (energy is a functional resource) and 'social' (energy is a means to relaxation, a cosy atmosphere). The Y axis begins with the value ‘extravert’ (energy is a basis for living, enjoyment and pleasure) and ends at the bottom with ‘introvert’ (energy is the basis for survival, necessity).

Nuon appears to position itself as a ‘premium brand’, wanting to be the ‘Mercedes’ of energy suppliers. With product and knowledge leadership in the area of renewable energy, Nuon is attempting to break through the commodity image. The dynamic aspect of green energy is better suited to a positioning such as ‘innovator’. Essent wants to build a relationship based on trust with its customers, with the aim of building a ‘partnership’. As the partner of its customers, Essent portrays itself as an extension of the household to unburden the customer (of their troubles) and offer solutions. Essent’s products and services are meant to bring warmth and cosiness into family life.

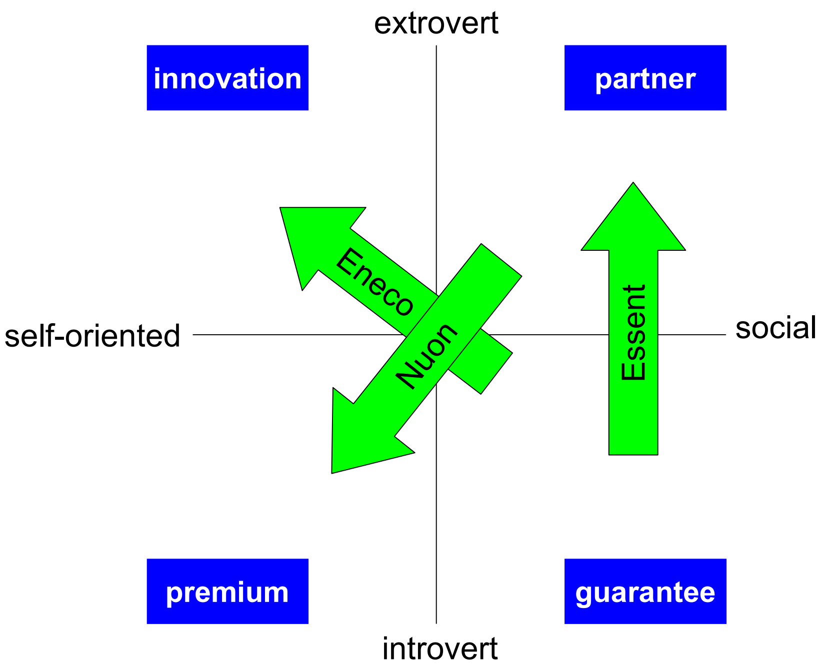


Figure 2.15 Positioning of the three largest Dutch energy suppliers in the Brand Strategy Research grid (BSR-grid)

Nuon

Nuon uses a narrow, multi-utility strategy because it lacks such areas of concern as waste treatment and cable services. Nuon ended its cable services because it required enormous investments, both financially and in 'human capital', in order to come close to succeeding as a 'single player'. Acquisitions of companies outside the energy sector, with other core competencies than those of Nuon, reveals that Nuon is seeking a more in-depth growth strategy. Based on its 'stakeholders philosophy', Nuon wants to find a balance between the interests of four interacting groups: customers, shareholders, employees and society. For society, the environment plays a very important role, which manifests itself in Nuon's ambition to be product and knowledge leader in the area of renewable energy. Along this same line Nuon has also developed 'home care' concepts. In addition, Nuon invests in intensifying its relationship with retail customers by acquiring installation companies that have a service network providing national coverage, and a national service and maintenance chain for houses. Such networks also open a portal to new customers. At the same time, Nuon also wants to distinguish itself as a supplier of integrated water chain solutions to companies and governments.

Eneco believes that an energy company can only excel in a single area and therefore chooses energy as its basic product. For the time being Eneco chooses functionality (energy without 'all the trimmings'), a trait that suits safeguard positioning in the market. Having seen their latest publicity campaign ('Times are changing'), their association with 'Air Miles' and their sponsoring of the Olympic Gamesit is possible that this positioning will tend more towards an innovator\premium positioning in the future.

New products and services

The large energy companies find themselves in a phase in which they are proactively working on a framework to be able to develop new services and products for the future. Nuon and Essent are both pursuing a multi-utility strategy that they see as a way of achieving profitable, continuous growth. In the retail market they translate this strategy into all sorts of products and services with the theme of 'unburdening' and comfort in and around the home. They continue to build on the reliable image they have developed as an energy utility. Maintaining or increasing trust is very important to strengthen their customer relations. In this context, Nuon as well as Essent have made acquisitions or taken an interest in installation companies. This makes it easier to acquire new customers or generate loyalty with existing customers.

Eneco

The third largest Dutch energy company, Eneco, sees no value in a multi-utility strategy. It sold its cable and telecom services, and also sees no synergy in combining energy with water supply. In 2000 Eneco was very focused on national consolidation through mergers and acquisitions. It is the last energy company to launch a publicity campaign that reveals its commitment to the retail market. Energy 'without all the trimmings', at a reasonable price, ties in with the core competence Eneco has built up in the 'business-to-business' segment.

Energy companies are investigating the possibilities of providing services with an added value. These include communication-related services and information management (security services, financing and energy management). The criteria for such services is that the consumer has a consistent experience with the brand. At a later phase, added value can be created by 'cross-selling' products or services (originating from sectors with poorly-known brands). The success of 'cross-selling' also depends on the extent to which energy companies themselves succeed in creating a strong brand name. In practice it is the question whether energy suppliers with a retail strategy can get access to 'brand magic' to the same extent as existing retailers. If that is not the case then they run the risk that retailers from outside the energy sector become more successful. Existing energy companies who want to become retailers thus have to create the market together.

Remu, which was taken over by Endesa (Spain), fears that an energy company in the retail market would quickly be forced to act defensively, resulting in more costs than benefits. Energy is not a product and energy 'alone' creates no value in. Remu therefore sees more potential in co-operating with companies from outside the energy sector for the development of new products. Remu believes that such a co-operation or alliance will create added value. Outside retailers have more experience in dealing with competition in the retail market. The 'back office' part of such a plan is handled by the energy company. By using this concept, with less risk of ending as road kill, the market decides which new products will define future scenarios.

Eneco's focus on energy is vulnerable to price competition, which results in process innovation becoming more important and profit margins being put under pressure. Eneco reports that possible new products lie in supporting outside initiatives via: the Internet, the ANWB, insurance companies and supermarkets. Eneco is currently participating in a shopping-savings campaign ('Air Miles') to gain the loyalty of existing customers or acquire new customers. Eneco also reports that it will launch new consulting and savings services. Although there are often more benefits to be gained with energy services, foreign studies indicate that small users often fix their eyes on price advantages to be gained when purchasing energy. Furthermore, these consumers find it illogical to combine savings services and energy supply in one package.

Pace of liberalisation

The 'prime mover advantages' once anticipated as a result of a faster and earlier liberalised Dutch energy market, relative to its neighbouring countries, have not materialised. Dutch energy companies have not been able to improve their competitive position relative to foreign players. Worse still: the difference with the most important foreign energy companies appears only to have increased. The accelerated liberalisation from the beginning of 2001 to the beginning of 2004 is also initiated due to the understanding that the backlog with foreign countries (especially England, Germany and Scandinavia) could become even more pronounced. It has emerged that the effects of an accelerated liberalisation lead to a proactive position of the existing energy companies and help to rationalize the production process. This is why the new production strategy is being implemented at an accelerated pace. It helps to make Dutch energy companies more competitive compared to foreign energy companies that are already used to competing in a free market. The learning process only takes shape by actually competing in a liberalised market, and at the original pace of liberalisation, preparation for a free market would also have started later. It is possible that the differences between Dutch and foreign energy companies primarily occur in the commercial market. A possible competitive advantage of Dutch energy suppliers is the trust built up over the years between small consumers and their existing supplier. This could benefit the positioning of the incumbents.

New entrants

Large foreign energy suppliers in the retail market have the same shortcomings as their Dutch counterparts. The expectation, therefore, is that some outside (non-energy) organisations would be better equipped to act as retailers in the Dutch retail market than large foreign energy companies. New non-energy entrants, however, can have other motives than profit maximisation, and are therefore better able to compete in terms of price. They possibly view energy as a means to intensify contact with their customers or as a way to acquire new customers.

New sales channels

In setting up new sales channels, the motives of comfort, enjoyment and financial benefit form important criteria. Consumers abroad are also bombarded in all sorts of ways: via supermarkets, mail-order companies, chain stores, fitters, gas stations, door-to-door salespeople, etc. A unique place, however, is devoted to the increasing role of the Internet. Not only are a number of new products introduced (e.g., to facilitate switching one's supplier), but the Internet can also increase market transparency, so competition can be intensified. Purely virtual energy companies, however, are not viewed as a threat by the incumbents because there is too little value in selling only energy. Moreover, the concept is fairly simple to copy if there is no underlying, well thought-out strategy.

Mobility expectations

Based on the mobility ratios from different countries, which are ahead of the Netherlands in terms of liberalisation, it seems that small consumers are not readily inclined to switch supplier. Only in the United Kingdom there is a moderate number of customers who have switched (see Figure 2.16). In other countries, where the retail market is free, the number of 'switchers' is still limited but definitely increasing. The question is whether these data can be applied to the Dutch market because the switching process abroad is, in most cases, not sufficiently elaborated. Consultation within the Platvorm Versnelling Energieliberalisering (PVE) between government, the energy sector and consumer interest groups about having a properly functioning, free energy market may lead to a good set of agreements between the relevant parties. This will enable the small Dutch consumers to switch supplier more easily. Nevertheless, the majority of energy companies expect that the mobility of the Dutch retail market will be small. Experiences abroad also show that considerable investments are necessary to acquire new customers. Small consumers appear more readily inclined to switch supplier if there is a significant price advantage to be gained. This led to defensive trading by the energy companies at the start of the liberalisation in Germany and, consequently, the profit margin of the industry worsened overall.

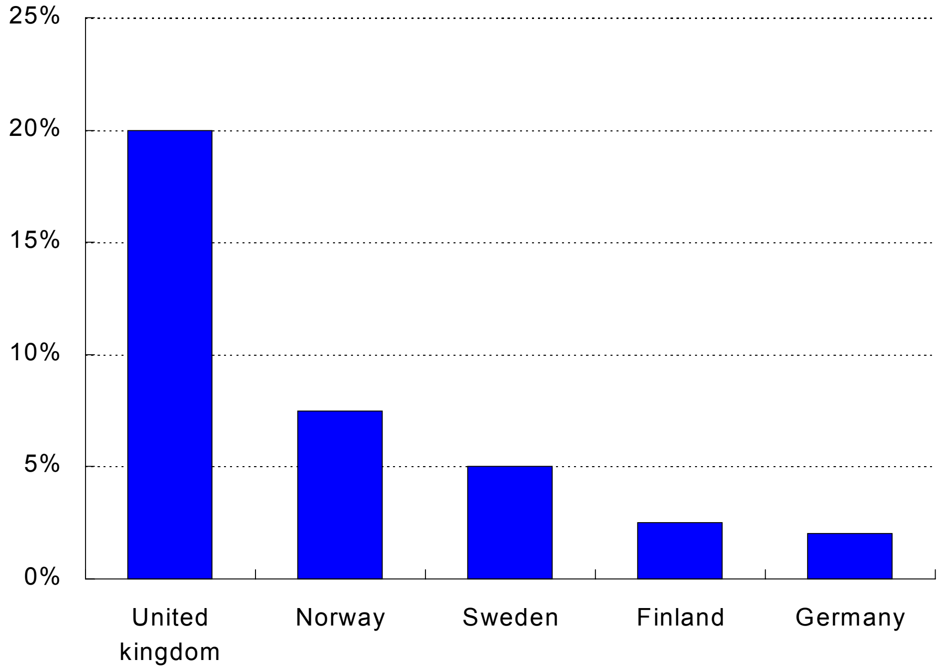


Figure 2.16 Mobility on foreign electricity markets in 1999 as percentage of the total number of consumers

Profit expectations

Dutch energy companies appear hardly or not at all prepared to start price competition in order to maintain market share. The energy companies do expect to make profits in the retail market but the margin will be small. Profit will be gained from the 'bundling' (differentiation). Furthermore, marketing costs are high so profits are also put under pressure. Many of the current energy companies foresee the arrival of new suppliers, including many 'price fighters', who will keep the margins under pressure.

Economies of scale

The large Dutch energy companies consider scaling-up necessary to survive in the European market. The minimum customer base needed for this is estimated to be about seven million (connections). Dutch energy companies believe that there is only room for nine large energy suppliers in all of Europe, and do not have the illusion that there will be a single Dutch party among them. Economies of scale provide a basis for the development and introduction of new products and services. It also makes it easier to develop the necessary core competencies and can help spread costs out among more customers. Dutch energy companies recognize this and will give, according to the amount of importance they attach to having their own identity, an interpretation to the eventually necessary scaling-up.

Own identity

Maintaining their own identity amidst the European market forces is an important ambition for Nuon and Essent. Both would like a larger market share because that would make it easier to hold a strong position in case of an eventual take-over. They would like to continue to exert influence on their future. Nuon is thinking more of a merger with a company that has a similar company philosophy in terms of the issues Nuon finds important. Moreover, it is not necessary for Nuon to have control as long as it is not controlled itself. A merger of two parties where neither has the majority would therefore suit Nuon well. Essent is considering an application for a stock market quotation in order to obtain its desired size, because it does not think it can survive in the long term in its current form and size. Co-operation with other companies is thus absolutely essential. Eneco considers 'own identity' to be less important. Eneco desires to be taken over by a foreign partner that has to meet a number of conditions, an important one being that the operating style of this partner leaves Eneco with a reasonable degree of autonomy. National consolidation will increase Eneco's chances for a relatively independent position.

The next generation of energy companies

What should existing Dutch energy companies do now to be part of the next generation of energy companies? The core competencies they have to develop are linked to the strategic direction they choose. If they choose to proceed as independent retailers, it is expected they will face intensive competition from a multitude of parties popping up from different quarters, and using the uncharted ground between different industries to put new products in the market. Energy companies that want to continue their position as retailer in the retail market will need to ensure that the consumer considers it logical to buy from such a type of company. Consistency can be achieved by elaborating such themes as unburdening, reliability or security in order to create a strong brand. If the energy companies succeed in establishing a strong brand name, e.g. based on a multi-utility concept, then the following step can be the expansion of the products-and-services package with non-energy-related products (cross-selling). In addition, they would have to avoid new products that might undermine their brand or positioning.

As an alternative, energy companies can choose to develop into service organisations, which take care of the payment for and supply of energy in a supportive (back office) role. Excellent new concepts can arise by combining the best of two different industries.

CHOICE OF TECHNOLOGY AND ENVIRONMENTAL CONSEQUENCES

The energy sector is a capital-intensive branch of industry. Liberalisation of the energy market has a great influence on the way in which investment decisions are made. This applies to the replacement and expansion of installations and systems, and even more so for investments in new energy technologies. Technological changes in the energy supply emanate from striving towards lower environmental impacts – especially reductions in greenhouse gas emissions – and the increased use of renewable energy sources.

Measures to limit the environmental effects of energy production have an increasing influence on the price of energy produced. The introduction of trade in emission reductions (NO_x, CO_2) will decrease emission reduction costs and also define the choice of technologies to be used.

The increasing demand for forms of green energy stimulates the development of renewable energy technologies. For the Netherlands, wind and biomass are the most important sources of renewable energy. This third part of *Energy Market Trends in the Netherlands 2001* provides insight into expected developments of two of these renewable energy technologies: offshore wind turbines and use of biomass in coal-fired power plants. These insights are preceded by an overview of technologies used for energy production in the Dutch energy market and in neighbouring countries, as well as an overview of the environmental effects of energy production.

Gas production

The Netherlands, Norway and the United Kingdom are the most important producers of natural gas in Western Europe. Figure 3.1 shows that gas production in Denmark, Germany and France is much lower, and that no gas at all is extracted in Belgium. Gas production in the Netherlands shows a sharp decline. More gas is imported, partly as a consequence of liberalising the energy market, and less gas is used for electricity production because of higher prices. The inset in Figure 3.1 shows that onshore gas production in the Netherlands is decreasing. The gas production of Denmark, Norway and the UK occurs practically all over the North Sea, while the gas production of Germany and France is mostly on land.

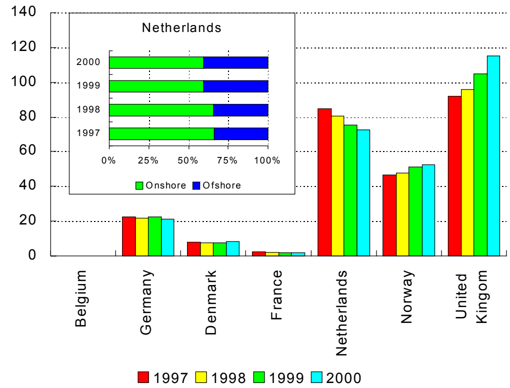


Figure 3.1 Gas production in the Netherlands and neighbouring countries

Gas storage

Countries with a low level of gas production, such as Germany and France, use gas storage to cope with seasonal fluctuations in gas sales. In the Netherlands, gas storage is used to optimise gas production from small gas fields and to supply gas in extremely cold weather. Seasonal demand can in large part be met with gas production from the Groningen gas fields. Most gas storage is underground: in old gas and oil fields or in salt caverns and aquifers that are made suitable for storage. When liquid natural gas (LNG) is stored above ground, there is also the possibility of transporting it by ship. This happens in such countries as Belgium and the UK.

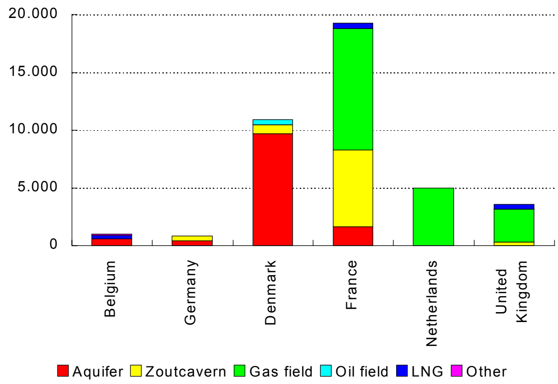


Figure 3.2 Gas storage capacity in the Netherlands and neighbouring countries in 2000, according to type

Figure 3.2 shows storage capacity of different types of gas storage in the Netherlands and its neighbouring countries. Figure 3.3 shows the number of each type of gas storage facility in each country listed. Storage capacity (million m^3) divided by the maximum supply capacity of the gas storage area (million m^3/day) indicates the number of days

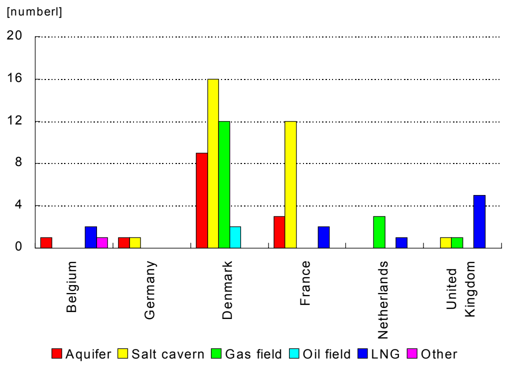


Figure 3.3 Number of gas storage facilities according to type

that the different types of gas storage in the different countries can be used (see Figure 3.4).

