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Equilibrium Modeling of a Power Market with a Capacity Market Designed to Promote Flexible Capacity

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Preface

This master thesis is written at the Department of Electric Power Engineering at the Norwegian University of Science and Technology on behalf of the course "TET4915 - Energy Planning and Environmental Analysis, Master's Thesis" the spring 2016. I would like to thank my supervisor Vijay Venu Vadlamudi for support throughout the semester. Also advices from PhD candidate Martin Kristiansen and associate professor Hossein Farahmand have been beneficial for this work. My father, Per, and my former fellow student, Christoffer Venås, deserver appreciation for being kind enough to proof read this thesis. Last but not least, I would like to thank my fellow student Magnus Askeland for the help I received to develop the MCP-model in GAMS.

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Abstract

Higher penetration of Renewable Energy Sources (RES) in the European power system has led to reduction in operating hours and revenues for conventional generators with load following capabilities. Therefore it has been argued there is a need for capacity remuneration mechanisms (CRM) to promote these generators. This thesis looks into a suggestion of a capacity market, where flexible generation technologies are paid higher prices for available capacity than less flexible generation technologies. Flexibility is here used as a term describing high ramping rates and short start-up and shut-down time for generators.

The main objective of this thesis is to develop an equilibrium model of a power market including a two-priced capacity market, with one flexible capacity price paid only to available flexible capacity, and one secondary capacity price paid to all available capacity. The model will be formulated as a mixed complementary problem (MCP). For comparison, a traditional single-priced capacity market and an energy-only market will be modeled. The three market designs will be tested on a one-node system representing the German power market in 2030, with high levels of intermittent RES.

In the model developed, each electricity producer represents a generation technology. Four producers, under the assumption of perfect competition, are included in the model; Nuclear, Coal, CCGT and OCGT generators. A MCP model has the ability of containing multiple objection functions. Each power producer optimize its profit individually, and the costs for the demand side and system operator are minimized. The two-priced capacity market categorize the producers in two groups:

- Flexible Producers: CCGT and OCGT
- Non-flexible Producers: Nuclear and Coal

The results and discussion of a base case will compare the installed capacity, load shedding, energy-based and capacity-based prices and revenues of producers of the three market designs. The goal is to see if the two-priced capacity model can promote flexible capacity. Sensitivity analyses are performed on a number of cases, to show the strength of the results from the base case.

In this thesis, the first known model of a two-priced capacity market is successfully constructed. It shows that this model indeed has the ability to give an advantage in the power market to flexible electricity producer over less flexible producers. Comparing the two-priced capacity

market with a traditional single-priced capacity market, it can be concluded that both designs result in equal total capacity installed reaching the wanted capacity reserve margin. However, the two-priced capacity market results in more flexible capacity installed. This work is a foundation of a model of the two-priced capacity market, and future work should expand the model to further investigate the benefits of the two-priced capacity market over traditional capacity market designs. This further work can provide information to the research field and to policymakers to help constructing a power market design fit for a future with high shares of intermittent RES.

Sammendrag

Økt mengde av fornybare energikilder (RES) i det europeiske kraftsystemet har ført til reduksjon i driftstimer og inntekter for konvensjonelle generatorer med last-følgende egenskaper. På grunn av dette har det blitt hevdet at det er behov for belønningsmekanismer for kapasitet (CRM) for å fremme disse generatorene. Denne avhandlingen tar for seg et forslag til et kapasitetsmarked, hvor fleksible generator-teknologier får betalt høyere priser for tilgjengelig kapasitet enn mindre fleksible generator-teknologier. Fleksibilitet er her brukt som et begrep som beskriver høye ramping-rater og kort oppstarts- og nedstengingstid for generatorer.

Hovedmålet med denne avhandlingen er å utvikle en likevektsmodell av et kraftmarked som inkluderer et to-pris-kapasitetsmarked med én fleksibel kapasitetpris, kun betalt til tilgjengelig fleksibel kapasitet, og én sekundær kapasitetspris betalt til all tilgjengelig kapasitet. Modellen vil bli formulert som et blandet komplementær-problem (MCP). Til sammenligning vil et tradisjonelt enkel-pris-kapasitetsmarked og et energy-only-marked modelleres. De tre markedsdesignene vil bli testet på et en-node-system som representerer det tyske kraftmarkedet i 2030, med høye nivåer av intermitterende RES.

I modellen som er utviklet representerer hver kraftprodusent en generator-teknologi. Fire produsenter, under forutsetning av perfekt konkurranse, er inkludert i modellen; atom-kraft, kull-kraft, CCGT og OCGT. En MCP-modell har evnen til å inneholde flere objektivfunksjoner. Hver kraftprodusent optimaliserer sin profitt individuelt, og kostnadene for etterspørselssiden og systemoperatøren er minimert. To-pris-kapasitetsmarkedet kategoriser produsentene i to grupper:

- Fleksible produsenter: CCGT og OCGT
- Ikke-fleksible produsenter: Atom-kraft og kull-kraft

Resultatene og diskusjonen av en base case vil sammenligne de tre markedsdesignene på følgene områder; installert kapasitet, last-kutt, energibaserte og kapasitetsbaserte priser og inntekter til produsenter. Målet er å se om to-pris-kapasitetsmarkeds-modellen kan fremme fleksibel kapasitet. Følsomhetsanalyser blir utført på en rekke caser for å vise styrken av resultatene fra base casen.

I denne oppgaven er den første kjente modellen av et to-pris-kapasitetsmarkedet vellykket konstruert. Det blir vist at denne modellen faktisk har mulighet til å gi en fordel i kraftmarkedet til fleksible kraftprodusenter over mindre fleksible produsenter. Sammenlignes to-pris-

kapasitetsmarkedet med det tradisjonelle enkel-pris-kapasitetamarkedet, kan det konkluderes med at begge resulterer i lik total kapasitet installert, slik at den ønskede reservemarginen for kapasitet blir nådd. To-pris-kapasitetsmarkedet installerer derimot mer fleksibel kapasitet enn enkel-pris-kapasitetsmarkedet. Dette arbeidet er et fundament av en modell av et to-pris-kapasitetsmarked og fremtidig arbeid bør utvide modellen til å ytterligere undersøke fordelene ved dette kapasitetsmarkedet fremfor tradisjonell design av kapasitetsmarkeder. Det videre arbeidet kan gi informasjon til forskningsfeltet og til politikere som kan være til hjelp for å konstruere et kraftmarket som passer inn i en framtid med høye andeler av intermitterende RES.

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Abbreviations

CCGT – Combined-Cycle Gas Turbine power plants

CO – Constrained Optimization

CP – Complimentary problem

CRM – Capacity remuneration mechanisms

KKT – Karush-Kuhn-Tucker

MCP – Mixed Complementary Problem

MPCM – Multiple-Priced Capacity Market

LTMC – Long Term Marginal Costs

OCGT – Open-Cycle Gas Turbine power plants

RES – Renewable Energy Sources

SO – System operator

VoLL – Value of lost load

1 Introduction

1.1 Motivation

Capacity remuneration mechanisms (CRM) are on the rise in Europe. In the last couple of years a number of countries in Europe have either introduced or considered CRM, this include Great Britain (GB) and France, where CRM were introduced in 2014 and 2015 respectively. After the deliberation of the power markets in the early 1990s the most common market design in Europe has been the energy-only market. However, some countries complemented the energy based market with CRM to ensure security of supply, as Ireland and Spain. The motivation behind CRM are the concerns about the adequacy of power generating capacity in power systems. There exists a number of different types of CRM, including capacity markets, similar for most of the designs are that electricity producers get remuneration based on their available capacity, with the intention of ensuring adequate capacity.

