Energy research Centre of the Netherlands

To an optimal electricity supply system

Possible bottlenecks in the development to an optimal electricity supply system in northwest Europe

M.J.N. van Werven
J. de Joode
M.J.J. Scheepers

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Abstract

It is uncertain how the electricity system in Europe, and in particular northwest Europe and the Netherlands, will develop in the next fifteen years. The main objective of this report is to identify possible bottlenecks that may hamper the northwest European electricity system to develop into an optimal system in the long term (until 2020). Subsequently, based on the identified bottlenecks, the report attempts to indicate relevant market response and policy options. To be able to identify possible bottlenecks in the development to an optimal electricity system, an analytical framework has been set up with the aim to identify possible (future) problems in a structured way. The segments generation, network, demand, balancing, and policy & regulation are analysed, as well as the interactions between these segments. Each identified bottleneck is assessed on the criteria reliability, sustainability and affordability. Three bottlenecks are analysed in more detail:

- The increasing penetration of distributed generation (DG) and its interaction with the electricity network. Dutch policy could be aimed at:
  - Gaining more insight in the costs and benefits that result from the increasing penetration of DG.
  - Creating possibilities for DSOs to experiment with innovative (network management) concepts.
  - Introducing locational signals.
  - Further analyse the possibility of ownership unbundling.
- The problem of intermittency and its implications for balancing the electricity system. Dutch policy could be aimed at:
  - Creating the environment in which the market is able to respond in an efficient way.
  - Monitoring market responses.
  - Market coupling.
  - Discussing the timing of the gate closure.
- Interconnection and congestion issues in combination with generation. Dutch policy could be aimed at:
  - Using the existing interconnection capacity as efficient as possible.
  - Identifying the causes behind price differences.
  - Harmonise market rules.

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Summary

It is uncertain how the electricity system in Europe, and in particular northwest Europe and the Netherlands will develop in the next fifteen years. The main objective of this report is to identify possible bottlenecks that may hamper the northwest European electricity system to develop into an optimal system in the long term (until 2020). Subsequently, based on the identified bottlenecks, the report attempts to indicate relevant market response and policy options.

Four major electricity system developments in Belgium, France, Germany and the Netherlands can be identified:
1. a further increase in electricity demand,
2. a gradually increasing share of RES-E generation,
3. a gradual shift towards decentralised generation,
4. the transition of national self-sufficient electricity systems towards a pan-European electricity system.

To be able to identify possible bottlenecks in the development to an optimal electricity system, an analytical framework has been set up with the aim to identify possible (future) problems in a structured way, trying to make an overview that is as comprehensive as possible (see Table S.1). The segments generation, network, demand, balancing, and policy & regulation are analysed, as well as the interactions between these segments. Each identified bottleneck is assessed on the criteria reliability, sustainability and affordability.

Table S.1 *Analytical framework*

	Generation	Network	Demand	Balancing	Policy & regulation
Generation	• Lack of transparency • Market power • Intermittent capacity • Lack of innovation • Risk averse behaviour				
Network	• Distributed generation • Lack of locational signals				
Demand	• Long term adequacy of supply		• Inelastic demand curve		
Balancing	• Intermittent capacity • Offering balancing power is not optimal	Congestion	Insufficient price information Insufficient demand response		
Policy & regulation	• Regulatory uncertainty • Stimulation of DG and RES-E is costly • Permits	Lack of innovation incentives Unbundling			Internally deviating regulation Complexity of regulatio and subsidy system

The bottlenecks that are considered to be the most relevant can be placed under four main themes, which correspond to the four above-mentioned electricity system developments. The last three themes are analysed in more detail.

- Adequacy of supply.
- The increasing penetration of distributed generation (DG) and its interaction with the electricity network.
- The problem of intermittency and its implications for balancing the electricity system.
- Interconnection and congestion issues in combination with generation.

The increasing penetration of distributed generation

The penetration of distributed generation (DG) is increasing in northwest European electricity markets and it is expected that this trend will continue in the future. If the penetration level of distributed generation continues to grow while the distribution grid remains unchanged, a chain of technical conflicts may develop unless such issues as operation, control, and stability of distribution networks with DG installations are properly addressed. By developing new business activities, thereby diversifying the business model, and by changing operational philosophies from passive into active network management, distribution system operators (DSOs) may overcome the threats that arise from the increasing penetration of DG. Policy options to remove bottlenecks concerning the increasing penetration of DG should be aimed at supporting and stimulating this kind of market response. Regulation needs to evolve such that it allows DSOs to have access to a wider range of options and incentives available in choosing the most efficient ways to run their business. An interesting policy option could be to create possibilities for DSOs to experiment with innovative network concepts. In addition, locational signals might be indispensable to solve problems with DG and ownership unbundling must be considered as a logical and necessary step in reaching the desired situation.

Intermittency

A transition towards a more sustainable electricity supply is expected in the coming years, which results in an increase in the use of intermittent energy sources. Great balancing challenges at different time scales are created by the limited predictability and the high fluctuations in production levels of RES-E generation as the energy sources are not controllable and fluctuate randomly. Generators may invest in flexible and fast responding peak capacity. However, the use of storage may (in the future) be more efficient than the deployment of (other) balancing power. Furthermore, energy suppliers may develop demand side response options in junction with electricity consumers. And finally, RES-E generators themselves may limit their power output in order to contribute to balancing the system. Policy should be aimed at creating the environment in which the market is able to respond in an efficient way. Enlarging the control area, by e.g. consolidating adjoining control areas (market coupling like the Nordel system), could make the balancing mechanism more efficient. And shifting the gate closure of the spot market as close to actual electricity delivery as possible is an option that enhances the accuracy of the forecasts of the electricity generation of intermittent sources.

Interconnection

The liberalisation of the electricity markets results in trading opportunities, and the cross-border interconnection lines are more and more used for trade reasons and price arbitrage, which may exhaust the capacities of the interconnectors and which may result in congestion. An obvious way to minimise congestion is to invest in additional interconnection capacity. However, before considering investment in new interconnection capacity, it is important to first use the existing interconnection capacity as efficient as possible. FACTS (Flexible AC Transmission System that is able to control the amount and direction of power flow over the transformer) may increase the availability of the interconnection capacity. Before investing in new capacity, the causes behind the price differences should be identified. Investment in the physical enlargement of interconnection capacity is not necessarily optimal if it is based on price differences that are caused by the lack of a level playing field. Investment decisions about interconnection should be based on structural reasons, such as differences in primary resources, fuel mix and load patterns between countries. Price differences that result from the difference between regulatory structures (lack of level playing field) may not be structural and therefore may not justify investment in interconnection capacity. In addition, the more market designs and rules between countries differ, the more likely it is that trade is impeded or distorted between markets. Regulatory issues that are of relevance comprise rules concerning the timing of gate closure, imbalance arrangements, the firmness of transmission access rights, the type of tariff regulation, unbundling, the ownership of interconnectors, market structure, and security of supply measures. For the longer term the import balance in the Netherlands is expected to decrease due to convergence of marginal power generation costs in the Netherlands and neighbouring countries. However, although the trend in imports may go downwards, the fluctuations in contractual and physical flows may not. Increasing price volatility and growth in intermittent electricity production (i.e. wind energy) can also in future be the cause for transit flows and periodic congestion on the interconnectors. If operational planning, management of transit flows and congestion management are improved, the current interconnection capacity of the Netherlands might just be sufficient on the longer term.

1. Introduction

It is uncertain how the electricity system in Europe, and in particular northwest Europe and the Netherlands, will develop in the next fifteen years. It is conceivable that, from a social cost perspective, it will become a sub optimal system. Interactions between unbundled activities have to be led by and realised through market mechanisms, but market imperfections may hamper a socially desirable outcome. In addition, government failures may hinder the development of an optimal system as well. The Dutch Ministry of Economic Affairs asked ECN to study which possible bottlenecks may be of relevance in the development to an optimal electricity system in northwest Europe in the long term (until 2020). Therefore, the main objective of this report is to identify the most important bottlenecks that hamper the (autonomous) development to an optimal electricity system in the long term. Subsequently, based on the identified bottlenecks, the report indicates relevant market response and policy options.

To be able to fulfil the objective, the project is divided into three stages.
1. Stage 1, covered in Chapter 2, describes possible developments in the northwest European electricity market, concerning:
   - Generation. Different existing scenarios are analysed. Furthermore, concrete plans are studied, concerning intentions of building new generating capacity like gas-fired installations and offshore wind parks. It is discussed to what extent these plans correspond to the (EU) scenarios. With the developments in generation, conventional generating capacity as well as distributed and renewable generating capacity (including wind and CHP) is taken into account.
   - Demand. The development of electricity demand is analysed.
   - Networks. Plans of reinforcing transmission grids, including interconnection, are studied. Furthermore, the impact of generation and demand developments on the network is discussed.
2. Stage 2, covered in Chapters 3 and 4, analyses if there are certain developments to be expected that can lead to deviations form the 'optimal' system. An analytical framework is set up to be able to identify the bottlenecks in a structured way. A distinction is made, similar to stage 1, between generation, demand and the network. Furthermore, the balancing mechanism is incorporated in the analytical framework, as well as policy and regulation. An important additional aspect that is taken into account concerns the interaction between those (market) segments. To be able to assess the relevance of the identified bottlenecks and to indicate the direction of change that the problem implies, relative to an 'optimal electricity supply system', three criteria are taken into account:
   - The reliability of the system, focused on the generation segment and the network. The responsibility for sufficient investments in generating capacity (adequacy of supply) is initially left to the market. The quality and reliability of the network is regulated. Bottlenecks can relate to market failure as well as to government failure.
   - The sustainability of the system. Important is the realisation of certain targets by means of (market conformable) policy measures.
   - The efficiency of the system. An efficient working of the electricity market, including free access for new entrants, and effective economic regulation of network costs are important factors for the total costs of the system.
3. Stage 3 indicates which market response may be valuable in reaching an optimal electricity system, on which areas current policy should be adjusted and where additional policy is desirable to remove the bottlenecks that are derived in stage 2. What should be left to the market and where is government intervention by means of policy measures and regulation desirable? Stage 3 is covered in Chapters 4 and 5.

2. Developments in the northwest European electricity supply systems

2.1 Introduction

This chapter gives a broad overview of the developments in the northwest European electricity systems regarding a) the demand side, b) the supply side and c) the (inter)national network.[1] The four countries studied are Belgium, France, Germany and the Netherlands. The information is obtained from various sources, ranging from national energy and scenario studies to policy papers.

It is important to note that the electricity market is dynamic, which is underlined by a number of factors. Firstly, the electricity market continues to be a growing market, albeit not at the rates seen in the past. This means that not only replacement and maintenance investments need to be done, but also investments in grid reinforcements, new grid connections and new generation units. Secondly, the noticeable shift on the supply side of the electricity system towards less-conventional technologies influences, among other things, the network, the balancing of the system, the quality of electricity: i.e. the functioning of the total electricity system.

Within the analysis, national as well as international studies on the long-term development of the electricity market are used. The studied scenarios are sometimes based on a *bottom-up* approach, but more often on *top-down* approaches (e.g. business as usual scenarios (BAU)). Another distinction that needs to be drawn is the goal of the scenario study. While some indeed focus on BAU-scenarios, some are constructed as 'sustainability', 'green' or 'no-regret' scenarios. In this report, an overview is given of these different scenario data. While focussing on the long-term, occasionally some current initiatives are described in order to contrast or underline long-term developments.

Section 2.2 will deal with developments on the demand-side, Section 2.3 with developments on the supply-side, and Section 2.4 with the development of the (inter)national network. The statistical information, on which the analysis is partly based, can be found in appendices A and B. Appendix A contains a table with information on the current status of the electricity market in the mentioned countries, while Appendix B contains a table with information on projected developments.

2.2 Developments on the demand-side

In contrast with expected stagnation or decline in the use of oil and coal in the primary energy supply, electricity will continue to increase its share. The northwest European demand for electricity will continue to show significant growth in the next ten years (0.3-1.5%), albeit at a lower rate than the previous decade (2.5-3.0%). Over the time horizon of 2005 to 2030, highest growth is projected in the first ten to fifteen years. Thereafter, growth will decline to a mediocre 0.3 to 0.8% per year on average. The reason for this decline is to be found within the larger context of historical electricity demand: electricity demand growth tends to decelerate throughout time due to market saturation and energy-saving technologies and innovations. Figure 2.1 shows this slowing down of electricity demand growth in the Netherlands.

[1] The sources that are used in this chapter (and which are also used for the preparation of Appendix A and Appendix B) are represented in a separate reference overview (References of Chapter 2).

However, the Netherlands is a notable exception in the above mentioned growth percentages. Projections indicate a growth of 1.5 to 2.0% between 2000-2020. A potential explanation for this relatively large growth is the specific economic structure of the Netherlands compared to the other countries (the relative large share of industry and utilities in total economy).[2] The projected speed of energy savings also shows a decreasing trend. In the Netherlands, the target of an annual average saving of 1.3% will not be met, according to Van Dril and Elzenga (2005). Projections show a maximum annual average saving of only 1.0%.

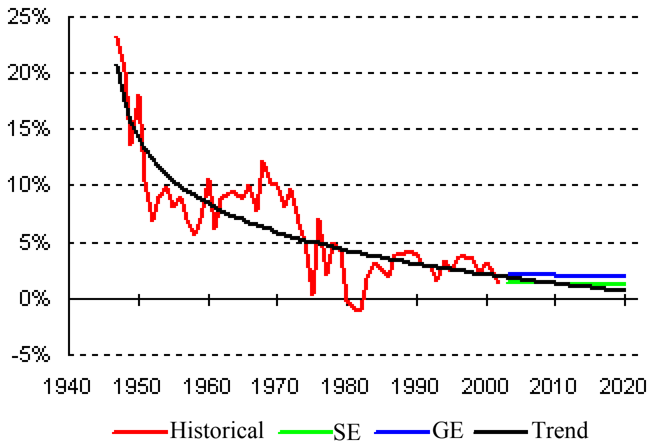

Figure 2.1 *Yearly growth in Dutch electricity consumption*
Source: Van Dril and Elzenga, 2005.

An important electricity system development on the demand side is the emergence of demand response.[3] This is important since it lowers the needed peak generation in times of reduced generating capacity availability or extremely high demand. However, demand response does not significantly contribute to energy savings, as it mainly shifts electricity demand to other time periods by temporally curtailing electricity usage. The degree to which demand response can lead to lower peak demand is highly uncertain. Only scarce attention is given to demand response in the various references. A potential reason for this lagging attention, for at least from the side of the electricity generators, is the dominant position of some companies on the Belgian (Electrabel) and French (EdF) electricity market and the still insufficient degree of market liberalisation. In highly developed electricity markets, such as the Scandinavian, demand response receives much more attention.

Concluding, it seems that the electricity system will be subject to a slow but robust growth in final demand (0.5-2.0% until 2020). This will imply a continuously expanding electricity sector in which not only old generation units need to be replaced or maintained but also new units will have to be built, whether it is conventional or unconventional, centralised or decentralised. The following section gives a short inventory of expected developments in this respect.

2.3 Developments on the supply-side

2.3.1 Supply-side developments in general

The expected supply developments concerning electricity generation and generating capacity cannot be discussed without taking a quick look at the current power plant composition. In this respect, the electricity systems in Belgium, Germany, France and the Netherlands are quite dis-

[2] A second explanation might be the differing approach underlying the growth figures. Bottom-up and top-down approaches tend to have different outcomes on this account.

[3] See also Section 4.2.3.

similar. Whilst France (78%) and Belgium (41%) rely heavily on nuclear generation, the Netherlands has only a minor nuclear generation share (4-5%). Germany and France have significant shares of renewable energy sources for the generation of electricity (RES-E), the RES-E share in Belgium and the Netherlands are mediocre. Also the share of gas in total electricity generation varies significantly, from 59% in the Netherlands to 5% in France. On the field of CHP, the Netherlands is the front-runner with 38%, measured as share in total generation, while Germany follows at a still significant 10%. France and Belgium's CHP production picks up a 5% share.

