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Capacity to spare?

A cost-benefit approach to optimal spare capacity in electricity production

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Abstract in English

The Dutch government considers to contract spare capacity as a safety net to prevent black-outs. The study tries to answer the question on the optimal size of the safety net, using a social cost-benefit approach.

The outcomes of this study suggest that the electricity market will not generate sufficient capacity to reach the social optimum. The optimum may be reached by contracting an additional 450 to 1,220 MW of spare capacity. The bandwidth reflects uncertainty about the expected level of competitiveness in the market. At this level, 9,000 to 16,000 MWh per year will remain unserved. This is two to three times the current amount, or 0.02 percent of annual demand. It is possible to complement spare capacity contracts with other instruments that guarantee security of supply, such as extensions of import capacity.

Key words: Electricity, security of supply, cost-benefit analysis

Korte samenvatting

De Nederlandse overheid overweegt om TenneT reservecapaciteit te laten contracteren als vangnet om stroomuitval te voorkomen. Deze studie probeert te bepalen hoe groot een dergelijk vangnet moet zijn, gebaseerd op een analyse van de maatschappelijke kosten en baten.

De uitkomsten van deze studie geven aan dat het niet vanzelfsprekend is dat de elektriciteitsmarkt uitkomt op het sociale optimum. De belangrijkste reden voor het niet bereiken van dit optimum is dat prijzen nu onvoldoende fluctuaties in de schaarste van elektriciteit volgen (afwezigheid van zogenaamde ‘real-time’ electriciteitsprijzen). De overheid kan ingrijpen door TenneT additioneel 450 tot 1.220 MW aan reservecapaciteit te laten contracteren. Deze ruime bandbreedte reflecteert de onzekerheid over de te verwachten mate van concurrentie op de markt. Bij die capaciteit wordt 9.000 tot 16.000 MWh aan elektriciteit niet geleverd, wat ongeveer 2 tot drie maal zo veel is als er nu verloren gaat door netwerkstoringen, ofwel 0,02 procent van de totale vraag. Het is mogelijk om de contracten voor reservecapaciteit in combinatie te gebruiken met het verhogen van importcapaciteit.

Steekwoorden: Elektriciteit, leveringszekerheid, kosten-batenanalyse

Een uitgebreide Nederlandse samenvatting is beschikbaar via www.cpb.nl.

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Preface

Security of supply in a liberalised electricity market remains an issue of great interest, both to policymakers and researchers. Clearing of the electricity market is hampered by inflexibility of demand to respond to fluctuations in scarcity of electricity supplies. Reserve contracts have been put forward as a short-term fix for this problem. In this case, the government contracts spare generation capacity from electricity producers to be used only in cases of near-outages.

In an earlier study, “Energy Policies and Risks on Energy Markets”, CPB concluded that keeping spare capacity in electricity markets using such reserve contracts is a very expensive way of securing supply. The same study stated that the economic viability of reserve contracts depends on the magnitude of the spare capacity held available. The current study studies the level of spare capacity at which the costs of this policy measure are equal to the benefits of avoiding outages to society.

This study is conducted by Mark Lijesen (project leader) and Ben Vollaard, under supervision of Marcel Canoy, Casper van Ewijk and Machiel Mulder. The project team would like to thank several persons for their valuable contributions. Emiel Rolink and Jaco Stremler from the ministry of Economic Affairs intensively guided the project. Frank Nobel from TenneT offered both valuable comments to preliminary results and served as a valuable source of information.

A steering committee from the Ministry of Economic Affairs composed of Bert Roukens, Klaas-Jan Koops, Erik Sieders, Jaccomien van Beek, Bert Wilbrink, Emiel Rolink and Jaco Stremler provided us with highly useful comments on an earlier version of the report. We thank them all for their useful contribution. The responsibility for this report is, of course, entirely ours.

F.J.H. Don
director

Summary

Policy background

The move to a liberalised electricity market has shifted capacity planning from the central level to electricity producers, implying that securing supply is primarily a matter of market parties. Triggered by several electricity outages in recent years (in the USA, Canada, Italy, Greece, England and Denmark), concerns have arisen whether market forces are able to provide customers with the level of reliability that they demand. This poses the question if, and at which magnitude, governments should intervene in electricity markets to secure supply.

Against this background, the Dutch government currently considers a wide range of policy options, including measures to improve the working of market mechanisms, measures to increase demand response and measures to increase the amount of spare capacity available in the market. Some of these policies take a considerable amount of time to implement. The more so, since there is little practical experience with the necessary sweeping changes in infrastructure and the institutional framework.

The Netherlands Ministry of Economic Affairs has asked the CPB Netherlands Bureau for Economic Policy Analysis to analyze the costs and benefits of one particular option that can be implemented on short notice: reserve contracts between the government and electricity producers. These contracts involve spare generation capacity that is only called upon in times of severe capacity constraints. The Transmission System Operator TenneT, responsible for keeping the nation’s electricity system up and running, already holds a small amount of reserve capacity, supplemented with an amount of reserved import capacity, for this purpose.

The reason that the government wants to step in to guarantee security of supply, lies in the key uncertainty in this market in transition. It is unclear to what extent the market is able to guarantee sufficient capacity. The price mechanism is thwarted by the fact that consumers cannot be charged in real time and hence cannot adapt their consumption pattern in case of capacity constraints. In turn, this market failure reduces incentives by firms to invest in extra capacity.

Both the introduction of real time pricing (which is not possible in the short run) and enhanced competition (which also takes time) will make this problem vanish in the future. The reserve contracts are therefore a temporary solution in safety.

Approach

A major challenge for any analysis into the security of supply is the uncertainty about the frequency at which electricity supply disruptions will occur. We are able to use data on

stochastic elements in demand and in the availability of capacity, but such data still contain many uncertainties. We address these uncertainties by dividing the analysis into two stages.

First, we compute a 'break-even frequency': this is the frequency of occurrence of an electricity outage at which the *costs* of contracting spare capacity are equal to the *benefits* of avoiding that outage through these reserve contracts – an approach developed in De Joode *et al.* (2004). The break-even frequency turns out to be independent from the scale of the crisis: the costs and benefits of preventing outages of different sizes increase at the same rate.

Second, we compare the computed break-even frequency to expectations about the frequency at which the outage is likely to occur. The expected frequency of an outage is likely to decrease with the scale of the crisis, as larger crises are less likely to happen than small ones. The expected frequency of a shortage of capacity consists of stochastic elements and 'flexibility factors'. Stochastic elements are fluctuations in demand and (the availability of) supply. We define flexibility factors as mechanisms in place to counteract these shortages, such as emergency imports and emergency capacity. The proposed instrument, reserve contracts, also provides a form of emergency capacity.

Thus we have a constant frequency at which the costs are equal to the benefits of preventing a specific crisis. And we have an expected frequency of that crisis that decreases with the scale of an electricity outage.

The optimal amount of spare generation capacity to be contracted is found at the point where the expected frequency and the break-even frequency coincide. This is the expected frequency of a crisis for which the costs of contracting spare capacity are equal to the benefits of the outage avoided.

The advantage of using this two-stage approach is that it makes a distinction between an outcome derived from relatively certain data and a partial outcome based on data containing a larger amount of uncertainty.

Notice that the calculated optimal capacity should not be interpreted as a forecast. Rather, it provides an order of magnitude and identifies the key uncertainties.

Reserve contracts: how they work and what they cost

The Transmission System Operator (TSO) contracts operational reserves from producers. These reserves are then taken out of the regular market, as they can no longer be used for generating electricity for the regular market. A system of auction bidding ensures efficient pricing, and the costs of keeping spare capacity are charged to consumers using the system fee. In case of an emergency, the TSO orders the spare units to be dispatched.

The costs of having reserve contracts consist of capital cost of keeping spare capacity and social costs following from price effects. We derive the capital costs from investment costs for modern closed cycle gas turbines. Discounted to the date of commissioning, total investment costs amount to 794 euro per KW. This implies that, at a return on capital of 10 percent, keeping 1 KW of capacity in reserve comes at an annual cost of 79.40 euro, which boils down to an annual average present value of 4.2 million euro per 100 MW. On top of that, retaining transport capacity for natural gas incurs annual average costs (present value) of 0.2 million euro per 100 MW of spare capacity.

The TSO pays the producers for holding spare capacity and passes on the costs to end-users through an increase in the system fee. The increase in the system fee implies an increase in end-user prices, causing two effects. First, end users reduce demand because of the price increase. This reduction is a welfare effect in itself. Second, the commodity price is likely to be lower in reaction to the decrease in demand. The combined effect is that not all costs are passed on to consumers, while some welfare is lost due to a decrease in demand. Foreign producers follow the decrease in the commodity price, so that a net welfare transfer from abroad takes place.

Electricity outages: their occurrence and costs

The benefits of spare capacity occur only in case of a crisis and are equal to the prevented costs of outages. If all lines of defence have failed, it will become impossible for supply to meet demand. This will have serious implications for the entire system, as it can no longer be balanced, implying the risk of a system break-down. The only thing the TSO can do under these circumstances is to disconnect groups of users from the net, to bring down demand through rationing. Disconnecting takes place on a regional basis and we assume that the TSO does not apply any regional or other priorities when disconnecting groups of users.

We define a crisis as a one-hour outage at peak hours without advance notice and assume that the size of the black-out is infinitely divisible. The estimates of SEO (2004) are the best available estimate of outage costs for the average Dutch electricity customer. The focus and approach of SEO (2004) provides the best fit with the aim of our analysis. The outcomes suggest a willingness to accept a one-hour outage of 5 euro for households and 52 euro for business consumers. For an average group of households and business consumers with a combined peak demand of 100 MW, this boils down to a present value of 0.3 million euro for every crisis.

The frequency at which reserve contracts break-even

Combining average annual costs of spare capacity with the benefits of avoiding a crisis yields the break-even frequency. If a disturbance of, say, 100 MW occurs for 14 hours per year, it turns out to be economically viable to build 100 MW of spare capacity. The break-even frequency of this crisis is once every 0.07 years. This may also be expressed as its inverse, amounting to 14 outages per year. As we have predefined outages to last for one hour, we find the break-even frequency to be equivalent to a total of 14 hours of electricity supply disruptions a year.

The expected frequency of electricity outages

The break-even frequency has to be confronted with the expected frequency of outages, which depends on unexpected variations in demand, unexpected variations in the availability of capacity and several 'flexibility factors' such as emergency imports. Deviations from average demand may occur for all sorts of reasons. The weather is likely to influence electricity demand, as are broadcasts of special events on television. Furthermore, supply interruptions may drive up spot market prices and thus influence demand. Apart from these clear-cut reasons, electricity demand is also influenced by minor events and coincidence.

We make a distinction between expected and unexpected demand variations. The latter are of more importance to our analysis, as expected demand peaks are likely to be flattened by price increases on the spot market. On this market, electricity is traded 24 hours in advance of actual delivery. In our empirical analysis, we find that unexpected demand variations may be described by a normal distribution, with mean 0 and a standard deviation of 632 MW.

Similarly, the frequency distribution of the unexpected unavailability of capacity is important for our analysis. Our empirical results suggest that the unexpected unavailability of capacity is best described by a truncated normal distribution. The underlying normal distribution has mean 22 MW and standard deviation 847 MW and is truncated at 0.

The most obvious line of defence against shortages in a well-functioning market is the price mechanism. If scarcity arises, prices rise and consumers respond by decreasing demand. Furthermore, the price mechanism also rewards producers for keeping capacity available to serve demand at higher prices. Given the distribution described earlier and the short run demand elasticity derived in this study, we calculate the optimal level of privately held spare capacity from a producer's point of view to be 2,100 to 2,300 MW on top of average peak load, depending on the level of competitiveness of the market.

Before we arrive at the optimal magnitude of spare capacity, we assess the magnitude of the currently available flexibility factors. These consist of a guaranteed level of 300 MW of emergency imports and an equal amount of contracted emergency capacity, summing up to 600 MW.

The optimal size of spare generation capacity

Comparing the expected frequency to the computed break-even frequency and taking into account the presence of 600 MW of flexibility factors, we find that the optimal size of additional spare capacity contracted by the TSO lies at 450 to 1,220 MW. The bandwidth reflects uncertainty about the expected level of competitiveness in the market. At this level of security, the amount of electricity not served due to outages amounts to 9,000 to 16,000 MWh, or roughly 0.02 percent of total demand. Sensitivity analysis shows that this outcome is robust to changes in the main inputs of the analysis. The outcomes are fairly sensitive to assumptions on the competitiveness of the market. A closer analysis of these figures may serve to increase the robustness of the outcomes presented here. Furthermore, the sensitivity suggests that increasing the competitiveness of the market probably is a cost-effective measure to increase supply security.

Note that our result is based on the instrument of reserve contracts implying that spare capacity is placed outside the market and left idle. This is an expensive but certain way to ensure supply security. If a more cost-effective way can be found, a higher level of supply security may be reached at equal or even lower costs. Increasing the share of transport capacity that is reserved for emergency imports may provide such a cost-effective way. Further research may be aimed at giving a thorough quantification of the costs of this option, as well as other alternative measures.

1 Introduction

1.1 Background

Supply security of electricity has been taken for granted in the Western world for many years. The confidence of a secure supply of electricity suddenly shattered with the occurrence of the California crisis in 2001. Soaring wholesale prices, rolling black-outs and even more near-black-outs focussed the world's attention on the vulnerability of the electricity system. Recent outages in the US, Canada, England, Denmark, Greece and Italy have emphasized the importance of electricity for modern day society. Triggered by the occurrence of major electricity blackouts, concerns have arisen whether market forces are able to provide customers with the level of reliability that they need.

The move to a liberalised market has induced a decrease of available generation capacity. The (mostly-idle) domestic capacity in excess of average peak load is expected to decline from 22 percent in 2003 to 9 percent in 2010 (TenneT, 2003). If the newly liberalised electricity market succeeds in bringing together demands of customers and services of suppliers efficiently, the decrease in spare generation capacity is an efficient response to market signals. Indeed, the inefficiently high level of spare capacity was one of the reasons for introducing reforms in the electricity market in the first place.

Policy makers want to make sure that the gains in efficiency are not offset by welfare losses because of black-outs. Several instruments are available to policy makers. The Dutch government currently looks at measures to improve the working of market mechanisms, to increase demand response and to increase the amount of capacity available in the market. A priori the latter solution is regarded as inefficient, but it is easier to implement on short notice. The Dutch government currently considers the use of so called reserve contracts to assure a sufficient level of spare capacity. CPB analyzes the costs and benefits of such a transition policy, and provides an order of magnitude of the needed capacity.

1.2 An economist's view

Economists tend to look at markets as efficient mechanisms to secure welfare maximising outcomes. In this view, government intervention is only beneficial to welfare is markets fail. What type of market failure justifies public intervention in the electricity production market? The key problem in the case of electricity is that time-varying demand has to be met at any instant whereas supply may be limited in the short run by capacity constraints.