The European power system is currently experiencing large changes, described as a new paradigm by a number of papers as in [1] and [2]. This is mainly because of the large number of intermittent renewable energy sources (RES) entering or about to enter the power system. High penetration of intermittent RES can result in a more challenging residual demand for system operators. System operators must be able to procure enough supply to meet demand of electricity at all times. To do so, flexibility amongst the conventional generators in the system is needed to synchronize with changes in residual demand. Flexibility is in this thesis used as a term describing high ramping rates and short start-up and shut-down time for generators. The higher penetration of RES in the power system has led to reduction in operating hours and revenues for conventional generators with flexible capabilities, therefore it has been argued (e.g. in [1], and [3]) that there is a need for CRM to promote flexible generation technologies.

1.2 Problems to be addressed

This thesis looks into a suggestion made by paper [1] of a multi-priced capacity market, where flexible power producers are paid higher prices for available capacity than less flexible power producers. The main objective of this thesis will be to develop an equilibrium market model of a power market including a two-priced capacity market, designed to promote flexible capacity. The model will be formulated as a mixed complementary problem (MCP). For comparison, two other market designs will be modeled, a traditional single-priced capacity market and an energy-only market. The models will be tested on a system representing the German power market in 2030 with high amounts of intermittent RES.

To see if the two-priced capacity model successfully can promote flexible capacity, the results of installed capacity, energy-based and capacity prices and revenues for power producers will be compared with the two other market designs. The multi-priced capacity market in [1] is no more than a suggestion of a power market design, and has not been modeled before to the author's knowledge.

1.3 Thesis structure

This thesis will consist of three main parts; a theory part (chapter 2), a methodology part (chapter 3) and a results and discussion part (chapter 4). Chapter 2 will explain theory of topics necessary for the understanding of the rest of the thesis. This part contains a literature study that covers the background and different designs of CRM in addition to situations of power markets in Europe. Other topics presented are basic concept of the energy-based market and complementary modeling. The methodology contains model description, nomenclature and description of data of a base case. Results of the base case of the models for the three different market designs, are presented and discussed in chapter 4. Results of sensitivity analyses, which are performed on a number of cases, are also presented. The conclusion and suggestions to further work of the thesis is given in chapter 5.

2 Theory

This section presents basic concepts of topics necessary to understand what is later discussed in this thesis. Some subsections in the theory part is based on a literature study conducted on CRM. The literature study was done with the intention of finding information about the background of CRM and different CRM-designs.

2.1 Energy-based markets

2.1.1 Generation technology mix

Generators are normally divided in three main categories after their different capabilities. Figure 2.1 shows the different categories' normal annual operation hours represented by a load-duration curve. Typical base load generation, e.g. nuclear power plants, cover the load that needs to be delivered 24 hours each day. Base load plants are normally designed to run for most of the hours each year and have both high installation costs and low operating costs.

Mid-merit load generation are able to run most hours of a day, but also to be dispatched, i.e. to follow the load when it changes. These generators run for a variable amount of hours each year as shown in Figure 2.1. Example of "follow-the load" plants are combined-cycle gas turbines (CCGT).

At last, to cover peak demand, there is a category referred to as peak load generation. These are plants designed to run a small number of hours each year and have normally low fixed costs and expensive operating costs. Their total annual operating costs are however small due to the few operating hours. Examples are oil-fired steam plants and open-cycle gas turbines (OCGT).

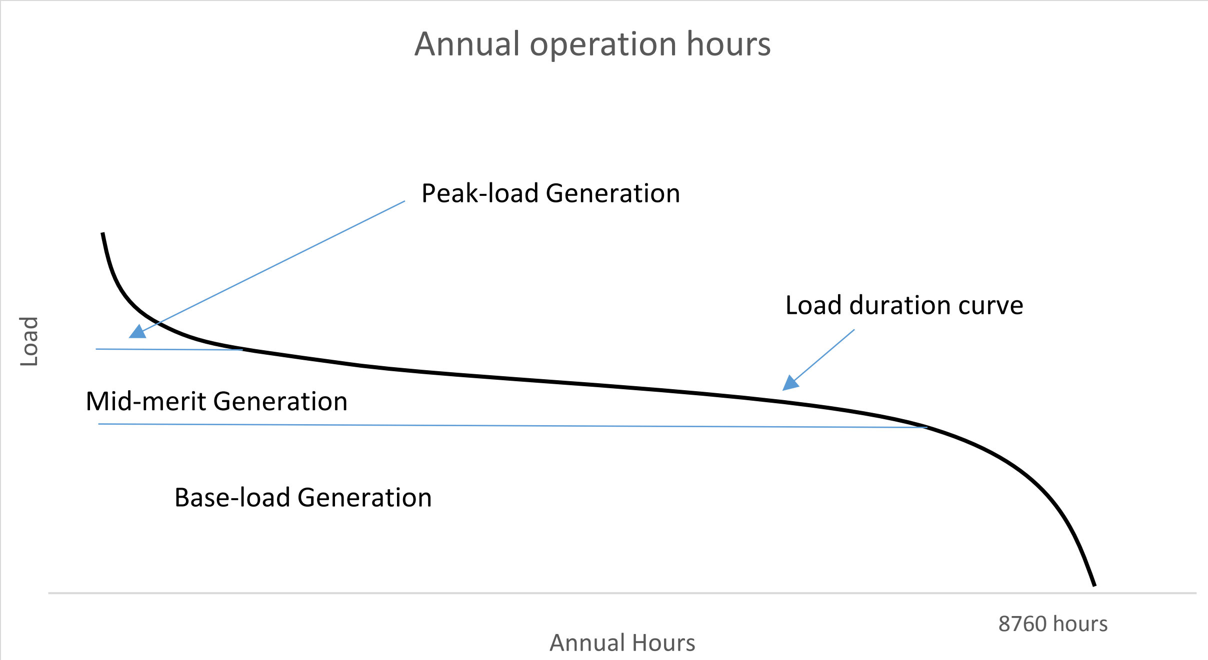

Figure 2.1: Annual operation hours of different generation technologies [4].

2.1.2 Merit-order in energy-based markets

Energy-only markets refer to energy-based markets, without any kind of CRM. This has been the most common design of power markets in Western Europe in recent years and have existed since the first deregulated markets came in the early 90s [5]. Energy prices in a liberalized energy market are decided by that the market operator receives bids from producers to supply electricity. The market operator stacks the bids in order from cheapest to most expensive, called the merit order list. To associate with economics, the merit-order list is comparable to a supply curve, and should in theory reflect producer's marginal cost-curve. The most expensive bid accepted of a buyer clears the market. "The clearing price" decides the price for all electricity sold in the market.