A general indicator of the total electricity generation capacity and electricity generation is the amount of domestic reserve capacity, that is: the difference between domestic installed capacity and load. On this front, France leads the field with a large overcapacity in nuclear plants giving a reserve margin of about 12%. Other countries have smaller margins, with Belgium having the least comfortable position of a mere 2% margin and Germany and the Netherlands 6%. Projections for the next 10 years show a slowly decreasing, but still high margin for France, but dramatically falling margins for the other countries, especially Belgium and the Netherlands.

2.3.2 The development of conventional generation

Within the horizon of 2020, the expected developments of conventional generation techniques vary per country. However, a general development that can be distinguished is the increasing scale of generating units. Plans of building a generating facility of 1200 MW are no exception anymore.

The role of *nuclear* generation has been looking quite straightforward up until a few years ago, with the decommissioning of units in Belgium, Germany and the Netherlands and nuclear expansion in France. While France aims at the replacement of old nuclear units by a new generation of nuclear reactors, the other three countries seem to be edging back to lifetime expansion of nuclear power plants. In the wake of the start of the Kyoto-protocol, several stakeholders have been arguing for a review of the 'nuclear option'. Especially Germany, where approximately a third of electricity generation is nuclear might find it hard to replace it by other techniques. However, it is far to early to anticipate a nuclear comeback and all scenario's show a declining share of nuclear electricity generation due to the phasing out agreements in these countries. However, this phasing-out is far from a decided race.[4]

Coal is of eminent importance for electricity generation in Germany, where it covers 50% of total generation. Although scenarios show a small decline in this share, the overall picture dictates that coal will remain very important, with in the long-run, 2020-2030, the emergence of coal as a fuel for supercritical coal plants. Of major importance in this expected development are the federal and state subsidies that are gradually being reduced. Another German climate-change driven scenario shows a large-scale transition of coal to gas fuelled generation with coal taking only a 20% share in 2020. Coal is expected to be almost non-existent in France, whereas Belgium (14%) and the Netherlands (26%) show significant shares of coal in total generation. Belgium's share is expected to decrease sharply in the next fifteen to twenty years, and is expected to make a comeback in 2030 with a 37% share (supercritical coal plants). Coal-fuelled generation in the Netherlands will remain more or less constant.

Gas fired electricity generation in the four countries studied is foreseen to increase, mainly due to climate change driven transitions away from oil and coal generation. Projections show generation shares varying from 50 to 63%.

[4] Recently, the British government announced to start a study to the option of nuclear power to meet the energy demand in the UK.

Expected developments concerning the generation from ***oil***-fuelled power plants show only one direction, that is: phasing out. Being already marginalised in most countries (except in supra-peak hours), the future will only see less and less oil-fired power plants.

Although some common observations can be made regarding developments in the four countries, the electricity market picture is not equal across the whole spectrum. The shift towards more decentralised generation is quite common, but the dominating technology types in the remaining centralised generation differ. Whereas the scenarios of the Netherlands and Belgium tend towards a high share of gas fuelled technologies, Germany and France seem to favour coal and nuclear generation respectively. In Germany, a large number of initiatives involve coal or lignite generation, whether it is a lifetime extension or capacity expansion of current plants or the construction of new ones.

2.3.3 The development of generation from renewable energy sources

Amongst the four studied nations, RES-E penetration is evidently the highest in Germany and France. Whereas Germany has a high wind penetration (5.8% of total generation in 2004), France's major renewable energy source is hydropower (11.8% of total generation in 2004). However, the EC's renewables targets for 2010 (12.5 and 21% for Germany and France respectively) demand an even higher penetration.[5] Germany aims for a wind power share of 10% of generation in 2010, with the gap being met with hydro and biomass. Another German target aimed at wind power development is the instalment of an additional 3.000 MW in 2010.[6] The DENA study expects an increase of offshore wind power capacity up to 36.000 MW in 2015 (Dena, 2005). France's current wind share on the other hand is much lower and leaves large scope for additional capacity instalments. The French government therefore targets an additional wind capacity of 7 to 10 GW (of which 0.5 to 1.5 GW offshore) in 2010. Other targets include an additional 2 GW of hydro and 1 GW of biomass over the same time span.[7]

In contrast with Germany and France, RES-E penetration in Belgium and the Netherlands is lower at 0.8 and 3.3% respectively. Belgium's main renewable energy sources are hydro and wind, whereas the majority of Dutch RES-E generation comes from biomass and wind. To reach their respective EC's targets for 2010, both countries aim at an increasing share of wind power. Belgium heads for a 6% target mainly through the commissioning of large offshore wind sites. Plans for a 2000 MW wind park exist, but integral costs of connection[8] to the mainland's transmission network seem huge. The Netherlands at the same time focuses on additional on- and offshore wind projects that should total about 1500 MW onshore in 2010 and 6000 MW offshore in 2020. Projections indicate that these targets are attainable. The Netherlands targets a 9% and 17% RES-E share in gross domestic consumption in 2010 and 2020 respectively. Also biomass capacity is projected to be expanding towards 1.4 to 2.0 GW in 2020 from 0.6 GW in 2000.[9]

2.3.4 The development of distributed generation (CHP)

CHP shares in total electricity generation are reasonable in Belgium, France and Germany (5%, 4-6% and 10% respectively) and very high in the Netherlands (38%). In the period up to 2020, the share in Dutch generation will stay more or less constant, while the other countries aim at an increase in the share of CHP in electricity generation. Projections for Belgium show a tripling of

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5 Note that the EC's targets are percentages of total gross domestic electricity consumption, not of total generation. This means that the percentages mentioned in this section do not match in definition.

6 Installed wind power capacity in Germany at the end of 2004 was 16 600 MW. For comparison: installed wind capacity in France was 380 MW and in the Netherlands 1100 MW. See: www.ewea.org.

7 For comparison: total French installed capacity is 115 GW, of which 25.4 GW consists of hydro plants.

8 Also called 'deep connection costs', which includes the costs that need to be incurred for grid reinforcements.

9 For comparison: total Dutch installed generation capacity is about 20.5 GW.

CHP production with the share in total generation potentially reaching 12.5% in 2020. The Belgian target of a 13% share in 2010, however, is even more ambitious. France looks to increase its CHP-production with 25% in 2020, compared with the 2001 level, while the German increase in the same period is projected to be somewhere between a staggering 100 to 200%.

It seems that, apart from the Netherlands, other countries will see a gradual shift towards decentralised electricity generation. Overall, RES-E and CHP-generation in all countries will continue to grow significantly, with additional capacity being connected to both the low and medium voltage grid. Notable exception in this respect is the large offshore wind parks that will be connected to the high voltage grid directly. All countries seem to be able to meet the 2010 European RES-E targets, although Belgium might face the toughest challenge.

Generally, three policy goals can be distinguished that drive the growth of DG and RES-E: the reduction of greenhouse gas emissions (e.g. the Kyoto Protocol), the use of renewable energy resources (e.g. the European RES Directive), and the energy efficiency improvement (e.g. the European CHP Directive).

2.4 Network developments

2.4.1 Development of the network

The availability of information on planned or current grid extensions or new connections vary per country and TSO. In Belgium, TSO Elia gives full disclosure on transmission grid investments and their rationale. Working documents of Elia therefore give a full overview of the impact of the emergence of wind parks and CHP initiatives on the grid. The largest investment in the national transmission network concerns the strengthening of the 380 kV connections in northwest Belgium, needed to connect the planned offshore wind park near Slijkens.

France's TSO, RTE, is somewhat less detailed in its publications on capacity investments (e.g. notably the Generation Adequacy Report). Next to a national perspective on demand projections and capacity requirements, only a few regions of 'special attention' are briefly discussed.

Germany is a special case, since the German network is owned by four regional TSOs: EnBW Transportnetze, E.ON Netz, RWE Transportnetz Strom and Vattenfall Europe Transmission. Information on grid investments is hardly available. Furthermore, Germany has a relatively weak regulator.[10] Regarding the identified electricity system developments, some DSOs are complaining on the large shares of intermittent electricity that need to be fed into the grid.

In the Netherlands, TenneT (the Dutch TSO) publishes a very detailed capacity plan in which all expected, needed and planned operations are discussed, even up to the regional level.

2.4.2 Development of interconnectors

When looking at total import capacity in relation to total domestic installed capacity, both Belgium and the Netherlands have higher margins than Germany and France. While Belgium and the Netherlands have a margin of 29% and 17% respectively, France and Germany have interconnection margins of 13% and 11% respectively. Of the four countries, only France currently is a (major) nett exporter of electricity.

In the near future, Belgium aims to increase its interconnection capacity with France. This should give an additional capacity of 700 MW from 2006 onwards. In the long run, maximum

[10] Federal Network Agency; in German: Bundesnetzagentur für Elektrizität, Gas, Telekommunikation, Post und Eisenbahnen; in short: Bundesnetzagentur (BNetzA).

capacity could be lifted to 4700 MW. At the same time, investments are undertaken in the coupling of Belgium with the Netherlands at Zandvliet. These could increase capacity with about 300 MW in 2007.

France, apart from undertaking the investments on the French side of the border enabling increased exports to Belgium, aim to increase interconnection capacity with Spain. From 2007 onwards, interconnection capacity with Spain will amount to 1200 MW.

Germany already experiences congestion problems on its interconnection with Norway. Cause of this congestion on both sides is the amount of wind power fed into the grid in Denmark and the north of Germany. Investment plans however, show an increase in capacity not earlier than 2008. In addition, Germany aims to strengthen connections with Poland both by new lines and reinforcement of existing ones.

The Netherlands focuses on expansion of interconnection capacity through new interconnectors with Norway and the United Kingdom. The former project is officially approved and will deliver a 600 MW connection with Norway in 2008, while the latter project (a 1300 MW connection) is under consideration.

An important objective of the European Commission, MS regulators, and other stakeholders, is to work towards the creation of an efficient and effectively competitive, single electricity market (ERGEG, 2005). The European Commission states (EC, 2004) that the overall objective of the internal electricity market is to create a competitive market for electricity for an enlarged European Union, not only where customers have choice of supplier, but also where all unnecessary impediments to cross-border exchanges are removed. Electricity should, as far as possible, flow between Member States as easily as it currently flows within Member States. This objective in combination with the described plans for new interconnections and reinforcements of existing interconnections indicate a major electricity system development: the transition of national self-sufficient electricity systems towards a pan-European electricity system.

2.5 Concluding remarks

In this chapter, the major electricity system developments in Belgium, France, Germany and the Netherlands are described on a number of accounts. Four major developments can be identified:

- a further increase in electricity demand,
- a gradually increasing share of RES-E generation,
- a gradual shift towards decentralised generation
- the transition of national self-sufficient electricity systems towards a pan-European electricity system.

The next chapter attempts to construct an inventory of bottlenecks that hamper the electricity system to develop to an optimal system, taking into account the above-identified developments.

3. Analysis of possible future bottlenecks

3.1 Introduction

The main objective of the electricity system is to satisfy the demand for electricity efficiently and reliably within certain technical, environmental and economic constraints (Hoogwijk 2004). This chapter attempts to identify the most important bottlenecks in the (autonomous) development to an optimal electricity system in northwest Europe in the longer term. An analytical framework is presented to identify possible bottlenecks in a structured way, taking into account the results of Chapter 2.

Three criteria are used to assess the relevance of the identified bottlenecks and to indicate the direction of change that the problem implies, relative to an 'optimal electricity supply system'. The first criterion is the reliability of the electricity system, focused on the generation segment and the network. The second criterion is aimed at sustainability, focused on realising environmental objectives by means of (market conform) policy measures. The third criterion, affordability, deals with the economic efficiency of the electricity system, which comprises market competition and the effectiveness of network cost regulation. An important element of affordability is the electricity price. Like in Chapter 2, the electricity system is divided into three segments: generation, network, and demand. An important aspect that is taken into account considers the interaction between the three segments. Furthermore, the balancing mechanism is incorporated in the analytical framework, as well as policy and regulation. In this chapter, the above-mentioned framework is explained in more detail and bottlenecks are identified and shortly analysed. Chapter 4 will discuss a number of the identified bottlenecks in more detail.

3.2 The analytical framework

To be able to identify possible bottlenecks in the development to an optimal electricity system, an analytical framework has been set up. The aim is to identify possible (future) problems in a structured way, trying to make an overview that is as comprehensive as possible. For this purpose the segments generation, network, demand, and balancing are plotted in a matrix. In this way, problems within the segments as well as interactions between the segments can be made clearly visible. In addition, the framework also includes policy and regulation in order to identify problems between the segments on the one hand and policy and regulation on the other. It offers a structured approach for the identification of problems and resulting bottlenecks, covering all relevant aspects of the electricity system. Table 3.1 gives the matrix that is used as the analytical framework.

Table 3.1 *The analytical framework*

	Generation	Network	Demand	Balancing	Policy	Regulation
Generation						
Network						
Demand						
Balancing						
Policy						
Regulation						

3.3 Overview of possible problems and resulting bottlenecks

When filling in the analytical framework, a list can be derived of problems that may cause the electricity system to develop to a less optimal system. Table 3.2 shows the matrix in which each matrix cell enumerates possible problems. In the following sub-sections, a more detailed description and explanation of each matrix cell and identified problems will follow. Thereby, the problems are qualitatively assessed against the three criteria reliability, sustainability and affordability. For each criterion, a qualitative value is given to indicate the direction of change that the problem implies, relative to an optimal electricity supply system, either a plus or a minus.[11]

Table 3.2 *The analytical framework including possible problems and bottlenecks*

	Generation	Network	Demand	Balancing	Policy & regulation
Generation	Lack of transparency Market power Intermittent capacity Lack of innovation Risk averse behaviour				
Network	Distributed generation Lack of locational signal				
Demand	Long term adequacy of supply		Inelastic demand curve		
Balancing	Intermittent capacity Offering balancing power is not optimal	Congestion	Insufficient price information Insufficient demand response		
Policy & regulation	Regulatory uncertainty Stimulation of DG and RES-E is costly Permits	Lack of innovation incentives Unbundling			Internally deviating regulation Complexity of regulation and subsidy system

3.3.1 Generation - Generation

Lack of information and transparency

Producers lack the information needed for socially optimal investment decisions (Hobbs et al., 2001). The exact characteristics of the demand function are difficult to estimate. Furthermore, in a liberalised electricity market, generating companies make investment decisions based on individual considerations. It is not centrally planned anymore. Therefore, generating companies do not know the expected development of total available capacity. In order for market participants to make rational economic decisions they should have access to reliable information on the fundamental drivers for the market and how these evolve (Newberry et al., 2003). This is particularly important for decisions that involve long-term commitments, such as investments in new generation facilities. Information deficiencies increase the investment risk and lead to lower equilibrium volumes of installed capacity (De Vries, 2004). Transparency is *necessary* to enable market players to obtain investments, but does not guarantee that *sufficient* investments will also be made. The latter also involves the estimate of risk made by investors, which is discussed in the next point. Insufficient transparency in a market may cause investors to invest less than would be invested if they had adequate insight into the availability of generation facilities (DTe, 2003).

[11] + means that the identified problem has a positive influence on the concerned criterion in reaching an optimal supply system, - means a negative influence. The indication n/a is used when the problem has no (direct) relation with the concerned criterion. Furthermore, a question mark is attributed if the discussed problem can influence the criterion in contradictory ways.

As a rule, the more information is made available, the better. However, there is the possibility that information provided to market participants facilitates collusion to undermine competition and hence is harmful to the performance of the market. A collusive outcome is more likely if price determination is transparent and competitors meet frequently (Newberry et al., 2003).

Table 3.3 *Lack of information and transparency*

		Score	Explanation
Reliability	- Supply	-	Less investments in generating capacity
	- Network	n/a	
Sustainability		n/a	
Affordability		-	Price increase as a result of scarce capacity Costs of possible blackouts

Risk-averse behaviour

Because there are so many non-quantifiable risks in a liberalised electricity market, it is not unlikely that investors in generation capacity choose a risk-averse strategy (Vázquez et al., 2002). In a general way it is possible to state that risk aversion has a negative influence on new capacity investment and that a risk-averse investment strategy would lead to less installed capacity than would be socially optimal (Parilla and Vázquez, 2005 and De Vries, 2004).