In a liberalised gas market, gas storage capacity is available for third parties. Gas storage is an interesting option for gas traders who purchase gas outside the heating season and supply it at times of high demand.

Electricity production

The way in which electricity is generated differs per country. This is mostly linked to the fuels that are available or can be relatively easily brought there. Figure 3.5 shows the fuel mix used to generate electricity in the Netherlands, Germany, Belgium and France in three consecutive years. In France and Belgium, electricity production is dominated by nuclear power plants. Nuclear plants also play an important role in Germany in addition to coal for electricity production. In the Netherlands, gas, besides coal, is the most important fuel used to generate electricity. The shifts in fuel use in successive years are generally small. For a large shift in the fuel mix, new power plants are often necessary, which cannot be achieved from one year to the next. The shifts that can be observed in Figure 3.5, especially for coal and gas, are caused by a combination of fluctuations in fuel prices and market forces in electricity production. The largest relative changes have occurred in the use of renewables for electricity production.

Cogeneration

The beneficial use of waste heat from electricity production is known as cogeneration or combined production of heat and power (CHP). CHP takes place at centralised electricity production, where the heat is distributed to buildings or greenhouses, or by energy customers themselves, mostly in industry and horticulture. Energy customers with a CHP plant can supply part of the electricity they generate to the grid. This is also known as

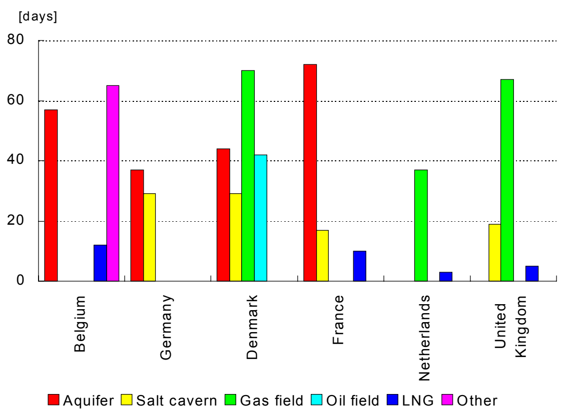


Figure 3.4 Average number of production days for various types of gas storage

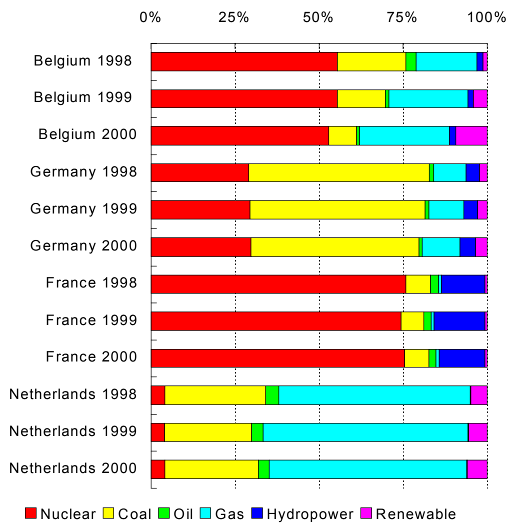


Figure 3.5 Fuel mix in electricity production

local electricity production. From an energy savings perspective, CHP is an attractive form of electricity production. The Dutch energy savings policy in the last few years has helped CHP expand enormously. In 1998 waste heat was used from 56% of the total electricity generated in the Netherlands. This is considerably more than in neighbouring countries (see Figure 3.6). The share of CHP used in electricity production in these countries could be increased in the coming years as a result of CO_2-reduction policies.

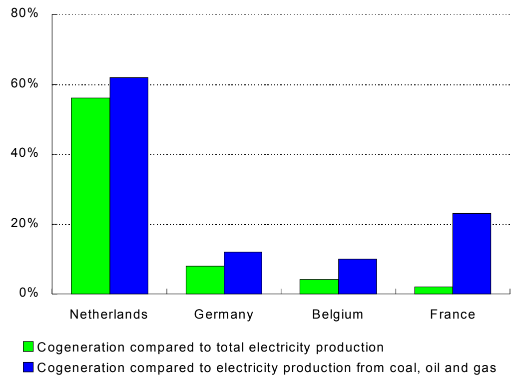


Figure 3.6 Electricity production from cogeneration plants in relation to total electricity production in 1998

Liberalisation of the electricity market obliges CHP to compete with large-scale electric power plants. In 1999 there was a slight increase in the use of CHP for electricity production while in 2000, mainly as a consequence of relatively high gas prices, there was a decrease. In order not to jeopardise energy efficiency policy, the Ministry of Economic Affairs has taken measures to provide extra financial support for the development and construction of CHP plants.

Renewable energy

Electricity production from sustainable and renewable energy sources is increasing as a result of an increased number of facilities. Figures 3.7 and 3.8 show a division into different types of renewable and sustainable energy sources in the Netherlands, Germany, Belgium and France for 1998 and 2000. There is a large distribution in the production output per renewable energy source and per country. Sustainable energy production with a relatively small output is shown separately in Figure 3.8.

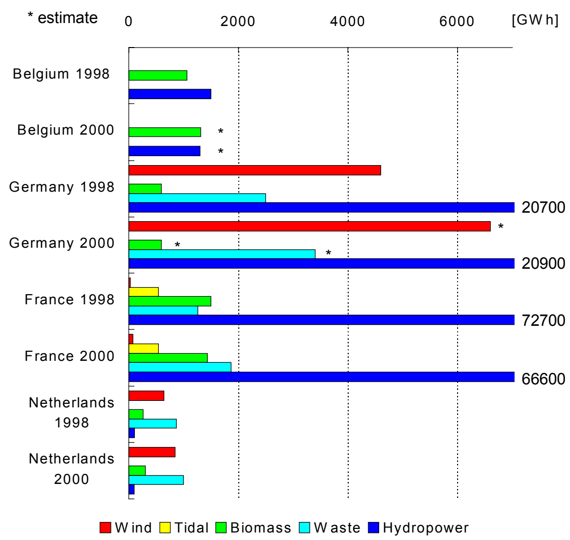


Figure 3.7 Electricity production from sustainable and renewable energy sources with substantial production volume

In terms of output, hydropower is the most important renewable energy source, with a considerable production volume in Germany and France. Hydropower-based electricity production in Belgium and the Netherlands occurs at a much smaller scale. The growth potential of hydropower is limited, meaning this form of renewable energy remain at about the same level. In France, tidal power is also use to generate electricity. However, this form of electricity production is limited to very specific locations.

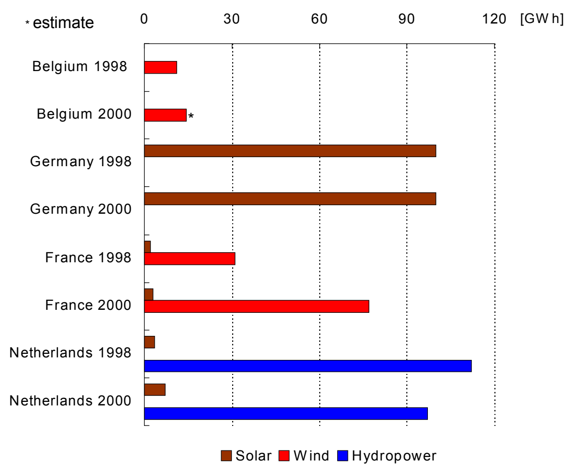


Figure 3.8 Electricity from sustainable and renewable sources with limited production volume

The output of wind energy in Germany is substantial, both in comparison with the three other countries and with other forms of sustainable energy. Wind energy production is limited in the Netherlands, while in France and Belgium it is even more modest. Nevertheless, it can be observed that the production volume of wind energy is increasing in all four countries. This also appears to be true for electricity production from biomass and waste, which after hydropower and wind energy, is the third most important source of sustainable and/or renewable energy.

Compared to other forms of renewable electricity production, solar energy production is modest. This is mostly because of the low production per square metre, which means a large area is necessary to achieve a substantial level of production. In spite of this, solar-based electricity production in Germany has increased considerably.

Emissions

Three types of air pollutant emissions from electricity production are shown in Figure 3.9 for the Netherlands, Germany, Belgium and France for 1998 and 2000. The emission levels depend on the type of fuel mix used (see also Figure 3.5), the efficiency of the power plants and emission-limiting measures. The use of nuclear energy, which does not cause any direct emissions of NO_x, SO_2, or CO_2, explains the relatively low level of emissions in France. In Belgium and Germany the use of nuclear energy also has a considerable effect on the level of emissions. Emissions in Germany are mostly caused by the use of coal. Emissions in the Netherlands and Belgium are caused by a mix of coal and gas. In Belgium the emissions of NO_x and SO_2 fell substantially in 2000 relative to 1998. A fall in emission levels, including CO_2, is also discernable in the other countries. The exception is in Germany where NO_x emissions rose.

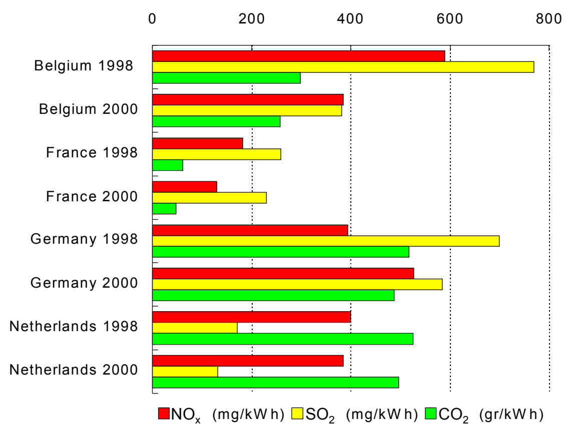
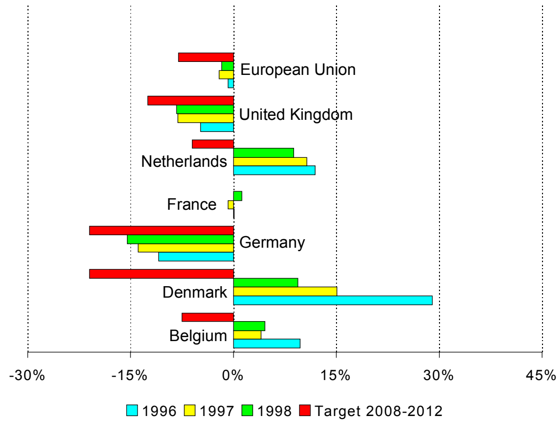


Figure 3.9 Air pollutant emissions from electricity production

Greenhouse gases

In the context of the Kyoto Protocol, the European Union has agreed to reduce greenhouse gas emissions in 2008 to 2012 by 8% relative to 1990 levels. This reduction target is thus divided among member states (see also *Overview: Energy policy and market regulation*). Figure 3.10 shows the reduction target and the changes in GHG emissions. GHG emissions in Germany and the UK from 1996 to 1998 were already lower than in 1990, which was also true for the European Union as a whole. GHG emissions in the Netherlands, Belgium and Denmark initially increased, but since 1996 the trend is decreasing. Eighty per cent of greenhouse gas emissions in the Netherlands are in the form of CO_2 emissions. In 1998 CO_2 emissions were almost 9% higher than in 1990, while in 1999 this dropped to 8% above 1990 levels.



.

Figure 3.10 Increase and decrease of greenhouse gas emissions compared to 1990 and the emission reduction targets for various European countries and the EU as a whole

Growth of renewable energy supply depends on the success of offshore wind energy

Offshore wind energy seems to be an enormous potential source of renewable energy to be tapped. The placement of wind turbines far from the coast should be less objectionable than on land. The supply of renewable energy can increase substantially with the use of offshore wind energy. However, whether the renewable energy target can be met depends greatly on the ability to solve new technological problems and the growth that can be achieved in the wind turbine industry. In addition, clarity is needed in terms of placement policy, licensing procedures and a stable market for green energy.

Why offshore wind energy?

The growth in the number of wind turbines placed in the Netherlands in the last few years has levelled out. One of the reasons for this is the lack of support for wind projects at the local level. This expresses itself in lengthy licensing procedures that often enable people living in the vicinity, or other parties concerned, to succeed in impeding the construction of wind farms. Arguments against wind turbines often include noise pollution, visual intrusion or poorly fitting into the landscape. As a result, the target for the year 2000 of 1000 MW was not met, and the wind capacity realised at the end of that year amounted to only 450 MW.

Placing wind turbines offshore has a number of advantages compared to onshore locations. At a sufficient distance from the coast, visual and noise pollution aspects are no longer issues. These advantages make it possible for offshore wind turbines to be larger (and thus have more capacity) and less attention needs to be devoted to reduce noise emissions, which entails additional costs for onshore wind turbines. Another advantage is the wind pattern, which is more uniform at sea than on land. A less highly fluctuating load means less wear. Offshore wind speed is also much higher than onshore, which means that more electricity can be generated per square metre of swept rotor area. On the other hand, investment costs are higher and accessibility to the turbines is poorer, so maintenance costs are higher.

The amount of space available for offshore wind turbines is many times more than onshore. The potential for wind energy is therefore also considerably greater. Based on the amount of available sea area outside the 12-mile zone (about 22 km) with a water depth of less than 20 metres, there is room for several thousand MW of wind turbines. The Netherlands has the advantage of a relatively shallow sea: nearly the entire Netherlands Exclusive Economic Zone (delimitation of the Netherlands Continental Shelf) is less than 50 metres deep. The Netherlands shares this advantage with countries such as Belgium, Denmark, the UK and Germany. Other European countries with an extensive coastline, such as Ireland and Spain, have a relatively smaller sea area with water depth less than 50 metres. When competition in renewable energy supply begins between the different European countries, the Netherlands will possibly have a comparative advantage because it has such a large sea area at its disposal.

Existing offshore wind farms

In the Netherlands there are currently two wind farms operating with turbines in the water. These wind farms are in the IJsselmeer at Medemblik and at Dronten, which are inland waterways. Although the same techniques are used for the foundations of these turbines as for shallow offshore and near-shore locations, the conditions for the turbines to operate are milder than in the North Sea. In this lake there are no effects from salt water, and both wave and wind loading are much lower.

In Denmark, Sweden and the UK also have operational offshore wind farms. In general these farms are built in shallow water (less than 10 metres) and relatively close to the coast. The UK is the first to have placed wind turbines in the North Sea. The harbour of Blyth brought two turbines of 2 MW each into use at the end of 2000. The conditions are similar to those known as 'near shore' in the Netherlands: a water depth of 8 metres at a distance of 1 km from the coast. Table 3.1 gives an overview of existing offshore wind farms in Europe.

Table 3.1 List of existing offshore wind parks in Europe

In operation since	Country	Location		Description
1991	Denmark	Vindeby	Baltic Sea	11 turbines of 450 kW
1994	Netherlands	Medemblik	IJsselmeer	4 turbines of 500 kW
1995	Denmark	Tunø Kob	Kattegat	10 turbines of 500 kW
1996	Netherlands	Dronten	IJsselmeer	28 turbines of 600 kW
1997	Sweden	Bockstigen	Baltic Sea	5 turbines of 550 kW
2000	United Kingdom	Blyth offshore	North Sea	2 turbines of 2 MW
2001	Sweden	Utgrunden	Baltic Sea	7 turbines of 1.5 MW
2001	Denmark	Middelgrunden	Baltic Sea	20 turbines of 2 MW

Plans for wind farms at sea

Besides the existing offshore wind farms, new plans are quickly being made to build more such wind farms all over Europe (see also Table 3.2). The Danish government already formulated a plan in 1996 to arrive at 4000 MW of offshore wind capacity in 2030. The locations up until 2010 have already been designated. A number of these farms will be constructed in the Danish part of the North Sea. Germany has also already designated locations. One of these lies to the north of Borkum island, close to the Netherlands' North Sea border, and will have a 100 MW capacity. Belgium has planned two farms: one between 6 and 12 km from the coast between Wenduine and Oostende, and the second at 12 km from the coast of Knokke. Furthermore, the British royal family, on the occasion of the Blyth offshore wind farm to be put into use in December 2000, announced that it was making other locations available along the British coast. These locations lie between the 12-mile zone and are the property of the British royal family, and will be leased from the Crown Estate. Insofar as is now known, the British plans consist of constructing approximately 500 wind turbines in farms with at least 20 MW and at most 30 turbines per farm. Sweden has planned four projects of 100 MW each, and Ireland is also planning two large projects in the Irish Sea between Dublin and Arklow.

Table 3.2 Plans for offshore wind parks in Europe until 2005

Country	Sea	Volume of plans in MW
Belgium	North Sea	200
Denmark	Baltic Sea en North Sea	750 (until 2008)
Germany	North Sea	800
Ireland	Irish Sea	740
Netherlands	North Sea /IJsselmeer	640
United Kingdom	Surroundings United Kingdom	1000 to 1500
Sweden	Baltic Sea	170
Total		4300 to 4800

Up to now the Netherlands has concrete plans for three wind farms: the demonstration project Near Shore Windpark at 8 to 12 km from the coast opposite Egmond aan Zee and two wind farms from E-Connection, just outside the 12-mile zone, also opposite Egmond aan Zee. The licensing procedures for these farms are well under way. In addition, there are plans for a near-shore wind farm of 300 MW along the Afsluitdijk.

Expected growth

The potential for European offshore wind energy is enormous. According to a study made by Germanischer Lloyd in 1997, the available space of European offshore locations is about 250,000 km^2. These locations are at a maximum depth of 40 metres and a maximum distance of 40 kilometres. Areas at sea used for other purposes, such as military training grounds and shipping routes, have already been excluded. With a power density of 5 MW per km^2, the total European potential could amount to more than 1.25 million MW.

In November 2000 the European Wind Energy Association (EWEA) made new predictions about the development of wind energy in Europe. It anticipates that the installed wind capacity in Europe in 2010 will be 60,000 MW, of which 5000 MW will be at offshore locations. For 2020 the total installed capacity is expected to be 150,000 MW, of which 50,000 MW is from offshore (see also Figure 3.11). Based on plans that have already been formulated (see Table 3.2), EWEA's expectations for offshore wind energy for 2010 seem definitely feasible and possibly also on the safe side. In the past EWEA always adjusted its expectations upwards. In 1991, for example, it was predicted that Europe would have a wind capacity of 4000 MW in 2000. In 1997 this figure was already raised to 8000 MW, while in 2000 the realised capacity amounted to 13,600 MW. Worldwide installed capacity in that year was in fact 18,450 MW.