The combination of time-varying demand and fixed short run supply is not as unique to electricity as some people in the field of electricity tend to think. All services are non-storable and many of them have fluctuating demand over time. Common examples are transport and medical services. Problems relating to time-varying demand and fixed short-run supply are associated to external effects, more specifically to congestion externalities. Adding one unit of demand above a certain threshold level has a negative impact on the quality of the good for all users. The marginal customer is therefore not charged for all the costs he incurs. In the case of electricity, an increase in demand beyond available capacity levels increases the probability of a black-out, thus imposing outage costs on all users.

The natural reflex of an economist to externalities is either pricing or granting (tradable) ownership rights. Taxing externalities at the level of the costs they incur (Pigouvian taxation) is the optimal way to either dampen demand, increase capacity or both. If all externalities are internal to the market at stake (i.e. users impose costs on each other, as is often the case with congestion), Pigouvian taxation is unnecessary and peak load pricing will suffice to reach the optimal outcome.

In its current lay-out, the electricity market already has peak load pricing in place, through the spot market and through the unbalance pricing mechanism. One of the problems here is that many consumers do not observe real-time prices and hence cannot react to them. Modern techniques may be used to solve this problem, but these solutions are costly and will take time to implement.

In order to understand the pricing mechanisms in the electricity market, let us devote some attention on how electricity is traded. The lion’s share of electricity is traded through bilateral contracts between end users and suppliers. The latter are generally referred to as load serving entities. Some 15 percent of electricity is traded or resold at the spot market. At this market, performed in The Netherlands by the Amsterdam Power Exchange (APX), buyers and sellers of electricity bid their offers 24 hours ahead of delivery. Prices are set on an hourly basis. After the spot market has closed, trade volumes for the following day are known. Load serving entities report their total trade volumes, consisting of bilateral contracts and spot market trade, to the TSO. Each load serving entity is responsible for serving as much load into the network as it takes from the network. If the load serving entity does not succeed, this causes unbalance.

If an unbalance arises, the TSO deploys so called regulatory reserves. These reserves consist of regular capacity, kept ready to retain the balance.[1] The owners of these reserves bid their capacity into a single buyer market. The TSO orders the bids from low to high priced ones and deploys the units in this order if necessary. If a unit if capacity is used to retain balance, the

[1] It may also consist of demand agreed to be lowered.

owner of the unit is paid the unbalance price, which is paid for by load serving entity causing the unbalance. Other than the spot market price, the unbalance price is a real-time price.
An alternative to pricing is keeping spare capacity available for emergencies. It is important to use this capacity in case of emergency only, otherwise market outcomes are likely to be distorted, because the public capacity will crowd-out private capacity. Our next question should be at what level to keep this capacity. As the box below shows, three economic characteristics play a role here: differences in preferences, economies of scale and pooling risks.

On-site backup power versus centralised reserves

Spare capacity may either be held at a central level or on the customer's premises. Apart from technical considerations (response time, network lay-out), three economic issues arise; differences in preferences, economies of scale and pooling risks. The latter two are strongly interrelated.

Let us turn to differences in preferences first. Different consumers desire different levels of supply security. As it is hard to differentiate products in the current institutional framework, this implies that a centralised system of spare capacity is bound to over-secure some customers, whereas other will feel the need to install additional back-up capacity. This lifts the total level of supply security above the social optimum.

This problem can be overcome if all spare capacity is built on-site, leaving room for an optimal allocation of capacity over customers. On-site back-up power is however less cost-efficient for two reasons. First, it is cheaper for electricity companies to increase the reliability of the system because of economies of scale, in terms of investment but also operations (Serra and Fierro, 1997). Second, back-up capacity, like many insurance goods, may benefit from pooling risks. A central generating unit may provide back-up power for customer A on one day and for customer B on the other, whereas on-site back-up would require the same amount of capacity on both locations. The efficiency gains from pooling risks depend on the probability that crises occur simultaneously. The smaller this probability, the larger the potential gains from pooling.

The above implies that on-site back-up power offers the possibility of adhering closely to customer's preferences, but centralised back-up is more cost-efficient. Product differentiation in the form of priority pricing (Strauss and Oren, 1993) or capacity subscriptions (Doorman, 2003) offers the opportunity to combine these advantages.

The discussion on differences in preferences and pooling risks applies to a higher level of aggregation as well.[2] Should a country strive for autarky, or pool risks within the framework of UCTE, a union of 22 European countries with synchronised transmission networks? The latter is far more appealing as the sheer size of the UCTE virtually guarantees advantages from pooling, since the incidence of a combined crisis in the entire UCTE-region is negligible.

1.3 Research question

Against the background of the uncertainty about the optimal level of spare generation capacity, the Ministry of Economic Affairs has asked CPB to look into the following question:

[2] Scale economies are likely to be exhausted at the national level.

What are the costs and benefits to society of maintaining spare capacity and what is, from the perspective of costs and benefits, the socially optimal level of spare capacity?

This question focuses on the optimal level of spare capacity, ignoring the question whether an electricity only market will be able to achieve this level. The latter question is posed implicitly by narrowing down the question to the public responsibility in maintaining spare capacity. Furthermore, we add the instrument of reserve contracts to the question.

What is the socially optimal level of spare capacity to be contracted by the government through reserve contracts?

If an electricity market is capable of reaching the socially optimal level by itself, the answer to the second question would obviously be “none”. Note that this does not imply that arriving at the answer “none” means that an electricity only market reaches the optimum by itself. It merely implies that the costs of adjusting the market outcome are higher than the benefits.

1.4 Scope of the study

We focus on the availability of electricity generation capacity. Therefore, we limit the analysis to power outages that are the result of a lack of generation capacity. Clearly, there are other and more common causes of outages, including technical problems in the transmission and distribution network.

Additionally, we focus on spare generation capacity as a way to improve reliability of electricity supply. As stated above, the question is at what level the benefits of maintaining spare capacity exceed the costs. Other ways of improving reliability exist, such as increasing import capacity or increasing demand response to shortages. Most of these policies will only work in the medium term. Given the short term perspective of this study, a focus on spare capacity is justified.

Finally, we limit the analysis to blackouts. Brown outs, such as fluctuations in voltage are outside the scope of this study.

2 Framework

2.1 Introduction

This chapter describes the framework used in this study. Section 2.2 briefly describes the general framework for cost-benefit analysis, which is the basis for our more specific framework. An important complication in analysing policies directed at supply security is that they refer to uncertain future events. As a consequence, expected efficiency of policies depends on the expected probability of those events. Following our earlier studies on this subject (De Joode *et al*. (2004), Lijesen (2004)), we compute break-even frequencies (section 2.4). Section 2.5 discusses the relationship between the size of the measure and the size of the event it tries to prevent, followed by a discussion of the factors determining the expected frequency of shocks in section 2.6.

2.2 General framework of cost-benefit analysis

Costs and benefits of a policy option are generally assessed by comparing a situation with the policy in place to the situation world without it (the no-project alternative). The difference between these alternatives is analysed against the background of one or several economic scenarios or base-lines. A cost-benefit analysis will follow the following steps:[3]

- Definition of project alternatives and the no-project alternative
- Definition of base-line scenarios, based on long-term economic scenarios and predefined risks
- Analysis of energy market effects
- Calculation of indirect effects using a macroeconomic analysis
- Calculation of external effects
- Determination of distribution effects.

The results of these steps constitute the entire costs and benefits of the project alternative compared to the no-project alternative. These results can form an input in the decision-making process.

The distinction between direct and indirect effects requires some attention. Direct effects are defined as those effects following directly from the policy measure. More specifically, we define direct effects as the effects of a policy measure in the specific energy market it is directed towards. These effects may expand to other markets. Consider a price increase in the electricity market. The increase affects the relative price of production factors, changing the

[3] See Eijgenraam *et al.* (2000) for a general framework and De Joode *et al*. (2004) for a framework more specifically tailored to the analysis of supply security policies.

cost price of all products for which electricity is used in the production process, as well as the use of other production factors. This may in turn affect relative prices of both consumer goods and the other production factors and so on. Some of the indirect effects are merely redistributions of welfare, or transferred direct effects.

Indirect effects may be actual welfare effects as well, for two reasons (Eijgenraam et al., 2000). First, distribution effects may cross borders, causing national welfare effects. Second, distribution effects may stimulate (or hinder) economic activity in markets that are subject to market failure. Let us again consider the case of electricity prices to illustrate the second point. If all markets were perfect markets, the demand elasticity would reflect all the effects of a price increase, so that the direct effect would exactly equal the effect on the economy as a whole, i.e. the indirect effect would be zero. This implies that if we observe a non-zero indirect effect, we may assume the presence of a market failure.[4]

Definition of direct and indirect effects:

Direct effects are the effects of a policy measure in the specific energy market it is directed at.
Indirect effects are effects that do not relate directly to a policy measure, but follow from its direct effects.

We calculate indirect effects in this report using CPB's general equilibrium model Athena. Athena predicts the effect of a policy measure or a security of supply crisis for the national economy as a whole. The difference between the total effect and the direct effect then constitutes the indirect effect, which may be either positive or negative.

2.3 The role of uncertainty

A general feature of disruptions of energy supply is that they come unexpectedly. The chance of their occurrence depends on several factors, on some of which we have to use data containing many uncertainties. The reasons that these uncertainties arise are twofold: First, data on some of the factors, especially detailed data on demand fluctuations are available for one year only. Second, the electricity market is a market on transition, implying that many features of the market are likely to change in the near future, making it hard to produce exact quantitative predictions of future developments.

To account for these uncertainties, we follow a two-stage approach. In the first stage, we follow the approach used in De Joode *et al.* (2004). This stage produces a fairly robust outcome, based on insights into the costs and benefits of the policy measures. In the second stage, the result of the first stage is confronted with expectations on the occurrence of crises, containing uncertain elements. The advantage of using this two stage approach is that a distinction is made between

[4] The entire line of reason holds for government failure as well.

fairly robust elements and elements that contain a larger degree of uncertainty. This allows the reader to keep this distinction in mind in the interpretation of our result.

The approach used in the first stage avoids the computation of probabilistic outcomes, by computing ‘if-then’ outcomes. These outcomes are then used to compute ‘break-even frequencies’, the (decrease in an) expected frequency of a certain scenario at which net benefits are exactly zero.

2.4 Computation of break-even frequencies

We use the methodology developed in De Joode *et al.* (2004), which avoids the problem of having to quantify the effects of a large number of possible crises, each of which has a small but unknown probability. Rather than trying to quantify these effects and their probabilities, De Joode *et al.* (2004) compute the effects of a single crisis and confront the benefits of avoiding that crisis with the average annual costs of the policy option aimed at preventing the crisis. This results in the computation of the break-even frequency, which is defined below.

Definition of break-even frequency:

The break-even frequency is defined as the frequency of occurrence of a predefined crisis at which the present value of the costs of the policy option exactly equal the present value of its benefits.

In mathematical terms, the break even frequency is defined as:

$$P_i = \sum_{t=1}^{T} \frac{c_t}{(1+r)^t} \Bigg/ T \frac{b_i d_i}{(1+r)^{T/2}}$$

where:

P_i break-even frequency for crisis i

d_i damage caused by crisis i

b_i fractional decrease in d_i , with $0<b_i<1$

c_t costs of policy at time period t

r discount rate

T time span of the policy

Break even frequencies as defined above have a value that has to be compared to expectations on the frequencies of the crisis defined. It will often be impossible to give an exact numerical outcome for the expected frequency, but a well-founded estimate will often be sufficient to judge the welfare effects of the option. If the break even frequency of the crisis is lower (higher) than the expected frequency, the welfare effects of the policy measure are negative (positive). If the BEF is smaller than one, the crisis should occur more than once a year.

We may illustrate the principle of the break-even frequency by an example taken from the analysis in De Joode *et al.* (2004). They find that keeping a reserve margin of 15 percent through capacity markets incurs average annual costs of 148 million euro (discounted value). The discounted value of the benefits, a prevented large black-out, equals 605 million euro. The quotient of benefits and average annual costs[5] is 4.10, implying that such a black-out should occur every four year to render the policy economically viable. If we were to expect a lower frequency (e.g. once every 5 years), it would not be efficient to implement the measure.

2.5 Size of the measure and size of the shock

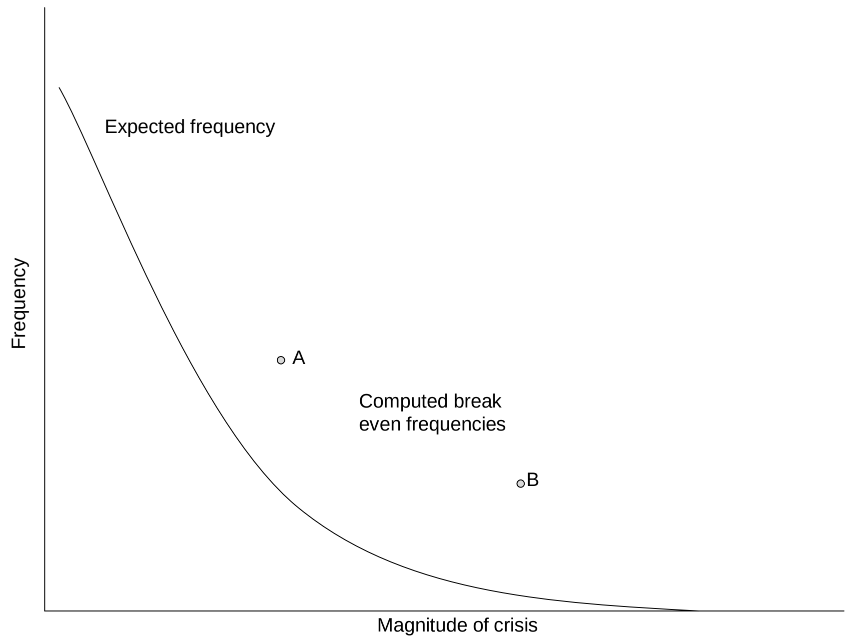
It is intuitively clear that a policy measure should be of the same order of magnitude as the crisis it tries to prevent. This is something to keep in mind when designing policy measures. The order of magnitude is however also important in the analysis of policy measures. In De Joode *et al.* (2004) policy measures are generally considered at a given size against the background of a given crisis. The conclusion from sensitivity analyses was that the break even frequency was inversely proportional to the size of the crisis; doubling the impact of the prevented crisis leads to halving of the break even frequency. The interpretation of the break-even frequency also changes in this case; a larger crisis is less likely to happen.

The reasoning above may be illustrated graphically. Suppose we have some information to base the expected frequency on. Expected frequencies for any crisis are likely to decrease with the magnitude of the crisis. A crisis causing a shortage of 20 percent is less likely to happen than a crisis causing half of that effect. Moreover, expected frequencies decrease exponentially, as larger crises require simultaneous occurrences of events. This explains the curbed line in figure 2.1.