2.1.3 Residual demand

Large shares of intermittent RES have entered or are about to enter European power systems. 28% to 38% of the power mix in 2030 will be intermittent RES, according to reference [6], with the large majority of the intermittent RES being wind and solar power. There are a number of other types of intermittent RES (e.g. tidal power), but this thesis will focus on solar and wind power when using the term. Due to low variable costs intermittent RES are often threated as free-of-use, i.e. when they are available they will produce electricity. This leads to what called residual demand. Residual demand is total demand subtracted generated intermittent RES, hence the demand conventional generators need to meet [7]. With a high share of intermittent RES can the residual demand be more variable and unpredictable than the total demand, which can be seen in Figure 2.2, where demand is the upper line and residual demand is the bottom line. As the figure shows can residual demand be negative, which means there is more intermittent RES production than demand, if transmission of power to adjacent regions is not possible, some of the RES production has to be shed to make sure supply equals demand.

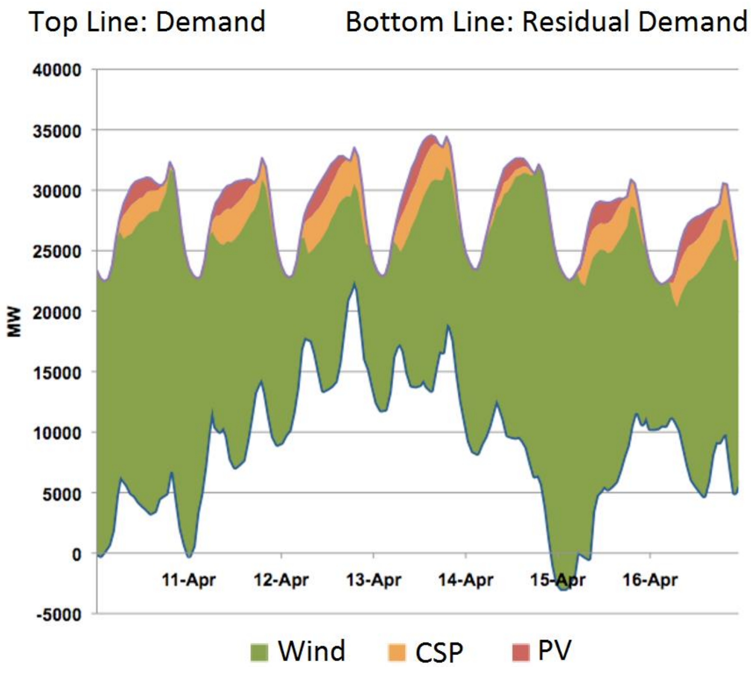

Figure 2.2: Residual demand is total demand subtracted intermittent RES production. [7]

Paper [3] says a power system with a high share of intermittent RES needs firm capacity with flexible capabilities to meet residual demand. Firm capacity is capacity the system operator can rely on being available at any time. The “firmness” of intermittent RES are considered low since they are weather dependent (e.g. sun and wind).

2.2 Situation of installed capacity in Europe

One of the main reasons why CRM are being discussed in Europe is the concern about future adequacy of power generating capacity. Figure 2.3, from paper [8] shows the remaining capacity subtracted the adequacy margin in 2020 for different countries, based on ENTSO-E scenarios. Stating that future capacity adequacy is promising for Norway and Netherlands, depending on scenario for France, Great Britain, Belgium and Denmark, but problematic for Germany and Ireland. This is backed up by paper [9], concluding that capacity adequacy might become a concern for a number of countries in the 2020s on the basis of simulation of the future European power system.

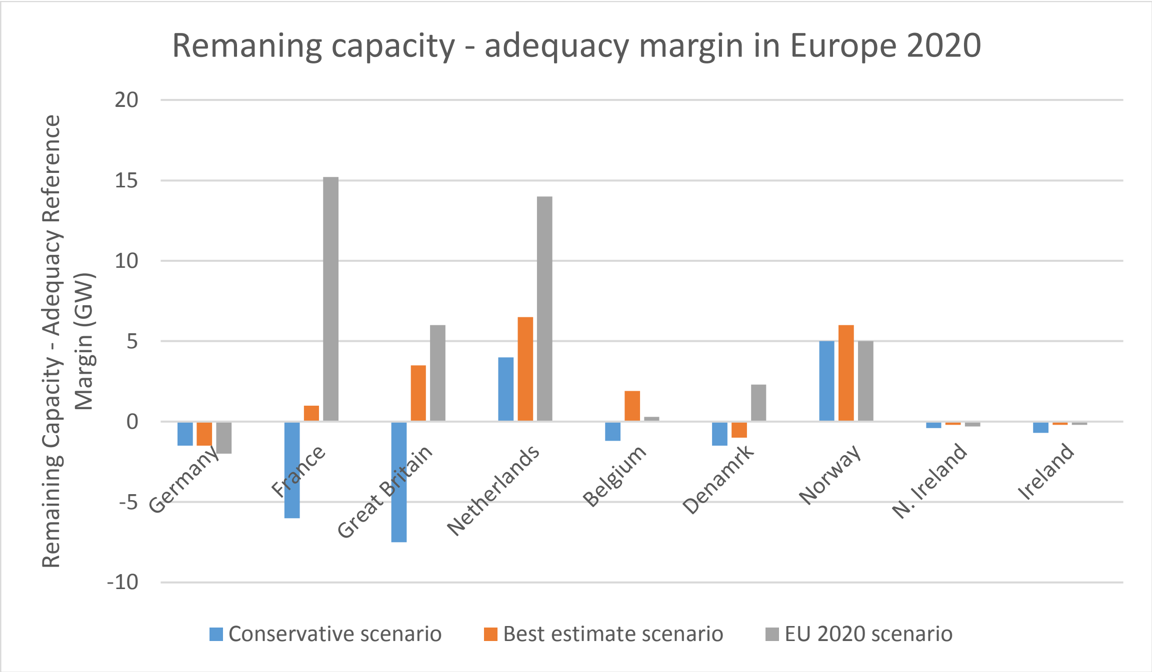

Figure 2.3: Forecasted remaining capacity subtracted adequacy reference margin in European countries in 2020 [8]

One reason for concern about future adequacy of capacity is that conventional power plants experience reduced operating hours and revenues due to the higher share of intermittent RES in the power systems. Paper [10] states that with the higher share of RES in the power system thermal generation becomes intermittent. The operation of thermal power plants becomes more uncertain when start-ups depend more on weather than demand-curves. This leads to the paper expects a decrease in load factor for Coal and CCGT towards 2035.

One example of load factor reduction of thermal plants from Spain is presented in [11]. The production hours per year for CCGT and coal power plants have been reduced dramatically between 2004 and 2010, which is shown in Figure 2.4. In the same time frame high shares of intermittent RES entered the Spanish market.