Table 3.4 *Risk-averse behaviour*

		Score	Explanation
Reliability	- Supply	-	Less investments in generating capacity
	- Network	n/a	
Sustainability		n/a	
Affordability		-	Price increase as a result of scarce capacity Costs of possible blackouts

Market power

Northwest European electricity markets exhibit strong oligopolistic characteristics, and probably will develop to a rather static market where only a small number of very large generators will be active (AER, 2003). Currently, the French and Belgian markets are dominated by one generator, while only three or four producers serve two-thirds or more of the markets in Germany and the Netherlands. This low number of generators may hamper the development of a competitive environment in the electricity market. Especially in case there is information asymmetry due to a lack of transparency (mentioned before), market power can be exerted easier (DTe, 2004a). If there is no strong price competition, it undoes many of the intended efficiency gains from liberalisation. It can lead to prices that are structurally above the competitive level and innovation incentives may be insufficiently present. Because of several barriers to entry, it is hard for new generating companies to enter the market. Investment in generation capacity is irreversible and engenders large sunk costs. Besides, it may be difficult for new market entrants to obtain sites for power plants, especially in densely populated areas. Incumbents may be able to re-use the sites of decommissioned plants, where they often already have a connection to the high-voltage grid and infrastructures for fuel and cooling water, and where they will probably face less difficulty in obtaining the necessary permits (De Vries, 2004). Generally, it is not completely clear whether generating companies in an oligopolistic environment will invest too little or too much in generating capacity. On the one hand, less generating capacity results in higher prices. On the other hand, if generation companies are able to artificially keep prices above the competitive level during normal market conditions, they may opt to overinvest in order to discourage new entry (De Vries, 2004)[12].

[12] The shift towards distributed generation (one of the main future developments recognised in Chapter 2) could, because of the shorter lead-time and smaller units, facilitate market entry, which may reduce market power. That,

Besides this long-term aspect of market power, which leads to strategic investment behaviour, market power can express itself on the short term as well. When reserve capacity becomes scarce and prices rise, there is a strong incentive to withhold generation capacity from the market in order to further increase prices. The reason is that when the capacity margin is slim, or when acute shortages already exist, the low price-elasticity of demand means that a small reduction in the supply of electricity may lead to steep price increases. In such a situation, generating companies are able to increase their revenues by keeping some generation capacity off the market, which results in a price rise which more than off-sets the lost volume of sold electricity (De Vries, 2004). During times of shortages, a little amount of capacity can already have a major impact on the market. Therefore, as pointed out by Stoft (2002), the increase in profits from withholding can be so high that it becomes attractive even for small generators who would have to withhold a majority of their generation capacity. During a period of scarcity, the electricity market is, even with relatively low market concentrations, susceptible to market power of generating companies (DTe, 2004a).

Table 3.5 *Market power*

		Score	Explanation
Reliability	- Supply	?	Less investments to increase prices More investments to discourage new entry
	- Network	n/a	
Sustainability		n/a	
Affordability		–	Artificially increased electricity prices

Increasing intermittent capacity

An increasing penetration of intermittent power into the electricity system causes additional costs, which are partly caused by the fact that intermittent sources are uncontrollable. Furthermore, output is variable (on the short term[13] as well as on the longer term) and unpredictable (especially on the longer term). Because of the possible non-availability of intermittent sources, intermittent capacity creates an additional need for tertiary reserves (back-up capacity) to be able to integrate increasing shares of intermittent capacity without affecting the reliability of the electricity system. These reserves are not used for setting off short-term deviations in output (which is done by the secondary control, see Section 3.3.4), but to be able to meet loads when there is little or too much power output from the intermittent sources. The non-availability of intermittent sources causes the capacity credit to be relatively low.[14]

Table 3.6 *Increasing intermittent capacity*

		Score	Explanation
Reliability	- Supply	–	Intermittent sources are variable, uncontrollable, and hard to predict
	- Network	–	Changing power flows are hard to handle[15]
Sustainability		+	Intermittent sources are renewable
Affordability		–	Additional need for tertiary reserves Intermittent capacity is relatively expensive

however, also depends upon economies of scale in bundling the output of many small generators on the market, for instance to manage imbalance issues.

13 See Section 3.3.4.

14 The capacity credit is the fraction of installed (intermittent) capacity by which the conventional power generation capacity can be reduced without affecting the reliability of the system (loss of load probability).

15 See Section 3.3.2.

Lack of innovation

Innovation, especially concerning conventional technologies, is insufficiently taking place within the current oligopolistic power generation market. Power producers try to reduce their risks, both market risks as well as technology risks. Innovation in power generation technology increases these risks, in particular because the unplanned unavailability of innovative power plants will be higher than for conventional power plants (e.g. experience with the IGCC plant in Buggenum). In the current market structure, unplanned availability will induce high costs for power producers because of loss of revenue and the unbalance costs that the power producer has to pay to the TSO. Furthermore, like in many other markets, incumbents have less interest in innovation. They will adopt a market strategy that protects their market position and optimise the revenues of assets they already have (e.g. incumbents opt for lifetime extension). Because the current market is, technically seen, on a high efficiency level, innovation means little efficiency gains while risks are relatively large. In theory, outsiders may enter the market with innovative technologies, but the entry barriers in power generation are rather high. The result will be static competition (AER 2003). The environmental quality of the electricity generation park will not improve. An exception is the electricity generation from renewables. For this type of power generation a protected (niche) market has been created. The higher costs and innovation risks are, in the Netherlands, compensated by the MEP feed-in tariff scheme.

Table 3.7 *Lack of innovation*

Lack of innovation		Score	Explanation
Reliability	- Supply	n/a	
	- Network	n/a	
Sustainability		–	Environmental quality of the generation park will not improve
Affordability		+	Conventional technologies are cheaper (on the short term)

3.3.2 Generation - Network

Increasing penetration of distributed generation (including RES-E)

Technological developments and EU targets for penetration of renewable energy sources (RES) and greenhouse gas (GHG) reduction are decentralising the electricity infrastructure and services. This increasing penetration of distributed generation (DG; including RES-E and CHP, whether or not intermittent) will lead to numerous technical challenges as DG, connected to the distribution network or at the customer side of the meter, is gradually changing the electricity supply system in northwest Europe. DG influences the arrangement of the power system as it interacts in a different way with the network system than centralised generation. In the past, electricity was mainly withdrawn from the distribution grids, but nowadays more and more decentralised produced electricity is also fed into the distribution grid. Because of the increasing DG-connections with the network, DSOs have to invest more and more to accommodate these units into the system and to keep the power quality and reliability on the desired level. It will not always be possible to charge these reinforcement costs to the newcomers on the grid (see also Section 3.3.7) and it will be difficult to determine who has to be charged for the costs (e.g. first mover problem[16]). Furthermore, changes in the network are made incrementally and not on the basis of a plan for an optimal network for the longer term. At a certain point it may not be possible anymore to handle large feed-in flows in medium and low network levels while keeping the network reliable at the same time. The current approach to network management limits the further growth of DG as the network reaches its physical borders (Ten Donkelaar and Scheepers, 2004). Especially the integration of intermittent capacity (and other capacity that is

[16] One generator locating in a specific place may not trigger a need for network improvements at all, while the next generator of the same size may be the cause for capacity expansion far in excess of its own needs (De Vries, 2004).

not load-following) into the electricity system continuously change the power flows through the network, and grids must be technically able to deal with this. Apart from the fact that grids must be able to handle the variability of intermittent power, intermittent resources may be located in remote areas far from population concentrations. The distance that must be covered for connecting to the grid can be long (increasing energy losses), and the required reinforcements in the grid can be expensive.

Currently, due to the fluctuating wind power from northern Germany, strongly changing international flow patterns regularly create unsafe situations in the northwest European electricity grid (TenneT, 2005a). Furthermore, these spontaneous electricity flows not only deteriorate the stability of the network, but also require bigger reserve margins concerning the allocation of international and interregional transport capacity (UCTE, 2005). It hampers an optimal working of the market, as less interconnection capacity is available to market participants. It has a negative impact on the trade of electricity and therefore on the development of an integrated European electricity market. If no action is taken, the expected growth of wind power in Germany in the coming years increases the risk of large-scale disruptions or blackouts in the northwest European electricity supply system in the near future.

Table 3.8 *Increasing penetration of DG*

		Score	Explanation
Reliability	- Supply	+	Installed (controllable) capacity increases[1]
	- Network	-	Changing power flows are hard to handle
Sustainability		+	DG is often more environment-friendly than conventional generation
Affordability		-	Network costs increase drastically if DG penetration is met by conventional reinforcements

[1] See also Section 3.3.1.

Despite the problems that the increasing penetration of DG could cause in the network, DG also can present several advantages to the network. DG may be able, when located close to loads, to reduce losses in transmission and distribution networks, postpone necessary network investments and provide local ancillary services. However, locational signals are a prerequisite (next point). But little or no use is made of these advantages, as DG is currently almost exclusively seen as negative load making no contribution to other functions of the power system (e.g. voltage control, network reliability, reserve capacity, etc.) (Ten Donkelaar and Scheepers, 2004). The high future use of technologies such as fuel cells, micro-CHP, wind turbines and PV cells, implies considerable impacts and costs to the system if the current view of DG is not dramatically altered.

Lack of locational signals

The costs and benefits of distributed generation to the electricity system are related to the geographical point of connection. Therefore, in an optimal system these costs and benefits must be reflected in the use of system charges, connection charges and electricity pricing to the distributed generator. The presence of significant physical interdependencies between the network and generators needs to be reflected in the economic and institutional design of the sector (De Vries, 2004). More specifically, locational signals that take into account long-run system costs and benefits should be incorporated. This locational (price) signal may be positive in the case of cost to the system, or negative in the case that DG entails benefits to the system (Scheepers, 2004). In the vertically integrated utilities of the past, operational control of the network was integrated with the dispatch of generators, and system development was also planned from an integrated perspective. But in the current unbundled, liberalised electricity systems in northwest Europe, locational signals are not present, and that may become a bottleneck in the development to an optimal electricity supply system.

The current system is based on fixed transmission charges that are primarily aimed at recovering network costs and do not offer an opportunity for coordination of generation investment with network development (De Vries, 2004). Furthermore, for connections smaller than 10 MVA, network connection charges are based upon shallow connection costs, while the deep connection costs are socialised.[17] A difficult issue with deep connection costs is that they are hard to determine, not transparent and, therefore, easy to abuse by system operators. In this way, system operators may obstruct the building of new generating capacity.

Table 3.9 *Lack of locational signals*

		Score	Explanation
Reliability	- Supply	n/a	
	- Network	–	DG at wrong locations engenders network problems
Sustainability		n/a	
Affordability		–	DG at wrong locations increases costs

3.3.3 Generation - Demand

Long-term adequacy of supply

With the introduction of competition in the electricity sector, the decision-making process concerning investments in generating capacity has changed dramatically. The question arises if long-term adequacy of supply is still guaranteed in the liberalised market. In theory, periodic price spikes should provide optimal investment incentives in an energy-only market. However, several factors may cause the investment equilibrium to deviate from the social optimum (De Vries, 2004). In addition, it is practically impossible to determine the optimal volume of generation capacity. The high social costs of a prolonged period of scarce electricity generation capacity or even interruptions of electricity supply, make the adequacy of supply problem one of the most important issues in the future development to an optimal electricity system in northwest Europe.

Table 3.10 *Long-term adequacy of supply*

		Score	Explanation
Reliability	- Supply	-	Adequacy of supply
	- Network	n/a	
Sustainability		n/a	
Affordability		-	Price increase as a result of scarce capacity Costs of possible blackouts

3.3.4 Generation - Balance

Increasing intermittent capacity

Intermittent capacity makes balancing generation and demand more complicated, creating a need for additional regulating (short term) and reserve power (longer term, see Section 3.3.1). The variability of intermittent sources on the short term (15 minutes to hours) tends to complicate the load following with the conventional units that remain in the system, as it makes the demand curve to be matched by these units (which equals the system load minus the intermittent power generation) far less smooth than would be the case without intermittent sources (UCTE, 2004). There is a need for additional secondary control (e.g. spinning reserves) to overcome these short-term fluctuations in power output and to be able to follow loads properly. Further-

[17] This holds for the Netherlands.

more, most intermittent sources are unpredictable to a certain extent. The longer the predictions look forward, the less reliable the predictions become. Therefore, the later the gate closure of the spot market, the better the forecasts of the electricity generation of intermittent sources, and the less balancing costs have to be made.

Table 3.11 *Increasing intermittent capacity*

		Score	Explanation
Reliability	- Supply	–	Intermittent sources are variable, uncontrollable, and hard to predict
	- Network	–	Changing power flows are hard to handle[1]
Sustainability		+	Intermittent sources are renewable
Affordability		–	Variability creates additional need for regulating power

[1] See also Section 3.3.2.

Offering balancing power is not optimal

The most efficient balancing system neutralises actual imbalances by deploying the generating balancing unit that has the lowest (marginal) costs at that time. The establishment of a balancing market facilitates the deployment of balancing units as a continuous, real-time process (at least for part of the balancing power). At each moment of imbalance, the balancing unit with lowest costs can be called upon. However, the efficiency of the balancing market is bound by the offers of market participants. Only balancing units that are offered to the balancing market are available for deployment. Therefore, it is of major importance that available generation capacity (that is suitable for balancing purposes) is actually offered to the balancing market. That determines the efficiency of the balancing mechanism. In northwest European electricity markets, access to the supply side of the balancing markets is mainly limited to large power producers *within* the concerning control area. This means that the efficiency of the balancing systems is restricted by the physical borders of the respective control areas (Van Werven et al., 2005). Low-cost balancing power from adjoining control areas that is available during a situation of imbalance, is not allowed to be offered on the concerned balancing market. This implies a less than optimal efficiency. A balancing market that is not efficient poses an obstacle to new market entrants (small generating companies): generating companies with more generating units are better able to handle their imbalances themselves than a small generating company with few units (De Vries, 2004).

Table 3.12 *Offering balancing power is not optimal*

		Score	Explanation
Reliability	- Supply	n/a	
	- Network	n/a	
Sustainability		n/a	
Affordability		-	Balancing market can be more efficient

3.3.5 Generation - Policy & Regulation

Regulatory uncertainty

Regulatory uncertainty increases (investment) risks. It is sometimes considered as one of the main factors leading to inadequate generation capacity. Especially in newly liberalised markets (which northwest European electricity markets are), regulatory uncertainty can be a significant factor. Some examples of sources of regulatory uncertainty are the following (De Vries, 2004):

- Fine-tuning the market design. The market design needs to be adjusted as the understanding of its dynamics evolves. This process of fine-tuning creates significant regulatory uncertainty for a long period of time.

- Political intervention. If within a certain period prices become many times higher than their historical levels, whether these are economically efficient or not, there is a risk that government intervenes and e.g. sets a low maximum price during a price spike.
- Changes in input markets. Natural gas is one of the main inputs in the generation of electricity, which means that the current restructuring of the European natural gas market creates additional regulatory uncertainty for the electricity sector.
- Changes to the regulatory conditions for the market. There is, among other things, uncertainty about the intention to decommission nuclear facilities and about future environmental rules, such as cooling water regulations or the CO_2 emission standards.
- Network expansion. An objective of the European Union is to expand interconnection capacity, which would significantly alter market dynamics. Expansion of interconnection capacity itself may be good for the market, but uncertainty about it increases risks.