Suppose that we have a predefined policy measure with a predefined crisis. Our computed break-even frequency may then be represented by point A in the graph below. Note that point A is above the curve of the expected frequency, implying that the policy is not efficient. If we analyse the effect of a crisis that is twice as large, the break-even frequency is depicted by point B, with a break-even frequency half of that of point A, but still above the expected frequency.

[5] Note that this approach is equal to the approach in the formula in the box on the previous page, beit that both the nominator and the denominator are divided by *T.*

Figure 2.1 Value and interpretation of break-even frequency



Instead of keeping the scale of the measure constant and changing the size of the crisis, one may also act the opposite way. This is especially useful for tracking possible scale effects in a certain measure. De Joode et al. (2004) illustrate this point by analysing different levels of the same policy measure (extending oil stocks).[6] They find that smaller stocks have a higher chance of being profitable if the crisis is smaller than the largest stock. If the crisis is sized such that even the largest stock would be depleted, the break-even frequency is equal for each stock level. This result suggests the absence of scale effects; each level of stocks prevents a proportional part of the crisis and (dis)economies of scale are absent on the cost side (i.e. b_i in the definition of break-even analysis is proportional to c_t).

In the particular case this research deals with, we compare similar policy measures of different magnitudes. How can this be done within the framework? Like in the previous case, we vary the size of the measure to check for scale effects. This time however, we do not vary the part of the crisis that is prevented (b_i in the definition of break-even analysis), but the size of the crisis (d_i in the definition of break-even analysis).[7] This implies that a policy measure to hold 10 percent spare capacity should be confronted with a possible crisis that may just be prevented by keeping 10 percent spare capacity. Likewise, a policy measure that involves a spare capacity percentage

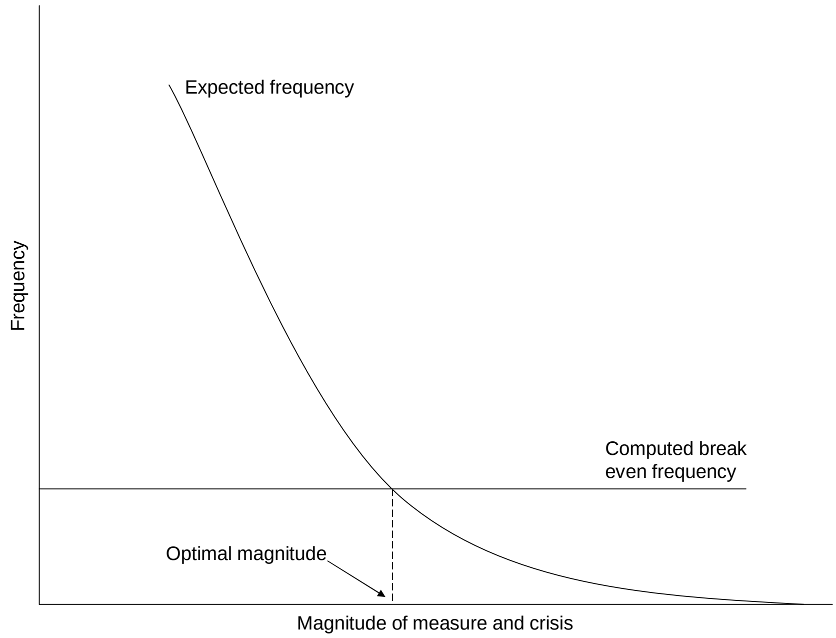
[6] They also vary the duration of the crisis, but do not adjust the crisis to the measure.

[7] Comparing both policy measures with the same crisis would yield an unfair comparison. If the selected crisis were too large to prevent with 10 percent spare capacity, the benefits of that policy option would be zero. Comparing the options on the basis of a crisis just large enough to be prevented by the smallest policy measure, would yield an incorrect image of the efficiency of the larger measure. After all, the policy is aimed at preventing a crisis twice as large, and its costs are much higher because of that.

of 20 should be judged against a crisis that may just be prevented by having 20 percent spare capacity.

If costs and benefits are linearly related to the size of the measure and the crisis respectively, this approach would yield a constant break-even frequency. If costs (benefits) increase more than linearly with the size of the measure (crisis), the break even frequency increases (decreases) with the magnitude. Expected frequencies for any crisis are likely to decrease with the magnitude of the crisis, as we have seen earlier. We adjust figure 2.1 by replacing points A and B by a line representing a continuum of points and by letting the x-axis represent both the size of the measure and the size of the crisis. Figure 2.2 shows a horizontal line, implying the absence of scale effects. Downward or upward sloping lines are also conceivable however.

Figure 2.2 Illustration of the derivation of the optimal magnitude of a policy measure



The optimal magnitude is found at the point where expected frequency and break even frequency coincide. On the left hand side of the optimal magnitude, the expected frequency exceeds the break-even frequency. Benefits occur more often than would be needed to make the policy measure just viable, implying that benefits exceed costs. An increase in magnitude up to the optimal magnitude therefore coincides with an increase of welfare. At any point further to the right, the break-even frequency exceeds the expected frequency, suggesting that increasing the magnitude of the measure is inefficient.

2.6 Expected frequency: stochastic elements and flexibility factors

If the optimal magnitude of a policy measure lies at the point where the break-even frequency equals the expected frequency, it is important to know both numbers. The former was defined clearly in section 2.4, the latter will be assessed in the current section.

It is important to recognize that the expected frequency of a shortage of capacity contains stochastic elements and so-called flexibility factors. Stochastic elements are fluctuations in demand and (the availability of) supply, causing shortages in the first place. We define flexibility factors as those mechanisms that counteract these shortages, such as demand response, producers' own spare capacity and emergency imports.

Let us look at the events that accompany a possible shortage. Suppose demand is at an unexpected high level, so that currently available capacity is insufficient to meet it.[8] The expected frequency of high demand and the (un)availability of capacity may be derived from the frequency distribution of similar events in the recent past. Monte Carlo simulations of both events yield a combined frequency distribution, reflecting the expected occurrence of a shortage.

If a shortage occurs, the first reaction will be an increase in the spot market price, causing (some) users to bring down demand. This may take either of three forms. First, demand may be reduced due to the price increase. Second, users that had already contracted electricity may decide not to use it and sell their portion on the spot market. The third form is increased supply from independent producers, especially from firms increasing their output from combined heat and power (CHP) generators.

If the spot market is unable to counteract the shortage, a second line of defence comes into action. The TSO buys capacity from producers especially for this purpose (the so called control- and spare capacity). This mechanism is used to retain the balance in the system if any of the players in the market does not supply or demand according to prior expectations. Producers may bid their spare capacity to this system, and large consumers can offer to refrain from using electricity they already bought. The capacity is then deployed in the order of bids, with the lowest bid being deployed first. Players that cause the unbalance are charged for the costs they incurred. These costs (also referred to as the unbalance price) follow the spot-market price, but are at a much higher level, giving a strong incentive to producers to hold spare capacity.

[8] Shortages may also follow from unavailability of capacity, or from a combination of demand and unavailability. This does not alter the events mentioned in the main text.

If the second line of defence fails, the TSO calls in its contracted reserves consisting of consumers who have agreed in advance to reduce demand and pare capacity contracted abroad. If this is not sufficient, the TSO has to ask for assistance from abroad. The Netherlands is a member of the UCTE, an organisation of 22 European TSO's with interconnected and synchronised grids. If one of the member states is confronted with a shortage, electricity will flow from other UCTE-countries to the member state in distress.[9] This will continue until either border restrictions are binding or the entire spare capacity of all UCTE member countries is exhausted. Note that the UCTE fallback option also relies on spare capacity, but risks are pooled over a much larger geographical area, so that the combined risk of shortage is smaller than the sum of individual risks.

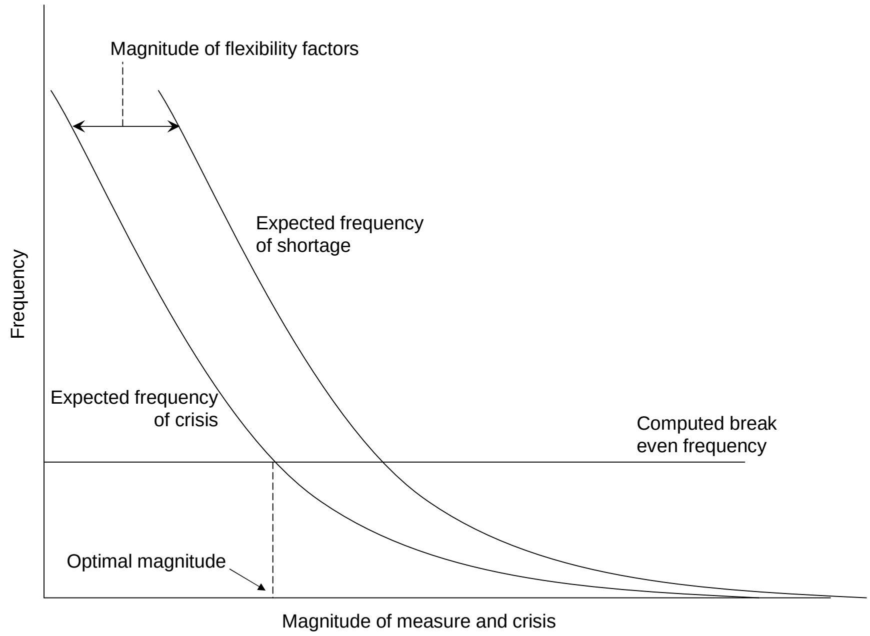
If even emergency imports fail to compensate the shortage, the TSO will have to disconnect groups of users from the net, in order to prevent a system black-out. Disconnecting will take place on a regional basis. This is consistent with the definition of a crisis in our study (see section 0 for a more detailed discussion).

Earlier in this section, we made the distinction between stochastic elements and flexibility factors. We will now place these terms in the context of our framework. Recall that figure 2.2 graphs a downward sloping curve for the expected frequency as a function of the size of the crisis. The slope of that curve is determined by the stochastic factors, i.e. fluctuations in demand and the availability of supply. The lines of defence sketched here do not influence the relationship between magnitude and expected frequency of a shortage. They do however influence the relationship between a shortage and the actual occurrence of a crisis, as figure 2.3 suggests.

The approach suggested by figure 2.3 is especially helpful if the magnitude of (some of) the flexibility factors is unknown. As this magnitude is the same for each level of frequency, we may also define the optimal magnitude as a measure including (some of) the flexibility factors. In some cases, we know a minimum level for a flexibility factor, but not its exact level. In these cases, we may shift the expected frequency curve by the amount of the minimum level and take the remainder into account when interpreting the 'optimal magnitude'.

[9] This is a direct technical consequence of having synchronised grids, rather than benevolence or agreements.

Figure 2.3 Illustration of the derivation of the optimal magnitude with flexibility factors



3 Costs of the policy option

3.1 Introduction

This chapter discusses the costs of keeping spare capacity, assuming a predefined design of the policy measure, which is discussed in the next section. Sections 3.3 and 3.4 discuss the capital costs and welfare costs of the policy option under consideration.

3.2 Design of the policy measure

The policy measure proposed here is labelled reserve contracts, pointing at the TSO contracting capacity from producers. Capacity is contracted purely for to deliver security and can therefore not deliver output to the market, as this would seriously disturb market outcomes through reactions of producers anticipating the TSO's supply. A system of auction bidding ensures efficient pricing, and the costs of keeping spare capacity are charged to consumers by increasing the fee that users of the network pay for the TSO's services. In case of an emergency, the TSO orders the spare units to be dispatched.

By the nature of its application, the capacity should be a so-called 'spinning reserve', implying that a plant is kept running below full capacity. The unused capacity is then defined as the spinning reserve. Note that supply security also implies that spare capacity can not be used in any other way. After all, any other employment would limit its availability in case of a crisis.

We distinguish between capitals costs of spare capacity, including the costs of having gas pipeline capacity ready, and the welfare costs following from these capital costs. Transaction costs are ignored, as the system of reserve contracts is very similar to the current mechanisms in place, and may therefore be adopted without having to change the organisation.

3.3 Capital costs of spare capacity

What are the capital costs of retaining spare capacity? To answer this question, one first has to establish what type of generators is used as spare capacity. Spare capacity will be standing idle for most of the time, and will have to be deployed rapidly if needed, preferably in the form of so-called spinning reserve. This practice may be applied to all types of fuel-fired generators, but is economically optimal for plants with low per unit capital costs. Gas fired-plants are therefore the obvious candidates for backup generation capacity.

We distinguish between open and closed cycle gas turbines. The latter are generally preferred over open cycle turbines because of their much higher thermal efficiency. There is some debate as to which type of generating unit has lower capital costs. East Harbour (2002) finds a capital cost figure for simple combustion turbines that is 17.5 percent below that of combined cycle turbines, whereas PB Power (2004) find the combined cycle plant to have 10% lower investment costs than the open cycle turbine. Differences between these estimates are probably due to scale effects, as PB Power (2004) analyses open cycle turbines of 40 MW, which is quite small for a generating unit.

The concept of ‘spinning reserves’ as defined above suits the combined cycle turbine better than the open cycle turbine. Since a large part of capacity will be in use for normal production, total generation costs rather than capital costs alone will be the main factor in technique choice. Because of its much higher thermal efficiency, closed cycle gas turbines have lower overall costs than other types of gas-fired plants.

The Nuclear Energy Agency (NEA) and the International Energy Agency (IEA), both agencies of the OECD, published a comparative study of the projected costs of base-load electricity generation, commercially available in the first decade of this century (OECD, 1998). Although the study is aimed at comparing techniques for base-load production, the information it contains is also useful for our study.

The technical assumptions in OECD (1998) concern the commissioning date (2005), the economic lifetime of the plant (40 years) and the settled down load factor (75% for fossil and nuclear plants). The economic assumptions include the currency unit (US-dollars as of 1 July 1996) and the discount rate for decision-making. OECD (1998) distinguishes between 5 and 10 percent. We focus on the latter, as we feel that a 5 percent discount rate does not reflect the uncertainties in Europe’s newly liberalised electricity markets).

OECD’s methodology strives for full cost coverage: all technology and plant specific cost components are taken into account, distinguishing between three types of costs:

- Investment costs include pre-construction, construction, major refurbishment and decommissioning costs. (see table 3.1).
- Operation and Maintenance (O&M) costs consist of costs for consumable materials other than fuel, emission control catalysts and waste disposal costs.
- Fuel costs include all costs related to fuel supply to the power plant. Apart from the commodity price of the fuel at stake, it comprises fuel-specific taxes, pre-treatment costs and transport costs.