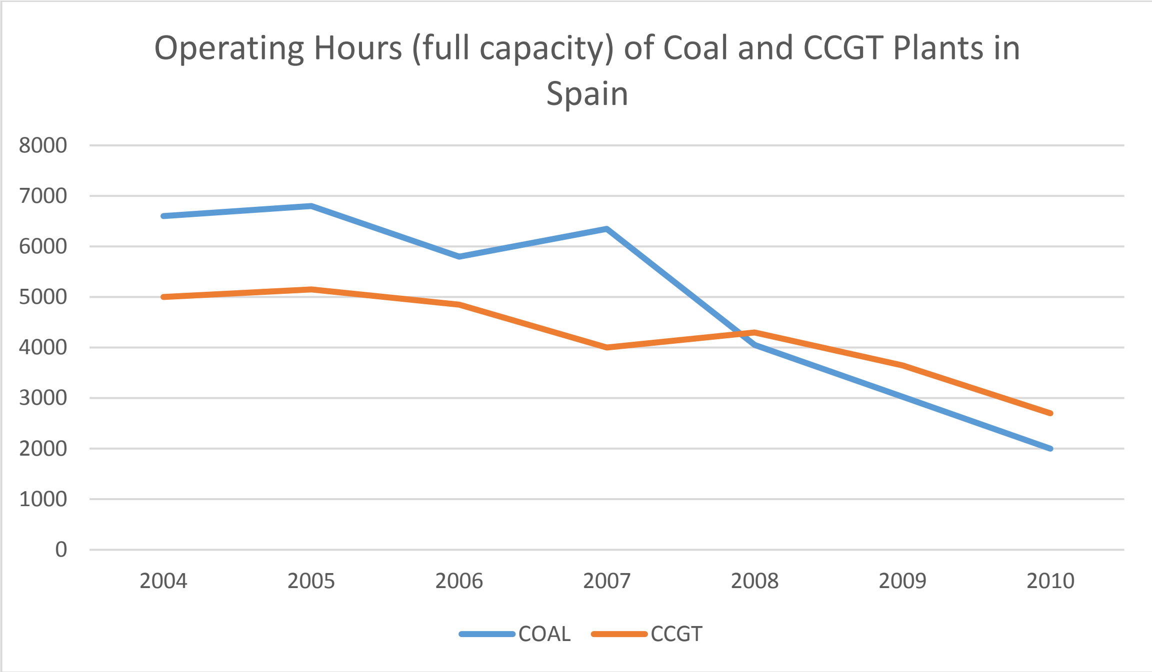

Figure 2.4: Reduction in Operating Hours of Coal and CCGT plants in Spain from 2004 to 2010 [11]

Reduced operating hours can lead to reduced revenues for power plants. Paper [8] states that gas fired power plants in Northwestern Europe are struggling to operate on a profitable basis, not only because of lower total amount of operating hours, but also because of fuel prices and CO_2 prices resulting in that the less flexible power plants nuclear and coal becoming more profitable than gas plants.

Reference [6] says that as the share of intermittent RES in the power systems increases, the room in the power market for base load plants, not technical or commercial capable of performing frequent start/stops and changes in output, shrinks. Generators capable of frequent changes in production and many starts/stops will be needed more. To ensure enough flexible capacity in power system, the reference says that the option of "capability-based" market instruments may be a better solution than traditional CRM, which remunerate available capacity equally. The next part of the thesis will explain existing designs of CRM, before the suggestion of the multi-priced capacity market is presented.

2.3 Capacity Remuneration Mechanisms

2.3.1 Background

The motivation for CRM comes from the underlying disbelief in the energy-based markets. To understand CRM it is important to understand these concerns.

Reference [12] states that price levels in liberalized energy-based markets during scarcity hours do not get high enough to cover the fixed costs of producers. The rise in price in scarcity hours is called scarcity rents, shown by R_S in Figure 2.5. The area labeled R_{MC} is what infra-marginal generators would earn if electricity prices are equal to marginal production cost of the generator that clears the market. In times of scarcity the scarcity rent will affect the clearing price to be higher than the marginal production costs. If the tendency of scarcity rent not being high enough are allowed to exist, it has the potential to result in underinvestment in generating capacity and hence higher rates of power supply emergencies and possible blackouts.

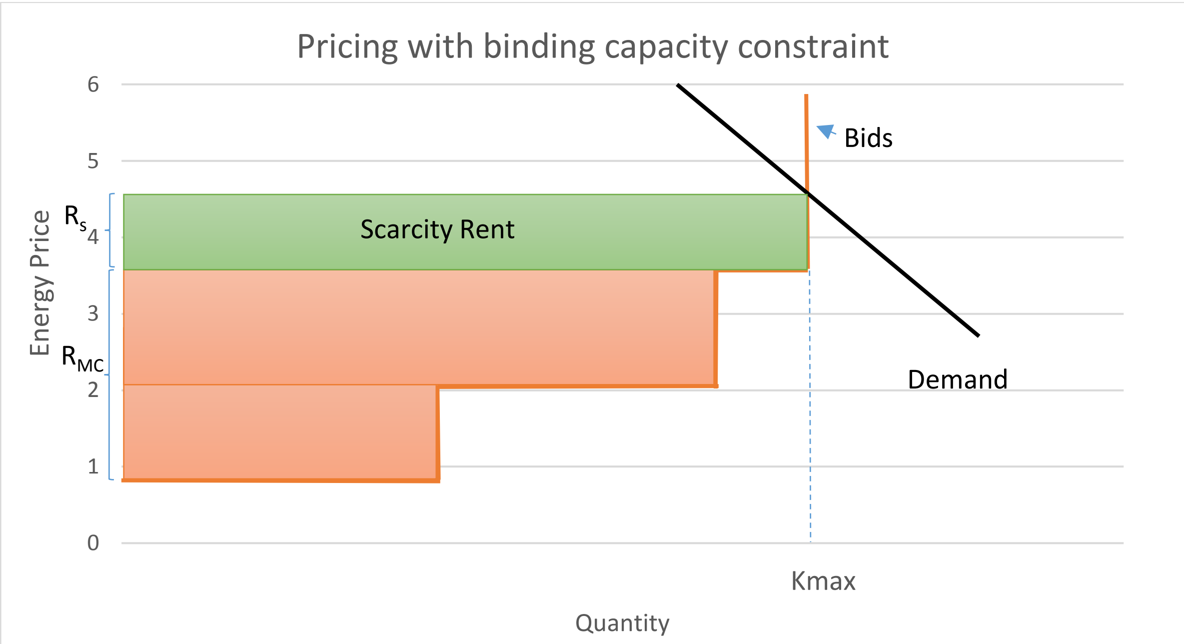

Figure 2.5: Scarcity rents in Energy-based market [12]

Another problem used as an argument against energy-only markets is that short-term prices, i.e. spot prices, are too volatile to attract investments in long term projects, without any guarantee of stream of revenues for producers as in a more regulated market [12].

The suggestion that energy-based markets perhaps cannot produce high enough streams of revenue to cover both operational costs and capital investment cost (i.e. fixed costs) is normally referred to as the “missing-money” problem, first used by [13] in 2006. The reference explains the missing money problem by investors being underpaid by energy-based markets whenever investments bring the capacity closer to the adequate level, which leads to that investments stop before adequate capacity is reached. This is referred to as the adequacy problem.