Table 3.13 *Regulatory uncertainty*

		Score	Explanation
Reliability	- Supply	–	Less investments in generating capacity
	- Network	n/a	
Sustainability		n/a	
Affordability		–	Price increase as a result of scarce capacity Costs of possible blackouts

Stimulating DG and RES-E by means of subsidies is costly

European policy is aimed at stimulating energy from renewable resources to increase the share of sustainable energy in the total energy supply system. There are different subsidies and fiscal instruments by which national governments promote the generation and use of RES electricity. This increases total costs of energy supply, which are socialised among the end-users. Another way of stimulating RES-E is the internalisation of the CO_2-price. RES-E then becomes relatively less costly, as the CO_2 emissions are minimal.

Table 3.14 *Stimulating DG and RES-E is costly*

		Score	Explanation
Reliability	- Supply	–	Intermittent sources are variable, uncontrollable, and hard to predict
	- Network	–	Changing power flows are hard to handle
Sustainability		+	DG and RES-E fit in a sustainable future
Affordability		–	Subsidies and fiscal measures increase costs

Permitting process

Obtaining the necessary permits for the construction and operation of generating plants may present an obstacle to investments. While the social benefits of a proper licensing process are clear, there may be negative side effects. The permitting process can be lengthy, which increases the time lag between an increase in demand and the deployment of a new generating unit. Furthermore, permitting requirements may create a barrier for new entrants to the market. Incumbents may be able to construct new plants at existing sites, for instance at the location of decommissioned old plants. This has the advantage of already having the infrastructures for electricity, fuel and cooling water present. In this way, concerning permitting requirements, they have an advantage compared to new entrants. Permitting requirements may have the effect of discouraging greenfield development of new plants. While this may be desirable from the point of view of land use planning, the effect of stimulating oligopolistic behaviour should not be disregarded (De Vries, 2004).

Table 3.15 *Permitting process*

		Score	Explanation
Reliability	- Supply	–	Less investments in generating capacity
	- Network	n/a	
Sustainability		+	Environmental benefits of permits
Affordability		–	Price increase as a result of scarce capacity Costs of possible blackouts

3.3.6 Network - Balance

Congestion

Congestion in the electricity grids, including interconnection lines, can hamper an efficient co-ordination between demand and supply. In the northwest European system, transmission tariffs do not vary continuously in order to include the costs of congestion and network losses in the dispatch calculations. Therefore, they do not provide efficient operational signals to market parties, as a result of which the network may not be able to accommodate all scheduled transactions (De Vries, 2004). This may result in congestion, which, on the short term, may imply problems with the efficient balancing of the system. Efficient balancing capacity may not be used to overcome a situation of (local) imbalance, because congestion prevents the physical power it produces to reach demand. Less efficient generation has to be deployed. It is, however, not always optimal to reinforce the network in order to solve the congestion problem. Costs of reinforcing the network have to be weighed up against the costs of other options, like deploying the less efficient balancing unit. Nevertheless, congestion gives a clear indication of efficiency losses in the system.

Furthermore, unplanned electricity flows or loop flows, e.g. from intermittent generation capacity, can lead to congestion of the network. That may prevent the planned and contracted electricity to reach the customers, and may result in interruptions of the electricity supply.

Table 3.16 *Congestion*

		Score	Explanation
Reliability	- Supply	–	Congestion may interrupt supply
	- Network	n/a	
Sustainability		n/a	
Affordability		–	Congestion hampers an efficient coordination between demand and supply

3.3.7 Network - Policy & Regulation

Regulatory lock-in and lack of innovation incentives

Regulation that currently applies for electricity networks in the Netherlands is based on principles of economic incentives regulation and performance regulation. This regulation simulates competition between monopolistic DSOs ‘on paper’. Economic incentive regulation provides DSOs with an incentive to reduce costs, i.e. to invest little and to cut back operational costs (e.g. maintenance and personnel). Because also the technical performance is measured and included in the price-cap formula (performance regulation), DSOs also have to keep power quality and reliability at a certain level. DSOs are obliged to connect everyone who wants to have access to the grid, while DG penetration is strongly increasing (see also Section 3.3.2). At a certain point it may not be possible anymore to handle large feed-in flows in medium and low network levels and to keep the network reliable. It will become necessary to change the network architecture and network management philosophy in a drastic way. However, the current regulation does not allow such a transition, for instance because investments have to be recovered from the use of system and connection charges within the regulatory period of three years. In principle, the regulator DTe may allow DSOs to make ‘large exceptional investments’[18], however the DTe will have difficulty to judge the necessity of such investments since it is not its task to make long-term plans and because it lacks specific knowledge on new technological concepts. The current regulation stimulates DSOs to do the same things more efficient, but it does not really give incentives for DSOs to look for better alternatives. Although DSOs own and operate assets in the electricity system with a very long technical and economical lifetime and therefore should have interest in long-term strategies and planning, they are currently focusing on the short term due to price-cap regulation and the regulatory periods of only three years.

According to the regulator DTe, investments by DSOs in research and development should be part of the companies’ regular operational costs. With help of the association of energy companies EnergieNed, the DSOs set up the program HERMES to organise and finance R&D in network technologies. Whether this program is successful and will sufficiently contribute to the R&D needs of DSOs is still unclear. The economic incentive regulation, however, stimulates DSOs to reduce their operational costs and therefore also investments in R&D. Furthermore, before new technologies and concepts can be deployed broadly in the grids, they should be demonstrated in real life circumstances. Performance regulation will, however, penalise DSOs in case new technologies and concepts fail and result in loss of power quality or reliability. DSOs might therefore not be willing to take any innovation risks.

Table 3.17 *Regulatory lock-in and lack of innovation incentives*

		Score	Explanation
Reliability	- Supply	n/a	
	- Network	–	Regulation does not allow a transition to new network architecture and management
Sustainability		n/a	
Affordability		–	Network costs increase drastically if increasing DG penetration is met by conventional reinforcements

Unbundling

Complete unbundling is more and more seen as a useful tool to ensure the independence of the system operators. However, a consequence of unbundling is that the electricity system is no longer planned in an integral manner. DSOs are not allowed to own generating capacity, even if it is used as substitute for line losses, for network reinforcements or extensions, or for ancillary services. Unbundling forms a hard boundary condition that forbids the DSO to extend its business model and to adjust its network architecture in this way.

Table 3.18 *Unbundling*

		Score	Explanation
Reliability	- Supply	n/a	
	- Network	–	Generation capacity cannot be owned to manage the grid
Sustainability		n/a	
Affordability		?	Unbundling may decrease prices Inefficient network management

[18] Dutch Electricity Law, Article 41b.2

3.3.8 Demand - Demand

Inelastic demand curve

Experience has shown that the demand for electricity in tight electricity markets does not decrease appreciably when the price for electricity rises. In other words, the demand for electricity appears to be inelastic in the short-term to increases in price. This low elasticity of demand stands in the way of an efficient electricity market. A necessary condition for demand to be price-elastic is that consumers have access to real-time price information (see next bottleneck). Most (small) consumers have no insight in actual prices, and thus do not gear their consumption patterns to changing prices. They are hedged against actual market prices by contracts with fixed prices and are not accustomed to react on a declining electricity supply with high prices. Moreover, there are hardly any available alternatives for most applications of electricity.

Therefore, prices become very volatile during times of shortages, because at that time supply is inelastic as well. The highly fluctuating prices do not necessarily reflect generation costs anymore. Higher price-elasticity of demand would lead to more stable electricity prices.

Table 3.19 *Inelastic demand curve*

		Score	Explanation
Reliability	- Supply	–	Demand insufficiently reacts to shortage Less stable prices increase investment risk
	- Network	n/a	
Sustainability		n/a	
Affordability		–	High prices insufficiently lower demand

3.3.9 Demand - Balance

Insufficient price information

As stated before, a necessary condition for demand to be price-elastic is that consumers have access to real-time price information. To this end, final consumers must have real-time meters. This is currently not the case with a large proportion of consumers, especially smaller ones. As their consumption is measured over periods of weeks or months, their bills can only reflect the average wholesale price during the billing period. The absence of real-time pricing disturbs the feed-back loop between supply and demand.

Table 3.20 *Insufficient price information*

		Score	Explanation
Reliability	- Supply	–	Demand insufficiently reacts to demand
	- Network	n/a	
Sustainability		n/a	
Affordability		–	High prices insufficiently lower demand

Insufficient demand response

Demand response is the ability of electricity demand to respond to variations in market prices in real time. It is a concept that seeks to lower peak demand during specific, limited time periods of scarcity, by temporally curtailing electricity usage, shifting usage to other time periods, or substituting another resource for delivered electricity (such as self-generation), focusing on when energy is used and its cost at that time. Demand response is about decreasing peak demand during specific, limited time periods of scarcity by making use of the flexibility that consumers can provide (Van Werven and Scheepers, 2004). It enhances the functioning of the electricity market during tightness in the short run by making demand more price-elastic. Increasing demand response will make it easier and cheaper to meet demand reliably and will reduce price volatility. It can be an efficient option in the balancing market.

Table 3.21 *Insufficient demand response*

		Score	Explanation
Reliability	- Supply	–	Demand insufficiently reacts to demand
	- Network	n/a	
Sustainability		n/a	
Affordability		–	Scarcity is met inefficiently

3.3.10 Regulation - Regulation

Different regulation between control areas

In addition to technical and operational standards, common market rules are needed to ensure a level playing field based on fair competition, cost-based pricing, access to the network, transparent and non-discriminatory network tariffs, proper cross-border-trade mechanisms, congestion management, and capacity allocation mechanisms. The more market designs and rules between control areas differ, the more likely it is that trade is impeded or distorted between markets. As a general rule, different designs and rules impede structural trade opportunities. Compatibility between key market rules therefore is important so that opportunities for trade can be fully realised. Regulatory issues that are of relevance comprise rules concerning the timing of gate closure, imbalance arrangements, the firmness of transmission access rights, the type of tariff regulation, unbundling, the ownership of interconnectors, market structure, and security of supply measures. However, full harmonisation of all trading rules and arrangements is not necessarily required for effective trade interaction between markets to occur. But regulatory arrangements need to be independent, with regulatory processes characterised by transparency, objectivity and consistency.

Table 3.22 *Different regulation between control areas*

		Score	Explanation
Reliability	- Supply	–	Trade is impeded; less trade means less available generating capacity
	- Network	n/a	
Sustainability		n/a	
Affordability		–	Efficient trade opportunities are hampered

3.4 Conclusion

To be able to identify possible bottlenecks in the development to an optimal electricity system, an analytical framework has been set up with the aim to identify possible (future) problems in a structured way, trying to make an overview that is as comprehensive as possible. The segments generation, network, demand, balancing, and policy & regulation were analysed, as well as the interactions between these segments. Each identified bottleneck is assessed on the criteria reliability, sustainability and affordability.

The bottlenecks that are considered to be the most relevant can be placed under four main themes, which correspond to the major developments that were identified in Chapter 2. These themes will be analysed in more detail in the next chapter:

- adequacy of supply,[19]
- increasing penetration of distributed generation,
- increasing use of intermittent sources,
- interconnection and congestion issues.

[19] The adequacy of supply problem is not taken into consideration in Chapter 4, as it is already extensively studied and analysed in other research studies.

4. Elaboration on key bottlenecks

The main objective of the electricity system is to satisfy the demand for electricity efficiently and reliably within certain technical, environmental and economic constraints (Hoogwijk 2004). In this chapter, a number of problems that are already discussed in Chapter 3 and that may impede this objective will be analysed in more detail. In addition, it indicates on which areas current policy should be adjusted and where additional policy is desirable to deal with or to remove these bottlenecks.[20] Furthermore, it is important to determine which responsibilities belong to the market and where government intervention by means of policy measures and regulation is desirable. The following issues that may keep the electricity system from developing to an optimal system will be discussed:

- The increasing penetration of distributed generation (DG) and its interaction with the electricity network. Section 4.1 will discuss this issue and is primarily based on the results of the DISPOWER project;[21]
- The problem of intermittency and its implications for balancing the electricity system. This issue is dealt with in Section 4.2 and is mainly based on the GreenNet project;[22]
- Interconnection and congestion issues in combination with generation. Section 4.3 concentrates on this issue and is largely based on preliminary results of the Encouraged project.[23]

4.1 The increasing penetration of DG

The penetration of distributed generation is increasing in northwest European electricity markets and it is expected that this trend will continue in the future.[24] Generally, three policy goals can be distinguished that drive the growth of DG: the reduction of greenhouse gas emissions (e.g. the Kyoto Protocol), the use of renewable energy resources (e.g. the European RES Directive), and the energy efficiency improvement (e.g. the European CHP Directive). In addition, the economic benefits associated with DG (such as higher efficiencies, enhanced system reliability, etc.) will promote a further increase of the penetration level of DG as well.

This section mainly deals with the implications of an increasing DG penetration on the distribution network and the business of distribution system operators (DSOs). Given the increased use of technologies such as micro-CHP, wind turbines and PV cells, ways to effectively integrate these technologies into the planning and operation of electricity networks have to be found, if costly network upgrades are to be avoided. If the penetration level of distributed generation continues to grow while the distribution grid remains unchanged, a chain of technical conflicts may develop unless such issues as operation, control, and stability of distribution networks with DG installations are properly addressed (Nielsen, 2002). Several technical experts have addressed the issue of growing DG levels in existing distribution networks (e.g. Nielsen, 2002; Strbac and Jenkins, 2001). They argue that there are several aspects that need to be fully understood in order to obtain maximum benefits from both DG and the electricity network, mainly:

- The distribution network and DG are interacting and actively affecting each other.

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[20] Chapter 5 will specifically focus on the Dutch case.

[21] Particularly on Van Werven and Scheepers (2005). See for more information on the DISPOWER project: www.dispower.org.

[22] Particularly on Van Werven et al. (2005). See for more information on the GreenNet project: www.greennet.at.

[23] Particularly on the preliminary results described in Van Werven and Van Oostvoorn (2005). See for more information on the Encouraged project: www.encouraged.info.

[24] Distributed generation can be defined as electric power sources that are directly connected to the distribution network or on the customer side of the meter (Ackermann et al., 2001). Examples are industrial, commercial and micro CHP, (medium) district heating, medium and small hydro, onshore wind, tidal energy, biomass and waste incineration/gasification, and solar energy (PV).

- No generic conclusion can be drawn regarding the impact of DG on the grid, as it depends on various characteristics (such as size and location of DG units).
- Both DG and the grid should be studied as one integrated, flexible, dynamic and complex structure, for to a great extend they do have a major impact on operation, control, and stability of each other.

Section 4.1.1 will discuss the impact of increasing DG penetration on the electricity system (particularly the distribution network), while Section 4.1.2 describes the impact on the business of DSOs. Sections 4.1.3 and 4.1.4 will elaborate on market response and policy implications respectively.

4.1.1 Impact of increasing DG penetration on the electricity system

Compared to conventional power generation, DG has different characteristics. In particular the location of DG units and the uncontrollability of RES-E generation are very different from conventional power generation. DG facilities are mostly connected to the distribution network at low and medium voltage levels; sites that were originally not meant to connect power generation facilities. The distribution networks traditionally have a rather inflexible design (e.g. a uni-directional power flow), which in principle can cause integration problems with higher DG penetration levels. Furthermore, a major problem with most DG units is that they are operated independently of (local) electricity demand. The majority of new DG being connected to the distribution network in northwest Europe at present is powered by wind or in the form of CHP. The intermittency of wind energy increases the burden on distribution lines.[25] And although CHP units can, in principle, be centrally dispatched, they tend to be operated in response to the requirements of the heat load or the electrical load of the host installation rather than the needs of the public electricity demand. Therefore, the distribution network must be capable of functioning in the extreme situation that there is no local DG generation while demand is peaking as well as in the reverse situation when there is full DG generation but little (local) electricity demand.