For the purpose of our study, we are primarily interested in investment costs. OECD (1998, table 9) states that the investment costs for Dutch figures for modern closed cycle gas turbines discounted to the date of commissioning amount to 794 euro per KWe.[10] Despite the use of common assumptions, some of the outcomes vary widely between countries. Investment costs for comparable plants in other countries range from 696 euro per KWe (Canada) to 951 euro per KWe (Brazil).[11] Including plants with different designs even broadens this range.

Table 3.1 Composition of investment costs for a Dutch CCGT power plant (€/KWe)

Base construction costs	631
Contingency	33
Interest during construction	120
Major refurbishment	10
Decommissioning	1
Total investment costs	794

Source: OECD, 1998, table 9, figures do not add to total due to rounding

As the methodology used in OECD (1998) has already taken account of timing issues in construction expenses, we may simply define the annual capital costs to be 10 percent (the discount rate applied in OECD, 1998) times the capital costs. This implies that keeping 1 MW of spare capacity comes at an annual cost of 79,400 euro, which boils down to an annual average present value of 4.2 million euro per 100 MW.

Apart from keeping spare generation capacity available, it is also necessary to keep spare gas transport capacity available, in order to fuel the plant if needed. Gas transport capacity will have to be contracted, incurring a cost not taken into account in the OECD figures. The website of the operator of the gas network in The Netherlands (www.gastransportservices.nl) lists fees for exit-capacity, with an average of 18.25 euro per year for every m^3/hour of capacity. Delivering 100 MWh output at 60% thermal efficiency requires 18,957 m^3 of natural gas. Keeping transport capacity available for 18,957 m^3 per hour incurs an annual cost of € 346,061, boiling down to an annual average present value of 0.2 million euro per 100 MW.

3.4 Welfare costs of spare capacity

Welfare effects from spare capacity arise from the capital costs discussed in the previous section. Apart from the capital costs themselves, the impact of these costs on market transactions causes welfare effects. We distinguish between effects in the electricity market itself and effects in other markets, labelling the latter as indirect effects. For direct effects, we

[10] kWe stands for kilo Watt equivalents. We convert the figures from 1996 US dollars to 2002 euro using the 1996 exchange rate and the cpi for the Netherlands, combining to a multiplication factor of 0.95.

[11] AN even lower value of 480 euro per KWe is found in PB Power, 2004. It is however not clear whether this is base don assumptions similar to those in OECD (1998).

distinguish between end users (domestic by definition), domestic producers and foreign producers.

We assume that all spare capacity is located and contracted in the Netherlands, implying that domestic producers bear these costs in first instance, as table 3.2 suggests. The TSO pays producers for holding spare capacity and passes on the costs to end-users through an increase in the system fee. This implies an increase in end-user prices, causing two effects. First, end users reduce demand because of the price increase. This reduction is a welfare effect in itself. Second, producers lower the commodity price in reaction to the decrease in demand. The combined effect is that not all costs are passed on to consumers, while some welfare is lost due to a decrease in demand.

Note that foreign producers follow the decrease in the commodity price, so that a net welfare transfer from abroad takes place. This effect is even larger than the welfare effect of decreased demand, but still relatively small in comparison to the capital costs of spare capacity.

Table 3.2 Average annual direct costs of 100 MW reserve contracts (discounted value in million euro)

Item	End users	Domestic producers	Foreign producers	Total domestic
Capital costs of spare capacity		4.4		4.4
Transfers due to higher prices	3.4	− 3.5	0.2	− 0.2
Effect of decreased demand	0.0	0.1	0.0	0.1
Total	3.4	0.9	0.2	4.3

Table 3.2 suggests that the welfare costs of retaining spare capacity are carried mainly by end users. We tested whether other levels of spare capacity yielded disproportional outcomes and found that this was not the case, implying that all costs mentioned here are linearly related to the size of the measure and scale effects are absent.

Indirect costs

Price effects in the electricity market have an effect on other markets as well, as electricity is used as an input in many production processes. These indirect costs are directly related to the direct costs born by end-users. Based on the ratio of indirect costs to direct costs of end-users in Lijesen (2004), we calculate annual indirect effects to amount to 1.5 million euro (present value) for 100 MW of spare capacity.

The size of the indirect effects is large relative to the direct effects of the measure. This requires an explanation, as indirect effects are generally fairly small. To understand why the effects are large in this case, let us recall how indirect effects lead to welfare losses. As we said earlier (section 2.2), indirect effects are essentially distribution effects, but they may lead to welfare effects if distribution effects stimulate or hinder economic activity in markets that are subject to market failure. There is no apparent reason to assume why this would cause larger indirect effects for electricity than for other goods, which should give rise to caution.

The problem may be avoided easily however. In the computation of the break-even frequency, we will divide the costs of the measure by its benefits in case of a crisis. We assume that indirect costs and indirect benefits are proportionally related to their direct counterparts. This implies that the size of the indirect costs and benefits no longer matters, as they will cancel out in the division. The assumption of proportional indirect costs and benefits makes sense, as both effects concern the same good.

External costs

The reduction in electricity demand mentioned earlier also reduces the external effects of electricity production. Since demand effects are limited, effects on external costs are limited as well. The policy option of keeping 100 MW of spare capacity lowers external costs by a few hundred euros, a figure that will not influence the outcomes of our analysis.

4 Benefits of spare capacity

4.1 Introduction

The benefits of preventing power outages are equal to the costs of outages. In this chapter, we will review the empirical literature on the costs of outages. We are looking for a reliable estimate of power outage costs in the Netherlands that we can use for our cost-benefit analysis. Section 4.2 introduces the types of costs related to power outages. We continue by defining the kind of crisis that is relevant to this study. From the perspective of this scenario, we review the literature on outage costs in section 4.4.

4.2 Costs of interrupting electricity supply: elements and measurement

To be able to conduct the cost-benefit analysis, we need a reliable estimate of power outage costs for the average electricity customer. We focus on the average customer, since we assume that every customer has the same change of having its electricity supply interrupted. After all, the transmission system operator (TSO) does not follow a policy of prioritising specific customers or areas when disconnecting groups.

No power outage is the same. To interpret and compare estimates of outage costs, we need some form of normalisation. In the literature, outage costs are often reported per kWh. This is useful when analysing the value of a scarce resource at a time of (incipient) interruptions. In this study, we are interested in the effects of different blackout scenarios. Since the duration of a blackout is a major determinant of outage costs, we prefer to look at the costs per unit of time.

Below, we discuss the types and determinants of outages costs, the methods to estimate these costs, and the empirical findings for the Netherlands. First, we distinguish between types and determinants of outage costs. Table 4.1 provides an overview of the types of outage costs for households and businesses.[12]

[12] The welfare loss due to changes in electricity prices (and therefore inputs) is not included in the table, since these costs are likely to be small in the case of a generation capacity-related outage (see Lijesen, 2004 on indirect costs).

Table 4.1 Types of outage costs

Businesses	
Loss of value added due to lower than planned production	The firm's loss in value added due to (partial) interruption of production, assuming pre-outage electricity prices for the whole economy. This loss is net of production that the firm is able to make up (e.g. through the use of overtime or extra shifts).
Additional outage costs	Loss due to damage (equipment damage, damage to raw materials, hazardous materials costs) Labour costs (additional cost to make up production, such as overtime charges)
	Back-up costs (the difference in the energy bill as a result of running back-up generation)
	Restart costs (costs to restart electrical equipment, other restart costs)
Households	
Welfare loss due to lost leisure time	A household's loss in welfare due to (partial) interruption of 'household production', assuming pre-outage electricity prices for the whole economy. This loss is net of gains in welfare through paid overtime etc.
Additional outage costs	Loss due to damage of equipment and stocks

The costs of a power outage depend on the specific circumstances and specific groups affected. The following major determinants of costs have been singled out in the literature:

- Customers located in the affected area: the welfare loss depends on the value added per hour (commercial and industrial customers), the value of leisure time per hour (residential customers) (SEO, 2003) – and on the dependency of customers on electricity. Some customers who are not highly dependent on electricity may be able to work their way around a power outage.
- Duration: costs per hour can vary with the duration of the blackout (Rathenau, 1994).
- Timing: the significance of electricity reliability events can vary with heating/cooling load (season), daylight (time of day), and customer behaviour/production schedules (weekday/weekend)
- Advance notice: with sufficient advance notice, electricity-dependent activities could be rescheduled, and sensitive equipment could be shut down properly.

The value of lost load is not straightforward to estimate, since a unit of undelivered power is not traded on the market. Principally, there are four ways to estimate outage costs. Table 4.2 provides an overview. There are pros and cons for any method; there is no agreement in the literature on the best method to estimate outage costs. The use of surveys based on hypothetical scenarios of blackouts is particularly challenging within the Dutch context, since most electricity customers have not been faced with choices in the area of reliability of power supply.

Table 4.2 Methods of estimation

Method	Description	Pros	Cons	Example of Dutch study
Proxy methods	inferring costs using 'informed judgment' and a hypothetical blackout scenario	based on easy-to-obtain statistical information	some cost categories not in regular statistics (e.g. stress), not very accurate, only aggregate information	SEO (2003)
Revealed preference for reliability	inferring costs based on consumers observed behaviour (e.g. investment in back-up power or acceptance of higher blackout risk for a lower electricity price)	based on customers' true valuation of outages	no estimate for customers without interruption insurance	none
Surveys: stated preference	cost estimates based on customer surveys, using hypothetical blackout scenarios	data on many attributes of blackouts and types of costs	based on hypothetical scenarios, possibly strategic responses	KEMA (2004), SEO (2004)
Surveys: case studies of actual blackouts	surveying customers on actual outage costs	realistic	incentive to exaggerate costs, hard to generalise results to outages with different attributes	Rathenau (1994)

4.3 Definition of a crisis

It follows from our framework that benefits only occur in case of a crisis. This requires a sound definition of the crisis at stake. The primary crisis prevented by retaining spare capacity is obviously a capacity shortage. Such a shortage may arise either from a high level of demand, a low level of available capacity, or both. Note however that a shortage does not imply a crisis by definition, as we have explained in section 2.6. Several other lines of defence come in first before the crisis takes place. If the crisis takes place, it comes in the form of a black-out. As we stated in the previous section, four determinants are of major importance in defining a black-out: composition of affected consumers, duration of the black-out, timing of the black-out and the question whether consumers are warned in advance.

If all lines of defence have failed, it will become impossible for supply to meet demand. This will have serious implications for the entire system, as it can no longer be balanced, implying the risk of a system break-down. The only thing the TSO can do under these circumstances is disconnect groups of users from the net, to bring down demand through rationing. Disconnecting takes place on a regional basis and we assume that the TSO does not apply any regional or other priorities when disconnecting groups of users.[13]

[13] If the TSO increases the efficiency of disconnecting by targeting groups of users with low valuations, the average valuation of black-outs will be lower, as will the benefits of preventing a black-out.

As we noted in section 2.5, our analysis requires the size of the crisis to be equal to the size of the measure. This makes sense with the type of crisis we define here. Every extra MW of capacity installed prevents one MW of having to be disconnected in case of a crisis. On the margin, one extra unit of spare capacity therefore prevents exactly one extra unit of crisis. We assume that the TSO chooses the regions to be disconnected in such a way that the amount of load to be disconnected is infinitely divisible.

We assume that the crisis is not preceded by a warning. Although the TSO might be aware of shortages as they arise, we can not be sure that the TSO can predict exactly when a shortage will lead to a crisis. The TSO may also not be aware of the size of the crisis, so that it can not predict which region to disconnect. Furthermore, even if the TSO would know all these things in advance, the short time lag would probably not be long enough to warn all users in the region. As our empirical work in the following chapter is based on hourly observations, we define the crisis to last an hour as well.

With respect to the timing of the crisis we note that capacity shortages are most likely to occur at peak hours. This is true regardless whether the shortage is caused by an increase in demand or a decrease in availability of capacity. In off-peak periods, both demand surges and unavailability of capacity can be absorbed by regular peaking plants.

The formal definition of the crisis is given in the box below.

We define a crisis as a one-hour black-out at peak hours without advance notice. The size of the black-out is infinitely divisible and the TSO does not apply any regional or other priorities when disconnecting groups of users.

4.4 Empirical findings for the Netherlands

Four empirical studies on outage costs have been conducted for the Netherlands: Rathenau (1994), SEO (2003), KEMA (2004) and SEO (2004). Three out of the four methods of estimation mentioned above have been used. No study infers outage costs based on observed preference for reliability, such as expenditures for backup generators. Given the high level of reliability of the Dutch electricity supply, not many customers have taken any precautionary measure against outages.[14]

[14] There is no data available on precautionary measures by households. However, given the price of backup generators it is hard to imagine that they are very popular among residential customers. According to KEMA (2003, p. 13), 38 percent of small and medium-sized enterprises uses one or more measures to limit the effects of outages (the sample bias discussed in this section may lead to a overestimation since customers most concerned about outages are most likely to respond).

Rathenau (1994) provides an analysis of the vulnerability of society to power outages and the possible consequences for businesses and households. It is the first study that analyses this issue within the Dutch context. The report provides some first estimates of outage costs. Customer surveys were used to obtain an estimate of the costs of six power outages in the period February 1989 to January 1993. Costs for households are limited to financial loss; loss of leisure time and discomfort are not included. The cost estimates for households and businesses vary widely, which is not surprising given the low number of observations (37 non-residential customers reporting damage due to any of 6 different outages, 16 residential customers reporting damage due to any of 2 different outages).[15] Given the low number of observations, this study does not provide reliable estimates of outage costs that we can use for our analysis.

KEMA (2004) is focused on getting the views of electricity customers on the desired level of reliability of power supply. It surveys households, small and medium sized enterprises and large, industrial customers about outage costs.[16]

They find that households are not willing to pay extra for an (even) higher level of reliability than they already enjoy.[17] The study does not provide a clear answer to the question what outage costs are for households. It is unclear what value to attach to the finding that households would like to be compensated for outages (median response is EUR 10 per hour). The estimate is based on a direct question whether customers would like to be compensated and at what price. Thus, the respondents were not facing a trade off when filling out the survey. Consequently, we cannot use this estimate as in input for our cost-benefit analysis.

The low response rate to the mail survey for small and medium sized enterprises (5 percent) raises concerns about sample bias. Maybe only the customers who are most concerned about reliability filled out the questionnaire.[18] Therefore, the obtained estimates may not be reliable. Again, given uncertainty about the method used, it is not clear whether respondents have taken a real look at the costs and benefits of higher or lower reliability. The authors find that 73 percent of enterprises are willing to accept outages that are twice as long (or twice as frequent) if their electricity bill is reduced by 10 to 50 percent (equivalent to EUR 35-175 according to SEO, 2004, p. 133). 27 percent of enterprises are willing to pay extra for better reliability (15% has a willingness to pay (WTP) of 5% of their electricity bill, 7% has WTP of 10% of their electricity bill and 4% has a WTP of 20-50% of their electricity bill). Because of possible sample bias and uncertainty about the trade-off underlying the questions in the survey, the use

[15] Customers who did not report any damage seem to be excluded from the data set, which introduces an upward bias in the estimate of outage costs.