Paper [14] argues that the adequacy problem comes from electricity markets cannot optimize the duration of blackouts. This is because there are no price set by the market in times of rolling blackouts (i.e. load shedding), as can be seen in Figure 2.6, due to the inelasticity of the demand curve in times of scarcity of supply. The adequacy problem is a tradeoff between more capacity and more blackouts. The paper argues that the fundamental purpose of capacity markets is to provide the capacity that optimizes the duration of blackouts, which will be a task for the regulator.

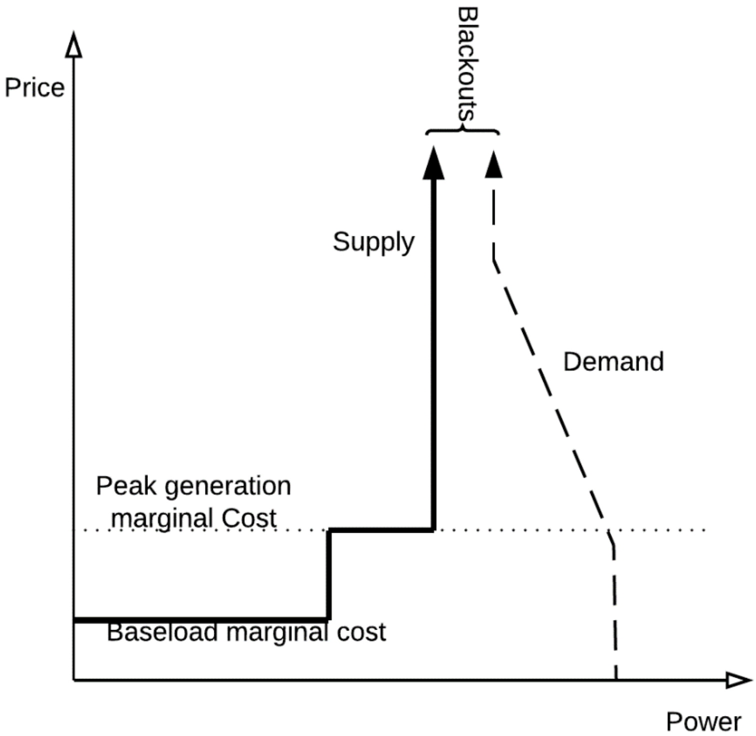

Figure 2.6: Limited elasticity in supply and demand curves can result in blackouts [14].

CRM work alongside the energy-based markets to ensure adequate installed capacity in the power system by securing reliable stream of revenue for producers. In general, according to paper [8], CRM have the benefit to consumers of higher level of reliability of supply and less volatile electricity prices.

2.3.2 Existing CRM-designs

This section gives an overview of existing types of CRM. CRM are in this report used as a broad term of a number of market mechanisms designed to ensure sufficient capacity. The scope of this thesis is not to give a detailed description of each type of CRM, but to investigate a new type of capacity market, namely the multi-priced capacity market. Therefore this section gives a brief overview of CRM, and describes what capacity markets are opposed to other types of CRM. References [5], [8], [11] and [15] are used to write this section.

Figure 2.7, from [15], gives a brief presentation of the most common CRM designs. As can be seen in the figure, the term capacity markets include capacity obligations, capacity auctions and reliability options. These three designs are volume based, meaning that producers are paid for a fixed amount of available capacity agreed between producer and a central body. This is opposed to capacity payments, where payments are set by the central body and not through a competitive process, which means that a central body pays a fixed amount to all generators with available capacity.

The capacity markets are market-wide, meaning that all generation technologies that offers available capacity can be remunerated. This is opposed to strategic reserves, which is a design targeted at remunerating available capacity of specific generation technologies, typically peak load plants. It must be noted that the Figure 2.7 present the way CRM-designs are normally implemented, and variations from this occur.

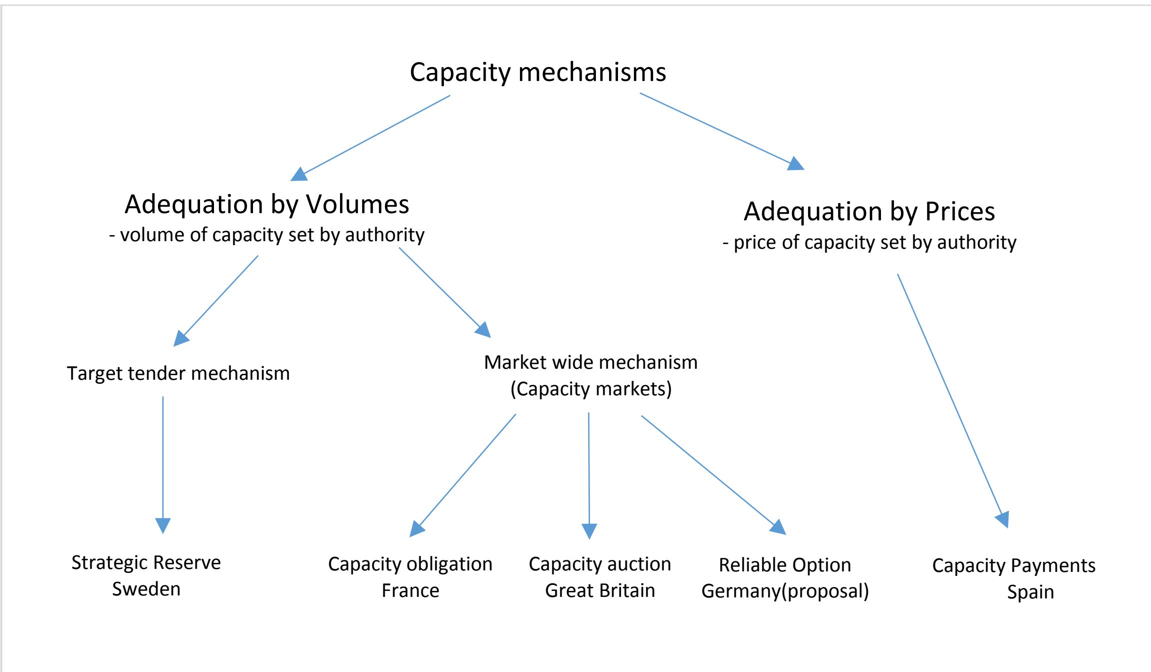

Figure 2.7: Diagram of CRM [15].

There are differences between the three capacity market designs. Amount of capacity can whether be set by a central authority which is common for capacity auctions (and in most cases for reliability options), or locally as for capacity obligations. In markets with capacity obligation suppliers are required to contract a fixed level of capacity to a price agreed between the central body and the producer. If available capacity is not sufficient, the producer receives a penalty through fines.

In capacity auctions the system operator (SO) sets a required amount of capacity months or years in advance. Paper [16] explains the process for a SO to set the demand curve for capacity, location, slope and height of the demand curve is usually determined so that the price at the desired reserve margin is sufficient to cover cost of a new peaking plant. Through a competitive auction which decides the market price for capacity, the producers secure contracts of delivering available capacity.