The specific DG characteristics have implications for the efficient working of the electricity system. An increasing DG penetration can create several problems for the distribution networks in terms of stability (especially voltage stability), power quality (mainly voltage flicker and harmonics) and network congestion; particularly when large amounts of DG are connected or DG is connected to weak grids.[26] As long as DG penetration is limited, connection of DG units to the electricity network will not cause many problems for the electricity system. However, if the amounts of DG grow, a number of problems can occur that can endanger the stability of the network and the reliability of electricity supply. The more DG is connected to a particular distribution network, the greater the challenge. The network constraints of DG can usually be solved by reinforcing the (distribution) network. However, from an economic point of view this is not always attractive as it may concern large, long-term investments. Given the increased use of technologies such as fuel cells, (micro-)CHP, wind turbines, and PV cells, new ways to effectively integrate them into the electricity networks have to be found, preventing considerable impacts and costs of (distribution) network upgrades. Modifying the network control and/or operation approach may be an option (see Section 4.1.3).

However, next to the challenges that distributed generation may pose on the distribution network, it can also bring several advantages to the electricity system, including enhanced system reliability, avoided transmission and distribution line losses and costs, congestion relief in the transmission system, and avoided infrastructure investments. The development of small-scale

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25 Next to network problems, challenges with system balancing may arise, due to the intermittent character of RES-E. However, this section concentrates on the implications to the network only. The balancing issue is discussed separately in Section 4.2.

26 See the below textbox for an explanation of voltage stability and power quality.

DG facilities near a load can postpone or avoid investments in additional distribution and transmission capacity. Moreover, certain types of DG also have the ability to offer certain network ancillary services, such as reactive power support, voltage control and frequency control.[27] However, it is only through aggregation and integration into power system planning operation that small size generation will be able to displace the capacity and flexibility of conventional generation plant, provide alternative solutions to network problems and displace network assets.[28] When properly integrated, DG could provide a range of services required by TSOs such as balancing of supply and demand, frequency regulation, various forms of reserve, congestion management, and voltage control. At the distribution level, in addition to voltage and flow control, new services could emerge including provision of security of supply and enhancement of overall service quality. However, the ability to offer advantages, as well as the possible challenges that DG poses to the electricity system, largely depend on the specific location of DG facilities. But if DG is properly sized and sited, it can clearly provide benefits to control, operation and stability of the electricity system.

Voltage stability and power quality

Voltage stability concerns the capability of the power system to maintain the post-fault voltages near the pre-fault values (Knazkins, 2004). Node voltages should be kept close to their nominal values in order to assure correct operation of customer equipment and to prevent equipment, both of the grid company and the customer, from being damaged. If an electricity system is unable to maintain the voltage within acceptable limits, the system undergoes voltage collapse. The voltage is a local parameter: voltage stability depends on the local grid properties, whether the connection is predominantly resistive or inductive in nature and secondly the controllability of the reactive power.[29] Therefore, voltage control is mainly a local matter and voltage problems must be solved in the vicinity of the location where the problem exists. In the transmission and distribution systems the voltages are controlled by controllers on the electrical generators in the power stations and by reactive power compensation.

Power quality examines the electric power produced by a DG unit with respect to:

- Reactive power generation. Reactive power is the result of a phase difference between alternating current and alternating voltage and causes additional losses in the grid.
- Flicker (dynamic voltage fluctuations). Flicker is caused by variations in the energy source (e.g. wind), which result in voltage amplitude variations. In particular wind farms are a potential cause of voltage flicker due to wind speed variations or power output variation due to passage of the wind turbine blades through the tower shadow (Knazkins, 2004). Voltage variations can lead to visible fluctuations in the intensity of the light produced by light bulbs. The visibility of the fluctuations depends on the amplitude of the voltage variations.
- Harmonic distortion. Harmonic distortion occurs if currents and voltages are not sinusoidal. Nonsinusoidal currents and voltages result in extra losses, which may cause problems in consumer appliances and may cause overloading of grid components. Harmonic distortion is mainly caused by power electronic devices (AC-DC converters), which contain switches.

[27] The majority of existing DG, however, has been installed for electricity supply purposes only. Hence, few generators are equipped with the infrastructure necessary to provide ancillary services. But future opportunities for DG to provide ancillary services will increase as DG penetrations and availabilities increase. Niche opportunities will emerge for DG to provide ancillary services, usually in circumstances where constraints restrict network development, e.g. environmental, planning, and terrain related constraints (Mutale and Strbac, 2005).

[28] However, contracts with DG operators do not solve network problems for the DSO in the same way as network reinforcements. The lifetime of DG units is shorter than that of the network. Furthermore, the DG operator may suddenly decide to stop operations, e.g. for economic reasons.

[29] Reactive power is the quantity associated with an alternating voltage and the out-of-phase component of the alternating current. It is independent of the amount of power associated with the voltage and the in-phase component of the current, but it strongly affects local voltage levels.

4.1.2 Tension between the market and regulation

As stated before, the growing electricity supply from DG has specific consequences for the distribution network, which falls within the business of DSOs. These consequences may lead to higher costs and decreasing revenues for the DSO. The network should be able to handle higher peak loads and flows through the network, which may require network reinforcements in some parts of the network. However, transport needs (which is part of the revenues for DSOs) may reduce as DG generally is located closer to demand. Furthermore, the net outflow may reduce since consumers may use part of the local DG generation directly. Therefore, from the perspective of DSOs, DG may be seen as a threat.

The main revenues of a DSO consist of use of system charges and connection charges. These are subject to economic regulation and are not market based. Determining the use of system charges on the basis of price or revenue cap regulation (economic incentive regulation) does not stimulate DSOs to innovate. Incentive regulation systems aim at encouraging cost minimisation of DSOs, which intrinsically goes against promotion of innovation (Leprich and Bauknecht, 2004).[30] This can be unhelpful to DG as it hinders a structural change of planning and management of the networks. Next to use of system charges, connection charges are generally regulated as well although in some markets, in the UK for example, competition in connections exists. If regulation prescribes the use of shallow connection charges, DSOs can only partially recover connection costs from DG operators.[31] In these circumstances DSOs will consider DG as a threat to their network business, which may hinder DG to become an integral part of the electricity market in the long run, and, therefore, may hinder the realisation of environmental policy targets. DG may have several characteristics that can be advantageous to DSOs, but the current regulatory framework sometimes hinders the DSOs to incorporate the resulting values into its business model (Van Sambeek and Scheepers, 2004).]

4.1.3 Response of the market

The introduction of competition and the accompanying regulation has led to different behavioural strategies of actors in the electricity market, depending on the experience that has been gained in the new electricity market structure. Roughly, three theoretical stages in the adaptation process of DSOs can be distinguished. First, new market structures and regulatory arrangements lead to stabilisation strategies. As changes to the regulatory framework are new to the whole electricity sector, every actor has to evaluate the corresponding implications and gain operational experience. Stabilisation means reducing uncertainty, and that is the first objective. It is not before the sector has insight of the new structures and, in the scope of the subject, becomes aware of the rapid development of DG, that DSOs enter a next stage: a defensive strategy. In this stage, DSOs will attempt to mitigate the impact of unfavourable regulatory and market developments on its business, which in some markets will include increasing DG penetrations. DSOs will seek to optimise their business operations within the prevailing regulatory context and minimise their exposures to it, often resisting change wherever new regulatory arrangements could lead to diminished profits. Such strategies may of course impact negatively on the development of DG. The last (and obviously most desirable) stage is the entrepreneurial strategy. In this phase, the strategy evolves from one of resisting change, to proactively seeking to influence regulatory developments. Such DSOs cooperating with regulators to implement new regulatory arrangements are able to develop new activities that can diversify their business model.

Currently, some developments are regarded as threats to the DSO's business model, whereas they may also be seen as a mere challenge. By developing new business activities, thereby di-

[30] See Scheepers (2004) for a more detailed elaboration.
[31] The costs of establishing a link to the nearest network connection point are called the shallow connection costs. New generation capacity or a large load increase, however, may also require expansion of the main network links, called the deep connection costs.

versifying the business model, and by changing the passive network operation policy into an active one, DSOs can turn perceived threats into opportunities. The impact of DG on the distribution network is presently assessed in planning studies by running traditional power flow computations, which seems reasonable if the penetration of DG is still relatively small. However, as the installed capacity of DG increases, its impact on the electricity system behaviour will become larger and, therefore, DSOs should start to use full-scale detailed dynamic analysis and simulations to ensure a proper and reliable operation of the electricity system with large amounts of DG (Knazkins, 2004). DSOs have to change their passive network management into an active one. An active DSO provides market access to DG by acting as a market facilitator and it provides several network and ancillary services through intelligent management of the network. This may include the incorporation of advanced information exchange between generation and consumption, the provision of ancillary services at the distributed level, management of the network to provide network reliability and controllability, and improve customer benefits and cost-effectiveness (Van Sambeek and Scheepers, 2004). The transition from passive to active network management may be accompanied by developing new services for the electricity market, creating new revenue drivers for the DSO. By developing new business activities, thereby diversifying the business model, and by changing operational philosophies from passive into active network management, DSOs may overcome the threats that arise from the increasing penetration of DG, incentive regulation and regulated connection charges.

4.1.4 Policy implications

As DG operators often do not pay cost-reflective network charges, they may choose to locate in places that cause disproportionately high network costs because they are not confronted with them (De Vries, 2004). Locational signals could be helpful to solve this problem. Connection charges should be variable in order to influence the locational decisions of generators, thereby being a reflection of more than only the shallow connection costs. The long-run system costs and benefits should be incorporated as well. This locational (price) signal may be positive in the case of cost to the system, or negative in the case that DG entails benefits to the system (Scheepers, 2004). An example is the use of lower connection charges in the south of England, in which demand exceeds the available generation capacity, while there is excess capacity in the north. However, a difficult issue with deep connection costs is that they are hard to determine, not transparent and, therefore, easy to abuse by system operators. Changing connection charges may be on bad terms with stimulating DG.

Because DSOs are operating in a regulated environment instead of a competitive market, the thesis that competition leads to innovation does not hold for DSOs. There is little incentive coming from the regulated market itself; regulation may even have a contradictory effect, as is shortly discussed in Section 4.1.2. Paradoxically, it is regulation that should simulate a competitive market environment. It should provide incentives to DSOs to change their passive behaviour into an active and entrepreneurial attitude. An interesting policy option could be to create possibilities for DSOs to experiment with innovative concepts, for example by allowing the DSO to apply the cost-plus principle in a specific demonstration project. In this way, experience can be gained without the DSOs facing too much risk.

Next to inappropriate regulation that slows down innovation, another barrier to the development of active DSOs can be an insufficient unbundling of the DSO with its parent company. Legal unbundling may not be drastic enough to let the DSOs act completely independent, thereby inhibiting them to become active entrepreneurs. Ownership unbundling should then be considered as a logical and necessary step in reaching the desired situation.[32]

[32] However, Dutch energy companies state that they will be financially weakened if the grids are split off from their business and, therefore, will become acquisition preys for foreign energy companies.

If the above-mentioned options still do not trigger DSOs to change their network management philosophy into an active one, it will be necessary to explore other ways to achieve the desired objective, preferably utilising incentive based approaches. However, coercion by the regulator is not the best way to get DSO co-operation in the development of DG. If DG has good potential, there should be enough benefits to elicit the enthusiastic participation of DSOs. But, apart from the need for a changing attitude of the DSOs, regulation needs to evolve such that it allows DSOs to have access to a wider range of options and incentives available in choosing the most efficient ways to run their business (Connor and Mitchell, 2002).

4.2 Intermittency

Due to the policy goals that are already described in Section 4.1 (i.e. the Kyoto protocol and the European RES-E Directive), a transition towards a more sustainable electricity supply is expected in the coming years. However, the characteristics of RES-E generation are different than of conventional generation, reflected in a different interaction with the electricity system. Impacts can be divided into a local and a system-wide component. Local impacts of RES-E generation are impacts that occur in the (electrical) vicinity of a RES-E unit and can be attributed to a specific unit (e.g. a wind turbine or wind farm). Local impacts occur at each RES-E unit and are largely independent of the overall RES-E penetration level in the system as a whole. Local impacts are already discussed in Section 4.1.1, which deals with the impact of DG on the electricity system. System-wide impacts, on the other hand, are impacts that affect the behaviour of the system as a whole. They are an inherent consequence of the application of RES-E generation, but cannot be attributed to individual RES-E units. Among other things, these system-wide impacts have consequences for balancing the electricity system and become stronger if the penetration level increases. Section 4.2 deals with the implications of (intermittent) RES-E on balancing the electricity system. Therefore, Section 4.2.1 first gives a short introduction of the balancing mechanism in general. Next, Section 4.2.2 discusses characteristics of RES-E and its implications for the electricity system (and in particular the balancing element). In Section 4.2.3 possible response options of market participants are described, while Section 4.2.4 deals with policy issues relating to balancing the electricity system.

4.2.1 Balancing mechanism

As stated before, the main objective of the electricity system is to satisfy the demand for electricity efficiently and reliably within certain technical, environmental and economic constraints. This requires day-to-day operation of installed generation capacity in a way that follows the fluctuating demand at the lowest overall costs, provided that environmental constraints are met (Hoogwijk, 2004). Supply and demand have to be balanced at different time scales, varying from seconds to minutes to days and longer. The market itself is responsible for balancing demand and supply on the longer term; the TSO is responsible for maintenance of the actual, short-term balance between supply and demand in the electricity system. Because the price mechanism does not work properly in the short term, the TSO uses an additional balancing mechanism to control demand and supply (within seconds to minutes). For this purpose, there are different kinds of generation capacity available, roughly dividable into three categories: primary, secondary, and tertiary control.[33] The UCTE has formulated specific rules and standards concerning the different categories of reserve power. When an electricity system of a certain control area is not in balance, electricity is automatically imported or exported from interconnected adjoining control areas, according to the laws of physics.[34]

[33] See Appendix C for an extensive explanation of primary, secondary and tertiary control.

[34] Involuntary exchange: the exchange of electrical power with other countries different from the agreed international exchange programmes. This situation cannot last for more than 15 minutes, according to UCTE rules.

The most efficient balancing system neutralises actual imbalances by deploying the generating balancing unit that has the lowest (marginal) costs at that time.[35] If the TSO makes long-term contracts for balancing power with power producers, there is a loss of efficiency because the TSO contracts balancing power beforehand while during actual deployment there may be options available with lower costs. In that respect, the establishment of a balancing market is an improvement, because the deployment of balancing units has become a continuous, real-time process (at least for part of the balancing power). At each moment of imbalance, the balancing unit with lowest costs can be called upon. However, the efficiency of the balancing market is bound by the offers of the market players. Only balancing units that are offered to the balancing market are available for deployment. Therefore, it is of major importance that available generating capacity (that is suitable for balancing purposes) is actually offered to the balancing market. That determines the efficiency of the balancing mechanism.

4.2.2 Impact of RES-E on the electricity system

Great challenges of RES-E generation are created by the limited predictability and the high fluctuations in production levels as the energy sources are not controllable and fluctuate randomly (depending on weather conditions). Intermittent RES-E is by nature a variable source of power. Using intermittent sources to produce electricity differs from generating electricity by conventional power plants, because availability and quality are largely outside control of the system operator (TSO). This has technical consequences as well as economical consequences for the power system at different time scales, varying from seconds to minutes to days and longer. Without special control measures, RES-E hardly ever contributes to primary frequency regulation. The frequency control capability has to be secured to provide stable operation of the grid and this may require more spinning reserve (instantaneously available backup power; secondary control) than in the case of a mix of conventional generation. This is a problem for the grid operator if a substantial amount of the consumer demand is generated by RES-E. Furthermore, the variability of RES-E on the longer term (15 minutes to hours) tends to complicate the load following with the conventional units that remain in the system. The impact of RES-E on frequency control and load following becomes more severe the higher the penetration level of RES-E is. Variability, predictability and controllability of RES-E will affect the need for reserves on different time scales.