[16] Given the low number of respondents, no statistical results are reported for the group of large, industrial customers.

[17] SEO (2004) attributes this result to strategic responses to survey questions. The result can also be explained by the idea that the costs of maintaining the current level of reliability exceed the benefits.

[18] Since ‘being concerned about power outages’ is a non-observed characteristic, weighting will not solve this problem.

of these findings for our purposes is uncertain, and therefore does not provide a reliable input for our analysis either.

SEO (2003) shows how outage costs differ between groups of customers and regions. The authors choose a method of estimation that fits this goal best (the ‘proxy method’). As we will see, their specific focus makes the estimates less suitable as an input for our analysis as it results in high uncertainty about the outage costs for the average customer.

The authors use informed judgment on the effects of outages and readily available statistics to get a rough estimate of outage costs. Cost estimates are reported for a hypothetical one-hour blackout for different parts of the country and different times of day. Total outage costs are equal to total loss of welfare due to lost production (businesses) and lost leisure time (households). The authors assume that electricity customers are not able to change their behaviour in a way that limits outage costs. All production in all sectors stalls during a blackout (all sectors are equally vulnerable to an outage and there is no back-up power). The value of lost production is equal to the sum of value added. All leisure time in all households is lost during a blackout. The value of leisure time for workers is equal to the average wage; for non-workers half the average wage.

Additionally, the authors assume that there is no advance notice, that outages are incidental, that people do not adapt their expectations on the probability of a future blackout and that no additional outage costs, such as lost stocks and start up costs, are incurred. Finally, they assume a linear relation between total costs and duration of blackout and total costs and the size of the affected area (constant costs per household/company). Given these assumptions, table 4.3 summarises their findings.

Table 4.3	Costs of a one-hour power outage, no advance notice, million euro, 2001			
	On average	During the day	At night	Sunday, during the day
Nationwide		156	98	81
Randstad		72	38	33
Rest of the country		84	59	48
All households		37	85	64
Individual household (euro)[a]		5	12	9
All businesses	121			
Agriculture	1			
Energy companies	3			
Industrial sector	10			
Construction	10			
Transport	5			
Services	69			
Government	24			

[a] Source is SEO (2004, p. 134).

Source: SEO (2003), table 4.1, table 5.1 and page 45.

The approach used in SEO (2003) is useful for their specific aim of identifying differences between user groups and regions. For the purposes of our analysis, the results are particularly crude for three reasons. First, outage costs are limited to lost output and lost leisure time, whereas the literature shows that additional outage costs due to damage to equipment and stocks and restart costs are considerable. For a sample of 794 Israeli firms, Beenstock et al. (1997, figure 1) show that at any moment during an outage, output costs make up no more than about 50 percent of total costs. Therefore, neglecting these outage costs can lead to a severe underestimation of total costs.

Second, the authors assume no behavioural response from customers. Everyone and everything ‘freezes’ during a power outage. In the case of businesses, not all output may be lost due to making up planned production in overtime (although at considerably higher costs[19]), precautionary measures (backup power and the like) and substitution (switching to activities that do not require electricity during an outage). Since there is not much information about this behavioural response, the authors impose the ‘all is lost’-assumption. But that may introduce a strong overestimation of total costs. The same reasoning holds for households. The authors make the case that households have limited options to switch to other activities, but just how limited they are, is unknown.

[19] Not only does a firm most likely pay for an hour during which not much has been produced, the firm will also have to pay the overtime-wage to catch up. The net welfare loss for society may be limited since most of the costs to firms are benefits to workers.

Finally, outage costs are assumed to be linear over time. In practice, high fixed costs arise at the beginning of a blackout, followed by slowly increasing variable costs during a blackout (Rathenau, 1994, Beenstock et al. 1997). Since the authors ignore many outage costs and do not have specific cost functions for households and businesses, they choose to ignore this issue. As a result, their estimates cannot reliably be generalised to outages of different duration.

To conclude, given the focus of SEO (2003) on the distribution of outage costs between groups of customers and geographical areas, the study does not provide reliable estimates of outage costs for the average customer that we could use as an input for our analysis. Without specific information about the behavioural response to a power outage and the actual effects of an outage, the authors have to make many assumptions that are known to be unrealistic.

Based on an extensive survey among households and businesses, SEO (2004) provides estimates of the amount of compensation for power outages of different duration and frequency. The preferred compensation reflects the willingness of customers to accept a power outage. The study is based on a type of survey known by the name of conjoint analysis. 2,481 companies and 12,409 households have rated 14 different scenarios of power outages on a scale of 1 to 10.[20] Each scenario pictures a power outage with certain attributes, such as duration and time of day. One of the attributes of a scenario is the reduction in the electricity bill that accompanies the outage. Based on a logarithmic regression of the customer's rating of scenarios on the attributes of outages, the authors derive a utility function with outage duration and electricity bill discount as variables.[21] The requested compensation per hour turns out to be a decreasing function of the duration of an outage (the monetary compensation is calculated based on the respondent's own estimate of the electricity bill). A similar function is derived for compensation and the frequency of outages. Table 4.4 shows some of the results for a number of outage scenarios. For the average household, the compensation tends to be 3 to 5 euro per hour. For the average business, the compensation is about ten times higher. All these estimates take the current situation as reference point (average total time without electricity is 30 minutes per year).

[20] Large electricity customers such as Shell, DSM and Corus, some 2 percent of the total number of firms, are not included in the sample.

[21] The regression is loglinear, which ignores the ordinal character of ratings. It is not clear whether and to what extent this leads to biased results.

Table 4.4	**Requested compensation for power outages, no advance notice, euros, 2004**			
	Average household		Average business	
	Total compensation	Average compensation per hour	Total compensation	Average compensation per hour
One outage per year, half hour	1.7	3.4	27.0	54.0
One outage per year, one hour	5.0	5.0	52.3	52.3
One outage per year, four hours	11.6	3.9	102.9	25.7
One outage of two hours per year	8.5	4.3	78.8	38.8
Two outages of two hours per year	11.2	2.8	100.2	25.0
One outage of three hours per year	10.4	3.5	93.9	31.3

Source: SEO (2004), table 5.1, p. 118.

At first sight, SEO (2003) seems to provide much higher estimates than SEO (2004). For an average household, the estimated cost for one outage of one hour per year is 5 euro in SEO (2004) and 9 euro in SEO (2003). The estimated outage costs for businesses differs more than a factor two. For all businesses, the estimated cost for one outage of one hour per year is 42 million euro in SEO (2004)[22] versus 121 million euro in SEO (2003). SEO (2004) does not include large electricity customers, but that is not likely to explain a gap of this magnitude. If we leave out the complete industrial sector from SEO (2003), their estimate only goes down to euro 109 million. However, this estimate from SEO (2003) is based on the assumption that all businesses – while running at full capacity – will be equally hit by the outage. When relaxing this assumption, SEO (2003)'s estimates go down. To illustrate: current outage costs (on average 2 hours without electricity in 4 years) are estimated at 48 million euro in SEO (2004, paragraph 16 in executive summary) and at about 78 million euro in SEO (2003, table 5.1: total costs per hour during the day, divided by two).

The estimates of SEO (2004) are the best available estimate of outage costs for the average Dutch electricity customer. The focus and approach of SEO (2004) provides the best fit with the aim of our analysis. There is one potential problem: the study provides separate estimates for households and businesses, whereas we need an estimate for the average electricity user. Some costs to businesses (e.g. wage costs during a blackout) are benefits to households. In a welfare analysis, these costs and benefits cancel out. On the other hand, the overtime needed to make up postponed production brings about a welfare loss to households. This implies that, by adding up the costs for households and businesses, we overestimate the costs of the latter and underestimate the welfare loss of the former. The net effect on welfare is unclear, but the misjudgement is probably minor.

[22] The average compensation per hour (52,30 euro) multiplied by the 800,000 business that are connected to the low voltage network.

To put SEO (2004) into perspective, we compare their results with the results from studies for other countries. We use Eto et al. (2001) and SEO (2004); both studies provide a survey of empirical studies on outage costs. Comparisons for outage costs per hour for the business sector as a whole are not possible since only separate estimates for the commercial and industrial sector are available. For residential customers, we find a number of studies that qualify for a comparison, although all of them have been conducted more than 10 years ago and most of them used other methods than conjunct analysis. As the table below shows, the results of SEO (2004) are in the same range as some studies for the United States.

Table 4.5 Estimated costs of one-hour and four-hour outages, residential customers, willingness to accept (WTA), 2004 euros

Country	Year	1 hour	4 hours	Notes	Reference
The Netherlands	2004	5.0	11.6	outage once a year	SEO (2004)
North-western USA	pre-1990	5.4	9.0		Sanghvi (1990)
South-eastern USA	pre-1990	8.8	11.9	winter weekday morning	Sanghvi (1990)
		7.5	10.1	summer weekday evening (1h) / afternoon (4h)	
Eastern USA	1992	5.7	-	summer afternoon	Sullivan et al. (1996)
Western USA	pre-1990	8.4	-	average per hour	Hartman et al. (1991)

Source: Eto et al. (2001), table 2-7, SEO (2004), table 5.3.

Based on the comparison of both Dutch and international studies described above, we conclude that SEO (2004) provides the most reliable estimates available. For consistency with our framework, we use the one-hour outage figure from this study, implying a willingness to accept a one-hour outage of 5 euro for households and 52.30 euro for business consumers.

Using the average ratio of households and business users, we account the costs of a 100MW outage of one hour. The present value of such an event occurring halfway our period of analysis boils down to 0.3 million euro.

5 Elements of expected frequency

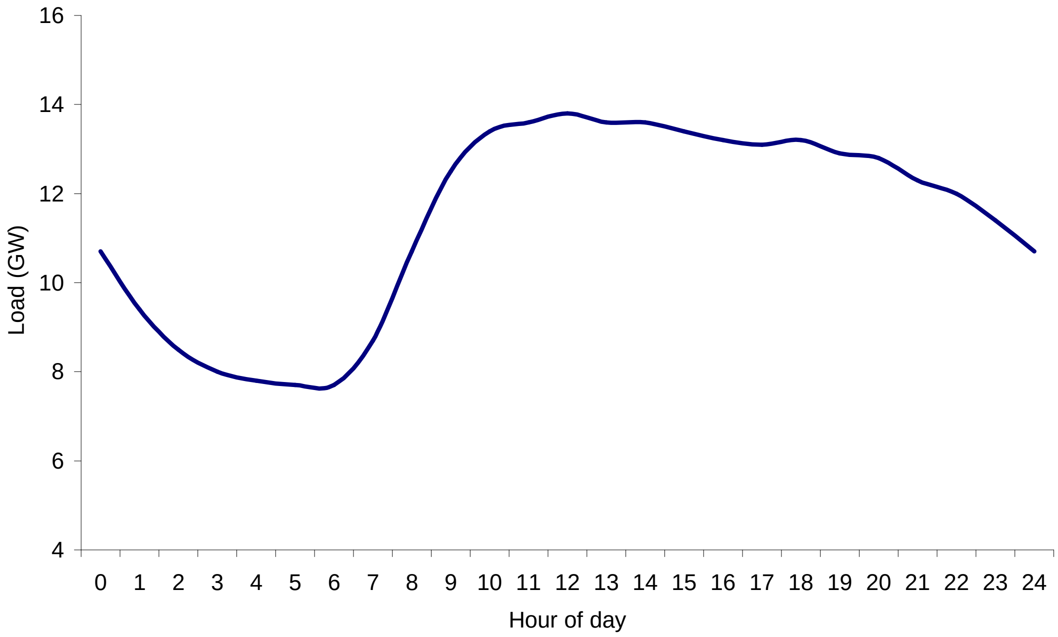
5.1 Introduction

This chapter focuses on the elements of the expected frequency of a crisis. As we stated in our framework (section 2.5) the size of the crisis should correspond to the size of the measure. The expected frequency of a crisis is determined by stochastic elements and so-called flexibility factors, like we stated in section 2.6. The two following sections describe both stochastic elements in the analysis, demand and availability of capacity respectively, followed by a discussion on capacity investments by producers and demand response from users. These elements are joined in a Monte Carlo analysis in section 5.5, yielding the expected frequency of a capacity shortage. Section 5.6 discusses the remaining flexibility factors.

5.2 Stochastic demand

Electricity demand fluctuates over time. The most common fluctuations are those by time of day. Electricity demand is low during night time, when demand only comes from non-stop production processes and public lighting. Demand rises fast in the early morning as households wake up and companies start up their activities. During business hours, electricity demand stays at a high level, starting a gradual decline from about six PM, as daytime companies seize their activities and households gradually reduce the use of appliances.

Figure 5.1 Average daily load in GW, 2003



Source: based on figures from www.TenneT.org

This pattern is reflected in the load curve, as shown on the previous page. We assume throughout our analysis that load figures reflect demand adequately.

The load pattern reflects the (non-existing) average day. In weekends and on holidays is at a lower level, flatter and the morning increase starts at a later time, all very common to the processes described above.

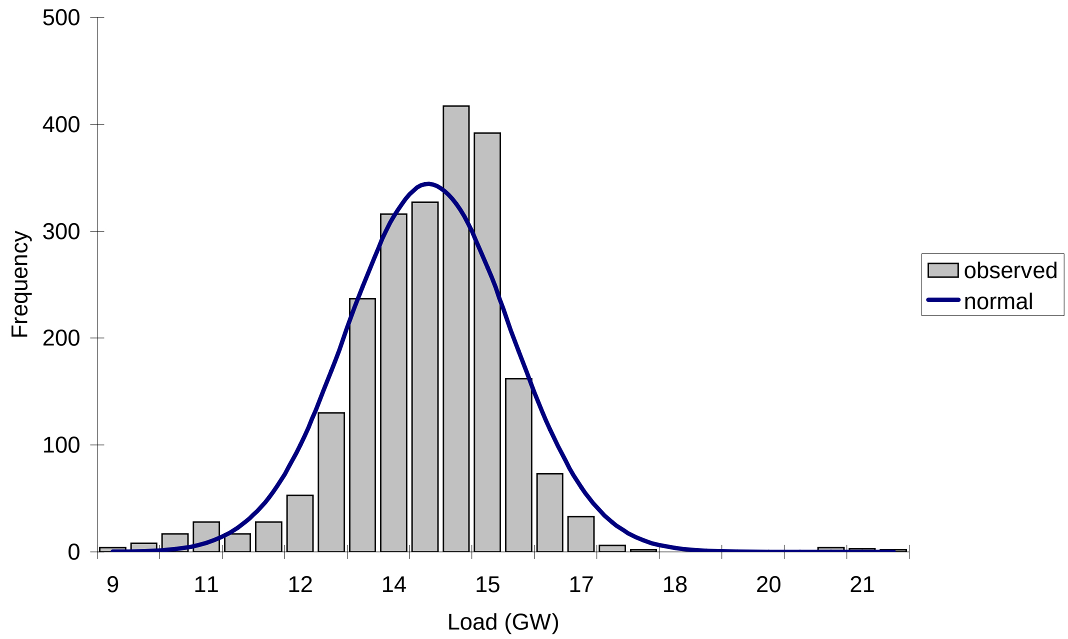
Demand fluctuations by time of day are not unique to electricity. The consumption of many goods and services are related to other activities and therefore to our daily patterns. Transportation is another clear example of a good with a recognizable time-of-use pattern.