Reliability options are based on capacity auctions, but include a financial instrument call option rather than a physical instrument. The idea is that the system operator sets a strike price. If the spot price, P, is higher than the strike price, P_{strike}, the producers must make their capacity of generators available if the system operator requires it. Reliability options are a quite newly developed design and are under consideration of implementation in Germany.

Section 2.3.4 explains a suggestion of a multi-priced capacity auction, where producers receive different prices in the capacity market, based on their flexible capabilities. From now on when it is referred to capacity markets, it is meant a centralized volume-based capacity market, like capacity auctions.

2.3.3 CRM-situation in Europe

Figure 2.8 gives an overview of CRM in Europe. It states which countries already have implemented CRM (Ireland, GB, France, Spain, Portugal, Poland, Romania, Greece, Sweden and Finland) and which countries are considering implementing it (Germany, Belgium and Italy). By looking at this figure it is clear that CRMs will be a part of the future in European power markets.

Most relevant for this thesis among the European CRM is the capacity market introduced in GB. The first capacity auction in GB took place in December 2014 and resulted in 49.3 GW capacity that is contracted to be delivered in 2018/2019. The capacity clearing price was lower than many expected, at the price of 19.40 £/kW-year [17]. Paper [18] assessed the proposal of this capacity auction in 2012 and criticized the design of remunerating all available capacity equally, and not taking capabilities of producers into account. Next section will present a suggestion of a capacity auction where different generation technologies gets different capacity prices.

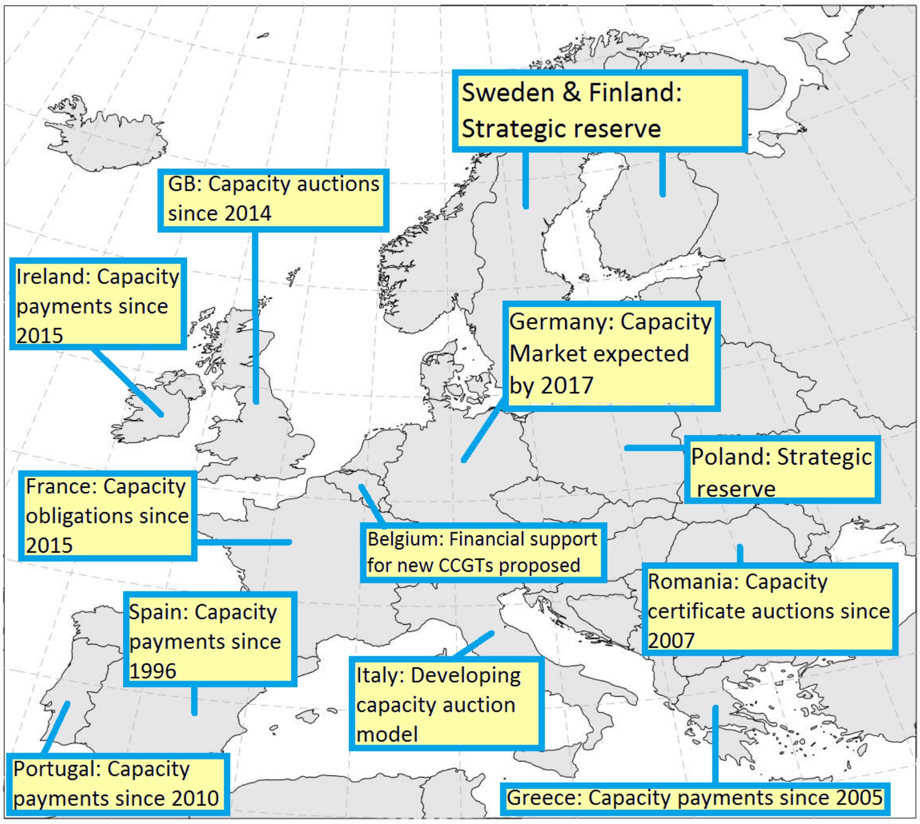

Figure 2.8: CRM in Europe [19].

2.3.4 Multi-priced capacity market

Already in 2004 there was a suggestion to introduce trenches in the capacity auction in the capacity market in the regional transmission organization PJM in USA. Different capabilities of generators would be used to divide the auction into categories. The idea was to remunerate different generation technologies differently to increase diversity of capabilities in the total supply. Suggestion is covered by [20] and contains constraints of ramping and start/stop time to categorize the generators.

Paper [1] has a suggestion similar to the one made for PJM. A multiple bidding round in a capacity auction that divides the generators in trenches based on load-following generation capabilities. The paper suggests three different categories for generation. As opposed to the single clearing price auction in a traditional capacity auctions, shown in Figure 2.9, the multiple clearing price auction will contain three different prices and quanta for different kinds of generation. This will herby be referred to as multi-priced capacity market (MPCM).

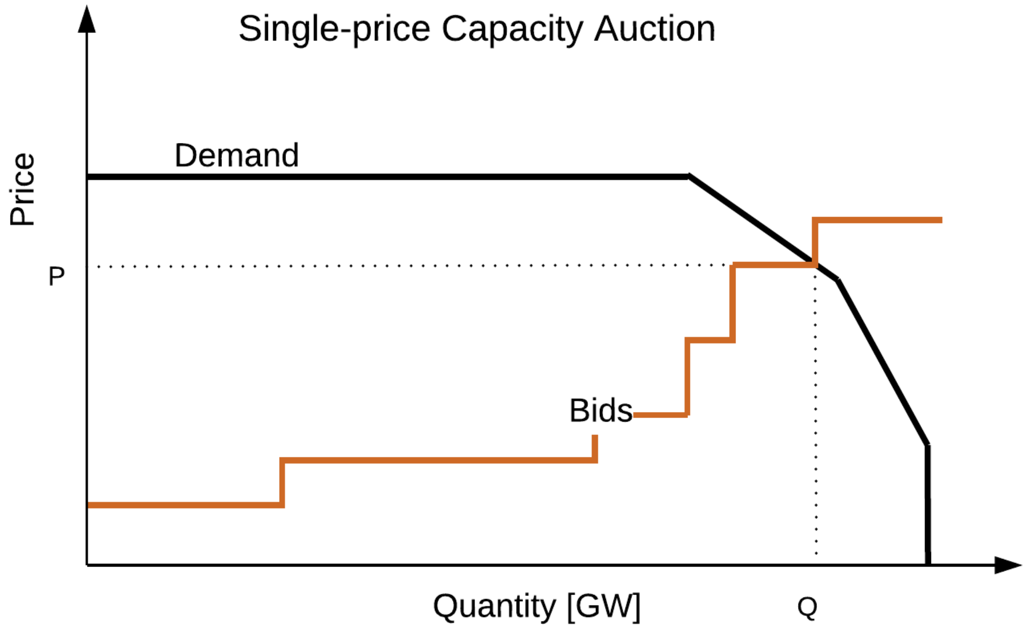

Figure 2.9: Single-priced capacity market [1].