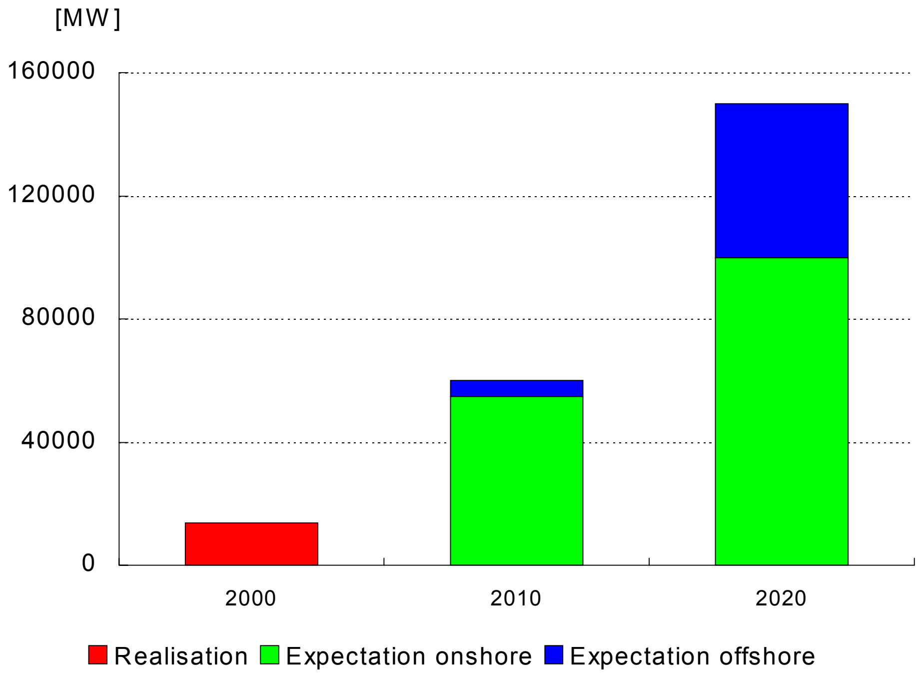


Figure 3.11 Expected/estimated development of wind energy in Europe according to the European Wind Energy Association

Recent ECN studies reveal that total available space in the Dutch EEZ is about 30,000 km^2. The available sea area outside the 12-mile zone with a depth of less than 20 metres is about 600 km^2. It is estimated that this area has room for approximately 3000 MW. The Dutch government has set a target of 1500 MW wind energy on land for 2010. For 2020 the target is 3000 MW on land and offshore. The capacity that can be placed in the available space outside the 12-mile zone at a water depth of less than 20 metres thus corresponds with the total target for

2020. If it is assumed that 1500 MW is needed from offshore production to meet the target for 2020, the necessary area amounts to at most 300 km^2. This is only 1% of the total available area. This 1500 MW should be enough for an annual electricity production of at least 4 TWh, which is expected to equal 3 to 4% of Dutch electricity consumption in 2010.

Increase in renewable energy

Compared with other ways of sustainably generating electricity, offshore wind energy has great potential in Europe. Recent studies on the effects of trading green certificates in the European electricity market indicate that offshore wind energy will make a significant contribution in reaching the EU target of 12% renewable electricity by 2010. Other renewable sources, such as biomass and hydropower, have a limited potential because of the restricted availability of agricultural land, biomass and waste streams, suitable locations, etc. Offshore wind energy is much less subjected to such restrictions, but rather to the speed of technological developments linked to the industry's production pace. Even though the potential is high, in principle, it is no simple matter to make such changes from one year to the next. It is therefore assumed that the industry's maximum growth rate determines development for the long term. The growth rate of the wind industry world-wide in the last years was between 25 and 30% per year.

In 2010, when 12% of the electricity used in Europe is supposed to come from renewable sources, it is expected that 27% will be from wind energy. This assumes a 30% growth rate of the wind turbine industry. While the potential of the other cost-effective sources will be completely exploited by then, electricity production from wind energy can continue to increase. Thus, it can be expected that the share of wind energy in the total renewable energy supply will increase in the future. Wind energy, especially offshore, will compete with other (more expensive) renewable energy options that are necessary to meet the target, and therefore determine the equilibrium price for a (European) green certificate. It is therefore not impossible that the costs of offshore wind energy will eventually determine the price of green electricity.

Countries with a large offshore wind potential, such as the Netherlands, can benefit from the growth in wind energy in the European trade of green electricity. So, instead of being a net importer of green certificates, the Netherlands can instead become a net exporter.

Effect on electricity supply

The changing nature of the wind will lead to a variable pattern in the electricity supplied by wind energy. Just as on land, there will be periods at sea with little or no wind. For a high installed capacity of wind energy (several thousand MW) it is not unimaginable that this variable supply affects the market price of electricity. To counteract such price fluctuations it may be necessary to set up special back-up capacity. Hydropower-based electricity could be used for this. Another possible solution is to spread out offshore wind farms. The wind does not blow everywhere with the same force at the same moment. Spatial distribution would also help avoid possible congestion problems in the electricity grid. Perhaps a special electricity grid for wind energy in the North Sea connected to grids in different countries would also be attractive to counteract price fluctuations and grid congestion. Such a grid would also make a link possible with, for example, hydropower plants in Norway. This sort of offshore electricity grid would be comparable to the already long-existing system of gas pipelines on the Continental Shelf.

Demonstration projects

Besides many challenges for offshore wind energy there are also constraints to realising large offshore wind farms. These constraints are mostly connected to investment risks caused by insufficient knowledge of long-term meteorological data, uncertainty in the success of different necessary technological developments and also administrative uncertainties. Technological developments can be stimulated by beginning with demonstration projects, just like many of the wind farms built in the Baltic Sea in the 1990s (see Table 3.1). This provides the necessary experience to build much larger wind farms. The Near Shore Windpark demonstration project near Egmond aan Zee is meant to help build up knowledge about technological solutions for the specific conditions and constraints in constructing wind farms in the North Sea, which are more extreme than in the Baltic Sea. Wind and wave loading are greater, as are distances to the coast. These conditions will greatly affect design, installation and maintenance.

Gap in meteorological knowledge

A good investment decision requires that the long-term yield of a project is reasonably well known. Offshore wind energy yield is determined by the wind supply and the structure of both the electricity market and the market for green electricity. There is still little known about the wind regime, in particular, of the North Sea. Average annual wind speed in each sector of the EEZ is mapped with an accuracy of approximately 1 to 1.5 m/s. This uncertainty, however, gives too large a range in expected electricity production and thus in the wind farm's annual turnover. Existing statistics are generally inaccurate (e.g. using the Beaufort scale) or unreliable (measured from moving ships at unknown heights). To gain more knowledge about the wind regime of the North Sea it is necessary to measure wind speed at a number of locations during several years. To optimally match the construction to wave loading, more knowledge is also needed about wave heights, such as for example the highest wave height over a period of 10 years. Because this can vary in relation to water depth, it is desirable to have measurements from various locations. More knowledge about wave loading increases the reliability of the total installation and thereby reduces the technical risk.

Uncertainty in technological developments

The uncertainty in technological development is evident in the question of whether the further scaling-up of turbines can keep pace with the demand for larger turbines. One can also wonder whether a 30% growth rate per year for 10 to 20 years for the turbine industry is realistic. This also depends on the ability of wind energy to compete in the renewable electricity market and thus with the demand for wind turbines. Not only is the development of the turbine industry important for this, but also the development of new concepts, such as installation techniques, types of foundations and electric infrastructure (see box *Developments in offshore wind technology*).

Developments in offshore wind technology

Wind turbines

The size of wind turbines is continuing to increase. The largest turbine at the moment has a rotor diameter of 80 metres and a capacity of 2.5 MW. By the end of 2002 it is expected that machines will be built with rotor diameters of nearly 100 metres and a capacity greater than 3 MW. A number of manufacturers have made designs for turbines of 6 MW. This development is particularly favourable for offshore wind energy, because a greater capacity per turbine is more cost-efficient. Whereas the share of total investment costs for a turbine on land is approximately 80%, it is expected to be about 40% or less for an offshore turbine. This is a result of higher expenditures for the support structures and electric infrastructure. If a higher capacity can be achieved per foundation then the costs will decrease per MW. The annual costs for operational management and maintenance can also be less in the case of higher capacity.

Foundations

As turbines are made with larger capacities or are placed offshore at greater depths, heavier foundations will need to be used. The mono pile, the most common foundation used until now, is guyed onto the seabed with a crane and pile driver from a pontoon. This combination can only be used in calm weather, thus low swelling. Therefore, the number of weeks that can be worked per year is very dependent on the weather. Experience with the Blyth offshore wind farm shows that swelling is a problem that should not be underestimated. As a consequence of light swelling, the total installation time for assembling this farm's two turbines was delayed considerably. New developments will be aimed at improving the foundations themselves and the required placement techniques.

Electrical infrastructure

Using conventional transmission cables leads, as the distance from the coast increases, to greater losses of the generated electricity during transmission. A solution is the use of HVDC (High Voltage Direct Current) technology. This entails higher initial investment costs but implies fewer cable losses. The use of HVDC transmission is, as expected, already cost-effective for distances of 40 km or more from the coast. Further developments in HVDC technology are well under way.

Maintenance

Developments in the offshore wind turbine industry are intended, among other things, to minimise maintenance costs as much as possible. Therefore one of the biggest challenges is to increase the reliability of the turbines. Offshore locations are less easily accessible than those on land, which means that, e.g., a turbine can remain out of operation longer in bad weather. This effect is clearly expressed in the cost price. Increasing reliability can, e.g., mean building the turbines from stronger materials, limiting the number of moving parts, and making components very durable in terms of resistance to the effects of offshore weather. Such effects include the possibility of wave and storm damage, salt water or salt spray corrosion, etc. Reducing maintenance-related costs would mean less often having to call out a maintenance crew, which would also signify a higher annual energy production because of the greater availability of the turbines.

Administrative uncertainties

Up until now there is no clear legal framework in the Netherlands in which the whole process of planning, licensing and implementing an offshore wind farm can actually take place. Remarkably, in contrast to the Netherlands, the governments of other North Sea countries have a special allocation policy. New wind energy developers in the Netherlands now have to wait until a license is obtained. For that matter, the location assignment of the Near Shore Windpark is an exception. A consequence of not having a clear location policy is that more initiatives are now being developed abroad than in the Netherlands.

Because of the scale of offshore wind projects compared with projects on land, the investments per wind farm are also higher. Investors therefore want a high degree of certainty, also in terms of long-term sales of green electricity. For this reason, the ultimate design of the green electricity market plays a big role. There will need to be clarity about the continuation of existing financial incentives, whether the market is based on an obligatory or voluntary share of renewable electricity consumption, and about the export and import possibilities of green electricity or green certificates (see also *Insight: Market organisation and strategy*). As investments in (offshore) wind energy are capital intensive, a lowering of investment risks leads to a lowering of the required return on invested capital. And as the cost price of wind energy greatly depends on financing costs, this could result in a stronger competitive position.

The future is still uncertain

What is important for the Netherlands is sufficient room in the EEZ for offshore wind farms, i.e. at water depths down to 20 metres outside the 12-mile zone. This space is sufficient to make a considerable contribution to the Dutch and European renewable energy targets. However, up to now, it is not sufficiently clear for developers who are active in the Dutch market what the possibilities are for placing an offshore wind farm. More clarity is desired regarding placement policy, licensing procedures and design of the green certificate market. On the other hand, existing plans are already so far advanced that 600 MW of offshore and near-shore wind capacity can be expected in the Netherlands in about 2005. This includes the wind farm along the Afsluitdijk. The extent to which the number of initiatives expands will depend on technological and administrative developments, the degree to which the demand for green electricity continues to be stimulated, and the extent to which there is co-ordination between the countries bordering the North Sea in terms of offshore activities.

For a rapid expansion of the renewable energy supply, hope is vested in offshore wind energy. Whether this expectation can be fulfilled depends on technological developments and policy choices. A build up of knowledge concerning offshore wind regimes is necessary to optimally adapt and dimension wind turbines to offshore conditions in order to reduce investment risks as much as possible. Developments in administrative decision-making procedures such as licensing or concession systems will be needed, but also the final form of the market for green certificates, to determine the pace at which offshore wind energy will be developed. Because of the great potential that offshore wind energy has compared to other renewable energy sources in Europe, this technology may determine the price of sustainably generated electricity in Europe. This is true on condition that technological developments are successful and that there is a uniform European renewable energy market at that moment.

Main role for coal-fired power plants in the Dutch renewable energy supply

In the last years the owners of Dutch coal-fired power plants have developed increasingly more initiatives to use biomass and waste-derived fuels as substitutes for coal. The substitution of coal with renewable sources is both favourable for the exploitation of the coal-fired power plants and to achieve Dutch renewable energy targets. There are, however, limits to the large-scale use of biomass and waste in coal-fired power plants. Moreover, large-scale use of biomass forms an impediment for the development of small-scale technologies.

Biomass use in coal-fired power plants is already a fact

At this moment all coal-fired power plants use biomass or waste, or they are at an advanced stage of preparation for this purpose. A sector-wide development can only get going if there are strong driving forces to stimulate such development. These forces do exist, primarily out of economic interests, and are strongly supported by the national energy and climate policy.

There currently are eight coal-fired power plants in operation in the Netherlands. Three of these, the Hemweg plant, the Amer 9 plant and the coal gasification CCGT power plant in Buggenum only came into operation in 1994/1995, and are among the most modern power plants in the country. The decision to construct these power plants was already made much earlier, at a time when the energy crisis was still fresh in everyone's minds and it was not clear to what extent, in terms of reliability and duration, the large Russian gas reserves would be available to the West. The ideas of diversification as well as an independent and stable energy supply were of primary importance. Although in the last phase of the decision-making process the emphasis was more and more focused on the environmental performance of these power plants compared to new gas-fired power plants, the plans were already too advanced and the political interests were too great to choose another course. Meanwhile, the politico-economic influence has changed such that the construction of new coal-fired power plants is practically out of the question, and existing power plants are coming under more and more pressure to improve their environmental performance. Although fuel substitution (use of natural gas) and efficiency improvements can be considered, the use of biomass in particular will play an important role.

The use of biomass in coal-fired power plants has several important advantages for Dutch owners:

- Dutch energy policy is aimed at having the share of sustainable and renewable energy in the national energy needs rise from the current 1% to 10% in 2020. The use of biomass and certain waste streams from existing electricity plants are generally viewed as an important option to be able to reach this target. Therefore, coal-fired power plants for power derived from biomass and waste are eligible, under certain conditions, for the REB diversion to producers (currently 1.94 €ct/kWh). This power can, under certain conditions, also be sold as green electricity, so the customer is exempted from paying the REB (for small customers it is currently 5.83 €ct/kWh). Owners can also, under certain conditions, claim investment-promoting measures (CO_2 reduction plan, EIA, VAMIL);
- A number of biomass and waste streams are less expensive than coal, so the operating profits can benefit by the use of biomass and waste;

- Investments are relatively limited. The use of biomass in coal-fired power plants is one of the least expensive options to produce green electricity;
- The use of biomass counts towards the covenant obligation to reduce CO_2. The Netherlands, together with a large number of other countries, committed itself by means of the Kyoto Protocol to limit its emissions of greenhouse gases. A significant part (6 Mton CO_2 equivalents) of the national target for the budget period of 2008 to 2012 (50 Mton CO_2 equivalents, of which 25 Mton within the country) needs to be realised through emission reductions at coal-fired power plants. This reduction can be realised by fuel substitution (coal replaced by natural gas) and improvement of the overall conversion efficiency, but also by the use of renewable fuels, such as biomass and certain waste streams. To this end the Dutch government made a voluntary policy agreement in 2000 with the owners of coal-fired power plants in the Netherlands. The government also promised that the fuel tax on fuels used to generate electricity (input tax) would be converted into a tax on the supply of electricity to end users (output tax). This tax conversion puts the Dutch power companies on a more level ground in terms of international competition.

The above-mentioned points have, in the last two years, led all Dutch coal-fired power plant owners to develop initiatives to use biomass (see Table 3.3). If it were up to the plant owners, these plans would actually be intensified in the coming years.

Table 3.3 Outline of current initiatives. Nearly all of these projects are operational or in a testing stage. The coal gasification CCGT power plant at Buggenum is at an experimental and preliminary study stage

Plant	Production capacity [MW_e]	Coal plant operational since	Technical concept	Fuel	Capacity Direct and indirect co-combustion [MW_e]
Gelderland 13 (Electrabel)	602	1983	indirect co-combustion	60 kton/year scrap wood(?)	18
Amer 8 (EPZ/Essent)	645	1981	direct co-combustion	75 kton/year paper pulp	2
Amer 9 (EPZ/Essent)	600	1994	separate gasification	150 kton/year demolition wood	30
Borssele 12 (EPZ/Essent)	403	1988	direct co-combustion	demolition wood	12
Maasvlakte 1/2 (E.ON Benelux)	2×518	1989	direct co-combustion	150 kton/year biomass pallets and 40 kton/year poultry manure	30
Demkolec (NUON)	253	1994	indirect co-combustion	various flows	12
Hemweg 8 (UNA/Reliant)	630	1995	direct co-combustion	75 kton/year sewage sludge	19

Technological options for the use of biomass in coal-fired power plants

Direct co-combustion
For direct co-combustion, biomass is pre-treated with coal, added to the boiler and combusted. The existing installation does not need to be adapted.

Indirect co-combustion
For this form of co-combustion, biomass is physically pre-treated, without thermal or chemical pre-treatment. Ultimately the biomass is added with the coal to the burner installation of the boiler.

Co-firing through separate gasification
Biomass gasification occurs in a separate installation and the low calorific gas is added to separate burners. There is therefore no gas purification installation as an intermediate step.

Co-firing through separate pyrolysis
Biomass is added to a separate pyrolysis installation, and the pyrolysis products (oil, gas, char) are then added to the boiler. For slow pyrolysis the char is added together with coal to the boiler. The remaining pyrolysis gases are also, if necessary after a gas purification step, combusted in the boiler. In the case of fast pyrolysis, the pyrolysis oil in separate burners is combusted in the boiler.

Co-firing through Hydro Thermal Upgrading
The biomass is place under high pressure and temperature, and converted into biocrude oil and in separate burners added to the boiler.

Steam integration
The biomass is combusted in a separate installation and steam integrated with a coal fired plant.