Because RES-E is not always available during parts of the day or the week and possibly during hours of maximal demand, and this non-availability is practically unpredictable for the long term, rising shares of RES-E generation create the need for additional back-up capacity (reserve power or tertiary control, see also Appendix C) in order to be able to balance the electricity system on the longer term (15 minutes to hours).[36] For each additional MW of RES-E capacity that is installed, only a small part can be considered to be available capacity from a system operating point of view. The fraction of installed RES-E capacity by which the conventional power generation capacity of the electricity system can be reduced without affecting the reliability of the total system is called *capacity credit*. The capacity credit depends on, amongst other things, the penetration level of RES-E generation, on the characteristics of the generation mix in the total system, and on the grid characteristics. A low or zero capacity credit means that the reserve margin (tertiary control) has to be increased by the installation of back-up capacity with good load-following capabilities. At low penetrations of RES-E generation, the capacity credit equals the load factor (Hoogwijk, 2004).[37] RES-E does have a capacity credit and can therefore be relied upon, although the energy source (e.g. wind) is not always available. However, as the level of RES-E penetration rises, the capacity credit begins to tail off and that means a need for additional back-up power that has to be installed to keep the system reliable.

[35] Demand response could be an option as well, but is, for the sake of clarity, not taken into consideration here.
[36] There are alternatives for back-up capacity, like storage and demand response.
[37] The load factor, also known as capacity factor, is the percentage of power generation as a fraction of the nameplate capacity (theoretical maximum capacity) of the RES-E conversion system.

Next to the possible non-availability of RES-E, which creates the need for additional back-up capacity (tertiary control), RES-E generation may have a fluctuating nature on a shorter term as well (within 15 minutes of actual delivery). This short-term variability has a negative impact on the load-following characteristics of the electricity system.[38] The fluctuating nature of RES-E on the short term causes a need for additional secondary reserves (regulation power). Additional secondary reserves must be deployed to overcome short-term fluctuations in power output. Besides, a change in operational strategy (dispatch or contracting of more load-following capacity) may be necessary. The variability in power output requires quick-start capacity, which is obtained by the secondary reserve and is mostly provided by conventional thermal power stations operating at less than full output (spinning reserves). However, high spinning reserve requirements lead to higher fuel use and therefore cause efficiency losses and higher emissions. Besides power plants are operating more often on part load, some of the operated conventional power plants will make more repeated plant starts - causing additional fuel costs, maintenance costs, and emissions. According to Grubb (1988), such operational losses might be in the range of maximum 5 to 8 percent of the fuel use in parts of the operated park. The level of spinning reserve at system level normally varies from 1 to 3 percent of the peak load, depending amongst others on the size of the largest plant. But if RES-E penetration becomes significantly high, estimates of the required spinning reserve given in the literature vary widely, but increase to about 10 to 85 percent of the installed RES-E capacity (Milligan, 2002; Grubb, 1988). Especially if the existing park relies on significant amounts of slow-start capacity, e.g. large nuclear or coal-fired plants, and/or if no good forecasting instruments are available, high values for secondary control are to be expected.

Undesirable power flows

Although not directly linked to the problem of balancing, one more issue of RES-E generation is discussed here: the effect on power flows. This effect of large amounts of RES-E on electricity flows can be illustrated by the recent changes in power flows in the border region of the Netherlands and Germany. The north of Germany is a substantial wind power producer and part of this power has to be transported to the south of Germany. However, a surplus of wind power in northern Germany, during windy periods, cannot be directly transported to the south of Germany, because the German electricity grid was not designed to transmit these electricity flows. Therefore, part of this power is transported to the south of Germany via the Dutch and Belgian grids, as the internal network in Germany cannot handle the flows itself. These spontaneous electricity flows not only deteriorate the stability of the network, but also require bigger reserve margins concerning the allocation of international and interregional transport capacity (UCTE, 2005). It hampers an optimal working of the market, as less interconnection capacity is available to market participants. Due to the fluctuating wind power from northern Germany, strongly changing international flow patterns regularly create unsafe situations in the northwest European electricity grid (TenneT, 2005a). These power flows cannot be influenced easily, since the direction of power flows in a standard transformer cannot be controlled. However, the Dutch grid operator TenneT recently installed special transformers with additional sets of windings, which not only maintain an amplitude difference between the two sides but also can control the phase difference between the voltages on both sides (a so called FACTS: Flexible AC Transmission System). In this way the amount and direction of power flow over the transformer can be controlled, albeit to a limited extent. The expected strong growth of wind power in the coming years increases the risk of large-scale disruptions in the electricity supply system in the near future, if internal transmission capacity remains insufficient.

[38] Due to storms, short-term fluctuations of wind power can become extreme, as sudden drops of significant amounts of wind power are possible if the wind speed exceeds the cut-out wind speed of the turbines.

4.2.3 Response of the market

Current market participants that operate in the competitive environment of the liberalised energy market (power generators, RES-E producers, energy suppliers, consumers) have to respond to the increasing RES-E penetration.[39] Power generators may invest in flexible and fast responding peak capacity. But there are alternatives for this conventional balancing option that may increase the efficiency of the balancing mechanism. The use of storage may (in the future) be more efficient than the deployment of (other) balancing power. Furthermore, energy suppliers may develop demand side response options in junction with electricity consumers, which can be an efficient way of neutralising deviations between demand and supply.[40] And finally, RES-E generators themselves may limit their power output in order to contribute to frequency control. These options will successively be described below.

Storage

Electricity storage systems can play a major role in balancing the future electricity system. It can help with controlling power flows for better matching generation with the demand profile. The management of intermittent sources is, however, not the only function that can be performed by energy storage systems. They can also be of use with obtaining a sufficient power quality degree, for avoiding network investments (i.e. load management) and for increasing reliability (transport and delivery applications). Storage can offer benefits to several market participants. Energy suppliers buying power from uncontrollable generators or intermittent energy resources can better comply with their energy projections that are submitted to the TSO and thus will be able to reduce balancing costs. RES-E operators can better manage and optimise the output of their generation facilities. Large customers could secure themselves of a secure electricity supply. And if DSOs would be regulatory allowed to operate storage devices[41], they could solve congestion problems and will be able to better stabilise conditions in the grid (i.e. maintain power quality and provide balance in energy and/or reactive power).

Demand response

The conventional way of maintaining the balance between demand and supply is to use flexible and fast responding peak capacity. Marginal costs of generation could, however, be considerably higher than the economic value of marginal demand. It is, then, economically more efficient to reduce demand instead of deploying additional generating capacity. To favour the economic efficiency of the electricity systems, demand response should be a fully accepted option in balancing the electricity system. Demand response at its most general level can be defined as follows: *Demand response is a concept that seeks to lower demand during specific, limited time periods, by temporally curtailing electricity usage, shifting usage to other time periods, or substituting another resource for delivered electricity (such as self-generation), focusing on when energy is used and its cost at that time.*[42] By making use of the flexibility that consumers can provide, demand response can be an efficient option in balancing demand and supply. A distinction can be made between industry and households. The main benefits of demand response relate to the functioning of the market. Demand response causes market power to mitigate, it contributes to less volatile prices, and it makes the probability of service interruptions decline. An active demand side helps to create a more flexible electricity market and thus facilitates a larger share of intermittent renewable energy and distributed generation (Skytte et al., 2005).

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39 Also DSOs, TSOs and regulators have to respond to the increasing penetration of RES-E. However, they operate in a regulated environment, which will be the subject of Section 4.2.4. Their business is strongly influenced by the boundaries of economic regulation that is or has been implemented in electricity markets.

40 However, demand response may be of less value in the short-term balancing of the electricity system (secondary control).

41 Unbundling does not allow DSOs to own generation capacity; question is whether a storage system is considered to be a generation unit. Regulation should explicitly state how DSOs may or may not operate a storage system. E.g. operating a storage system for network management is allowed, but trading in electricity (e.g. price arbitrage) should not be allowed.

42 Based on Harrington and Jones (2003), Pavan (2003) and IEA (2003).

Improving demand price elasticity is a matter of consumer education and, most importantly, investing in the necessary communications infrastructure to provide consumers with the necessary information (including real-time price information). In addition, consumers may need to invest in equipment that can help them program their loads, for instance timers or devices that switch off loads if the electricity prices exceed a specified level. Implementing these arrangements on a large scale would take considerable time and investment.

Power limitation and contribution to frequency control
Generally, RES-E generation is programmed to produce the maximum amount of power given the variations in the energy source. Thus the power is dictated by the energy source and RES-E does not contribute to frequency control. In order to support the grid frequency by RES-E, the RES-E units should react to changes in frequency. By sacrificing some energy yield, RES-E units can contribute to frequency control. For instance in the case of wind power, a margin is kept between the actual generation and the production based on the actual wind speed. During a frequency dip, the wind farm increases its power to the maximum available value at that moment. Since power control in wind turbines is relatively fast, this helps the frequency recovery. However, this control option has a price, since a certain amount of RES-E is sacrificed.

4.2.4 Policy implications

In current northwest European electricity markets, access to the supply side of the balancing markets is mainly limited to large power producers *within* the concerning control area.[43] This means that the efficiency of the balancing system is restricted by the physical borders of the control area. Low-cost balancing power from adjoining control areas that is available during a situation of imbalance, is not allowed to be offered on the concerned balancing market. This implies a less than optimal efficiency. A possible option to mitigate this problem is to enlarge the control area, by e.g. consolidating adjoining control areas (like the Nordel system).[44] A requirement is that the interconnection capacity between the former control areas is sufficient to prevent congestion resulting from increasing balancing flows. That may imply that current networks have to be reinforced or new lines have to be constructed. Costs and benefits have to be weighed to determine which is the most efficient.

Another option is to shift the gate closure of the spot market as close to actual electricity delivery as possible. Most intermittent sources are unpredictable to a certain extent. The longer the predictions look forward, the less reliable the predictions become. Therefore, the later the gate closure of the spot market, the better the forecasts of the electricity generation of intermittent sources, and the less problems with balancing due to the unpredictability of RES-E occur.

4.3 Interconnection issues

An important objective of the European Commission, Member State regulators, and other stakeholders, is to work towards the creation of an efficient and effectively competitive, single electricity market (ERGEG, 2005). The European Commission states (EC, 2004) that the overall objective of the internal electricity market is to create a competitive market for electricity for an enlarged European Union, not only where customers have choice of supplier, but also where all unnecessary impediments to cross-border exchanges are removed. Electricity should, as far as possible, flow between Member States as easily as it currently flows within Member States. However, currently, a number of Member States are not particularly well interconnected.

Initially, the development of interconnectors was driven by system security requirements: the high-voltage interconnectors within the EU have been developed predominantly for short-term

[43] Energy suppliers (demand response) and DG operators sometimes have access to the balancing market as well.
[44] In Germany, the option is studied to consolidate the current four control areas into one new one.

security reasons. However, the liberalisation of the electric power markets resulted in trading opportunities, and the cross-border interconnection lines are more and more used for trade reasons and price arbitrage, which quickly exhaust the capacities of the interconnectors (Brunekreeft, 2005). Congestion may be the result.

4.3.1 Benefits and costs of interconnection

Interconnection can provide different advantages and benefits. In the first place it provides reliability and it increases the robustness of the system. Furthermore, it increases efficiency and reduces the possibility to abuse market power. Interconnection makes it feasible to select the cheapest generation available in the system. Price differences are the signal that efficiency gains can be obtained. To make a sound decision whether to invest in new interconnection capacity, the causes behind the price differences should be well understood. Price differences must originate from structural, long-term causes. Differences in primary resources, fuel mix and load patterns are such causes. Furthermore, it is important to note that price differences that result from the difference between regulatory structures (lack of level playing field) may not be structural and therefore may not justify investment in interconnection capacity. It may be a 'false driver' for interconnection.

The advantages of interconnection come at a cost, and, partly due to the structure of the electricity system, they may not be fully exploited. Firstly, there are investment costs, which are high for building new interconnections. Next to the investment costs, there are energy losses that are caused by transporting electricity. Not only the length of the interconnection lines itself is of relevance, the transports that may be induced by interconnecting two systems (including loop flows) are of major importance as well. Next to energy losses, especially if wind penetration is high, loop flows (as discussed in the textbox in Section 4.2.2) may reduce the interconnection capacity that is available for the market and, therefore, reduce the possibility to make use of the advantages, causing the interconnector to become less efficient. Another important issue is that, because interconnection capacity competes with domestic generation, interconnection could lead to an increasing import dependency.[45] Importing countries, where domestic electricity generation is relatively costly, may therefore become increasingly dependent on foreign countries, which may create political resistance. And finally, there may be strong opposition from residents in the areas where the transmission and interconnection lines have to be built. Since nobody wants to have overhead lines in his backyard, the installation of such lines causes negative externalities in terms of decreasing land value and disfiguring of landscape. The construction of new transmission lines can become almost impossible due to opposition from residents in the affected areas (Keller and Wild, 2003).

4.3.2 Response of the market

As most interconnection lines fall under regulation, the market is not expected to respond in an extensive way. However, market participants are allowed to invest in interconnection lines. So-called 'merchant' network investments are facilities that are not built under the initiative of regulators or TSOs, and whose remuneration is not determined by regulation, but by the market (CEER, 2004).[46] In some exceptional cases it might be envisaged that interconnectors could be constructed on a merchant basis. In that case, the remuneration of the transmission facility is unregulated and is determined by the market value that the transmission owner can obtain from arbitrage or from selling capacity on the line. However, the merchant model is not considered suitable as a general model for interconnector investment in Europe (EC, 2004). Under the existing EU Regulation, regulated investments are assumed to be the general rule.

[45] Note that this is a political aspect of interconnection, not an economic one.
[46] If an investment in interconnection capacity is made by the TSO, which is a regulated actor, the interconnector is referred to as a 'regulated transmission line'.

Merchant transmission investment is only profitable if the discounted value of earnings from sales of new transmission capacity exceeds investment and operation costs (Keller and Wild, 2003).[47] Earnings from transmission will be higher if more congestion occurs. Since the income of the merchant investor is directly derived from the congestion rents, the investment that would maximise the profits of a merchant investor is typically of a lower capacity than the optimal investment that the regulator would have chosen, if it were able to assess the optimal investment (CEER, 2004). In general, the socially optimal network investment would reduce the remaining congestion rents too much, from the point of view of investors. In actual transmission networks of developed countries, congestion rents globally collect a small fraction of the total costs of the transmission network. This is why merchant investments can only contribute to the development of a transmission network in some specific instances, but they cannot be relied on as the main mechanism to develop the network.

4.3.3 Policy implications

The electricity grid in northwest Europe cannot be considered a copper plate. Relatively small cross-border capacities and insufficient allocation of these capacities can lead to congestion within the EU, which impedes the imported electricity to freely flow to demand areas (and hinders the export of electricity to neighbouring regions). Whatever advantages there may be with interconnection, these are unachievable if congestion occurs in an extent that it prevents them to be passed along across Member State borders. Therefore, in order to be able to benefit from the potential advantages of interconnection, congestion should be minimised. An obvious way to do that is to invest in additional interconnection capacity, possibly with special transformers that are able to control the amount and direction of power flow over the transformer. However, the advantages and benefits should be well compared with the integral costs and barriers that arise with expanding interconnection capacity (investment costs, energy losses, increasing import dependency).

In addition to technical and operational standards, common market rules are needed to ensure a level playing field based on fair competition, cost-based pricing, access to the network, transparent and non-discriminatory network tariffs, proper cross-border-trade mechanisms, and congestion management. An important aspect is the allocation mechanism of interconnection capacity. The more market designs and rules between countries/regions differ, the more likely it is that trade is impeded or distorted between markets. As a general rule, different designs and rules impede structural trade opportunities. Compatibility between key market rules therefore is important so that opportunities for trade can be fully realised. Regulatory issues that are of relevance comprise rules concerning the timing of gate closure, imbalance arrangements, the firmness of transmission access rights, the type of tariff regulation, unbundling, the ownership of interconnectors, market structure, and security of supply measures. However, full harmonisation of all trading rules and arrangements is not necessarily required for effective trade interaction between markets to occur. But regulatory arrangements need to be independent, with regulatory processes characterised by transparency, objectivity and consistency.

[47] If the TSO invests in regulated transmission lines, it can recover the costs by use of system charges.

5. Concrete implications for Dutch policy

Chapter 5 attempts to make the policy implications concerning the three issues that were discussed in the previous chapter, more concrete for the Dutch situation. It can be seen as a possible 'to-do list' for the Dutch government.