When it comes to security of supply, these demand fluctuations do not constitute a problem. As one can see from figure 5.1, peak load is spread over about one third of the day. Furthermore, normal peak loads occur every working day, implying a fairly broad base to earn a return on investments in generation capacity.

Another type of demand fluctuations is more important when it comes to security of supply. The load curve presented in figure 5.1 is an average, and deviations from that average may occur for all sorts of reasons. The weather is likely to influence electricity demand, as are broadcasts of special events on television. Furthermore, supply interruptions may drive up spot market prices and thus influence demand. Apart from these clear-cut reasons, electricity demand may also be influenced by minor events and coincidence.

Figure 5.2 illustrates demand deviations from the average for working day peak demand hours, by graphing the frequency of demand volumes. This type of fluctuations is more important to supply security than regular day-to-day fluctuations by time of day. The cases of high demand levels at low frequencies are of special interest here, as it may not be efficient for producers to invest in sufficient capacity to meet these levels. It implies that the investments in capacity will have to be recovered in a couple of hours per year.

Figure 5.2 Frequency distribution of load (GW) during working day peak hours (9 AM-6PM), 2003

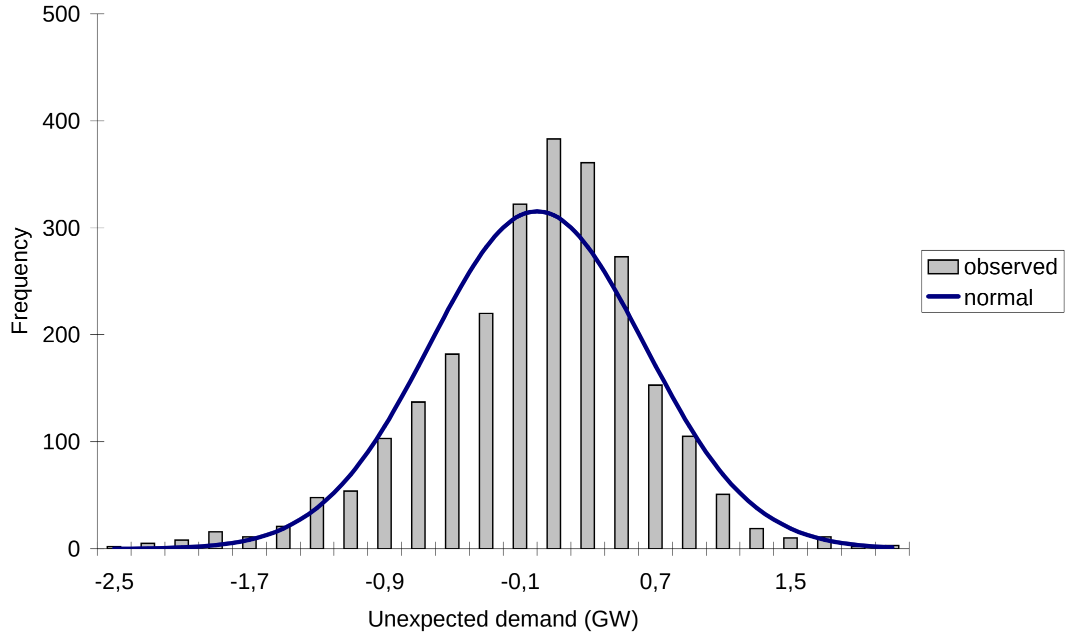


Source: based on figures from www.TenneT.org

The shape of the histogram looks somewhat like an inverse lognormal distribution. The inverse lognormal distribution is however impracticable for the purpose of our analysis, as it imposes a maximum on demand, which would define away the problem we are trying to analyse. We proxy the histogram above by a normal distribution, rendering a lesser fit but avoiding the problem of a truncated maximum. The normal distribution (with mean 14,308 MW and standard deviation 1,308 MW) to be used in further analysis is graphed over the histogram to reflect the differences.

Our analysis distinguishes between expected and unexpected demand variations. Although it is virtually impossible to look into the minds of electricity producers and determine whether they perceive demand variations as expected or unexpected, we may look into factors that determine demand, check whether these are predictable and determine to what extent they explain the variation in demand. We conducted such an analysis (see Appendix A), and from it we derived a frequency distribution for unexpected demand variations. Figure 5.3 graphs the frequency distribution of unexpected demand against a normal distribution.

Figure 5.3 **Frequency distribution of unexpected demand variations (GW) during working day peak hours (9AM-6PM), 2003**



Source: based on figures from www.TenneT.org

The graph suggests that the unexpected demand variations may be described by a normal distribution, with mean 0 and a standard deviation of 632 MW.

5.3 Stochastic availability of capacity

Like demand, supply has stochastic elements. The most important element for the purpose of our analysis is the availability of capacity. Generating units may be unavailable for two types of reasons. The first type is that the operator seized operations according to plan, for instance because of planned maintenance or because production is uneconomical. The second type is quite different, as it regards unexpected unavailability, for instance because of technical failure. The first type of unavailability is not of interest to our analysis, as expected outages are accounted for by producers and may be planned so that they do not coincide with peak demand. This type of unavailability is therefore unlikely to cause any supply security problems.

The latter is not true for unexpected outages. These may occur at any point in time and will cause problems if they occur simultaneously with demand peaks. It is therefore important to know the frequency of such unexpected outages. Information on the unavailability of production capacity is unfortunately not available itself.[23] We may try to approximate the

[23] The Dutch TSO, TenneT, has very recently started gathering and publishing these data. Figures on 2003 are not available however.

figures by looking at figures that are related to unexpected events in the electricity market. To understand this, we will first look at the way the Dutch TSO acts to cope with unexpected events.

If an unexpected event happens, no matter whether it is a shortage or a surplus and irregardless its cause, the TSO commissions swing reserves to counteract the event and retain balance in the network. To a supplier, causing unbalance is expensive, so we can assume that a supplier will never deliberately disturb the balance. This implies that any unbalance in the system is either caused by deviations from expected demand $(D-\overline{D})$ or deviations from expected availability of capacity (θ):

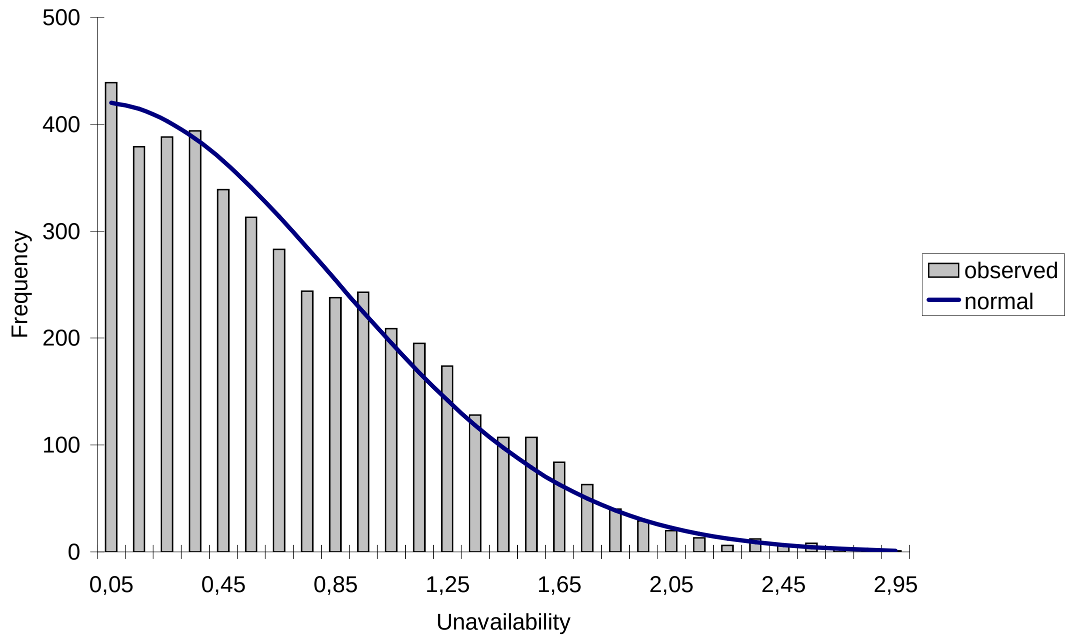
$$unbal = \theta + (D - \overline{D})$$

Figures regarding unbalance in The Netherlands are available from the website of the TSO, as are load figures. We construct expected demand $\overline{D}$ from load figures, by averaging load over periods with common characteristics (see Appendix A for details on the construction of expected demand). Deviations from expected availability of capacity can now be defined as:

$$\theta = unbal - (D - \overline{D})$$

For the purpose of our analysis, deviations from expected availability of capacity are only interesting if they cause shortages. Unexpected overcapacity will not cause risks in terms of security of supply, so we concentrate on unexpected unavailability of capacity, denoted by positive values for θ. Figure 5.4 graphs the frequency distribution of the unexpected unavailability of capacity. It is clear from the figure that a truncated normal distribution (the underlying normal distribution has mean 22 MW and standard deviation 847 MW and is truncated at 0) fits the data adequately.

Figure 5.4 Frequency distribution of unexpected unavailability (GW) 2003



Source: based on figures from www.TenneT.org

5.4 Regular capacity and demand response

The most obvious line of defence against shortages in a well-functioning market is the price mechanism. If scarcity arises, prices rice and consumers respond by decreasing demand.[24] Furthermore, the price mechanism also rewards producers to keep capacity available to serve demand at higher prices. Finon *et al.* (2004) identify peak prices as the main driver behind investment in new capacity. Both factors are interrelated. If demand response is large, the incentive to build new capacity is limited somewhat, as prices will not rise as high as they would in the case of small demand response.

The measurement of demand response is troublesome. Observable demand response takes place at the spot market. The Amsterdam Power Exchange (APX) generously publishes data on day-ahead spot market volumes, prices and bids on its website. Despite the richness of this data, one cannot distil information on demand response from it, for three reasons.

First, some demand bids in the spot market reflect non-responsive demand. A wholesaler or retailer may have sold a certain amount of electricity without having contracted the full amount yet. Another example may be a retailer being confronted with unexpected demand from its customers (e.g. households), who do not react to price signals. In both cases, intermediaries buy electricity on the spot market for their non-responsive customers.

[24] Demand response and supply response from independent producers are essentially the same.

Second, some supply in the spot market is actually foregone demand. It is common practice for large users to buy a fixed (hourly) amount of electricity at a given price through long term contracts. If some of the electricity turns out to be obsolete (e.g. due to lower than expected production), it may be sold back to the spot market. Likewise, if spot market prices surge, large consumers may decide to seize production and sell their pre-contracted electricity on the spot market.

The third reason why spot market data are an inadequate source of information to quantify demand response to price shocks is that an unknown part of the response is realised outside the spot market. Bilateral contracts between electricity wholesalers or retailers and their customers may contain some form of real-time pricing, bringing down demand in times of scarcity. Likewise, wholesalers or retailers may reward their customers on a bilateral basis for not using contracted electricity or for delivering electricity from their CHP-units.

An alternative to the use of spot market data is the use of bottom-up data, as is done by Deloitte (2004). The study by Deloitte utilises the notion that energy users will weigh the costs of postponing electricity consumption (and thus commodity production) against the benefits of reselling (or not buying) electricity on the spot market. These costs are determined on a low level of aggregation and then confronted with APX spot market prices of 2002 and 2003.

This method overcomes the problems mentioned above, but has the disadvantage that the outcomes depend heavily on current spot-market prices. These prices are fairly low, as the market is still characterised by the historical level of overcapacity. As capacity becomes scarcer, spot market prices are likely to become both higher and more volatile, giving room for larger demand responses.

Furthermore, the approach followed Deloitte (2004), like any approach using bottom-up data, ignores the effect of the efficiency gap, relating to unexploited opportunities for cost-effective measures to save energy (see Koopmans and Te Velde (2001) for a more extensive discussion). It should be noted that Deloitte (2004) is probably aware of this risk, as they consequently refer to demand response in terms of potential amounts.

The problems related to the use of bottom-up data may be overcome by estimating the relationship between demand and spot market prices. This will also measure the effect on demand response outside the spot market, as bilateral pricing mechanisms are often linked to spot market prices. Patrick and Wolack (1997) estimate the site-level demand for electricity for five different industries in England and Wales (Water supply; Steel tubes; Copper and copper alloys; Ceramic goods and Hand tools and finished metal goods). They find small own price elasticities, ranging from almost zero to -0.28, but mostly not exceeding an absolute value of 0.02.

We use average hourly load and pricing data to establish demand response parameters for 2003 peak-load (see Appendix A for more details). Like Patrick and Wolack (1997), we find small price elasticities. The overall price elasticity found in our empirical analysis equals -0.0014.

Although demand elasticities are low, demand response is likely to be sufficient, as long as spot market prices are allowed to rise to any height. If this happens, spot market prices will also yield a strong incentive for producers to build sufficient capacity. We use the main mechanism from our electricity model to illustrate this point. Consider the following equilibrium equation for capacity of firm i:[25]

$$\sum_{h \in \{q_{hi} = Q_i\}} p_h - Gbq_{hi} - \lambda_{hi} = \frac{\partial C(Q_i)}{\partial Q_i} \tag{5.1}$$

where p_h denotes the per unit price at hour h, G denotes the conjectural variation term, expressing the competitiveness of a market, and b represents the slope of the inverse demand curve. Firm i's output in hour h (q_{hi}) is limited by its capacity Q_i. Parameter λ_i represents the marginal costs of production, and $C(Q_i)$ denotes capital costs. The equation above simply states that optimal capacity is reached at the point where accumulated net revenues of output at binding capacity levels ($q_{hi}=Q_i$) equal marginal costs of building an extra unit of capacity. Note that the term 'net revenues' includes a correction for imperfect competition.

The value of conduct parameter G is unknown, since no empirical information is available on the competitiveness of the liberalised electricity market. In its current setting, all institutional barriers to entry are eliminated. Some minor barriers remain, such as scarcity of suitable production locations, scarcity of specialised knowledge and effects of imperfect capital markets in combination with the large asset bases of incumbents. In general however, electricity markets may be fairly competitive, especially once the integration of the single European market is completed. We therefore assume G to have a fairly low value, keeping a range from 0 to 0.1 to account for uncertainties.