Perspectives and barriers

For an average load factor of 6,000 hours, annual production from ongoing initiatives is approximately 735 GWh, or 6.5 PJ of avoided primary fossil energy per year. This is roughly 14% of the total contribution of renewable energy in the Netherlands in 2000. The largest contribution, about 11.5 PJ (approx. 28%), is credited to waste incineration plants (AVIs). Coal-fired power plants, however, have many more possibilities. Current initiatives substitute approximately 3% of coal input with biomass. Depending on technical limitations this could increase to between 20 and 40% in the coming years. Whether that actually happens depends, besides productivity, especially on technical possibilities. The main barriers, which particularly apply during co-combustion of higher percentages of biomass (>10%), are formed by:

- Problems with supply quality, pre-treatment (including danger of dust explosions during pulverisation) and input to burners;
- Potential problems with the capacity of diverse components, such as fly ash ventilators, fly ash purification equipment, gypsum removal system, air pre-heaters, etc.;
- Potential problems in the boiler: high temperature corrosion, slagging, contamination and erosion (from ash);
- Potential problems with the quality of the liquid waste streams (washing water) and solid by-products (fly ash, gypsum).

Ultimately these technical problems will define the limits for the maximum amounts of biomass that can be used in Dutch coal fired plants. Use of 20 to 40% biomass in coal-fired plants can contribute substantially towards reaching the intermediate target of 5% renewable energy in 2010 (approx. 163 PJ of avoided fossil fuels). Biomass utilisation corresponds with 40 to 80 PJ of avoided fossil fuels. Technically, a scenario in which biomass use increases to 15% in 2005 and 30% in 2010 is definitely not inconceivable. This means that coal fired plants could play an essential role in the coming years in helping to reach the Dutch renewable energy targets.

A large number of the technical constraints seem solvable. It is possible, however, that it will cost more to generate green electricity in coal-fired power plants, yet it will probably remain one of the least expensive options to reach the renewable energy target. What could still prevent large-scale use?

Availability of biomass

In many of the discussions about the large-scale use of biomass, its availability for energy generation plays an important role. In the short term, however, it is unlikely that there will be a shortage, because even if the price for biomass gradually increases, the inexpensive and easy to use fractions will be more utilised. Recent studies, such as the 'Energy Recovery from Waste and Biomass' or EWAB Marsroutes (Novem), have shown that in 2005 there will be about 168 PJ of waste and biomass (26 PJ from manure) available for energy generation increasing to 177 PJ in 2010 (23 PJ from manure). Irrespective of the extent to which all the streams can actually be utilised, biomass can be purchased in the international market. The cultivation of energy crops in the Netherlands will not have any effect in the short term, because the prices for these crops are (still) too high and there are enough other fractions available. Biomass can also be purchased in the international market at prices that are lower than the (energy) crops grown in the Netherlands.

Environmental effects and energy output

An important development in policy has led to VROM's proposal in which emission limits for new stand-alone installations and co-firing in existing coal fired plants are regulated. VROM seeks to substitute this guideline at the end of 2001 for the current, relatively non-transparent policy concerning emission requirements (see box *Current regulatory procedures concerning emission requirements*). VROM's proposal differentiates between 'clean' and 'contaminated' biomass. This proposal includes a 'white' list of 200 different streams ranging from waste wood to vegetable residues from the food industry, and is accompanied by a light licensing regime. A 'yellow' list, which requires a more stringent licensing regime, is more generic, and includes all substances not found on either the white list or the list of hazardous waste substances. The regulatory procedures for 'clean' biomass are restricted to limit values for NO_x, SO_2 and dust. 'Contaminated' biomass also includes limit values for components that are not or hardly expected to be utilised in 'clean' streams, such as heavy metals, dioxins and HCl. Emission limit values regarding CO and C_xH_y only apply for the utilisation of 'contaminated' biomass, although these two substances can be formed from burning any material that contains carbon. With regard to dust and SO_2, limit values for 'clean' biomass are more flexible than for 'contaminated' biomass. For the design of this standardisation proposal, as much as possible is linked to the new European emission policy being developed concerning emission standards for combustion and waste incineration plants.

Current regulatory procedures concerning emission requirements

Standards concerning emissions from the use of biomass and waste in incineration plants in the Netherlands are currently not clearly regulated. Depending on the way in which these fuels are utilised in different installations there are different orders and directives or combination including the following:

1. Environmental Management Act, Order governing combustion plant emission requirements A and B (BEES-A for installations with a capacity > 0.9 MW_{th} and BEES-B.
2. Directive on Emissions to the Air (BLA). The BLA is applies to installations that process (incinerate) household waste or a mixture of household and industrial waste.
3. Co-firing Circular of 1994 for co-firing in coal fired plants to 10% (on mass basis). In this case a license is granted based on the BEES-A, supplemented with requirements from the BLA. For co-firing in coal-fired plants up to 10%, the BEES-A (installations with a capacity > 0.9 MW_{th}) applies in principle, and if necessary its requirements are supplemented with requirements from the BLA. For more than 10% co-firing the NER is applied.
4. NER, General limit values for process emissions from the Netherlands Emission Directive (NER, 1992) for co-firing more than 10% in coal fired plants. Furthermore, the NER includes special regulations for processing biomass in installations that are perpetuated with a short measure of oxygen (pyrolysis and gasification), and for installations to incinerate communal (RWZI) and/or industrial waste water sludge.

VROM’s proposal has been presented to the provincial governments, who grant licenses for power stations and waste incineration plants. The provinces expressed a critical response to the draft standardisation proposal. The main point of criticism, however, concerned the environmental performance of co-combustion and co-firing. Waste streams included on the white list, and thus subject to a lighter licensing regime, can contain supposedly ‘safe’ elements that are in fact harmful to the environment. Wood can actually, depending on where the tree has grown, contain mercury and heavy metals. When this wood is co-combusted in coal fired plants it is true that the relative increase in mercury, partly because of the large flue gas streams in these plants, is only very little, but in absolute terms there is a substantial increase in mercury emissions. In specific cases (the Maasvlakte and Borssele plants), the province has made supplementary requirements concerning mercury emissions caused by co-firing and co-combustion of biomass and waste streams, regardless of whether the substances treated are on the white or yellow list. As a result, to prevent standard ‘filling’, not only is a concentration standard used, but likewise a maximum is set for annual mercury emissions in kg/year. In a general sense, provinces support the use of biomass for reducing CO_2 emissions, as long as the environmental situation does not worsen or, in fact, improves. Initiatives in this area need to fit into an effective and efficient national structure for waste removal. CO_2 emissions resulting from different parts of the chain (pre-treatment, transport) also need to be considered in the assessment process.

The other important point of criticism concerns energy output from co-combustion and co-firing. From an environmental protection perspective, the desirability of co-combustion and co-firing of biomass and/or waste in power plants are also determined by the energy content of the streams concerned. For streams with a low heat content (< 9 GJ/ton), provinces are inclined to prefer alternative processing methods. Furthermore, there may not be any adverse consequences with regard to energy generating efficiency.

Ultimately, the position taken by the provinces can lead to a barrier being raised for the large-scale use of biomass in coal-fired plants. Whereas the new VROM directive, in principle, attempts to provide clarity and uniformity about emission requirements and licensing at the policy level, the provinces, who are actually responsible for the licenses, can still give their own interpretation to this. An illustration of this is the reaction of Essent to Zeeland's provincial environmental plan *Groen Licht* (green light), which includes requirements for the co-combustion and co-firing of biomass and waste that are more stringent than those in national agreements. Essent argues that this jeopardises the survival of its business in the province of Zeeland, and that the (financial) barriers erected by the provincial government worsens its competitive position.

Waste policy

At the moment in the Netherlands work is being done to formulate a National Waste Management Plan (LAP). This plan, which was sent as a rough draft in June 2001 to the Lower House, is supposed to be decided upon in 2002 by the Minister of VROM. Besides the Ministry of VROM, the Dutch Waste Deliberation Organ (AOO) also plays an important role related to this plan. Currently, an environmental effect report (MER) is being written, and there is a discussion taking place between VROM, other parties from the AOO and social organisations. The government is focusing its waste policy in successive order of priority on prevention, reuse and, as much as possible, recovering energy during incineration. A number of matters in the discussion are taking an increasingly definite form:

- Landfill capacity will probably not be expanded.
- There will very likely be a higher landfill tax that will lead to a shift from dumping to prevention and useful application.
- Although there is activity geared towards an open European market for waste incineration as a form of removal, country borders remain closed until there is a level playing field. The reason for this is that a part of the Dutch low calorific combustible waste would be exported abroad, where it could be incinerated at less cost (the waste from these countries would then be dumped). Consequently, the price of low calorific waste, which is equal to the present landfill tariff of approximately 104 €/ton, would fall and the cost-effectiveness of many AVIs would suffer.
- For useful application, a free European market is required.

In the end this policy forms an impulse to separate high calorific (industrial) waste from low calorific streams, and utilise it for beneficial applications such as in coal fired plants, in cement ovens and in installations designed to burn high calorific streams. Expansion of capacity will also especially take place for the latter use, and it is expected that AVI capacity will not be expanded.

If this development actually continues, it will mean that, because of the extra landfill tax on waste, relatively inexpensive high calorific waste streams would become available that are now dumped. These waste streams can replace coal, but are not regarded as 'green' because they include a relatively high amount of plastics. Such waste streams could form a formidable competitor as an alternative fuel to biomass for coal fired plants. Owners of coal-fired plants may indeed find it more attractive, from a technical perspective, in connection with constant quality and a reliable supply, to use these fractions. The landfill tax will additionally make these fractions inexpensive in the market and thus able to compete with the use of biomass, despite promotion of the latter through the REB discount and the REB nil tariff.

European definition of biomass

In practice, terms such as clean biomass, contaminated biomass and waste are often mixed up and there are often different definitions used. Directly linked to this is the extent to which electricity from biomass can be considered green or renewable, and what emission requirements need to be applied to the different installations. The discussion in response to these questions is relevant in both the Netherlands and at the European level. At the European level there is currently work being done on a 'Directive to promote electricity from renewable sources in the internal electricity market'. There is also a directive being prepared 'concerning the reduction of certain contaminants in the air emitted from large combustion installations', and in 2000 a directive came into effect 'regarding the combustion of waste'. With regard to emission requirements, it has been established that the combustion of all biomass that falls under the definition in the first-named Directive is considered as 'clean' biomass and does not come under the incineration directive. 'Clean' biomass is subject to the lighter licensing regime that also applies to large combustion installations. 'Contaminated' biomass, which is not included in this definition, and other waste are subject to the stricter emission limits of the incineration directive.

Although two of the three directives are still in the design phase, there seems to be a definite consensus being developed between energy ministers from the EU member states, the European Commission and the European Parliament. The following definition of biomass is used:
"…biodegradable fraction of products, waste products and residues from agriculture (including vegetable and animal substances), forestry and related departments, as well as the biodegradable fraction of industrial and household waste…"

In principle, electricity that is generated from these sources is considered renewable according to the draft directive. This electricity can be counted towards the renewable energy target and claim can be made for possible financial benefits.

At first there was much debate about the incineration of sludge and manure to generate electricity. There was also extensive discussion about the place of electricity originating from the incineration of household waste in AVIs. If this were to fall outside the definition it would have tremendous consequences for Dutch renewable energy production. About 28% of current production would no longer be counted towards the Dutch objective.

In July 2001 agreement was reached in the European Parliament about use of the broad definition, which includes sludge, manure and combustion of the organic fraction of household waste in AVIs, to be applied towards the renewable energy target. This means an important constraint, in terms of using sludge and manure in coal fired plants, has been removed. It is expected that the new directive, which includes this definition, will become definitive this year.

Acceptance by energy consumer

The opening of the Dutch green electricity market since 1 July 2001, certification of green electricity and the connected trade in certificates, have created a situation in which suppliers are increasingly able to differentiate themselves with various forms of sustainably generated electricity (see also *Insight: Market structure and strategy*). Because of the free choice available to the suppliers of green electricity, customers can also make their wishes known for the way green electricity is generated. Irrespective of whether biomass generated power from coal fired plants can be considered green electricity in legal terms and to reach the renewable energy target, it is important what the consumer of this power thinks. In this regard, the perception of green is especially important. Wind and solar energy have an advantage over biomass, especially when biomass is co-combusted with coal in large power stations. This could, partly through the influence of images from campaigns made by suppliers and interest groups (environmental organisations), lead to a decreasing acceptance of customers. Although there are no indications that this will play an important role in the short term, it could form a barrier in the long term for further use of biomass in coal fired plants.

Small-scale biomass-fired plants

Having seen the possible developments regarding the large-scale use of biomass in Dutch coal fired plants, the question is whether room still exists and if there are chances for the growth of small-scale biomass plants up to 50 MW_e. In recent years a number of plants have been brought into operation in Schijndel, Cuijk, Lelystad, etc. Much attention in the Netherlands is also being devoted to R&D concerning small-scale plants. Nevertheless, there are a number of reasons to believe that the position of small-scale options for incineration, decomposition and gasification for the benefit of heat and/or electricity generation to 2010 will not substantially increase in level of importance:

- The emission requirements (according to the new VROM proposal) are more difficult to realise and more expensive for small-scale plants than for large ones.;
- Easy to contract and inexpensive, available streams are already being used in large-scale plants;
- The costs for the construction and exploitation of small-scale plants are relatively higher than for the use of biomass in existing AVIs and coal fired plants;
- Large-scale application of small-scale plants still requires relatively much R&D effort;
- The license application demands a relatively high pre-investment, which is easier to procure for large-scale projects;
- Problems associated with a surrounding area, in terms of transport, storage and pre-treatment, can be relatively worse for small-scale plants;
- For small-scale projects, it can be more difficult to assess and cover uncertainties and risks.

In sum, the role of small-scale biomass plants in the short term appears to remain only marginal and to limit itself to a few niche markets. In the longer term, when coal fired plants are decommissioned, there is also the question of whether small-scale plants can replace the role of coal fired plants. There can, after all, be a ‘lock-in’ effect where the transport infrastructure (via water), storage facilities, pre-treatment and procedures are in the favour of new large-scale plants. This also applies to the production of gaseous and liquid fuels from renewable sources. A possible market for this would still need to be completely designed, and the expectation is that new large-scale technologies, in particular, would capture an important position. However, it does not seem plausible that gaseous and liquid fuels from renewable sources will play a large role in the short term in the energy market, because further technological development is necessary, costs are still too high and the accompanying policy is less stringent than it is, for example, for renewable electricity. However, it is imaginable that, based on the interest shown for the transport sector, R&D activities in this area will increase sharply.

Future expectations

Currently, co-combustion and co-firing in coal fired plants contribute a bit less than 7 PJ of avoided fossil fuel to the amount of renewable energy produced in the Netherlands. In the future this could, depending on a number of technical preconditions, increase to about 60 PJ in 2010. Coal fired plants could thus make an important contribution to the renewable energy target of approximately 163 PJ in 2010 (about 5% of total energy consumption in the Netherlands). No growth is expected for the AVIs, which currently furnish around 11.5 PJ of avoided fossil fuel.

The availability of biomass does not form a constraint, especially and also because it can eventually be purchased in the international market. A possible refinement of the definition at the European level is also under way, so this will no longer form a constraint. The most important obstacles to achieving this contribution are formed by a number of developments:

- The VROM proposal for new emission requirements has led to a discussion about the environmental and energy performance of the use of biomass and waste in coal fired plants. Provinces have expressed their objections to this.
- Waste policy can lead to an alternative non-green fuel that could possibly be more attractive to use for the owners of the coal-fired plants.
- In the longer term the acceptance of green electricity from coal fired plants by customers, partly because of the influence of images from campaigns created by suppliers and interest groups (environmental organisations), could sharply decrease.

Based on the comparative disadvantages of small-scale biomass plants in relation to the large-scale use of biomass in coal-fired plants, perspectives for small-scale installations do not appear promising. A possible exception could be their use for the production of gaseous and liquid fuels. For the time being there will be limited demonstration projects.

ENERGY PRICES

A well-functioning liberalised energy market should lead to cost efficiency for the energy supply, enabling the energy prices to reflect these costs. However, there must be a distinction made between the part of energy prices that are actually established by competition, such as the production and supply of energy, and the part that has to do with regulated activities in the energy market, such as energy transport. Government levies, such as the fuel tax and regulatory energy tax, are also part of end-user prices.

Competition in the supply of electricity can cause an initial fall in prices. However, in the mid to long term there may be a supply shortage, which will cause prices to increase and, in particular, fluctuate more. In the gas market, the relationship between gas price and oil price may play a less important role as a consequence of an increasing gas-to-gas competition. For the moment, however, competition in the gas market is even less developed than in the electricity market.

In this last part of *Energy Market Trends in the Netherlands 2001* an overview is first given of different prices, tariffs and taxes that play a role in the gas and electricity markets. This is followed by two analyses that give insight into price formation in the electricity market and the structure of both gas and electricity prices. Furthermore, the structure of the current prices for green electricity is also described. Lastly, expectations are given about energy prices in a future, fully open energy market.

Fuel prices

Figure 4.1 shows trends in fuel prices from the last thirty years. These fuel prices apply to large industrial consumers and electric power plants. The prices are given in euros 2000 and in this way are corrected for inflation. In the period since 1985 there have been relatively stable fuel prices, of which the average of the three fuel prices show a light decreasing trend. However, in 2000 a significant oil price increase led to a break in this trend. Because the gas price in the Netherlands is linked to the oil price, the price developments of these two fuels are nearly the same. At the beginning of 2001 the oil price again fell somewhat. There is no direct link between the price of coal and oil. Nonetheless, the oil price does have some effect the on coal price.

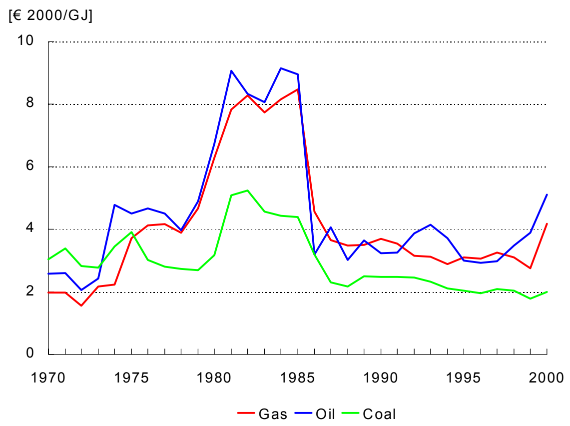


Figure 4.1 Inflation corrected fuel prices of the last thirty years in euro 2000

Spot market electricity prices

The national electricity markets in Europe have been designed in different ways. There can be an obligatory power pool where all electricity is traded or a voluntary power exchange that also has a bilateral contract market. Figure 4.2 shows the development of spot market prices of different power pools and exchanges in Europe. The power pool in the UK has been replaced with a voluntary power exchange since March 2001. Formally, Spain's OMEL is also a voluntary power exchange, but is in reality a pool where 90% of electricity volume is traded. Germany's EEX and LPX, Scandinavia's Nord Pool and the Netherlands' APX are all voluntary exchanges that compete with a bilateral contract market.