Similar to traditional capacity auctions the SO decides the demand curve for capacity. In the MPCM is the need of peak-load generation, mid-merit load generation and base load generation is reflected by the demand curve. The demand curve will therefore have three decreasing-areas. It will be at initial price value until demand of peak-load is met, then decrease to demand-valuation price of mid-merit load before declining to base-load demand-value when mid-merit load demand is met, and at last go to zero when total demand of capacity in the system is met, as shown in Figure 2.10.

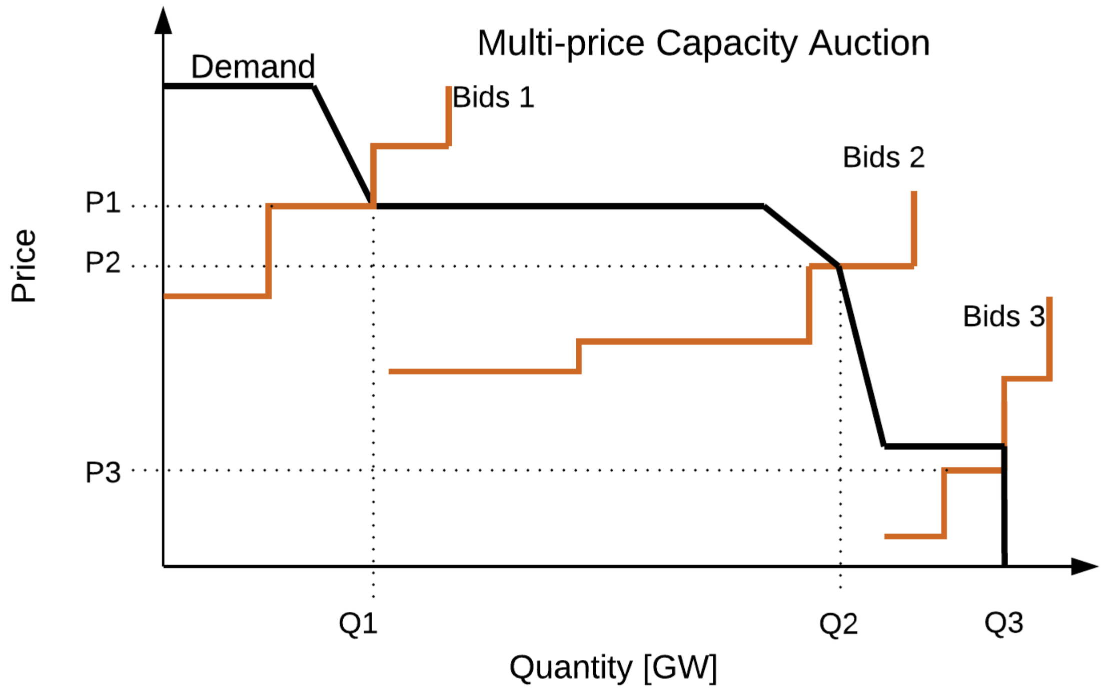

Figure 2.10: Multi-priced capacity market [1].

The first bidding round, where only the most flexible and dispatchable generators (i.e. peak load plants) are allowed, will end up at a fairly high price and a quantum corresponding to what operator sets as optimal for typical peak load. The second bidding round welcomes the typical mid-merit sources, and will end up a medium price and at a quantum corresponding to demand-curve need for peak load and mid-merit load. At last the third bidding round includes all firm capacity and will result in a fairly low electricity price.

The prices are shown as P1, P2 and P3 and quanta as Q1, Q2 and Q3 in Figure 2.10, for bidding round one, two and three respectively. The idea with the multiple clearing price auction is that flexible energy sources will get an advantage over less flexible sources in the power market [1].

2.4 Complementary-based modeling of power markets

The model presented in section 3 is a MCP model. This section will describe the theory behind complementary modeling.

Equilibrium complementary modeling has the trait of solving many actors' individual optimization function simultaneously, giving the optimum solution for all of them. This is an advantage when modeling a power market with a number of actors. According to reference [21] complementary-based power market models directly solves a system of conditions, that include generators' and consumers' first order optimality conditions plus market clearing. This reference is used to write the following section, including the Karush-Kuhn-Tucker (KKT) conditions.

It is known that if a constraint is not binding, the dual variable of this constraint will have the value of zero. A complimentary condition between a positive variable (x_i) and a function ($G_i(\boldsymbol{x})$) can be written as shown in equation 1:

$$x_i \geq 0; G_i(\boldsymbol{x}) \leq 0; x_i * G_i(\boldsymbol{x}) = 0 \tag{1}$$

Here $\boldsymbol{x}$ is a vector of positive variables ($\mathbf{x} = \{x_i\}$).

$$0 \leq x_i \perp G_i(\boldsymbol{x}) \leq 0 \tag{2}$$

A compact notation of equation 1 can be seen in equation 2. The ⊥ sign says that at least one of the adjacent inequalities must be satisfied as an equality [22].

[CP]: Find a $\mathbf{x}$ such that: $$0 \leq \boldsymbol{x} \perp \boldsymbol{G}(\boldsymbol{x}, \boldsymbol{y}) \leq 0 \tag{3}$$

Equation 3 shows a general complimentary problem (CP), where $\boldsymbol{G}(\boldsymbol{x}, \boldsymbol{y}) = \{G_i(\boldsymbol{x})\}$. This is a square problem, which means number of individual conditions are equal to number of variables in vector $\boldsymbol{x}$. The complimentary problem is a linear complimentary problem if all the functions ($G_i(\boldsymbol{x})$) are affine, i.e. $G_i(\boldsymbol{x}) = A_1 * x_1 + A_2 * x_2 \ldots + A_n * x_n$.

The general form of a MCP problem is presented in equation 4. This is a more general form than the complementary problem. It may contain non-linear functions. Given two vectors of variables $\boldsymbol{x} = \{x_i\}$ and $\boldsymbol{y} = \{y_j\}$ where x_i is a positive variable, and two vectors of functions $\boldsymbol{G}(\boldsymbol{x}, \boldsymbol{y}) = \{G_i(\boldsymbol{x})\}$ and $\boldsymbol{H}(\boldsymbol{x}, \boldsymbol{y}) = \{H_j(\boldsymbol{x})\}$, then find $\boldsymbol{x}$ and $\boldsymbol{y}$ such that:

[MCP]: $$0 \leq \boldsymbol{x} \perp \boldsymbol{G}(\boldsymbol{x}, \boldsymbol{y}) \leq 0 \text{ and } \boldsymbol{H}(\boldsymbol{x}, \boldsymbol{y}) = 0 \tag{4}$$

2.4.1 Karush-Kuhn-Tucker (KKT) conditions

When formulating non-linear optimization problems as complementary problems are KKT conditions essential. A general constrained optimization (CO) problem, here a maximization problem can look like equation 5 [21]:

$$\begin{aligned} &\text{[CO]:} && \text{MAX } F(\boldsymbol{x}) \\ &\text{s.t.:} && G(\boldsymbol{x}) \leq 0 \\ & && \boldsymbol{x} \geq 0 \end{aligned} \tag{5}$$

It is assumed that the feasible region of the CO problem is convex and that any local optimum of the CO problem is a global optimum.