Using the equation, we can construct a table to demonstrate the calculation of the amount of capacity kept by producers to serve the day-ahead market. Table 5.1 shows that, at an assumed value for G of 0.1, the accumulated net revenues of 1 463 MW of additional capacity approximately equal the marginal costs of building this capacity (828 euro per KW, as stated in section 3.3)

[25] Lijesen and Ten Cate, 2004. Redundant subscripts are ommitted for simplicity.

Table 5.1	**Net revenues from day-ahead trade at an additional capacity level of 1 463 MW, at *G*=0.1**		
Demand in excess of average peak demand (GW, at p=0)	Probability of occurrence	Price (€/MWh)	Net revenues (€/KW of capacity)
3.45	0.05%	9147	9.67
3.30	0.08%	8457	14.77
3.15	0.12%	7766	21.96
3.00	0.20%	7076	31.70
2.85	0.31%	6385	44.35
2.70	0.48%	5695	59.96
2.55	0.72%	5004	78.00
2.40	1.07%	4314	96.98
2.25	1.56%	3623	113.98
2.10	2.22%	2932	124.11
1.95	3.11%	2242	119.92
1.80	4.27%	1551	90.84
1.65	5.76%	861	22.77
1.50	7.63%	170	0.00
<1.50	92.37%	30	0.00
Total			829.03

Note from the second column in table 5.1 that the units will be standing idle for most of the time. Also note that spot market prices will be at very high levels for some hours, taking into account that the highest price measured in 2003 was about 2,000 euro per MWh. The increase in peak prices follows from the gradual reduction of overcapacity. The optimal capacity level of 1,463 MW and a maximum load (before price effects) of 3 450 MW implies a demand response of approximately 2,000 MW, about 15 percent of peak demand.

Table 5.1 suggests an optimal level of 1,463 MW of capacity to serve the day-ahead spot market. In a similar manner, we calculated that an additional level of 634 MW of capacity would be optimal to serve the unbalance market.[26] Adding both figures yields a total capacity of approximately 2,120 MW on top of average peak load.[27] Similar calculations were performed for alternative levels of market competitiveness. Table 5.2 below lists the outcomes of these calculations.

[26] Note that this number refers to profitable spare capacity, which is not the same as contracted capacity discussed in section 5.6

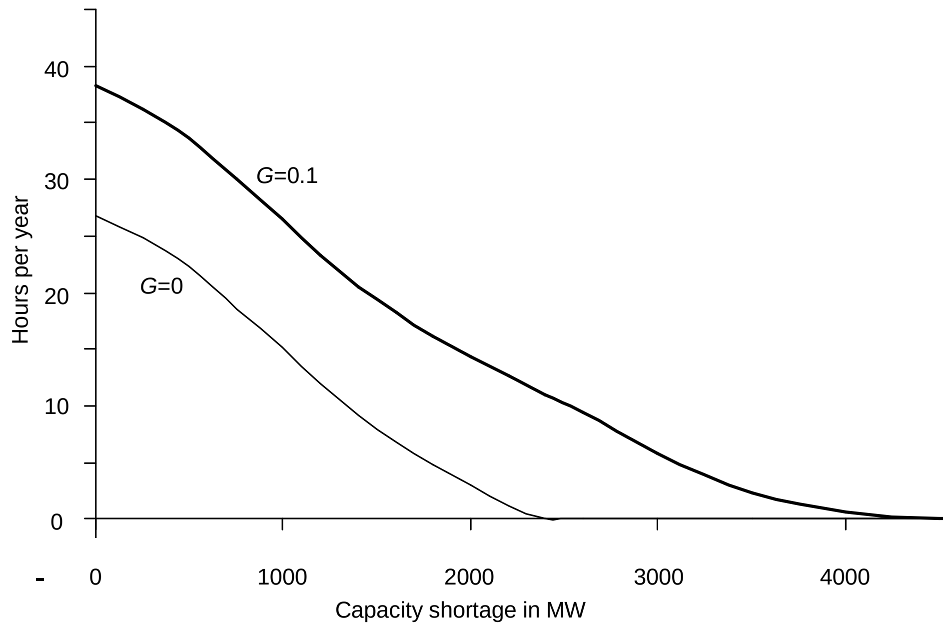
[27] The figure is expressed in MW's of 2003 and will grow proportionally to average peak load.

Table 5.2	Optimal level of additional capacity for different levels of competition, MW
G=0 (fully competitive)	2 330
G=0.02	2 290
G=0.04	2 240
G=0.06	2 200
G=0.08	2 160
G=0.1 (fairly competitive)	2 120

The outcomes suggest that competitive markets will generate higher levels of equilibrium capacity, which is obviously consistent with oligopoly theory. Likewise, higher levels of competition will reduce the need for government intervention, as will be clear from our analysis further on.

5.5 A Monte Carlo simulation of insufficient regular capacity

We use the distributions found in the previous sections to calculate the expected frequency of a shortage. This is equivalent to the right hand downward sloping curve in figure 2.3. We use 2003 values for our analysis, linking up with the figures used in the sections before. For reasons similar to those outlined before, we limit ourselves to working day peak hours (9 AM-6PM). The results from the Monte Carlo simulation are expressed as chances. We multiply these chances by 2,259 (the number of working day peak hours in a year) to arrive at a measure expressed in hours per year. The use of this measure eases the comparison with the break-even frequency, the inverse of which is also measured in hours per year.



The curves in figure 5.5 represent the frequency distribution of demand superseding supply by a certain amount at the given levels of *G*. This amount is expressed relative to the average peak load in 2003 and grows proportionally with average peak load over time. In the following section, we devote attention to the factors that lie between the theoretical construction of the expected frequency of shortages and the actual predicted frequency of crises (see section 2.6 for a more elaborate discussion).

5.6 Other flexibility factors

As we said earlier, emergency imports automatically solve national shortages because of the feature of grid synchronisation. The limits to emergency imports lay either in lack of capacity at a UCTE scale or in lack of cross-border transport capacity. The former is not likely to play a major role, simply because the scale of the Dutch system relative to the entire UCTE network.

Therefore, transport restrictions are more likely to be binding. It is however hard to say at what level they will be binding. As shortages are likely to occur during peak periods, the larger part of the import capacity will probably already be in use. The TSO has reserved 300 MW for emergency imports, which is obviously the minimum level. All other free import capacity may be used for emergency imports as well.

The above implies that we have a guaranteed level of 300 MW of emergency imports and an unknown level of unguaranteed emergency imports. We use the guaranteed level in our analysis as a known flexibility factor and take the unknown extra import capacity into account in the interpretation of our results.

TenneT, the Dutch TSO, currently also holds some emergency capacity, consisting of 150 MW of guaranteed demand response and 150 MW of spare capacity abroad. Apart from this, TenneT annually contracts 250 MW of regulatory capacity. This can however not be viewed as emergency power as defined in this study, as regulatory capacity is used in the unbalance market, and is therefore included in the regular capacity equilibrium discussed in section 0.

Based on these considerations we calculate the total amount of flexibility factors at 600 MW. Note that this is a minimum value, as unguaranteed available import capacity is not taken into account here.

6 An assessment of the optimal level of spare capacity

6.1 Introduction

This chapter assesses what level of spare capacity is optimal from a welfare point of view, given the design of the measure as defined in section 3.2. Section 6.2 calculates the break-even frequency of the policy measure, followed by a confrontation with the expected capacity in section 6.3. We conclude this chapter by analysing the sensitivity of our results to some of the inputs and assumptions.

6.2 Break-even frequency of keeping spare capacity

In chapters 3 and 4, we assessed the costs of keeping 100 MW of spare capacity and the benefits of preventing a one hour black out of 100 MW. According to our theoretical framework, outlined in chapter 2, these figures may be combined to express the break-even frequency of keeping 100 MW of spare capacity. Table 6.1 presents average annual costs, benefits in case of a crisis and the break even frequency following from these figures.

Table 6.1 Costs and benefits of 100 MW of spare capacity (discounted value in million euro)

Average annual costs	
Direct effects	4.3
External effects	− 0.0
Total average annual costs	4.3
Total benefits in case of a crisis	
Total benefits	0.3
Break-even frequency	
Once every … years	0.07

The break even frequency of once every 0.07 years may also be expressed as its inverse, being a crisis occurring 14 times every year. As the crisis is defined as a one-hour blackout, it implies a total of 14 hours of black-out a year. This may seem a high number, but one should keep in mind that it concerns a relatively small crisis. To place the number in the right perspective, we formulate its interpretation as follows: If a disturbance of 100 MW occurs for 14 hours per year, it is economically viable to build 100 MW of spare capacity.

6.3 Expected frequency of black-outs

The break-even frequency found in the previous section is to be confronted with the expected frequency, the elements of which are quantified in chapter 5. We use figure 5.5 as the basis for our calculations. This graph reflects the range of expected frequencies of a shortage in capacity as a function of the magnitude of the shortage. As our framework suggests, we should subtract the other flexibility factors to obtain the expected frequency of a crisis. The latter may be compared to the break-even frequency. The break-even frequency can be plotted as a horizontal line in the figure, since we have assessed the absence of scale effects.

Figure 6.1 below graphically shows the derivation of optimal capacity. The right hand curve reflects the range of expected frequencies of a shortage in capacity as a function of the magnitude of the shortage, as derived in section 5.5. To prevent overcomplicating the figure, we only show this curve for *G*=0.1.This curve is shifted to the left by an amount of 600 MW to correct for known flexibility factors. The shifted curve (shown for both ends of the range of *G*) reflects the (maximum value of the) expected frequency of a crisis as a function of the magnitude of the crisis. The (maximum value of the) optimal size of spare capacity may be found by intersecting this curve with the horizontal line reflecting the break-even frequency. This intersection lies at approximately between 450 and 1220 MW.

Figure 6.1 Derivation of optimal capacity (MW)

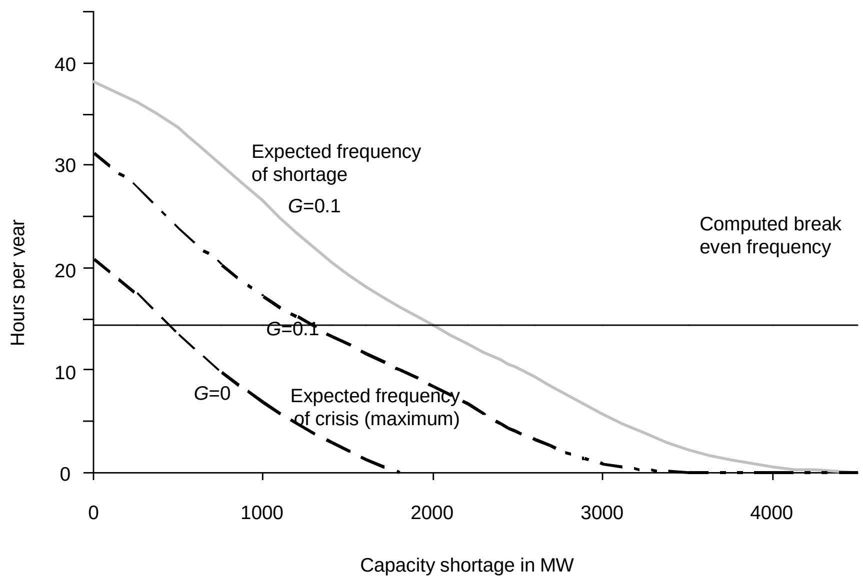
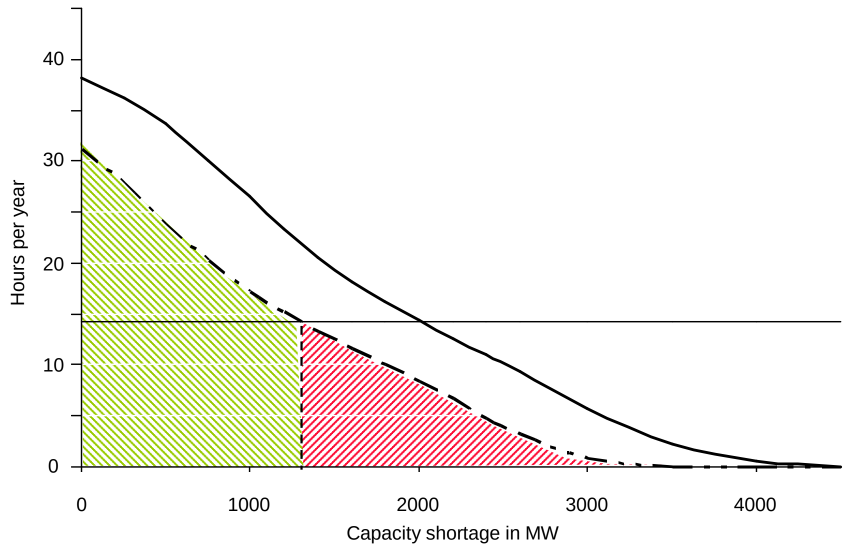


Figure 6.1 suggests that contracting an extra 450 to 1220 MW of spare capacity, depending on the expected level of competitiveness, would yield the social optimum. The graph also reveals other information, such as the amount of capacity at which the number of shortage hours is negligible (3,500 MW at the lowest level of competitiveness). The figure may also be used to quantify the amount of unserved electricity. To that end, we simplify the figure somewhat and shade the respective surfaces to obtain the figure below. For the sakle of ease of interpretation, we only present the result here for G=0.1.

Figure 6.2 Unserved electricity and prevented outages



The shaded surface to the right side of the optimum reflects the amount of electricity not served due to outages. This can be calculated to amount to approximately 16 thousand MWh, or 0.02% of total demand. The shaded part to the left of the optimum reflects prevented outages, summing up to 29 thousand MWh. For the highest level of competitiveness in our analysis, these figures amount to 9 thousand and 25 thousand MWh respectively.

The figures in this section may also be used to get an impression of deviating from the optimal situation, by shifting the vertical line. Likewise, the use of cheaper options for spare capacity may be simulated by shifting the horizontal line downward, yielding a higher level of spare capacity and decreasing the amount of unserved electricity.

6.4 Net costs of deviations from the optimum

In the previous section we have calculated the socially optimal amount of additional spare capacity. This figure is based on our calculation of welfare effects. Other considerations than welfare effects may also apply however. In order to be able to weigh these considerations it is important to have some insight into the welfare losses attached to deviating from the optimum. Two specific deviations are of special interest; the one in which the government refrains from any action and the TSO does not contract any additional spare capacity. The other deviation of special interest is that of contracting enough spare capacity to continue the current level of full security. We compare these values to the optimal level of spare capacity at G=0.04, being 750 MW. Full security is reached at an additional level of spare capacity of 3,500 MW. [28]

Not contracting any additional spare capacity would save society 43.5 million euro of costs per annum. It would however also imply that the annual damage caused by shortages would rise by 49.1 million euro, implying a net cost 5.6 million euro every year. The other extreme, raising the amount of contracted capacity to a level of full security, incurs additional annual costs of almost € 160 million, while preventing an annual 68.3 million euro of damage from outages. The net annual costs of this level of security amount to 73.9 million euro. Table 6.2 summarises these results.