Electricity prices in the APX spot market differ from other exchanges. Fluctuations are particularly notable, but also the level of the prices. These are determined by local market conditions (see also *Insight: Energy prices*). The strong correlation between spot market prices in the LPX (Leipzig) and the EEX (Frankfurt) exists because the prices in both exchanges refer to the German electricity market.

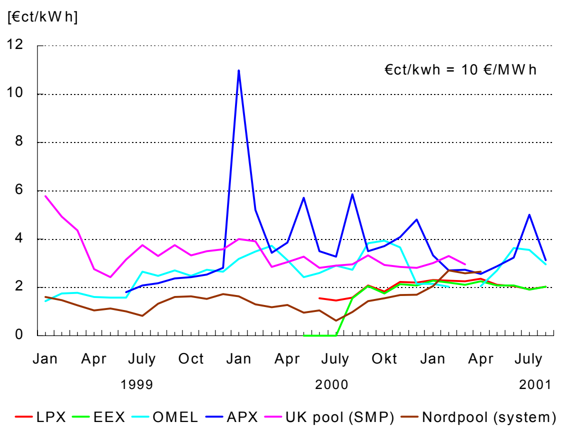


Figure 4.2 Spot market electricity prices on various power exchange markets in Europe (monthly average)

End-user gas prices

Figure 4.3 shows average end-user prices for gas. The old tariff system, the so-called zone system, ended with the liberalisation of the gas market. Since then the gas price for captive customers, which includes households, has been regulated. Industrial customers with an annual consumption of 10 million m^3 or more have been free since 2000. These customers are charged a transport tariff that is dependent on maximum hour capacity. Dividing annual consumption by maximum hour capacity gives the equivalent full load hours (i.e. load hours). Figure 4.3 shows end-user prices for a free customer for two different load factors. The increase in end-user prices for both households and industrial customers is largely caused by the increasing price of oil. The sharp increase in end-user prices for small consumers, including households, for both electricity and gas is also caused by an increase in the REB.

End-user electricity prices

End-user prices for gas and electricity are comprised of a commodity price, profit margin, transmission tariff and possibly energy taxes. The development of end-user prices for electricity is shown in Figure 4.4 for households and industrial customers. The figure shows average prices, as there are price differences between the different network companies (see also Figures 4.7 and 4.8). Transmission tariffs for electricity are regulated and for large consumers consist of a capacity component (kW) and a variable component (kWh). Transmission costs are therefore dependent on both the consumed capacity and the load hours of a large consumer.

Figures 4.5 and 4.6 show the structure of end-user prices for electricity in different European countries. Not only

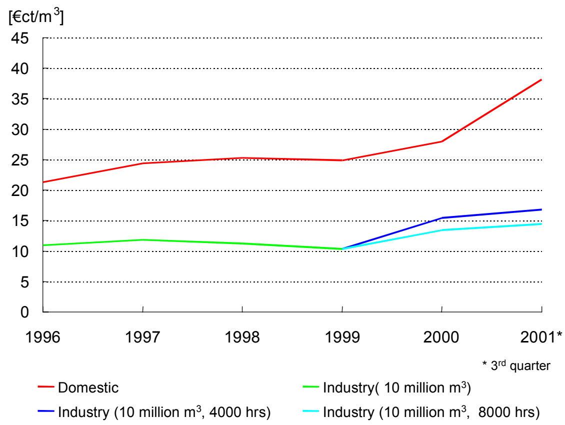


Figure 4.3 Average end user gas prices for domestic use and industrial consumers (excl. VAT)

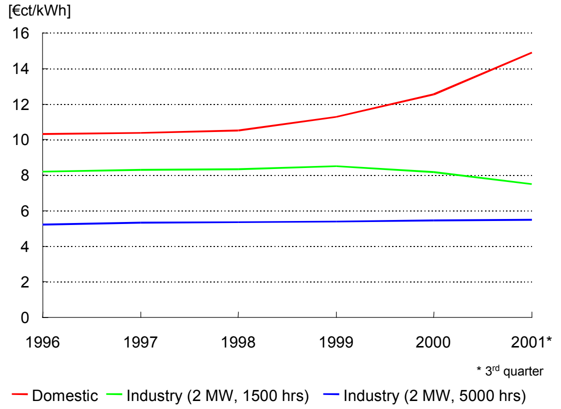


Figure 4.4 Average end user electricity price for domestic use and industrial consumers (excl. VAT)

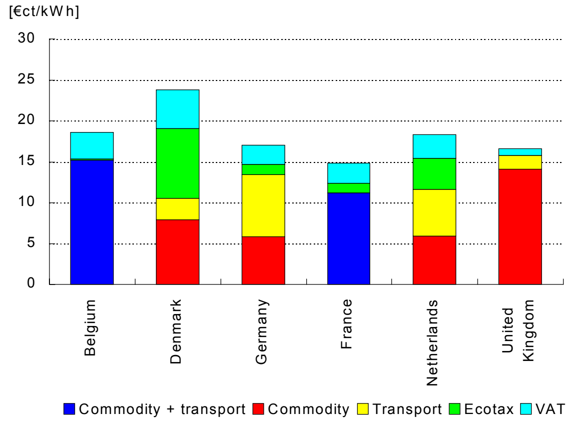


Figure 4.5 Composition of electricity prices for households in various European countries in 2000

commodity prices, but also transmission tariffs and taxes differ significantly per country. For France and Belgium no distinction has been made between commodity price and transmission tariff for households. This is also the case for industrial consumers in Belgium.

Electricity production from different countries can, in principle, compete with each other. In spite of this, there can be price differences because of limitations in the cross-border network capacity (see also *Insight: Energy prices*).

The transmission tariff structure is different for each country, so the maximum levels for transmission tariffs are also different. There are especially large differences in transmission tariffs for households (Figure 4.5). Taxes (ecotax and VAT) also vary per country. More than half of the end-user price for households in Denmark is comprised of taxes. In the Netherlands the electricity price for households is also largely comprised of taxes. Figure 4.6 shows that large consumers in Denmark, Germany and the Netherlands are charged an ecotax, but not in Belgium, France and the United Kingdom.

Regulated tariffs in the gas market

For the gas network, the principle of negotiated access applies (see also *Insight: Energy policy and market regulation*). In this way regulated tariffs only apply to captive customers. DTe established these network tariffs for all gas network operators in the Netherlands (see Figure 4.7) for 2001. The structure of the network tariff system is based on the old tariff system (zone system) so that the tariff level depends on total gas consumption. As annual gas consumption increases the grid tariff falls. An efficiency discount applies in the case of network tariffs charged to captive customers (see also *Overview: Energy policy and market regulation*).

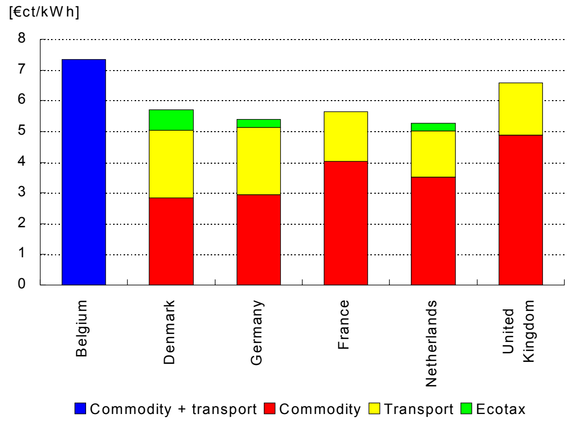


Figure 4.6 Composition of electricity prices for large-scale consumers in various European countries in 2000

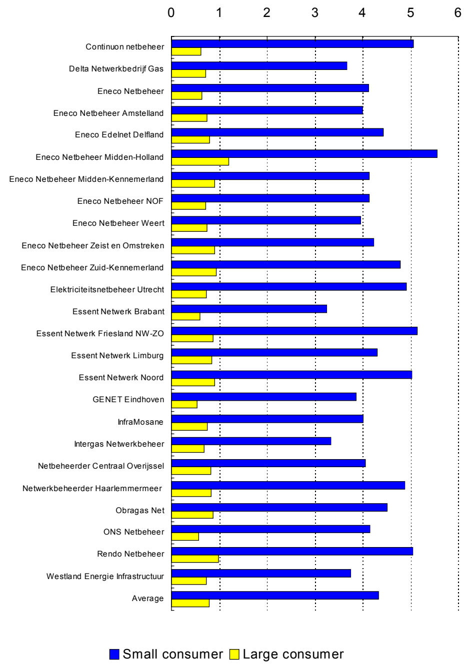


Figure 4.7 Gas transport tariffs for two types of consumers for various grid operators in 2001

Licensed suppliers of gas to captive customers can increase the purchase price with a surcharge (see Figure 4.8). This regulated surcharge can be seen as a gross margin to cover the gas company's costs. Although the surcharge is relatively small compared to the ultimate end-user price (see Figure 4.3), the differences in the levels of the surcharge between the different gas companies is large.

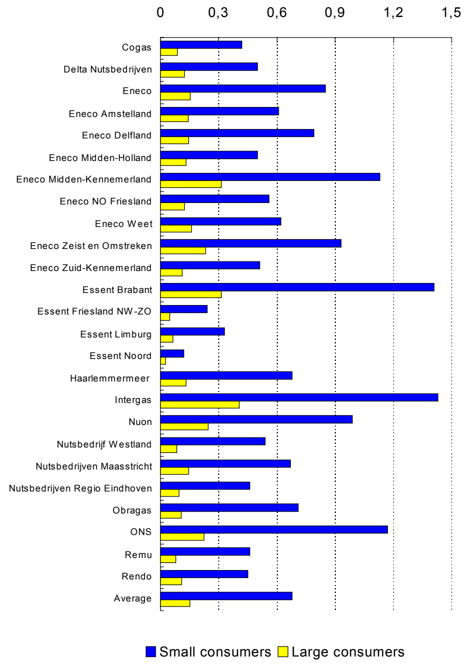


Figure 4.8 Regulated storage at cost price for license holders in gas supply to bound consumers in *2001*

Regulated tariffs in the electricity market

Figure 4.9 shows the electricity network tariffs of different network operators for three types of customers. These tariffs are established by DTe. The level of the tariffs is based on the costs of network companies in 1996, to which subsequently an efficiency discount is applied (see also *Overview: Energy policy and market regulation*). The voltage level at which the customer is connected determines to a large extent the final network tariff. The lower the voltage level of the connection the higher the transmission costs. In Figure 4.9 it is assumed that households are connected to the low-voltage grid, large consumers to the medium-voltage grid and very large consumers to the high-voltage grid. Not all the network companies have a high-voltage grid at their disposal. In that case, very large consumers would also be connected to the medium-voltage grid (not shown in Figure 4.9).

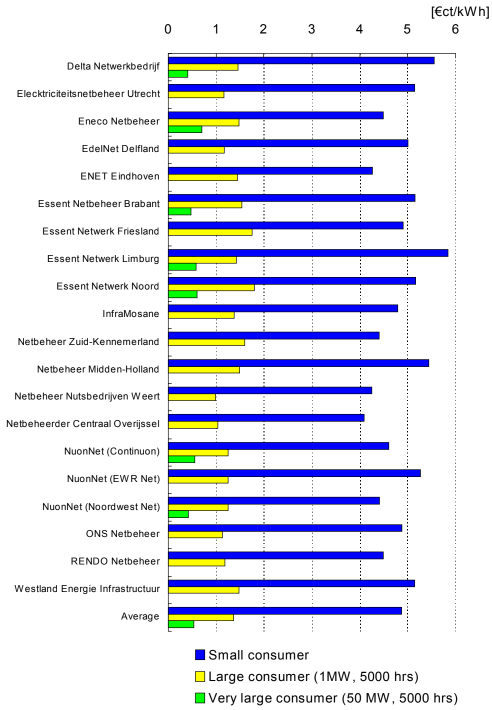


Figure 4.9 Electricity transport tariffs in 2001 for three types of consumers for various grid operators

For captive electricity customers, the price for the supplied electricity (commodity price) is also subject to regulation. This regulated commodity price is known as the supply tariff (see Figure 4.10). Each quarter the DTe establishes the level of these supply tariffs based on yardstick regulation (see also *Overview: Energy policy and market regulation*). As a result of this yardstick regulation, the differences in the supply tariff level among the various license holders will quickly become smaller.

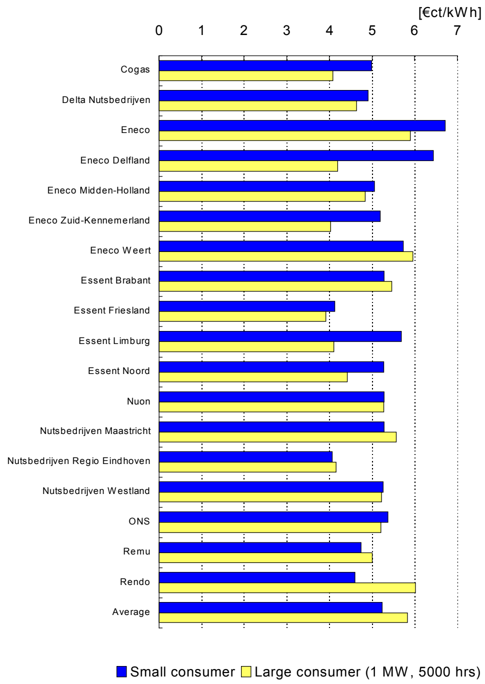


Figure 4.10 Electricity supply tariffs for bound consumers for various license holders (third quarter 2001)

Taxes

As of 1996 a regulatory energy tax (REB) has been applied to both natural gas and electricity in the Netherlands. Since then, in the framework of greening the Dutch tax system, this tax has risen sharply. The actual tariffs for 2001 are given in Table 4.1. With regard to the REB, electricity generated from renewable sources is subjected to a nil tariff.

In addition to the REB there is also a fuel tax (BSB) placed on gas. In 2001 this BSB was 1.03 €ct/m^3 for gas consumption up to 10 million m^3 per year and 0.68 €ct/m^3 for consumption above that level. In connection with international competition in the electricity market, fuel used to generate electricity is exempted from the BSB as of 2001.

Table 4.1 Tariffs for the Regulatory Energy Tax (REB) in 2001

Electricity annual consumption (kWh)	REB €ct/kWh
0 - 10,000	5.83
10,000 - 50,000	1.94
50,000 - 10 million	0.59
> 10 million	0

Gas annual consumption (m^3)	REB €ct/m^3
0 - 5,000	12.03
5,000 - 170,000	5.62
170,000 - 1 million	1.04
> 1 million	0

Price formation and market behaviour in the electricity market

Effective price formation in the wholesale markets for electricity is particularly important for the development of the electricity sector. As of 2001 there has been an auction system for import capacity, which has improved competition between the Dutch electricity market and the markets from Germany and Belgium. Large price fluctuations in the APX give reason to suspect market manipulation, which makes it desirable to have effective monitoring of the electricity market and possibly intervention by the regulator DTe. In addition, it is not entirely certain whether an efficient renewal and expansion of production capacity will take place solely on the basis of price signals from the electricity market. Additional measures may be necessary to safeguard a guaranteed and affordable electricity supply.

Wholesale markets for electricity

After the liberalisation of the Dutch electricity market in 1998, two wholesale markets emerged: a bilateral contract or over-the-counter (OTC) market, and the Amsterdam Power Exchange (APX). The APX is a voluntary market in full competition with the bilateral OTC market. In anticipation of the liberalisation of the electricity markets in Europe, a number of market parties established the APX to create a trading place for electricity. The APX currently trades in a day-ahead market and a balancing market. The day-ahead market has been active since May 25, 1999. The balancing market has been developed to give market parties the possibility to correct possible imbalances that can arise in the course of a day as a result of unexpected variations in electricity demand or production. Trading in the APX occurs in an anonymous way, i.e., the trading parties do not have to disclose their identities. Furthermore, contracts traded in the APX are standardised in order to facilitate trading.

Spot market

The day-ahead market is considered as a spot market. In the spot market participants submit bids on electricity for every hour of the following day (‘day ahead’). Once the market is cleared the prices are given for every hour. Since its inception the day-ahead market in the APX has showed considerable price volatility. Until the end of 2000 the Protocol was blamed for this (see *Overview: Energy policy and market regulation*), because electricity trade in the APX in this period was primarily based on electricity imports. However, the characteristics of the electricity system also have an important effect on price formation in the spot market. Three factors play a relevant role here. First, electricity has to be constantly balanced (in terms of supply and demand), otherwise imbalances could jeopardise the stability of the entire network. Second, it is not feasible to store electricity, which means suppliers and customers are not able to hedge themselves with physical volumes from periods in which electricity prices increase significantly. Third, electricity demand is practically price inelastic in the short term. When prices rise consumers hardly reduce their demand, mainly as real-time pricing is not available. These three characteristics create short-term inelastic supply and demand curves during peak loads, which result in rapid and significant price increases. To avoid the possible financial risks that may result, energy utilities have to hedge against large price volatility (see box *Hedging and derivatives*).

The APX spot market still lacks liquidity, i.e., the number of buyers and sellers is still low, allowing trading parties to influence prices via their transactions in the exchange. This does not lead to effective price formation. Nevertheless, the shares of electricity traded in the APX are slowly increasing, especially since the Protocol ended at the end of 2000. Figure 4.11 shows the development of electricity volume traded in the APX. This figure shows the average monthly volume traded relative to physical supply. Volume traded in the spot market is expected to increase further. On some days the day-ahead market reaches an 11% share. To increase the transparency of the spot market, the APX has begun (since August 2001) to publish the aggregated supply and demand curves.

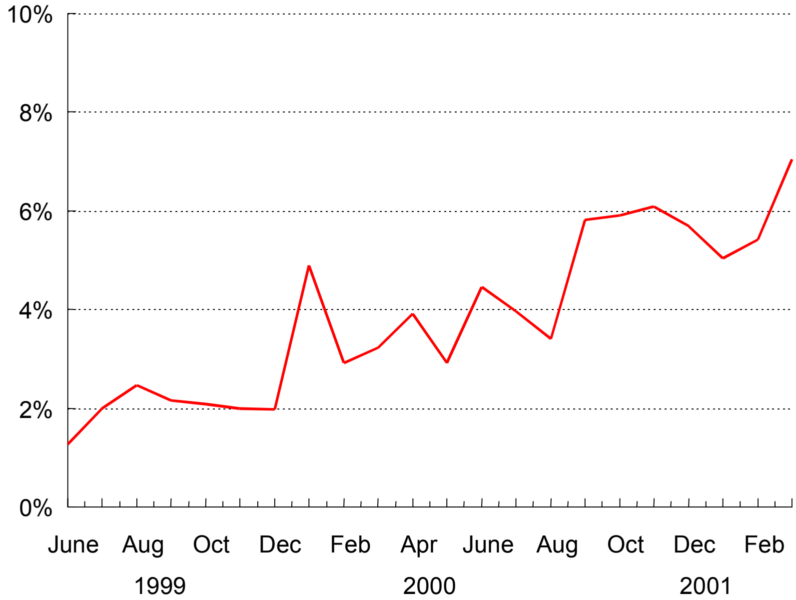


Figure 4.11 Market share of electricity traded on the APX (monthly average trade volume compared to physical supply)

The Over-the-counter market

The OTC market developed as a result of the liberalisation of the Dutch electricity market. The trading here is based on bilateral transactions with tailor-made contracts. Examples of contracts traded in the Dutch OTC market include day-ahead and forward contracts, swaps and options (see box *Hedging and derivatives*). Traders in this market are connected with one another through phones and screens that enable them to be continuously informed about the (electricity) supplied and demanded contracts. Firms such as Platts, Dow Jones and Argus report information about the OTC market that they obtain from a cross-section of traders in the OTC market. The reporting is done on a voluntary basis. While the information on prices is usually reliable, information on volumes traded generally is not.