5.1 The increasing penetration of DG

The liberalisation of the electricity market in the Netherlands caused the system of fixed prices for CHP power supplied to the grid to be replaced by one where generated electricity is sold at actual market prices. The relatively low price of electricity in the off-peak periods combined with the high price of gas, affected the profits of many CHP systems. In the future, electricity prices will increasingly determine how CHP is used, and it will become more and more important to be able to respond flexibly to price changes. On balance, the trend in gas and electricity prices is favourable to CHP, owing mainly to the higher price of off-peak electricity (Van Dril and Elzenga, 2005). Trade in CO_2 emissions could also give rise to new investments in CHP if the market price of CO_2 is high enough and passed on sufficiently in the price of electricity. However, until 2020 trade in emissions will have a relatively limited effect (Van Dril and Elzenga, 2005). But in general, because of government policy that stimulates the generation of electricity from RES-E and CHP, it is expected that electricity supply of DG will increase in the Netherlands (DTe, 2004b). This is supported by the sharp rise of the share of renewable energy, mainly wind, biomass and waste, in the Reference Projections (Van Dril and Elzenga, 2005).

This significant growth of DG may create several problems, as is shortly discussed in Section 4.1. However, it is still quite unclear what impact an increasing penetration of DG has on the economy of system operators. An important first step is to gain more insight in the costs and benefits that result from an increasing penetration of DG.[48]

If the increasing DG penetration indeed leads to specific costs and benefits, it should be analysed if intelligent network operation of system operators can offer efficiency gains. It is unclear to what precise extent the active integration of DG into the system (as opposed to passively connect it to the network) can offer advantages to the electricity system. To what extent does a change from a passive network operation policy into an active one reduce investments of system operators? And to what extent, if it is integrated properly, DG is able to offer advantages to the network, such as enhanced system reliability, avoided transmission and distribution line losses and costs, congestion relief in the transmission system, and avoided infrastructure investments?[49] An interesting policy option might be to create possibilities for DSOs to experiment with innovative concepts, for example by temporarily allowing a DSO to apply the cost-plus principle in specific demonstration projects. In this way, DSOs can gain experience with innovative network management concepts without facing high (financial) risks.

For the stimulation of new network management concepts and to increase the efficiency of the electricity system, locational signals are probably indispensable. In order to influence the locational decisions of generators, connection charges should be variable, thereby being a reflection of more than only the shallow connection costs. The long-run system costs and benefits should

48 ECN submitted a proposal (within the HERMES framework) to assess the economic impact of the increasing penetration of DG and RES-E on the networks.

49 Because DG is connected at low and medium voltage levels, its electricity generation may reduce transports via the high voltage transmission grids. Therefore, as from 2006, DG operators in the Netherlands with an electricity production of more than 150 MWh per year are compensated for the resulting reduction of grid losses on the transmission grid of TenneT (via the so-called 'RUN' regulation; RUN is an acronym for 'Regeling Uitgespaarde Netverliezen').

be incorporated in the connection charges. In this way, locational decisions of DG operators are based on the costs and benefits of the *integral* electricity system, which may lead to an efficiency increase.

A last hot topic in the Netherlands concerns the unbundling issue. Legal unbundling may not be drastic enough to let DSOs act completely independent, thereby inhibiting them to become active entrepreneurs. Ownership unbundling should be considered as a logical and necessary step in reaching the desired situation.

5.2 Intermittency

Because of government policy that stimulates the generation of electricity from RES-E, it is expected that electricity supply of RES-E will increase in the Netherlands. As can be found in Appendix B, the target for the share of RES-E in the Dutch electricity consumption is 9 percent for 2010 and is expected to further grow to 17 percent in 2020. The limited predictability of RES-E generation and the high fluctuations in production levels, have technical consequences as well as economical consequences for the power system at different time scales, varying from seconds to minutes to days and longer. The market should respond to this development itself, by making use of options such as demand response, storage, power limitation, and investment in flexible generating capacity (see Section 4.2.3). But it is uncertain if the Dutch market will indeed react sufficiently. Monitoring market responses could be helpful in getting more insight into this question.

Dutch policy should be aimed at creating the environment in which the market is able to respond in an efficient way. New and innovative technologies that arise in the market should be stimulated. It can, for example, be considered to introduce an investment or exploitation subsidy for storage facilities (or let storage technologies fall under the MEP subsidy). Storage may reduce the need for possibly inefficient peak generation.

Another policy option concerns the coupling of the Dutch market with neighbouring control areas in the sense that regulating and balancing power from abroad is available for the Dutch market. Recently, the French, Belgian and Dutch regulators published a road map to integrate the wholesale electricity markets of France, Belgium and the Netherlands. Important elements of this road map concern cross-border intraday trade and balancing trade. This should offer more flexibility to market actors, optimise the utilisation of capacities, enhance competition in the near real-time markets and reduce the balancing costs of TSOs (CRE et al., 2005).

Furthermore, in cooperation with other northwest European countries, it might be useful to bring the timing of the gate closure under discussion. RES-E generation is better predictable on the shorter term and, therefore, a gate closure closer to real-time reduces the need for generating capacity that is attributed via the balancing mechanism. In this way, generating capacity is shifted from the balancing mechanism to short-term market trade, and that may increase the efficiency of the electricity system.[50]

5.3 Interconnection issues

Before considering investment in new interconnection capacity, it is important to first use the existing interconnection capacity as efficient as possible. FACTS (Flexible AC Transmission System), for example, may increase the availability of capacity. And market coupling may allocate the interconnection capacity more efficiently. In the Netherlands it was expected that with the employment of two FACTS in 2003, import possibilities of the Dutch transmission grid

[50] This proposition only holds if it is assumed that the balancing mechanism is less efficient than the working of the market.

could be increased to 4700 MW. However, because of the decreasing export possibilities of Germany due to the spectacular growth of wind power in northern Germany, the import capacity could not be increased structurally. Furthermore, the extremely high exports of France from time to time and the distribution of these transports, create such transit flows in Belgium that the available capacity from Belgium to the Netherlands occasionally has to be restricted (TenneT, 2005b). Due to these and other insufficiently predictable effects, it has not yet been possible to structurally increase the available interconnection capacity above 3350 MW. TenneT should improve its capability to flexibly deal with the increasing unpredictability and unexpected power flows, for example by implementing new technologies in the grid, such as FACTS, or enhanced calculating methods (KEMA, 2004). The extension of the interconnector capacity between France and Belgium (end of 2005), may already lead to increased import possibilities for the Netherlands in 2006 (TenneT, 2005b). And the placement of FACTS in the Belgian grid on the border with the Netherlands in 2007 will make it possible to better manage transports across this border (DTe, 2004c).

If, after increasing the use and availability of the existing interconnection capacity as much as possible, price differences still occur, investment in new capacity can be considered, but should not be seen as the only option. Before investing in new capacity, the causes behind the price differences should be identified. Investment in the physical enlargement of interconnection capacity is not necessarily optimal if it is based on price differences that are caused by the lack of a level playing field. As stated in Section 4.3.1, price differences that result from the difference between regulatory structures may not be structural and therefore may not justify investment in interconnection capacity. It may be a 'false driver' for interconnection. Therefore, it is of major importance to denude the causes of price differences, if investments in interconnection capacity are considered. It is of great importance that Dutch market rules do not differ too much from market rules in surrounding countries. The more market designs and rules between countries differ, the more likely it is that trade is impeded or distorted between markets. In the road map that was already mentioned in the previous section, the regulators of France, Belgium and the Netherlands request the TSOs to submit a joint proposal for a full harmonisation of auction rules, such as auction times, timeframes, firmness level, products' nominations and secondary markets (CRE et al., 2005).

A last notion concerns the future changes of imports in the Netherlands. The Reference Projections (Van Dril and Elzenga, 2005) show a decrease of the nett imports of the Netherlands in the future (from 17 TWh in 2003 to 3-7 TWh in 2020) as a result of decreasing price differences, i.e. marginal costs of electricity production in the Netherlands and neighbouring countries are in general expected to converge. It should be noted that these figures are quite sensitive to scenario parameters. Furthermore, although the trend in imports may go downwards, the fluctuations in contractual and physical flows may not. Increasing price volatility and growth in intermittent electricity production (i.e. wind energy) can also in future be the cause for transit flows and periodic congestion on the interconnectors. If operational planning, management of transit flows and congestion management are improved, the current interconnection capacity of the Netherlands might just be sufficient on the longer term.

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Appendix A Current status of the northwest European electricity supply systems

Table A.1 *Demand*

		Belgium	France	Germany	The Netherlands
Total E-demand	[TWh]	80.6[6]	386.8[4] 445.1[8]	502.5[5]	111[7]
Average annual growth in E- consumption	[%]	2.9[1] 2.5[3]	2.5[1]	3.0[1]	2.8[2]

[1] 1990-2000 [5] 2001
[2] 1993-2003 [6] 2002
[3] 1995-2000 [7] 2003
[4] 2000 [8] 2004

Table A.2 *Supply*

		Belgium	France	Germany	The Netherlands
General					
Total generation capacity	[GW]	14.6[2]	115[2]	129.8[3]	20.5[2]
Total generation[1]	[TWh]	83.4[3]	553.5[3]	581[3]	87.2[2]
Reserve capacity (remaining capacity)[51]	[GW]	0.3[7]	14.1[7]	8.2[7]	1.3[7]
Remaining capacity as percentage of total capacity	[%]	2[7]	12[7]	6[7]	6[7]
Conventional					
Share gas in total generation[52]	[%]	23.1[1] Total thermal generation 58[2]	4.7[4] Conventional 10.1[6]	9[3]	59.4[4]

[51] According to UCTE definition: remaining capacity = guaranteed capacity minus load on third Wednesday in January, at 11 a.m.
[52] Excluding net import.

		Belgium	France	Germany	The Netherlands
Installed gas capacity	[GW]		Conventional gas 27.9[6]	22.6[3]	7.3[2]
Generation from gas	[TWh]		53.1[2] Conventional 55[6]	54[4]	19.4[2]
Share oil in total generation[2]	[%]	1.2[1]	0.9[4]	1[3]	2.9[4]
Installed oil capacity	[GW]			7.5[4]	
Generation from oil	[TWh]		-	6[4]	-
Share nuclear in total generation[2]	[%]	58.8[1] 41[2]	78.9[4] 78.1[6]	28[3]	4.1[4]
Installed nuclear capacity	[GW]		63.4[6]	23.6[3]	0.5
Generation from nuclear	[TWh]	48[2]	415.2[2] 427[6]	164.8[4]	3.7[2]
Share coal in total generation[2]	[%]	15[1] 14[2]	3.8[4]	50[3]	28.0[4]
Installed coal capacity	[GW]			53.1[3]	4.1
Generation from coal	[TWh]			294[4]	23.2[2]
Unconventional/green					
Renewables: generation share[2]	[%]	0.8[2]	14.3[3]	7.5[4]	3.3[5]
Installed wind capacity		1%[2] (hydro+wind)	56 MW[2]	16.6 GW[6]	1.1 MW[6]
Wind generation	[TWh]	0.47[2] (Hydro + wind)	-	22[6]	0.97[2] (Hydro + wind) 1.3[5]
Share wind and solar in total generation	[%]	1[2] (hydro +wind)	0.2[2]	5.8[6]	2.[4]
Installed hydro capacity	[GW]		25.4[6]	8.9[3]	
Hydro generation	[TWh]	0.47[2] (Hydro + wind)	72.5[2] 64.5[6]	26[4]	0.72[5]
Share hydro in total generation	[%]	0.4[1] 1[2] (hydro +wind)	13.4[2] 11.8[6]	4[4]	0.1[4]
Solar generation	[TWh]				0.03[5]
Biomass capacity	[GW]				0.6[2]
Biomass generation	[TWh]		-	19.4[4]	2.3[5]

		Belgium	France	Germany	The Netherlands
Share biomass in total generation	[%]	1.4[1]	0.6[4]	3[4]	4.3[4]
Main RES-E sources		Hydro and biomass	Hydro	Wind and hydro	Biomass and wind
Status renewable energy market		Existence of three different regional systems hinders RES-E development.	Besides the mature hydro-sector, other RES are still insignificant.	Mature, large growth rates even at high penetration rates. Biomass is lagging behind other RES.	Clearly increasing but not yet matured.
Renewables: Support mechanisms	[ct/kWh]	Green certificate system with mandatory demand or minimum feed-in tariff. Additional investment support schemes. Minimum prices are: Wind offshore 9 Wind onshore 5 PV 15 Biomass 2 Hydro 5	Tendering system (>12MW) with guaranteed price and Feed-in tariff (<12MW): PV 15 Hydro 6 - 7.5 Biomass 4.9 - 6 Wind 3 - 8.5	Tax exemptions, investment subsidies, feed-in tariff: PV 4.8 Hydro 6.6-7.7 Biomas 8.6 - 10 Wind 6-9	Feed-in tariffs (MEP): Mixed biomass/waste 2.9 Biomass (large) 7 Biomass (small) 9.7 Wind onshore 7.7 Wind offshore 9.7 Tidal/ wave/hydro 9.7
Distributed generation/CHP					
CHP: Current generation share	[%]	5[2]	4 - 6[2]	10.6[3]	42.6[2] 38.3[4]
CHP Electricity generation	[TWh]	Flanders: 7.3[3] Wallonia: 0.8[2] Belgium: 5.5[2]	16.3[2]	46.0[3]	37.2[2]
CHP: Current generation capacity	[MW]	1540[2]	5276[2]	18747[3]	7600[6]

	Belgium	France	Germany	The Netherlands
CHP: Support mechanisms	Rebates on input taxes.	Obliged purchase mechanism through contracts with 6.1 - 9.15 ct/kWh. Tax reductions on input fuel. 12-month depreciation scheme.	The EEG (Erneubare Energie Gesetz) provides a legal obligation for all DSOs to take off the output from well-defined renewables at a fixed rate above the market price.	MEP

[1] 1999
[2] 2000
[3] 2001
[4] 2002
[5] 2003
[6] 2004
[7] 2005

Table A.3 *Network*

		Belgium	France	Germany	The Netherlands
TSO		Elia	RTE	- EnBW Transportnetze - E.ON Netz - RWE Transportnetz Strom - Vattenfall Europe Transmission	Tennet
National: Net ownership	[kV]	380-26	400-63	380-220	380, 220 and partly 150. Intention to buy total 150 and 70
National: Unbundled?		Legally	Legally	Legally	Legally
Number of distribution companies		27	166	950	20
Unbundling		Legally	Management	Unbundled	Legally
International: Import capacity (NTC)	[GW]	4.6	14.0	12.2	4.7
International: Imports	[TWh]	16.6	3.0	37.0	20.9
International: Exports	[TWh]	9.1	79.9	22.2	4.5
International: Net imports	[TWh]	7.6 4.3[2]	- 76.9	14.9	16.4
International: Import capacity as % of installed capacity	[%]	29	13	11	17
International: Interconnections		France, Netherlands	Spain, Italy, Switzerland, Germany, Belgium, United Kingdom	Netherlands, France, Denmark, Sweden, Poland, Czech Republic, Austria, Switzerland	Germany, Belgium

[2] 2000.