Table 6.2 Net annual costs of deviations from the optimum (present value, million euro, *G=0.04*)

	0 MW	750 MW	3500 MW
Additional costs	− 43.5	0	159.5
Additional benefits	− 49.1	0	68.3
Net costs of deviation	5.6	0	73.9
Level of security	99.95%	99.98%	100.00%

The last line of the table reports on the level of security provided by the contracted amount of additional spare capacity. This percentage corresponds to 100 percent minus the expected percentage of undelivered demand. In the case of full security, this level equals 100.00% by definition. In the social optimum, approximately 25,000 MWh of electricity will not be delivered due to outages, corresponding to 0.02% of total demand. This implies a level of security of 99.98%. If no additional spare capacity is contracted, outages will prevent the delivery of over 40,000 MWh of electricity, equivalent to 0.05% of total demand.

6.5 Sensitivity analysis

The results presented in the previous section depend on several assumptions, defined in earlier chapters. In this section, we assess the impact of several key assumptions on our outcomes. We distinguish between two types of sensitivities. Firstly, we look at how our outcomes would

[28] Full security implies an expected frequency of outages of less than 0.005%. A watertight guarantee against outages can obviously not be provided

change if our key inputs were changed by 10 percent of their initial value. This classic approach to sensitivity analysis tries to give general insight into the sensitivity of the analysis to changes in the main inputs. We identify capital costs of spare capacity, willingness to accept outages, variance of unexpected load demand and the discount factor as our main inputs. As discussed earlier in the report, these inputs are fairly robust, though some uncertainties remain. Taking into account deviations of 10 percent probably represents the likely range for capital costs and willingness to accept. For the variance of unexpected peak load demand this is less clear. As we have no detailed information on other years than 2003, it is hard to say whether 10% is a likely range here.

The second approach is aimed specifically at the level of market competitiveness. As we formulated in section 5.4, we assumed the electricity market to be fairly competitive, or may be even fully competitive. To reflect this, we varied conduct parameter *G* between 0 and 0.1, which is comparable to varying a standard conjectural variations parameter between -0.9 and -1. As we have seen earlier, higher levels of competition induce higher levels of private investments, reducing the need to hold public spare capacity.

Table 6.3 lists the outcomes of our sensitivity analysis. Variations in the levels of key inputs are given in both directions. The right-hand column of the table refers to variations that lead to a higher outcome for optimal spare capacity. The middle column shows the opposite effect.

Table 6.3 Sensitivity analysis for optimal magnitude of spare capacity (MW)

	Lower optimal capacity	Higher optimal capacity
Variations in levels of key inputs (at *G*=0.04)		
Capital costs +10%, -10%	600	900
Willingness to accept black-out -10%, +10%	600	900
Variance of unexpected peak load demand -10%, +10%	690	790
Discount rate +2%-point, -2%-point	700	790
Combined effect of all the above	400	1150
Level of competitiveness (*G*)		
0 (very competitive)		450
0.02		600
0.04		750
0.06		910
0.08		1060
0.1 (fairly competitive)		1220

Table 6.3 suggests that our results are moderately sensitive to changes in our key inputs, in particular to changes in the level of competitiveness (G). If the power market is very competitive, the optimal magnitude of spare capacity is 450 MW. At lower levels of competitiveness significantly higher levels of spare capacity would be needed. This result

implies two things. First, further research should be aimed at giving a more precise quantification of this measure. Second, policies at increasing the competitiveness of the electricity market may, if successful, greatly reduce the need, and therefore costs, of retaining spare capacity.

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7 Conclusions and discussion

7.1 Introduction

This chapter draws conclusions from the analysis presented in the previous chapters and answers the questions stated in chapter 1. Section 7.2 contains the results and their interpretation, followed by a comparison to earlier results in section 7.3.

7.2 Result and interpretation

In the debate on security of supply it is sometimes implicitly assumed that interruptions should be prevented at all costs. This is obviously an incorrect assumption. The fact that both supply interruptions and preventive actions incur costs, suggests that an optimal level of supply security lower than absolute security can be calculated. The aim of our analysis is to assess the costs and benefits to society of several levels of supply security. To that end, we analysed social costs and benefits of retaining spare capacity and confronted them with the probability distribution of unpredictable capacity shortages. We express the outcomes of our analysis in Megawatts of 2003 for ease of interpretation. The use of these outcomes for future years should take into account the growth of average peak load levels. We also recall that our results should not be interpreted as forecasts. Rather they give an order of magnitude and point out the key uncertainties in this market

We used a simplified version of our electricity model to simulate optimal capacity for private electricity producers. The first step is to analyse how much capacity private producers are likely to hold if no policy action is taken. Based on the demand volatility and the short term price elasticity observed in 2003 peak hours, we that find producers will hold approximately 2,100 to 2,300 MW of capacity on top of the average peak load. Note that this capacity is relative to the *average* peak load, implying that the first MW of this amount is deployed for 50 percent of all peak hours. This means that the load factor of these units will be below the average load factor, but not extremely low. Their construction is financed mainly from peak prices, either at the day-ahead spot market or from unbalance pricing.

Peak prices will also ensure that predictable demand peaks will be flattened at the spot market. As electricity on the spot market is traded 24 hours in advance, this implies that shortages can only arise from unexpected demand peaks and unexpected unavailability of generation capacity.

Our analysis suggests that the socially optimal level of supply security can be reached by holding 1,050 to 1,820 MW of back-up capacity. At this level, approximately 16,000 MWh per year will not be served. This corresponds to three times the level of electricity currently not being served because of network interruptions.

The Dutch TSO currently has two mechanisms in place to counteract unexpected capacity shortages; long-term contracts for emergency power capacity, as well as reserved transport capacity for emergency imports. The combined level of these mechanisms currently provides a guaranteed back-up capacity of at least 600 MW.

The above implies that the optimal level of supply security may be reached by expanding the combined capacity of level of emergency power contracts and emergency imports by 450 to 1,220 MW. The bandwidth reflects uncertainty about the level of future competition in this market.

The result is robust for changes in the level of price elasticity, since a change in the price elasticity would merely affect the balance between private investments in capacity and demand response. The result is somewhat sensitive to the unexpected volatility of demand.

The result above is based on retaining spare capacity, placing it outside the market and leaving it idle. This is an expensive but certain way to ensure supply security. If a more cost-effective way can be found, a higher level of supply security may be reached at equal or even lower costs. Increasing the reserved transport capacity for emergency imports may provide such a cost-effective way. The option is costless up to the point where congestion arises. From that point onwards, costs arise either from investments in more import capacity or a reduction of the level of competition on the domestic market. The average level of available import capacity amounts to 1,300 MW in 2003 peak hours, suggesting that these costs will be absent for a large share of the time. Further research may be aimed at giving a more exact quantification of the costs of this option. It should also be noted that the benefits of this option are lower if shortages occur over a large geographical region. In that case, import capacity may be insufficient to secure supply. The size of the UCTE region (22 European countries) lowers this risk to a great extent. Additional research may result in more quantified insight on this matter.

Finally, a non-economic argument, which is not further explored in this study, for investing in spare capacity has to do with ‘a feeling of certainty’. In a liberalised market consumers may feel insecure about a number of things (Shall we switch operators? Will there be enough capacity?). In such an environment, it could be sensible to invest in spare capacity.

7.3 Comparison to earlier results

In an earlier study (Lijesen, 2004) we already concluded that keeping spare capacity is an inefficient way to secure electricity supply. However, as we point out in the text box below, this result was derived based on a specific scenario of a power outage and a specific design of the policy measured aimed at preventing it. The current study focussed on the optimal magnitude of the reserve contracts. This section compares the current results to that found by Lijesen (2004).

Earlier findings of cost-benefit analysis and the contribution of this study

In an earlier cost-benefit analysis, Lijesen (2004) looks at two measures to prevent an unannounced 24 hour power outage for the complete Randstad:[a]

- The transmission system operator (TSO) requires electricity traders to back their own peak load plus a level of spare capacity (15% of normal peak demand) with contracted capacity. Traders are allowed to trade bilaterally units of capacity, which creates a capacity market.
- The TSO buys operational reserves (15% of normal peak demand) directly from producers. This spare capacity is only dispatched in cases of an emergency.

These measures only pay off when such a black out happens more often than once every 4 years. Thus, looking at costs and benefits to society, maintaining 15% spare capacity level is a wise strategy if we expect such a major power outage to happen every 4 years.

[a] A third policy instrument, capacity payments, appears not to be successful in preventing power outages – at least when set at 1 cent per kWh.

The results of the current study confirm the main outcome in Lijesen (2004); keeping spare capacity at the level of 15 percent of normal peak demand is not efficient. Some differences arise as well however. An important difference is that the current study uses flexible scales for both policy measures and disturbance, whereas Lijesen (2004) compares 15 percent of spare capacity to a 24-hour outage of the Randstad area. Although the comparison is not very much out of size in terms of capacity, the length of the crisis differs strongly from the one-hour crises defined in the current study. This is the main cause for numerical differences between both studies, especially the difference between the numerical value for the break-even frequency.

Some other differences apply as well. Lijesen (2004) uses figures from SEO (2003) to value outages, whereas the current study uses SEO (2004)’s lower estimates. Cost figures in both studies are based on the same figure from OECD (1998), although the costs of keeping spare gas transport capacity was ignored in Lijesen (2004).

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Appendix A Derivation of unexpected demand fluctuations

This appendix discusses the derivation of expected demand (used to calculate θ in section 5.3), unexpected demand (used in section 5.2) and the demand elasticity (used in section 0). We determine the relationship between demand and its determining factors, among which the spot market price. We proxy demand by the load figures published on TenneT's website. Load data are available on the basis of 15-minute intervals, but we aggregate these figures to hourly data in order to use them in the same analysis as our other data. Spot market prices are published on an hourly basis on the web site of the Amsterdam Power Exchange. Maximum day temperatures are retrieved from the website of the Dutch meteorological institute, KNMI.

Electricity demand is influenced by a great deal of factors. As electricity is used as an input to many production processes, demand is partly determined by the characteristics of these processes, such as time of day, national and religious holidays and the summer holidays. Economic growth and technical change are other determinants of production processes influencing electricity demand. Weather also plays a role in determining electricity demand, particularly through the use of air conditioning on hot days and lighting equipment in the winter months of the year.

Estimating the relationship between prices and quantity constitutes a great number of difficulties, especially because demand fluctuates greatly under influences other than prices. This causes the demand curve to shift along the supply curve, causing correlation between the price variable and the error term. We solve this problem by estimating a two stage least square regression, using lagged price as an instrumental variable for price.[29] The table below lists the results of the empirical estimation.

[29] For optimal efficiency, all other explanatory variables are used as instruments as well.

Table 7.1 Estimation results for electricity peak demand (GW)		
Variable	Coefficient	t-Statistic
Price (€/MWh)	− 0.000217	− 2.3
Trend	0.0074	34.9
Time of day dummies, hour starting at:		
9 AM	12.204	134.5
10 AM	13.184	178.1
11 AM	13.330	180.0
Noon	13.175	174.0
1 PM	12.922	170.8
2 PM	12.994	171.7
3 PM	12.824	169.5
4 PM	12.580	166.2
5 PM	12.499	137.8
6 PM	11.908	131.2
Day of week dummies		
Thursday	0.1877	5.7
Friday	0.1734	5.2
Month of year dummies		
January	− 0.7893	− 11.1
February	− 0.4444	− 6.7
April	0.6621	12.5
July	− 0.9965	− 11.1
September	− 0.5164	− 10.2
October	− 0.4052	− 8.2
Weather variables		
Maximum day temperature	0.0126	3.3
Maximum day temperature times noon-4 PM-dummy	0.0239	5.8
Daylight times 9 AM dummy	0.00002	5.3
Daylight times 5 PM dummy	0.00002	3.5
Daylight times 6 PM dummy	0.00006	13.5
Holiday dummies		
Summer holidays North (dummy)	− 0.372	− 4.2
Summer holidays South (dummy)	− 0.176	− 3.5
Week 53 (dummy)	− 1.210	− 9.8
Adjusted R^2		0.754
No of observations		2510

Most of the (dummy) variables in the table speak for themselves, others will be explained briefly below. The trend variable counts days from January 1st, aiming to represent the combined effect of economic growth (+) and technical progress (-) on electricity demand. The values for the time of day dummies act as time of day specific constants in the equation. The cross term between maximum temperature and the ‘noon-to 4PM’ dummy reflects the fact that air-conditioning units are used mainly during the hottest hours of the day. The daylight-variable is constructed as the quadratic difference from the longest day (measured in days). Cross-terms with early and late hours are constructed in order to correctly represent their effect on electricity use.

Summer holidays in the Netherlands are differentiated over three regions; North, South and Centre. As the summer holidays in the Centre region overlaps with those in both other regions, no dummy is added here. The dummy for ‘week 53’ reflects that many companies are closed in the week between Christmas and New Year.

The price parameter implies a price elasticity of -0.0014. The distinction between expected and unexpected demand can be derived from the predicted values and residuals from the analysis. The left hand column of table 5.1 is constructed using the predicted value while keeping the price at zero.

Appendix B Glossary

Black-out	Situation where no electricity is delivered in a certain region during a certain period
Break-even frequency	The frequency of occurrence of a predefined crisis at which the present value of the costs of the policy option exactly equal the present value of its benefits.
Brown-out	Situation in which the quality of delivery is seriously lowered. This often results in temporary disturbances of electrical appliances or variations in the brightness of lighting.
Capacity shortage	Situation where electricity demand exceeds available production capacity
Demand response	Reaction of demand to prices, often a decrease in demand because of an increase in price
Direct/indirect effects	Direct effects are the effects of a policy measure in the specific energy market it is directed at. Indirect effects are effects that do not relate directly to a policy measure, but follow from its direct effects.
Flexibility factors	Mechanisms that counteract capacity shortages.
Load	Amount of electricity per unit of time transported over the network.
Optimal capacity	Level of capacity at which an increase or decrease of the level can not increase welfare.
Reserve contracts	Auctioned contracts between the TSO and producers to keep spare capacity available.
Spare capacity	Capacity not used for production delivered to the market.
Spinning reserve	Reserve capacity ready to be deployed in 15 minutes.
Spot market	Market where electricity is traded 24 hours before delivery.

Spot market price	Hourly price of electricity, realised at the spot market.
Transmission grid	High voltage (often national) electricity network.
TSO	Transmission System Operator: operator of the transmission grid.
UCTE	Union for the Co-ordination of Transmission of Electricity; union of TSOs of 22 European countries who have synchronised their networks.
Unbalance price	Price paid by load serving entities for unbalance caused by deviations from projected supply.