Market power

Manipulation of the market is an issue that has to be thoroughly examined in the restructured electricity markets. Because of the nature of electricity, firms who own generation capacity are able to manipulate the market very effectively. This is especially true for producers who have not yet sold all the electricity they have generated, because they can still profit from an increase in the spot price until the time comes for the electricity to be delivered. A producer can strengthen its market position by purchasing futures contracts. By the time the electricity has to be delivered, the producer not only possesses its own production capacity, but also a part of the capacity of other producers. By holding back its own capacity or feigning technical breakdowns and covering supply obligations by having purchased futures contracts, this producer forces other producers to use their capacity with higher marginal costs, and thereby cause the price of electricity to increase. Market power can be effectively exercised during peak-load periods, when the electricity supply is at its highest. During the peak-load period, the withdrawal of capacity will have a larger effect than during periods of off-peak loading.

Hedging and derivatives

Electricity prices are influenced by changes in electricity demand, availability of generated capacity, fuel costs and other production costs. In a liberalised electricity market, a significant volatile spot price exists, subjected to demand and supply functions, in contrast with the previously used price system that was based on production costs, fixed margins and cost balancing. To hedge against financial risks from price volatility, energy companies and other market participants can make use of bilateral contracts or derivatives. Futures, forwards, options and swaps are tools specially designed for hedging. They are called derivatives because their values depend on the values of other assets. These kinds of contracts are not used primarily by most producers, traders and large energy consumers to earn money, but rather to facilitate financial planning.

One common derivative is a forward contract. This is a tailor-made bilateral contract that is generally traded in the OTC market. Under a forward contract a party is obliged to buy or sell electricity at a future date, at a pre-established (forward) price. If the spot price of electricity is higher at the maturity date than the forward price then the buyer would gain a profit. However, if the spot price is lower than the agreed price then the seller would profit. With forward contracts the counterpart is a trader.

Futures are also deferred delivery contracts like forwards, although they have a number of features that forward contracts do not have. Futures are standardised contracts, i.e., they have a predetermined delivery date, location and quantity, which make the price more transparent They are traded in organised exchanges. The counterpart for futures contracts is a clearinghouse. Participating parties pay gains and losses daily, i.e., price differences of the futures are settled via the clearinghouse each day once trading ends.

Other types of derivatives are swaps and options. A price swap is a negotiated agreement between two parties to exchange (swap) specific price risk exposures over a predetermined period of time. Options are derivatives that ensure the market participants a commodity within a defined price range. The buyer of a put or floor option pays a premium for the right to sell electricity at a predetermined price, at a specified point in time. On the other hand, the buyer of a call or caps option pays a premium for the right to buy the commodity at a predetermined price, at a specified point in time.

A well-regulated electricity market would prevent this sort of abuse. In the first half of 2001 a number of price spikes occurred in the APX day-ahead market, arising suspicion that market power was being exercised in the Dutch electricity market. TenneT, the transmission system operator (TSO), conducted an investigation into this matter and confirmed that the price spikes were caused by disruptions in generating capacity, maintenance work in Dutch and Belgian plants, and (removal) regression in capacity caused by cooling water restrictions. Furthermore, TenneT determined that nothing exceptional emerged regarding grid capacity or bidding patterns during the daily and monthly auctions on import capacity. However, TenneT added that the price developments are cause for closer monitoring of market behaviour. DTe have since announced that they will set up a monitoring system to analyse price developments and the behaviour of firms in the electricity market.

Prevention and deterrence

There are two possible ways to curtail market power: prevention and deterrence. Prevention entails measures that reduce the possibility to exert market power by those parties holding futures contracts. For example, placing a limit on the number of positions that can be taken by firms in the electricity market will constrain the ability of owners of generating capacity from accumulating large market shares. This can considerably reduce the vulnerability of the market to manipulation.

The other option, deterrence, is to impose sanctions on those who attempt to manipulate the market. However, it is not easy to establish when or to what extent a firm is exercising market power. For example, a firm can withhold capacity by claiming technical problems in its generating plants. Furthermore, prices in the day-ahead market can rise significantly when demand approaches maximum available capacity, making it difficult to distinguish whether the price increase is due to the nature of the market or to the exercise of market power. It can also be easier to observe market power in some trading systems than in others. In mandatory 'power pools', like the old system implemented in the UK and California, all production capacity was made available in one location. This facilitated data gathering, making it easier to identify the manipulator. However, this is much more difficult in an electricity market like the one in the Netherlands, because trade is decentralised and partly anonymous.

Congestion management

Price differences between the electricity markets of the Netherlands and Germany and Belgium stimulate the import of electricity. These differences have led to demand significantly exceeding available import capacity in the last two years. Available import capacity was divided into different categories (see Table 4.2) by TenneT in 2000. However, because market participants found this allocation unsatisfactory, TenneT together with its Belgian (ELIA, previously CPTE) and German (RWE Net and E.ON Netz) counterparts, as of January 2001 established an auction system for yearly, monthly and daily contracts, for both import and export. If capacity constraints arise in the interconnectors, capacity for the next day-ahead auction is immediately reduced. If the constraints in the interconnectors are bigger, then the capacity allocated to monthly contracts is likewise reduced. The results of the auctions are available on the Internet (see *Further information*). The prices paid for the available capacity of yearly contracts are shown in Table 4.2. The auction prices for monthly contracts and day-ahead contracts are shown respectively in Figures 4.12 and 4.14.

Table 4.2 Allocation of import capacity in 2000 and 2001

	2000	2001
Total available capacity	3,500 MW	3,900 MW
UCTE obligations	300 MW	300 MW
Former SEP long-term contracts	1,500 MW	900 MW
Annual contracts	800 MW	
APX day-ahead market	900 MW	
Annual contracts (auction)		900 MW
Monthly contracts (auction)		550 MW
Daily contracts (auction)		Other

The monthly auctions occur two weeks prior to the delivery period. Figure 4.12 shows the price development of different monthly auctions up to September 2001. Table 4.3 and Figure 4.12 show congestion at the interconnectors for yearly electricity import contracts from Belgium and Germany and for monthly import contracts from Germany.

Table 4.3 Prices paid on the auction for the 900 MW import capacity for annual contracts in 2001

Border-crossing connections	From	To	Price Year 2001 (€/MW)
ELIA – TenneT	Belgium	Netherlands	26,324
TenneT - ELIA	Netherlands	Belgium	105
RWE Net – TenneT	Germany	Netherlands	95,484
TenneT - RWE Netz	Netherlands	Germany	307
E.ON Netz – TenneT	Germany	Netherlands	92,203
TenneT - E.ON Netz	Netherlands	Germany	750

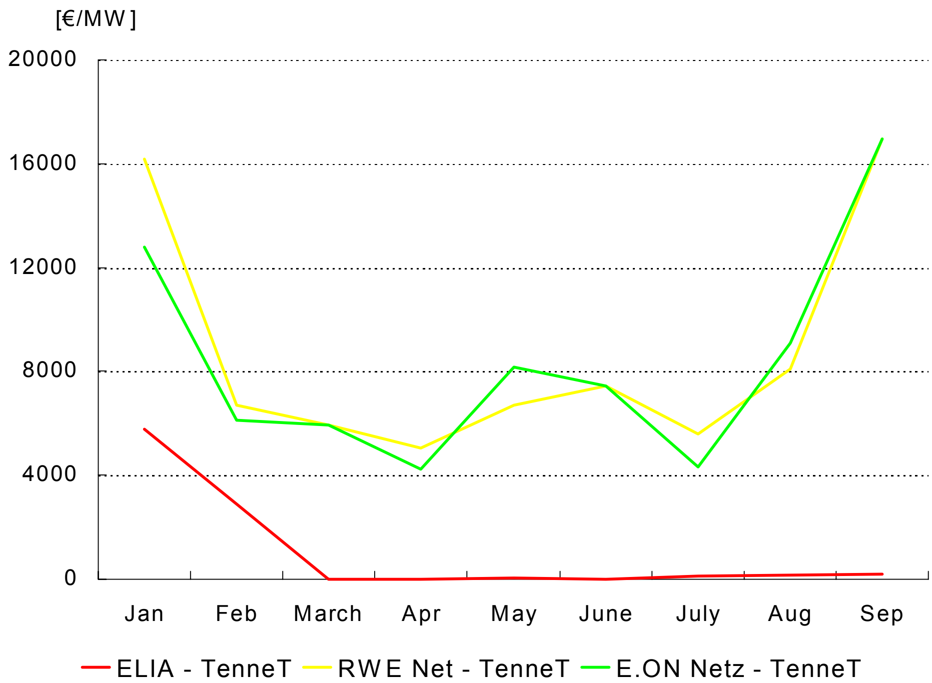


Figure 4.12 Auction prices of import capacity for monthly contacts in 2001

Day-ahead auctions and import capacity

The capacity offered for day-ahead auctions is non-continuous and varies during the day, making less capacity available during periods of peak demand. Figure 4.13 shows the average available import capacity for day-ahead auctions from January through May 2001. The figure also shows the average capacity that is allocated to interested parties. The closer the two curves the higher the congestion level. When they overlap it indicates that all available capacity has been allocated.

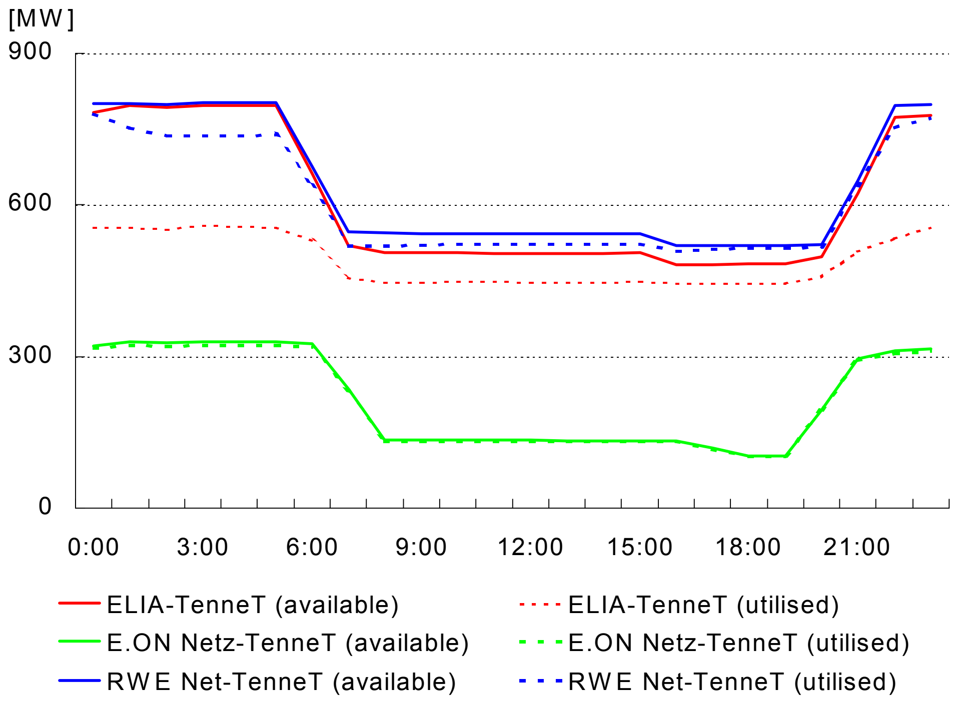


Figure 4.13 Available and obtained import capacity for day-ahead contracts (average for the period January-May 2001)

From Figure 4.13 it seems clear that the interconnector used to import electricity from Germany to the Netherlands is fully utilised during the day. Although there are also day-ahead auctions to export capacity (transfer electricity from the Netherlands to Belgium and Germany), allocated capacity remains less than available capacity. The average costs for import capacity during periods of congestion are shown in Figure 4.14. This figure also shows price differences between day-ahead contracts in the APX (Dutch) and LPX (German) power exchanges. It can be concluded that congestion levels for interconnectors at the German-Dutch border are caused by price differences between the electricity markets in the two countries.

In a competitive market with no arbitrage opportunities and where no transmission costs or extra tariffs are charged, the price for import capacity will equal the difference between the expected wholesale prices in the two neighbouring countries. Something to consider is that day-ahead auctions work with the expected wholesale market prices for the following day. If under competitive behaviour, the auction prices given would thus indicate the price differences that can arise between the two countries for certain periods of the day.

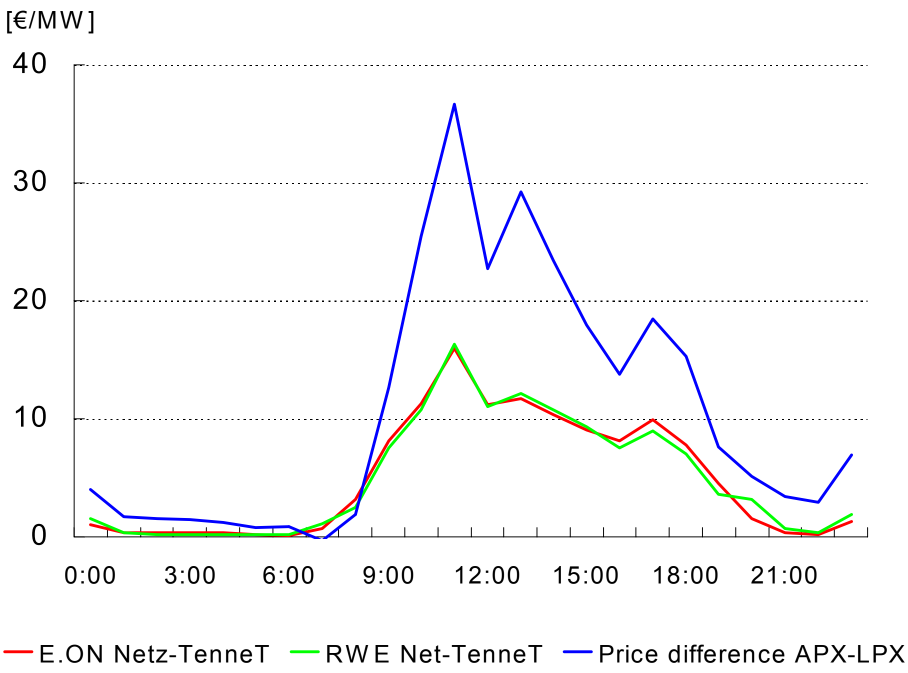


Figure 4.14 The price for import capacity of day-ahead contracts and price differences between power exchange markets in the Netherlands and Germany

Disadvantages of auction system

The auction system as implemented by the national TSOs is an efficient and market-based system, because the bids reflect exactly the market value as perceived by the market parties. In other words, the import capacity is allocated to the party that is prepared to pay the most. However, this system also has disadvantages:

- Electricity contracts can be independent of the capacities to be auctioned. If there is limited available capacity, especially for day-ahead auctioning, then the risk arises that no or less capacity is auctioned, so that contracts cannot be fulfilled.
- It favours market participants that trade larger volumes.
- Because of the low liquidity of the auction markets, market domination and manipulation are important issues. An economically efficient allocation of capacity requires a guaranteed minimum number of participating market parties. For example, Electrabel, because of its high market concentration in the Belgian market, has a lot of influence on the interconnector between Belgium and the Netherlands.

Alternative system

There are other ways of organising the transmission of electricity between countries. For example, a market splitting system exists in Scandinavia. This method consists of splitting a power exchange into different bidding regions, each having a limited capacity of exchange. Market parties are unable to trade electricity directly between the regions, as this inter-regional exchange is managed by the Nordic Power Exchange ('Nord Pool'). The spot price in each region is determined by supply and demand, and the available transfer capacity of the interconnectors to other regions. Congestion is reflected when the spot price in one region is higher than the one in another region. The market mechanism enables the exchange of electricity between the regions. The advantages of this system are:

- price reflects available generation capacity;

- market participants are stimulated to trade in the spot market, reducing risks of market domination because of the increase in liquidity;
- in the long term producers, because of the high prices, will invest in areas where there is scarcity in the electricity supply;
- price signals are available to all market participants.

The introduction of this system, which is attractive in theory and preferred by many experts, can only be successful in certain types of electricity markets. In the continental European market a number of physical, structural and market barriers to implement this mechanism exist. The extremely meshed network in this area hampers the delimitation of bidding regions and the establishment of available transmission capacity.

Import of green electricity

In order to buy green electricity produced in foreign countries, importers must on top of buying green certificates abroad, import the physical electricity. The green electricity sold by a supplier over a year has to be balanced by the green electricity produced, for both its export abroad and import to the Netherlands. This means that an energy supplier can import the physical electricity once it has reached its lowest price (commodity price and auction price combined). The physical electricity, regardless of when it is actually generated, is therefore most likely to be imported during off-peak periods.

Adequacy of electricity supply

The long-term adequacy of the electricity supply was a relevant issue in the centrally regulated system that existed before the recent liberalisation of the energy market. In order to ensure adequacy of supply, the SEP developed a policy to have about 12% more available capacity than peak demand. The costs of this reserve capacity were covered by the tariffs charged to customers. To ensure the long-term supply security, SEP created ten-year plans for the required new production capacity.

In a liberalised electricity market there is no central body that determines whether to maintain old power plants or invest in new production capacity. Investment in new capacity is therefore left to the market parties. In theory a competitive market would send firms correct price signals to encourage investments in new capacity. There are, however, market imperfections that might ensure that the reality is different. Risk aversion and market manipulation can lead to a lack of investments in new production capacity. Firms may not be willing to invest in needed peak plants, because these plants have a low average running time and therefore provide uncertain income. Furthermore, electricity producers could intentionally cancel investments in the sector, leading to a capacity shortage that would force the most expensive power plants to be put into operation, and causing the market price to rise. Finally, at moments of extreme peak demand or due to calamities, the electricity supply could be jeopardised. *Mechanisms to ensure adequate supply* describes a number of ways to better ensure supply security.