Table A.4 *Balancing*

		Belgium	France	Germany	The Netherlands
Responsible party		ELIA	RTE	The four separate TSOs.	TenneT
National or regional		National	National	Regional	National
Balancing period		15 minutes	30 minutes	15 minutes	15 minutes
How are charges set?		Regulated	Market based	Market based	Market based
Single price or dual price system		Dual	Dual	Single	Dual
Intraday market?		yes	yes	partial	yes
Market structure: remarks		Electrabel obliged to **VPP** auctions.	EdF has made available 6 GW of generating capacity via a **VPP**	Several state **investigations** in E-price setting.	Obliged capacity auction NUON
Regulator		CREG, VREG	CRE	Regulierungsbehorde für Energie Telekommunikation und Post (Reg ETP)	DTe
Role of regulator in Competition Law		Advisory	Regulator within competition authority	Limited, no formal role	Regulator within competition authority
Distribution network			90 - 95 % operated by EdF		To be disintegrated from generation.
Number of suppliers		41	20-25	1050	37
Top 3 suppliers' share	[%]	90	88	50	88 (households)
Allocation method interconnectors		First-come, first served /Auction	First-come, first served /Auction	Auction	Auction

Appendix B Development of the northwest European electricity supply systems

Table B.1 *Demand*

		Belgium	France	Germany	The Netherlands
Average annual growth in E- consumption	[%]	1.3-1.9[4]	1.5[3]	0.5-0.7[1]	1.5-2.1[2]
		1.5[2]	1.2[11]		1.3-2.0[7]
		1.3[7]	1.1-1.4[2]		
		0.8[11]	0.6-0.9[6]		
		1.2[3]	0.3-0.6[9]		
Total E-demand	[TWh]	+ 16[8]	532[5]		124-132[5]
		94-100[5]	601[10]		141-161[10]
			503-520[5]		
			519-544[10]		
			527-561[12]		
Energy saving (energy in general)					- 0.9-1.0[2]
					- 0.8[7]
Energy saving target	[%]				-1.3

[1] 1999-2020
[2] 2000-2010
[3] 2000-2030
[4] 2002-2011
[5] 2010
[6] 2010-2015
[7] 2010-2020
[8] 2011 w.r.t. 2001
[9] 2015-2020
[10] 2020
[11] 2020-2030
[12] 2030.

Table B.2 *Supply*

		Belgium	France	Germany	The Netherlands
General					
Total generation	[TWh]	95[8] 96[6] 110[10] 120[12]	608.3[6] 671.3[10] 713.5[12]	611[8] 650[1] 600[10]	106.7-114.1[6] 131.0-153.8[10]
Average annual growth in E- generation	[%]	1.6[2] 1.3[7] 0.9[11]	1.6[2] 1.3[7] 0.9[11]	0.5[1] 1.1[2] 0.3[7] 0.9[11]	2.0-2.7[2] 2.0-3.0[7] 2.1-2.9[3]
Total capacity	[GW]	22.5[12]	125.5[6] 147.3[10] 171.9[12]	132.1[6] 150.0[10] 166.6[12]	24.0-26.2[6] 29.4-38.5[10]
Reserve capacity (remaining capacity)[53]	[GW]	-1.9[6] -5.2[9]	12.0[6] 11.1[9]	5.5[6] 1.4[9]	-0.9[6] -2.8[9]
Remaining capacity as percentage of total capacity[53]	[%]	-13[6] -42[9]	10[6] 9[9]	4[6] 1[9]	-4[6] -11[9]
Projected development of generating capacity		In 2020: 71% of capacity and 63% of generation will be gas-fired. Many wind capacity planned/under construction. Dismantling of nuclear capacity.	Until 2020, share nuclear remains constant (new plants are planned). New capacity largely wind-propelled.	Rising share of gas (to 20%) and coal (to 60%). Renewables rise to 13 % Dismantling of nuclear capacity in period until 2020 (possibility of lifetime extension.	Gas remains the major component. Large share WKK. Stagnant or decreasing share of coal. Nuclear plant at least until 2013 in operation

53 According to UCTE definitions: on third Wednesday in January, 11.00 a.m.

		Belgium	France	Germany	The Netherlands
Conventional					
Generation capacity nuclear	[GW]		63[6] 63[10] 51[12]		0.5[6] 0-0.5[10]
Generation from Nuclear	[TWh]	40[6] 35[10] 0[12]	451.1[6] 451.9[10] 409.1[12] 407-433[6] 364-404[10]	10-25[10]	3.7[6] 0-3.7[10]
Share nuclear in total generation	[%]	0[12]	68[10]	5-10[10]	3.3[6] 0-2.4[10]
Generation from Coal	[TWh]	43[12] (super critical hardcoal)	9-32[6] 12-34[10]	110-310[10]	26.5[6] 18.4-35.9[10]
Generation capacity coal	[GW]		5[6] 7.5[10] 12.6[12]		3.7[6] 2.3-4.9[10]
Share coal in total generation	[%]	<1[9] 37[12]		20-60[10]	23.2-24.9[6] 14.0-23.4[10]
Generation from Gas	[TWh]	70[10] 80[12]	Total thermal generation 75.9[6] 106.8[10] 187.2[12] 14-102[10]	120-300[10]	17.2-19.6[6] 18.2-38.6[10]
Share gas in total generation	[%]	63[10] 60[12]	max. 62	20-50[10]	17.1[6] 11.8[10]
Unconventional/green					
Renewables: 2010 EC target	[%]	6	21	12.5	9

		Belgium	France	Germany	The Netherlands
Renewables: other targets			Additional capacity in 2010 [MW]: Biogas: 100 to 500 Biomass: 300 to 1000 Solid Waste: 200 - 700 Wind power: 7000 - 10000 (incl. at least 500 - 1500 offshore) Geothermal: 20 to 120 Hydropower: 400 to 2000 Solar: 1 to 150	+ 500MW wind in 2006 (1.5TWh) +3000 MW wind in 2010 (7-10TWh)	RES-share in E-consumption 2005 6 % 2010 9 % 2020 17 % Wind: 2010 1.2 - 1.6 GW on shore 2020 3.5 - 6 GW off shore
Renewables: projected shares in total consumption	[%]	Share of renewable capacity: 2000 0.8 2020 1.5 2030 4 (mainly wind) Share of renewable generation: 2010 - 2030 ± 4 % 3.5 % 2010 3.1 % 2020 4.8 % 2030 2.5 % (2010) 5% (2030) Biomass: 3 % in 2020	13.8 % 2010 13.2 % 2020 12.2 % 2030	12.7 % 2010 15.6 % 2020 17.6 % 2030 10.6 % (2020) 4 - 10 % (2020)	8.9 - 9.3 % (2010) 16.2 - 23.5 % (2020)
Projected generation renewables	[TWh]	+2.9-5.4[8] 5.4[12]		24-50[10] 63.8[10]	10.8-12.1[6] 22.3-36.8[10]

		Belgium	France	Germany	The Netherlands
Projected capacity		+1421MW[5] +0.9-1.7MW[8]			3.3-3.8GW[6] 7.0-11.1GW[10]
Installed biomass capacity	[GW]				1.3[6] 1.4-2.0[10]
Installed hydro capacity	[GW]		25[10] 25[12]		
Installed wind capacity		+1015MW[5]	5GW[4] 12[6] 16[9] 17[10] 19[12]		Onshore: 1.2-1.6[6] 1.9-2.9[10] Offshore: 0.7-0.9[6] 3.5-6.0[10]
Generation from wind	[TWh]	2.5[12]	7.1[6] 38.4[10] 42.9[12]		
Generation from hydro	[TWh]		74.3[6] 74.3[10] 74.3[12]		
Generation from biomass	[TWh]		3[4] 8[6] 10[10]		
Distributed generation					
Projected generation	[TWh]	+3.9-5.5[8]	35-100[6] 40-210[10] 18[6] 20[10]	100-140[6] 110-175[10]	46.8-50.7[6] 50.1-57.4[10]

		Belgium	France	Germany	The Netherlands
CHP Projected share in E-generation	[%]	8.1[6] 14.4[10] 12.9[12] 8[6] 12.5[10] 11[12]	5.3[6] 5.3[10] 6.4[12]	11.8[6] 11.5[10] 12.4[12]	43.8-44.4[6] 37.4-38.2[10]
Projected capacity		+1368MW[5] +700-1000MW[8]	200MW[4] 500MW[6] 1000 MW[9]		9.9-10.8GW[6] 11.2-12.9GW[10]
Target generation	[TWh]	Flanders: 5[6] Wallonia: 13.3[6]			
Target share	[%]	13[6]			

[1] 1999-2020 [7] 2010-2020
[2] 2000-2010 [8] 2011
[3] 2000-2020 [9] 2015
[4] 2006 [10] 2020
[5] 2009 [11] 2020-2030
[6] 2010 [12] 2030.

Table B.3 *Network*

		Belgium	*France*	*Germany*	*The Netherlands*
Projected net import	[TWh]	4.5[3] 4.6[4] 4.6[5]	-61-81[3] -60[3] -38[4] -50[3] -50[4]		15.2[3] 3.2-7.2[4]
Maximum import level	[MW]	3700[1] 4700[2]			
Interconnections: Development plans		France to Belgium 3.700MW in 2007 >4.000 MW later	France to Belgium 3.700MW in 2007 >4.000MW later	?	Connection between Norway and the Netherlands of 600MW in 2008. Possible connection between the UK and the Netherlands of 1300MW in 2009

[1] 2006 [4] 2020
[2] 2009 [5] 2030.
[3] 2010

Appendix C Primary, secondary and tertiary control

Supply and demand has to be balanced at different time scales, varying from seconds to minutes to days and longer.[54] The market itself is responsible for balancing demand and supply on the longer term. The TSO is responsible for maintenance of the actual, short-term balance between supply and demand in the electricity system. The TSO uses a balancing mechanism to control demand and supply within seconds to minutes. For this purpose, there are different kinds of generation capacity available, roughly dividable into three categories: primary, secondary, and tertiary control. The UCTE has formulated specific rules and standards concerning the different categories of reserve power (UCTE, 2000). Beneath, these UCTE rules and standards are discussed.

Primary control

The frequency is the number of oscillations of currents and voltages per second (50 Hz in Europe and 60 Hz in the US). The frequency is a system wide variable and is the same at any location in the power system. There is a direct relation between the frequency and the rotational speed of all generators in the power system. A mismatch between power generation and power consumption (imbalance) leads to a change in frequency. Since there is practically no storage in the system[55] this mismatch must be corrected immediately. In each control area the grid operator is responsible for maintaining the frequency close to the required value. Frequency problems can be solved anywhere in the system by increasing or decreasing the electric power generation at least as long as sufficient transport capacity is available to get the power to the demand centres. From an economic point of view it is often better to generate power as near to the demand location as possible to reduce transport losses.

If a sudden deviation between demand and supply in the interconnected European electricity grid occurs, the balance between supplied and demanded power has to be directly restored as much as possible by means of the primary control on generating units. If there is an outage of generation in a control area, the nominal frequency of 50 Hz drops. The frequency is the measure that indicates if generation and load are in balance on a certain moment. Disturbances of this balance are neutralised by the rotating mass of the generators in power plants. If a surplus of energy is fed into the electricity system, the rotation speed of the turbines increases. In case of a shortage, rotation energy is extracted from the turbines, and the rotation speed decreases. Technical devices detect the frequency changes and intervene to restore the power balance and to bring back the frequency to its nominal value (of 50 Hz). The frequency is the signal for previously determined generation units throughout the whole UCTE system to raise or diminish their output within seconds, limiting automatically the frequency deviation occurring in the system. This control function, the primary regulation, is shared by all UCTE countries, which act simultaneously. The bigger the system, the smaller the risk that disturbances cannot be overcome, provided that no congestion problems occur on the net. A large system can overcome extensive disturbances within seconds by direct regulation of the rotation speed of generating units.

Some characteristics of the primary control:

- The maximum instantaneous deviation between generation and demand to be corrected by primary control is 3.000 MW for all UCTE partners together.
- Each country contributes to primary control in accordance with its respective contribution coefficient C_i, where C_i is the share of annual electricity generation in country i in total UCTE production. This share is determined annually.
- Primary reserves should be activated within 15-30 seconds.

[54] Appendix C is derived from Van Werven et al. (2005).

[55] Only the rotating masses of the generators and motors connected to the grid form a small buffer.

- After activation, the altered output must be able to be maintained for at least 15 minutes.
- There is no payment for the primary control that generators supply.

Secondary control
After the automatic activation of the primary control, the TSO activates to restore frequency to the pre-set value of 50 Hz, within minutes, the secondary regulation reserve generating capacities to secure the import/export balance with neighbouring control areas. When this is achieved, the units acting in primary regulation in the whole synchronous system return to their normal operational conditions, prepared to balance a new impair. This secondary control (or spinning reserve, or rotating reserve) is provided chiefly by storage stations, pumped-storage stations, gas turbines, and by thermal power stations operating at less than full output. The costs that TSOs make with contracting the secondary reserves are remunerated by the Use of System (UoS) charges (network charges), paid by the end users.

The function of secondary control in a given control area is the maintenance of the scheduled power exchange programme between the control area concerned and all adjoining interconnected control areas. Its goal is the restoration of the synchronous system frequency to its set point value (50 Hz). Secondary control takes over from the primary control reserve deployed by all UCTE members to offset an imbalance between generation and demand. Ideally, only the TSO of the control area where the imbalance appeared will respond and initiate the deployment of the requisite secondary control capacity. These actions on generated power and frequency will take place either in response to minor deviations which will inevitably occur in the course of normal operation, or in response to a major discrepancy between generation and demand associated e.g. with the tripping of a generating unit. Secondary control must begin within 30 seconds of the disturbance concerned, i.e. when the action of primary control is completed, and must be fully deployed within 15 minutes (the minimum duration that primary control must be able to maintain the altered output after activation). The size of the secondary reserve within a country depends on the peak load in that country and can be derived from Figure C.1.

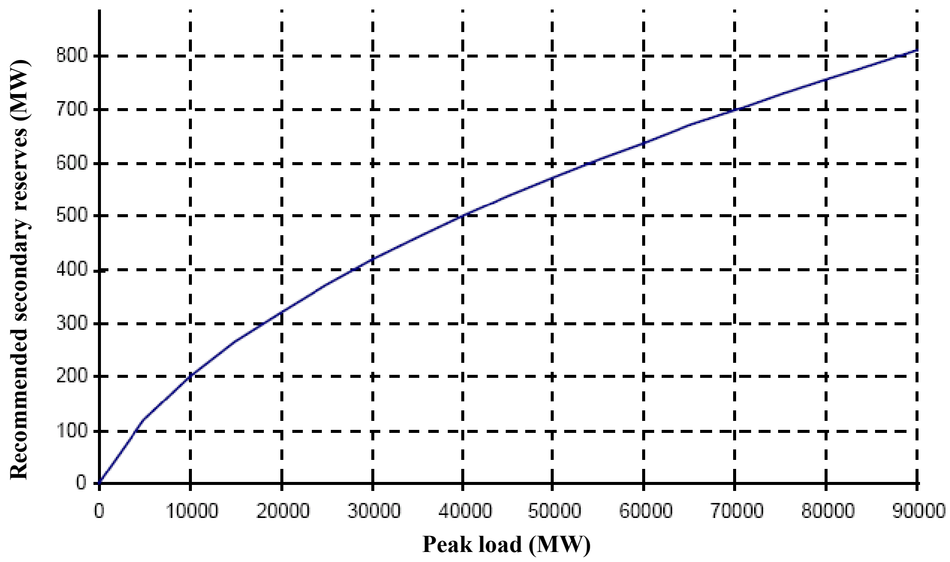

Figure C.1 *Recommended size of secondary reserve within a country*
Source: UCTE, 2000.

Primary and secondary reserve is provided in the framework of the ‘frequency control’ system service by those power plant operators that have implemented, in co-operation with the TSOs, the necessary technical measures and have been bound by the TSO by contract to provide this reserve, and are called upon to make it available. Hence, this reserve is well known to the TSO.

Tertiary control
If the imbalance deviates outside the specified standards, more drastic measures are required. If secondary reserves are lengthy used, offers of tertiary reserves are called upon. Tertiary control (or reserve power or stand-by reserve) is generating capacity or interruptible load that must be available in the market to maintain the balance in the electricity system during exceptional deviations in demand or supply. These reserves are offered on the balancing market. Tertiary reserves are provided by the power plant operators that have to start thermal power stations for this purpose. Reserves are activated as a function of the contractual arrangements concluded between customers and power plant operators, independently to a large extent of TSOs. In some countries (e.g. in the Netherlands), the TSO has contracted additional, permanent options on 'emergency power' to be dispatched if the balancing market cannot be appealed to. These options also fall under tertiary control and cause a discrete leap of the balancing price when called upon.