In the Netherlands there is no extra remuneration for electricity producers besides the market price, i.e., the present system pays the market price to the plants that generate electricity. However, TenneT does contract 550 MW as reserve (regulating and emergency capacity) for which a fixed sum is paid (about 4% of the maximum peak capacity in 2000). Reserve capacity is also provided to the balancing market but, similarly as for regular capacity, is only paid for when it is in operation. In principle, firms with a capacity greater than 60 MW are obliged to bid in the reserve capacity market. In the present Dutch electricity market, however, a certain amount of capacity remains available that is too expensive to be dispatched. Because of this overcapacity and the present market conditions, no new investments should be expected in the short term.

Mechanisms to ensure adequate supply

The following is an overview of a number of theoretical or already implemented mechanisms that provide an incentive to make extra capacity available.

Capacity Payments

The generating companies can be given capacity payments with the aim of encouraging the construction of new capacity and thereby increasing total generating capacity. In theory a capacity payment should cover part of the fixed costs of a power plant, removing the uncertainty about future prices covering long-term marginal costs (incl. capital costs). The system has a regulated character, which does not make it compatible with a liberalised market. Moreover, it has not been proven that it successfully improves the adequacy of the system.

Capacity markets

This system is implemented primarily in the United States. Under this system, where an organised market trades capacity, regulatory authorities determine the amount of capacity each consumer has to buy. Furthermore, the regulator also determines the maximum amount that each producer is allowed to sell.

Capacity owned by the system operator

This measure obliges the TSO to buy and operate power plants that would otherwise be mothballed or decommissioned. It provides a reserve capacity that would only be dispatched if the market price is higher than a pre-established maximum level. The fixed costs of these plants would be covered by the system tariff charged by the TSO to the consumers, while the variable costs would be covered by the market price. The disadvantage of this method is that it is market interventionist and thus not compatible with the current liberalised market.

Market for reliability contracts

This mechanism obliges consumers or the system operator to buy reliability contracts from the producers. These reliability contracts are in the form of call options that would set a price ceiling for the electricity. If the market price of electricity is higher than the option price then consumers could exercise the option at the pre-established price, for which they could obtain the electricity. The premium paid for the option can be seen as income for the producer, to pay the fixed costs of the plant. The producer would be fined if it does not deliver the electricity. The advantage of this mechanism is that it is market-based.

A short time ago, however, a new investment decision was made public. Intergen, a joint venture between Shell and Bechtel, will start building a new power plant in the Botlek area. This news surprised the whole sector, as it is known that current prices are not high enough to cover the long-term marginal costs of a new power plant. To assure themselves of financial support for the project, Intergen signed a 15-year contract with Nuon. This agreement seems logical when considering Nuon's position. An assessment of electricity prices, based on an analysis of future electricity supply and demand, shows a price increase in the spot market as of 2005. The Intergen plant is expected to be put into operation only in 2004. Furthermore current significant price fluctuations in the spot market arouse suspicion that the market was being manipulated. Electricity suppliers such as Nuon do not own significant capacity. This exposes them to the volatility and uncertainty of the market, as they have hardly any possibility to charge customers according to the price variations. The fact that the Dutch market system allows

long-term contracts between producers and suppliers or distributors, encourages suppliers to rely on these contracts in order to hedge themselves against the uncertainty and volatility of the electricity market. A consideration that also played a role in Nuon's decision was that a new supplier entered the market so the dominance of existing players may be challenged.
The Intergen-Nuon venture does not solve the problems of guaranteeing an adequate supply in the long term, because this would also require a well-functioning electricity market. Discussion about supply security has been renewed between energy specialists and policy makers, partly in response to recent problems in California and Scandinavia. In both cases no extra incentives except price signals were given to producers.

Price formation in the future Dutch electricity market

Recent experiences in Dutch and foreign electricity markets have brought about the realisation that the electricity market could develop in an unwanted direction. Market power and uncertainties about adequacy of supply play a greater role than was initially expected. For price formation in the future Dutch electricity market, a distinction can broadly be made into two scenarios.

The future market could develop as a market in which market power is exercised by dominant electricity producers. In this scenario electricity prices would be higher than in a fully competitive market, and market manipulation would occur especially during peak periods. It can be expected that high prices will stimulate the construction of new capacity, by both existing market participants and new players, because electricity prices would be higher than the long-term marginal costs of new power plants. There is still a risk that inefficient over-investing in the electricity sector might occur. The result would be similar to the situation in England and Wales where, as a result of high electricity prices in the last decade, new entrants have built new gas-fired power plants that ultimately resulted in overcapacity.

There can also be low prices in the electricity market when there is a high degree of competition, both between electricity producers in the Netherlands and with imports from abroad. No production capacity is held back in this scenario, so spot market prices reflect marginal costs of the most expensive plants used. This scenario begs the question of whether low prices provide the right incentives for investors to build new capacity. The question is even whether producers would devote sufficient attention to the maintenance of existing plants.

Structure of current and future energy prices

End-user prices for gas and electricity customers are comprised of three components. These price components are susceptible to competition in the energy markets, regulation by DTe and the government's fiscal policy. An analysis of the price components and their future development provides insight into the structure of end-user prices in the current, partially liberalised energy market and for a fully open energy market. A separate analysis provides insight into the 'green price' that energy suppliers now charge in the free green electricity market. Based on an analysis of future developments in the energy markets and for tariff regulation, an assessment is made for end-user prices in the mid to long term.

Captive and free customers

Until the entire energy market is liberalised in 2004, two different types of customers can be distinguished: free customers, who are already free to choose their energy supplier, and captive customers, who are still 'assigned' to an energy supplier, i.e., the license holder. Until 2002, the only free customers in the electricity market are very large consumers with an electric capacity larger than 2 MW. As of 1 January 2002 customers with an electric capacity smaller than 2 MW and a connection value larger than 3 × 80 Amperes will also have a free choice. In the gas market all customers with an annual consumption of 10 million m^3 or more have, since 2000, been free to choose their gas supplier. As of 2002 customers with a minimum consumption of 1 million m^3 will also have this freedom of choice.

Since July 2001 all energy customers have been free to choose their supplier of green electricity. In 2001 only the 'greenness' of the green electricity supplier is at stake while the electricity itself comes from the license holder. As of 2002 green electricity customers will obtain both 'greenness' and their electricity from their green electricity supplier (see also *Insight: Market organisation and strategy*).

Three price components

End-user prices for both captive and free energy customers are comprised of three components. The first component is the price for the good (gas or electricity), or 'commodity'. This price component is therefore also known as commodity price. The second component is related to transport and other services supplied by the network operator, and is generally known as the transport tariff. The third component is the total of the government levies added to the energy price.

Competition in a liberalised energy market takes place mainly in the areas of production and supply of the commodity. Transport and other services from the network operator are more or less regulated, e.g., transmission tariffs for electricity are fully regulated by DTe. Conversely, in the case of gas, tariffs for transport and other services are not determined by DTe, but should be published by the supplier. With the aid of guidelines, DTe has precisely defined the basic services to be provided by network operators and other service providers in the gas market (including gas storage companies). Free customers who want to make use of certain services can negotiate with the supplier about the tariff and other conditions.

Structure of end-user prices

The structure of end-user prices in 2001 for electricity and gas can be compared with price levels and structure in the near future. Future prices are based on the year 2004, because by then both the electricity and gas markets will be fully liberalised. For both years the end-user prices are split into the earlier described three components: commodity price, transport tariffs and taxes. When it is considered useful, a further splitting of the separate components is made. The level of the commodity prices depends on market developments, and for 2004 can be determined based on analyses of developments in the energy markets. The level of regulated components can be found in DTe publications, but is also partly based on estimates of the effects that DTe's guidelines will have on future tariffs. With regard to government levies, it is presumed that the level of the taxes will remain unchanged to 2004. A detailed explanation of the different components can be found in the different text boxes.

Electricity

Figure 4.15 shows end-user prices for electricity in 2001 for different types of customers and the expected prices for 2004. For households the price is based on a single tariff, and their end-user prices are shown with VAT. End-user prices for the different types of large consumers are given for two different load hours. Load hours means the equivalent full load hours calculated by dividing the annual consumption by maximum hour capacity. Large consumers with a capacity starting at 1 or 2 MW are assumed to be connected to the medium-voltage grid, while very large customers with a capacity starting at 50 MW are connected to the high-voltage grid.

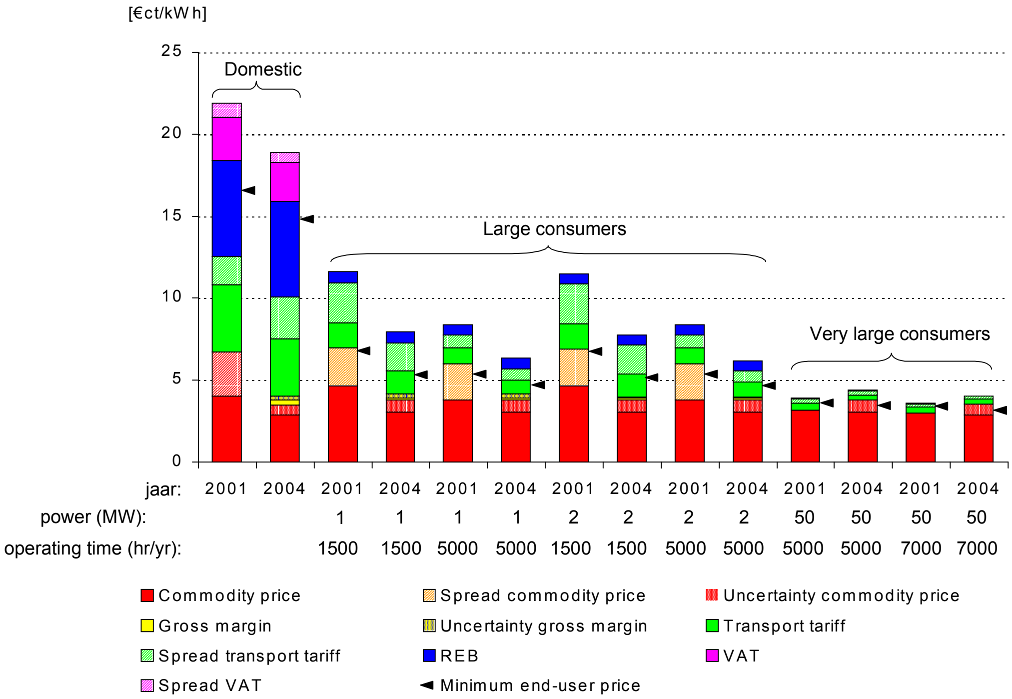


Figure 4.15 Composition of electricity end-user prices electricity in 2001 and in 2004 for various types of consumers

Figure 4.15 also shows that end-user electricity prices for households and most large consumers are expected to be lower in 2004 than in 2001, while an increase is expected for very large customers. Figure 4.15 includes a spread resulting from differences between network operators and license holders, and uncertainties related to future prices and tariffs. The top of each column shows the maximum possible end-user price, while the lowest possible price is also indicated. Taking account of spreads and uncertainties, it is not impossible, although Figure 4.15 suggests a price decrease, that prices may increase in individual cases or the reverse.

The differences in the level of the end-user prices between the different types of customers are caused by differences in transport tariffs and taxes. Customers connected to a lower network level pay a higher transport tariff. Taxes on the kWh price are higher as customer use is lower. A considerable part of end-user prices for households is comprised of the REB levy. Very large customers, on the other hand, pay hardly any REB as this energy tax is nil for consumption of 10 million kWh or more.

Structure of electricity price in 2001

Commodity

- *Commodity price*: Captive customers are faced with regulated commodity prices, or so-called supply tariffs. These supply tariffs are established by DTe based on yardstick regulation (see *Energy policy and market regulation*) every quarter for every license holder. The supply tariffs of the captive customer groups in Figure 4.15 are equal to those from the third quarter of 2001. Very large customers are already non-captive in 2001. The commodity price for these customers is established in the wholesale market (see also the previous analysis in *Insight: Energy prices*). The price shown for the year 2001 is the average market price in the APX in the first half of 2001. In calculating the commodity price for large consumers, irrespective of the load hours, it is assumed that 68% of the electricity is purchased during peak hours. For very large customers, it is assumed that 58% of electricity consumption occurs during peak hours.
- *Spread in commodity price*: The spread of the supply tariffs emanates from the tariff differences between the various license holders (see also *Overview: Energy prices*)

Transport

- *Transport tariff*: Electricity transport tariffs for free and captive customers are taken from DTe publications. The transport tariff reflects the costs of three services: transmission, system and connection.
- *Spread in transport tariff*: The spread in the transport tariffs is the result of differences between the tariffs of the different network operators (see *Overview: Energy prices*).

Taxes

- *REB*: The nil tariff for REB is abolished for the first 800 kWh (see also *Overview: Energy prices*). Every household is credited with € 142 annually on their electricity bill, irrespective of their annual consumption of gas and electricity. This amount is not deducted from the electricity tariffs shown in Figure 4.15.
- *VAT*: Households are charged 19% VAT. The VAT levy applies to all price components, including the REB.
- *Spread in VAT*: The spread in the VAT is the consequence of the spread in the commodity price and transport tariff.

The end-use price for very large customers is mainly determined by the commodity price. It is expected that this commodity price will be higher in 2004 than it was in 2001 because, as a consequence of a reduced overcapacity for electricity production, the price in the wholesale electricity markets will increase (see also the previous analysis in *Insight: Energy prices*).

The expected commodity price for households in 2004 is lower than the regulated supply tariff in 2001 (commodity price plus margin of license holder). The supply tariff for captive large consumers with 1500 load hours is also relatively high in 2001. However, this difference is much smaller for large consumers with 5000 load hours. This is because the supply tariff is comprised of a kWh component and a kW component. The kW component has much more influence on the final end-user price per kWh in case of less load hours.

Structure of electricity price in 2004

Commodity

- *Commodity price*: In 2004 the commodity price for all consumer groups will be determined by price formation in the wholesale electricity market. The commodity price is related to the marginal costs of electricity production, which are largely comprised of fuel costs.
- *Uncertainty of commodity price*: The uncertainty of the commodity price in 2004 greatly depends on the uncertainty of fuel costs associated with electricity production and by the uncertainty about the degree of competition in the electricity market.
- *Gross margin*: After 2004 the commodity price will reflect the purchase price for energy suppliers. For energy suppliers who supply electricity for the retail market there is a gross margin assumed on top of the commodity price: 10 to 15% for households and 5 tot 10% for large consumers. Very large customers are assumed to obtain their electricity directly from the wholesale market.
- *Uncertainty of gross margin*: The uncertainty of the gross margin reflects possible price differences among energy suppliers and is, in addition influenced by the uncertainty of the commodity price.

Transport

- *Transport tariff*: Transport tariffs for 2004 are calculated based on the transport tariffs from 2001 and the efficiency discounts for network operators, as published by DTe (see *Overview: Energy policy and market regulation*). Because the efficiency discounts for 2004 are still unknown, it is assumed each grid operator will have a 4% discount.
- *Spread in transport tariff*: The spread in the transport tariffs is caused by tariff differences between the various network operators.

Taxes

It is assumed that REB and VAT in 2004 will be the same as in 2001.

The same effect is true for transport tariffs. Both the lowest transport tariff applied by network operators and the corresponding spread are lower for more load hours as a result of a fixed kW component in the transport tariff. The efficiency discounts established by DTe and applied to the costs charged by the network operator will, in most cases, cause transport tariffs to be much lower in 2004 than in 2001.

In 2004 the load hours will no longer have a direct effect on the commodity price, as can be seen when comparing end-user prices for 1 MW capacity at load hours of 1500 and 5000. The kW component no longer plays a role in the commodity price as it did in the supply tariff of 2001. However, the load hours can have an effect on the price level, because it can affect the relationship between off-take during peak and off-peak hours.

Gas

The end-use prices for gas in 2001 and 2004 for different types of end-user are shown in Figure 4.16. The end-use price for households includes VAT. Figure 4.16 also shows the gas prices for large consumers with an annual consumption of 1 million m^3 and for very large customers with an annual consumption of 10 million m^3 or more. A distinction is made for large consumers and very large customers between two different values of load hours. It is assumed in the figure that the large consumers are connected to the main grid of a regional distribution company, while the very large customers are directly connected to the national transmission network. Furthermore, it is assumed that regional energy suppliers and very large customers use the services provided by Gasunie Transport Services.

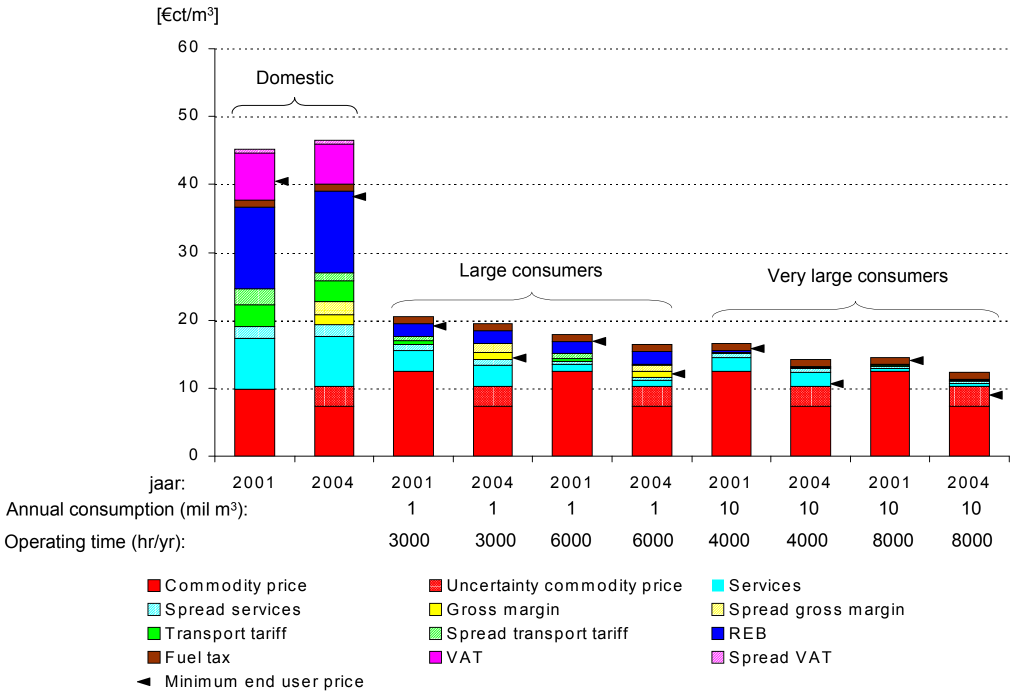


Figure 4.16 Composition of gas end-user prices in 2001 and in 2004 for various types of consumers

For households, the end-user price in 2004 is expected to be practically the same as in 2001. For large and very large consumers, gas prices could turn out to be lower than in 2001. Because of the linking mechanism between oil and gas price, development of the commodity price for gas lags somewhat behind oil price development. Gas prices in 2001 were therefore still under the influence of high oil prices from 2000. Because changes in the commodity price for households are bound to a maximum, the effect of the oil price increase is not fully incorporated into this commodity price for 2001. Subject to an uncertainty margin in the development of the oil price, it is expected that the commodity price for gas for all types of customers will be lower in 2004 than in 2001. In this case it is assumed that the gas-oil price link will continue for the time being.

The lower gas price indicated in Figure 4.16 can actually turn out to be higher (or lower) in individual cases, because the different price and tariff component spreads and uncertainties are included. This situation applies, for example, to households. However, the likelihood of this is small as residential customers are then expected to have the lowest tariffs for all components in 2001 and be charged the highest tariffs in 2004. The top of each column in Figure 4.16 indicates the maximum possible end-user price, while the lowest possible end-user price is also indicated in the figure.

Structure of gas price in 2001

Commodity

- *Commodity price*: The commodity price for large and very large consumers is calculated using Gasunie's pricing and services system (CSS). Based on this tariff system, the commodity price is linked to the oil price. The prices in Figure 4.16 have been calculated using the average oil price from the first two quarters of 2001. For households, the lag effect from the sharp oil price increase in 2000 is taken into account.
- *Gross margin*: The licensed gas suppliers of captive customers are allowed to impose these customers with a surcharge on their purchase price (commodity price + services). This can be seen as a regulated gross margin for these suppliers. The surcharges are determined and published by DTe (see also *Overview: Energy prices)*.
- *Spread in gross margin:* The spread in the gross margin reflects the differences in the surcharges added by the different license holders.

Transport

- *Services*: The costs for services are calculated using Gasunie's pricing and services system (CSS). This system incurs these costs depending on the load hours of gas off-take, and the distance from the customer to the entry points of the Gasunie grid.
- *Spread in services*: The uncertainty of the costs for services is determined by the spread in the distance from different customers to the entry points.
- *Transport tariff*: The transport tariffs for captive customers are regulated and determined by DTe.
- *Spread in transport tariff*: The spread in these regulated transport tariffs arises from the differences between the transport tariffs of the different regional network operators.

Taxes

- REB: The level of the REB levy depends on the annual consumption (see also *Overview: Energy prices*).
- BSB: A fuel tax is put on gas and known in Dutch as BSB (see also *Overview: Energy prices*).
- VAT: Households are subject to a 19% VAT. The VAT levy applies to all price components, including the REB.
- *Spread in VAT*: The spread in the VAT is a result of the spread in the gross margin and the transport tariffs.

Structure of gas price in 2004

Commodity
- *Commodity price*: It is assumed that the commodity price in 2004 will still be linked to the oil price, as in Gasunie's current pricing and services system.
- *Uncertainty of commodity price*: Account is taken of an uncertainty in the commodity price that arises from the uncertainty in the oil price (17 to 25 $ per barrel).
- *Gross margin*: It is assumed that energy utilities maintain a gross margin on the purchase price. This margin is 10 to 15% for small and large consumers. It is assumed that very large consumers obtain their gas directly from gas companies.
- *Spread in gross margin:* The spread in the gross margin arises from the uncertainty in the oil price.

Transport
- *Services*: The tariff system for Gasunie's services will be changed as of 2002. It is assumed here that the tariffs in the new system will no longer be distance-dependent, but that the tariff will remain dependent on the load hours. It is believed that on average the new tariff will not sharply deviate from the currently used tariff.
- *Spread in services*: The introduction of a new tariff system for Gasunie's pricing and services system may entail a shift in the assignment of costs. It is assumed here that this shift would fall within the old distance-dependent spread.
- *Transport tariff:* Transport tariffs for 2004 are calculated based on the transport tariffs from 2001 and the efficiency discounts for regional network operators for 2002 and 2003 (see also *Overview: Energy policy and market regulation)*.
- *Uncertainty of transport tariff*: The expected difference in transport tariffs between the different regional network operators is shown with a spread.

Taxes
It is assumed that REB, BSB and VAT in 2004 will be the same as in 2001.

Just as for electricity prices, the price components of transport and taxes for gas customers with a relatively small annual consumption comprise a relatively large part of the end-user price. Because households face a relatively high transport tariff (for the national transport and regional distribution networks) and also have to pay considerable taxes, the commodity price only determines about a quarter of the end-user price. For large consumers, the share of the commodity price in the end-user price is at least half. For very large customers, the share of the transport tariff in the end-user price is marginal.

When Gasunie's service tariffs are compared between large and very large consumers, the services component appears to be highly dependent on the load hours. Service tariffs for large consumers with 6000 load hours are, for example, approximately 60% lower than for 3000 load hours. For 2002 the tariff system of Gasunie Transport Services have to be adapted to DTe's new guidelines (see also *Insight: Energy policy and market regulation*). Because the costs will remain based on the capacities of transport networks and other facilities, the new tariffs are expected to remain highly dependent on the load hours.

Green electricity

The increase in the REB since 1 January 2001 and the nil tariff for green electricity means that the price difference for small consumers between green and conventionally generated electricity ('grey power') will be practically non existent. The number of consumers who switched from 'grey' to green power sharply increased in the first half of 2001. Moreover, consumers are free to choose their green power supplier since 1 July 2001 (see also *Insight: Market structure and strategy*).

Different prices have been charged by energy suppliers for the 'greenness' of the electricity. In 2001 energy suppliers used the following three pricing strategies:

1. A number of energy utilities, including Essent, equate the end-user price for green power in a certain supply area to the end-user price for grey power in that area. Other suppliers, such as Energieconcurrent, offer green power with a fixed discount related to the end-user price for grey power in the same supply area.
2. Nuon charges a fixed tariff for the greenness of the power, while other price components depend on the supply area.
3. Energy utilities, such as Eneco en Remu, always charge the same end-user price for green power, irrespective of the supply area of the customer.

The three pricing strategies result in different prices that customers pay for the greenness of the green electricity. For the first two systems mentioned, the green price depends on the supply area in where the customer is located, while in the third system the price of the greenness varies depending on the supply area. Figure 4.17 shows the structure of green electricity prices for households in 2001 charged by the three largest energy distributors in the Netherlands (Essent, Nuon and Eneco) in their own supply area and the areas of their competitors. For the sake of comparison, the end-user price for grey power that applies in the supply areas of the three different distributors is also shown.

The green electricity price is split into a commodity price, a transport tariff, the 'green price' and VAT. The commodity price and the transport tariff are determined, respectively, by the license holder and the grid operator in the customer's supply area. As of 1 January 2002 the green supplier is also permitted to supply the commodity and determine its price. The green distributor is then no longer dependent on the commodity price charged by the license holder in the supply area.

Figure 4.17 shows that the price for greenness in a supply area is very dependent on the distributor. Nuon applies a fixed surcharge of 0.52 €ct/kWh for greenness, in addition to the price obtained from the REB exemption. Of the three distributors represented in the figure, Nuon has the lowest commodity price. However, Nuon is obliged until the beginning of 2002 to charge for green electricity the supply tariff that is valid in the specific supply area. By deciding on its own supply tariffs as of 2002, Nuon could lower the end-user price for green electricity in regions outside its own supply area.

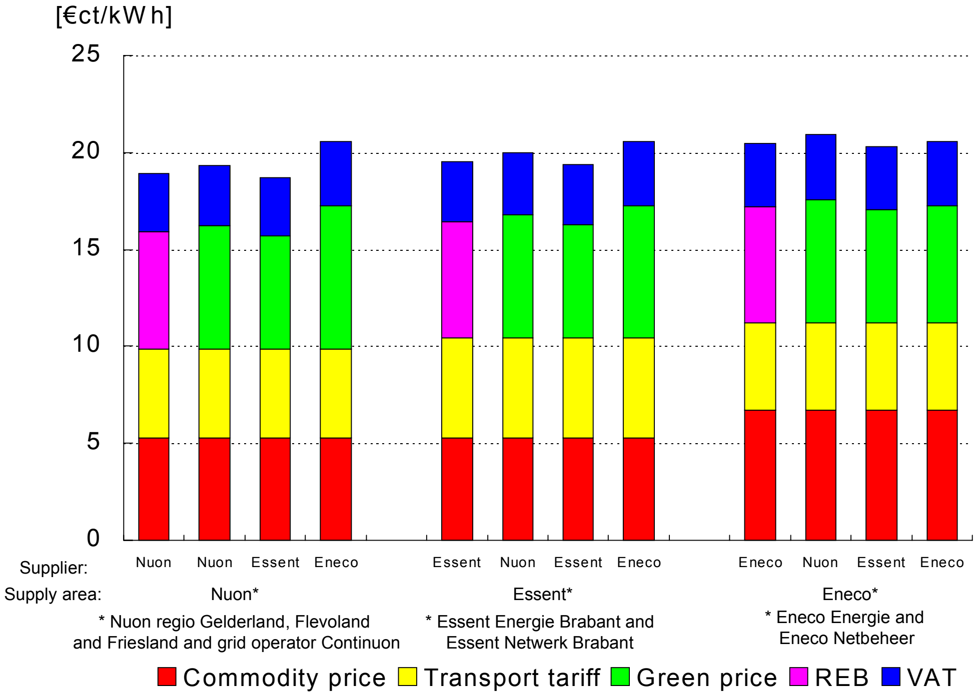


Figure 4.17 Composition of green electricity end-user prices for households in various supply areas for various suppliers in 2001

When consumers choose Essent as their green supplier, they pay the same price as they would for grey power. The price charged by Essent for the greenness is thus equal to the REB tariff that would apply to grey power for every supply area. As of 2002 Essent will also be free to determine its own commodity price for green electricity in other supply areas. When Essent continues to use the same pricing strategy, this will have no effect on the end-user price for green electricity. The green electricity price remains equal to the price for grey power in the supply area. However, a shift does occur between the price for the greenness and the price for the commodity. The price for greenness in Eneco's supply area will rise when Eneco charges also in 2002 a higher commodity price than Essent for grey power. It must be noted though that the differences in the commodity prices for captive customers in different supply areas, as a result of DTe's regulatory system, will quickly diminish.

When consumers choose Eneco as their green electricity supplier, the price for greenness depends on the supply area in which they live. The figure indicates that Eneco charges the same end-user price for green electricity in every supply area. Eneco bases this fixed green electricity price on its own conventional electricity price plus a surcharge of about 0.23 €ct/kWh. By charging a uniform tariff, the price level for greenness varies whereas the end-user prices among the different supply areas remain fixed. Eneco's green price in Nuon's supply area is relatively high as Nuon's commodity price is lower than Eneco's. If after 2001 Eneco continues to use the same pricing strategy and not change its commodity prices, then the end-user price for green electricity will also not change.

The green price in 2001 can also vary for other green electricity suppliers. This depends on the choice of pricing strategy (see also *Overview: Market organisation and strategy)* and possibly the commodity price for grey power (see also *Overview: Energy prices).*

End-user prices after 2004

Based on expected developments in price setting in the gas and electricity markets and on trends in tariff regulation, an assessment can be made for end-user prices after 2004. By taking uncertainties into account in the different price components, a range is given in Figures 4.18 and 4.19 of the level of end-user prices for electricity and gas after 2004 for different types of end users. It must be explicitly stated here that the range represented is not a prediction of future end-user prices, but an assessment with a certain probability when trends and developments take place according to the expectations described below.

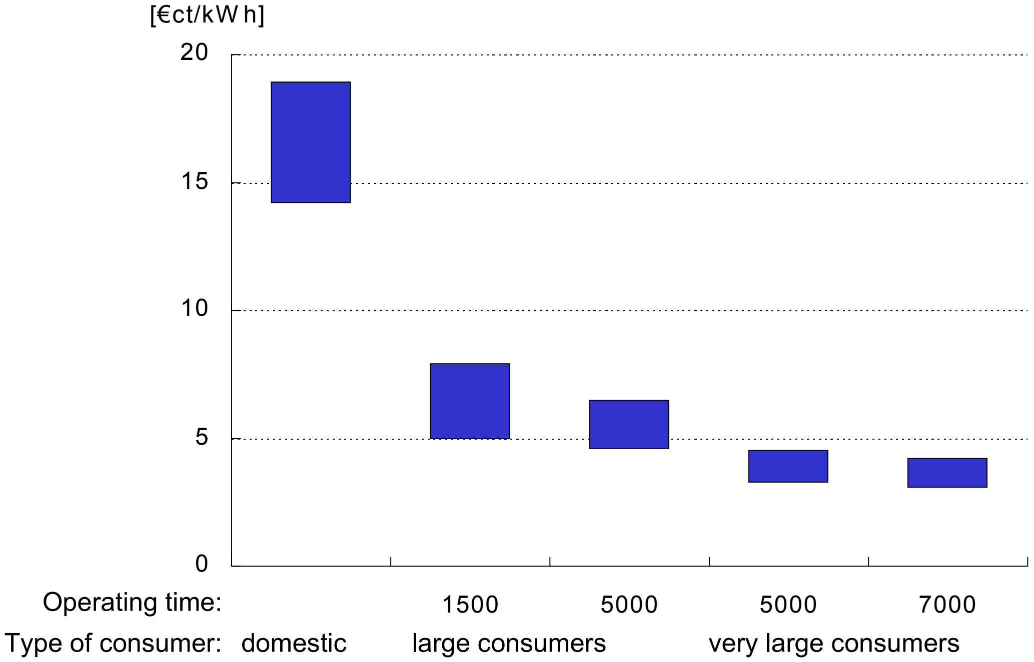


Figure 4.18 Electricity end-user prices 2004 indicated with a band-with resulting from expected/estimated developments of various price components and uncertainties involved

Commodity price

It is expected that the overcapacity of generating power in the Dutch electricity market after 2004 will sharply decrease, making the electricity market more susceptible to strategic behaviour by market participants (see also the previous analysis in *Insight: Energy prices*). It is believed that this will result in an increased commodity price. The scarcity in the electricity supply will be especially noticeable during peak hours. Large consumers will notice the commodity price increase the most, because for them the commodity component comprises a relatively large part of the end-user price and they have a relatively larger off-take during peak hours.

Of course, fuel costs for electricity production also continue to play an important role in the level of the commodity price of electricity, as these costs largely determine the marginal costs. Expectations are that marginal costs for electricity production in the future electricity market will be determined by the price of natural gas. Because of the eventual disappearing of overcapacity, it is possible that the electricity price becomes more influenced by long-term marginal costs, i.e., capital costs of power plants will also be reflected in the price. The long-term marginal costs will, most likely, be determined by the costs for gas-fired power plants.

In the longer term the oil price is expected to be lower than the oil price in 2000, making the gas commodity price lower than in the first half of 2001. Furthermore, it is expected that after 2004, because of the further development of gas-to-gas competition, the link between the gas and oil price will be weakened. Price spikes in the oil price would then not, or hardly influence the gas price. The gas price will, moreover, be more influenced by gas import from abroad (see also *Insight Energy policy and market regulation).*

The gross margin to be charged by energy suppliers can be put under pressure by competition in the retail market. However, energy suppliers have no direct interest in a price war (see *Insight: Market structure and strategy*), but could be tempted into one by new entrants. The likelihood that the gross margins in the retail market come under pressure is greater for electricity than for gas.

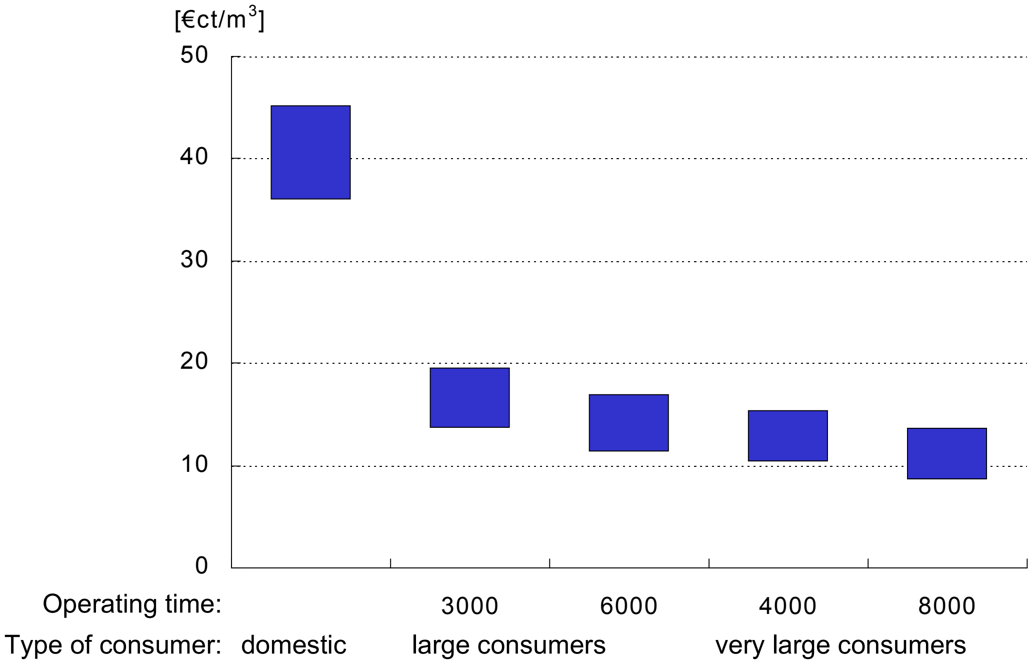


Figure 4.19 Gas end-user prices after 2004 indicated with a band-with resulting from expected/estimated developments of various price components and uncertainties involved

Transport tariffs

The end-user price of electricity for small consumers is largely, about 20 to 35%, determined by the transport tariff. These transport tariffs are expected to converge, as a consequence of the price-cap regulation, to an average tariff level in the future that is about 20% lower than in 2001. Because transport tariffs only play a limited role in determining the end-user price for large and very large consumers, changes in the transport tariffs for these customer categories will be less noticeable.

As of mid 2001 little was known about future tariffs for services from the national and regional gas network operators and other providers, such as gas storage companies. The guidelines prescribe that the tariffs must be based on costs. Efficiency discounts, however, are not applicable. An eventual fall in tariffs will be the result of negotiation between network operators and network users.

Expectations are that the biggest effect of the new guidelines will be increased competition between gas suppliers. Besides shifts within the tariff structure, for the time being no big changes in the level of gas transport tariffs is expected. The consequence of shifts may be that certain customer categories are charged a higher transport tariff, while other customers pay less.

Taxes

The working group 'Greening of the fiscal system II' has recently investigated a possible broadening and increase of the REB. Broadening would mean that large and very large consumers pay more REB, while an increase in energy costs would be compensated by lowering the partnership tax. The working group, however, has made no formal recommendation for actual broadening and increasing of the REB. As far as future end-user prices are concerned, for the time being it is assumed policy will remain unchanged with regard to the VAT, BSB and REB levies.