Then the KKT conditions of the CO problem look like equation 6:

$$\begin{gathered} 0 \leq x_i \perp \frac{\boldsymbol{\partial} F}{\boldsymbol{\partial} x_i} - \sum_j \lambda_j \frac{\partial G_j}{\partial x_i} \leq 0 \quad \forall i \\ 0 \leq \ \lambda_j \perp G_j \leq 0 \qquad \forall j \end{gathered} \tag{6}$$

Here the KKT conditions are a set of complementary conditions which solution is an optimal solution to the CO problem, and the CO problem is an optimal solutions for the KKT-conditions.

2.4.2 MCP in gams

To solve the MCP problem in GAMS the PATH solver is chosen. According [22] the following points are specifics that needs to be taken into account when writing the model in PATH:

- When writing inequalities it is required to use “greater than or equal to” (0 =g= G(x,y)), instead of the alternative of writing “less than or equal to” (G(x,y) =l= 0).
- Dual variables of equality constraints have to be free.
- Dual variables of inequality constraints have to be positive.
- Correct dual variable needs to be connected to correct equation. Instead of ⊥, is “.” used.

The GAMS code of the model of Design 3, presented in section 3, can be found in the appendix.

3 Methodology

This section will present the details of the model developed in GAMS. The model contains three different organizations of the market. These will be referred as design one, two and three:

- Design 1 [D1]: Energy-only market
- Design 2 [D2]: Volume-based capacity market
- Design 3 [D3]: Volume-based capacity market with two prices

The model is developed on the basis of the model presented in the working paper [23]. Also the project work of a fellow student [24], which is based on the working paper, has been beneficial for the development of the current model. It is a MCP equilibrium market model of energy-based market and capacity market. Design 1 and 2 are reproduced from [23] while Design 3 is developed in this work. The three designs are briefly presented in Table 3.1, showing which markets and prices they contain.

Table 3.1: Presentation of the three power market designs modeled

	Design 1	**Design 2**	**Design 3**
Energy-based market?	Yes, with an hourly electricity price in €/MWh	Yes, with an hourly electricity price in €/MWh	Yes, with an hourly electricity price in €/MWh
Capacity-based market?	No	Yes, with an annual capacity price, paid to power producers for every MW capacity they make available to the market	Yes, same as for Design 2, but with two annual capacity prices, one for flexible producers and one for non-flexible producers

Instead of the multi-priced capacity market presented in section 2.3.4, it has been decided to model a two-priced capacity market (Design 3). This has the advantage of being easier to present. The process of expanding a two-priced capacity market to a multi-priced capacity market would be exactly the same as expanding the single-priced capacity market (Design 2) to a two-priced capacity market. Since the principles behind the construction of a multi-priced and a two-priced model is the same, a more complex multi-priced model has the potential to confuse the reader with the increased number of variables and constraints. The scope of this thesis is to develop a capacity market promoting flexible capacity, and this scope is well preserved in the two-priced capacity market model.

The nomenclature is presented below, followed by the mathematical description of the model. The relationships between the objective functions and the following constraints are explained in detail. It will be specified which equations belongs to which design. Equations market with [D1] and [D2] are reproduced from [23], while equations marked with [D3] alone are produced in this work.

3.1 Nomenclature

Sets, parameters, variables and dual variables are marked with which design they are applied in. Those not marked are applied in all designs. Parameters variables and dual variables dependent on p are dependent on both f and b in Design 3.

Sets

P	producers, including all types of producers [D1], [D2]
H	hours
F	flexible producers [D3]
B	non-flexible producers [D3]

Parameters

DEM_h	Demand data of hour h, [MW]
DEM^{MAX}	Maximum demand, [MW]
FC_p	Yearly fixed costs of installation of producer p, [€/MW]
INJ_h^{WIND}	Wind energy injected at hour h, [MWh]
INJ_h^{SOLAR}	Solar energy injected at hour h, [MWh]
P^{MAX}	Maximum market price, [€/MWh]
RS^{LS}	Reliability standard: Max load shed of total demand, [%] [D2], [D3]
RS^{CAP}	Reliability standard: Reserve margin above maximum demand, [%] [D2], [D3]

RS^{FLEX} Reliability standard: Required amount of flexible installed capacity of max demand, [%] [D3]

VC_p Variable Costs of producer p, [€/MWh]

Variables

cap_p^{cm} capacity made available of producer, p, to capacity market, [MW] [D2], [D3]

cap_p^{inst} installed capacity of producer p, [MW]

dem^{cm} capacity demand in capacity market, [MW] [D2]

dem^{flex} demand for flexible capacity in capacity market, [MW] [D3]

dem^{base} demand for non-flexible capacity in capacity market, [MW] [D3]

$gen_{p,h}$ generation output of producer p, [MWh]

ls_h load shed in hour h, [MWh]

ps_h generation shed in hour h, [MWh]

Dual variables

α energy-based price adaption to fulfil load shed standard, [€/MWh]

β marginal cost of capacity reserve margin, [€/MW] [D2] [D3]

δ marginal costs of flexible capacity standard, [€/MW] [D3]

γ price in capacity market, [€/MW] [D2]

γ^{flex} flexible capacity price in capacity market, [€/MW] [D3]

γ^{base} secondary capacity price in capacity market, [€/MW] [D3]

λ_h price in energy-based market, [€/MWh]

$\mu_{p,h}$ scarcity rent of generation, [€/MWh]

ϕ_p scarcity rent of capacity, [€/MW] [D2] [D3]

3.2 Model description

As the model in [23] this model assumes perfect competition where all market participants are price-takers. Each generation technology in the model is represented as a market participant, here called a producer, which means each generation technology will be seen as one company. Intermittent RES are considered free-of-use and injected into the system. Intermittent RES are not considered as firm capacity. In Design 3 are the power producers divided in two categories, namely flexible producers and non-flexible producers. Each producer maximize its profit individually, which can be seen in Figure 3.1 and 3.2. A transmission system is not considered.

The model consists of one node only. Every hour in one year will be simulated. Initially no capacity is installed, which leads to an optimal generation mix when all producer install their optimal amount of capacity in hour one of the simulation. Uncertainties about future demand and other external risks, are not considered. To justify these assumptions it has to be noted that the focus of the thesis is on the comparison of the different market designs, not modeling of a fully realistic power market.

Figure 3.1 and Figure 3.2 are overviews of the model of Design 2 and Design 3 respectively. Figure 3.1 show that each producer (p = 1, 2, …, P) maximizes its profit based on the three decision variables, installed capacity, generated power and available capacity to the capacity market. The demand side and system operator is modeled together, with the objective of minimizing the costs, given the decision variables of demand for capacity and load shedding. Two reliability standards are available for the demand side and SO, namely short term operational security of supply, stating a maximum limit for how much load can be shed of total demand, and long-term capacity adequacy, stating a capacity reserve margin above maximum demand. The optimization problems are subjected to the energy market, with hourly market price λ, and the capacity market, with annually market price γ. Figure 3.1 is valid for Design 1 as well, excluding capacity market constraints, capacity market decision variables for producers and demand for capacity decision variable.

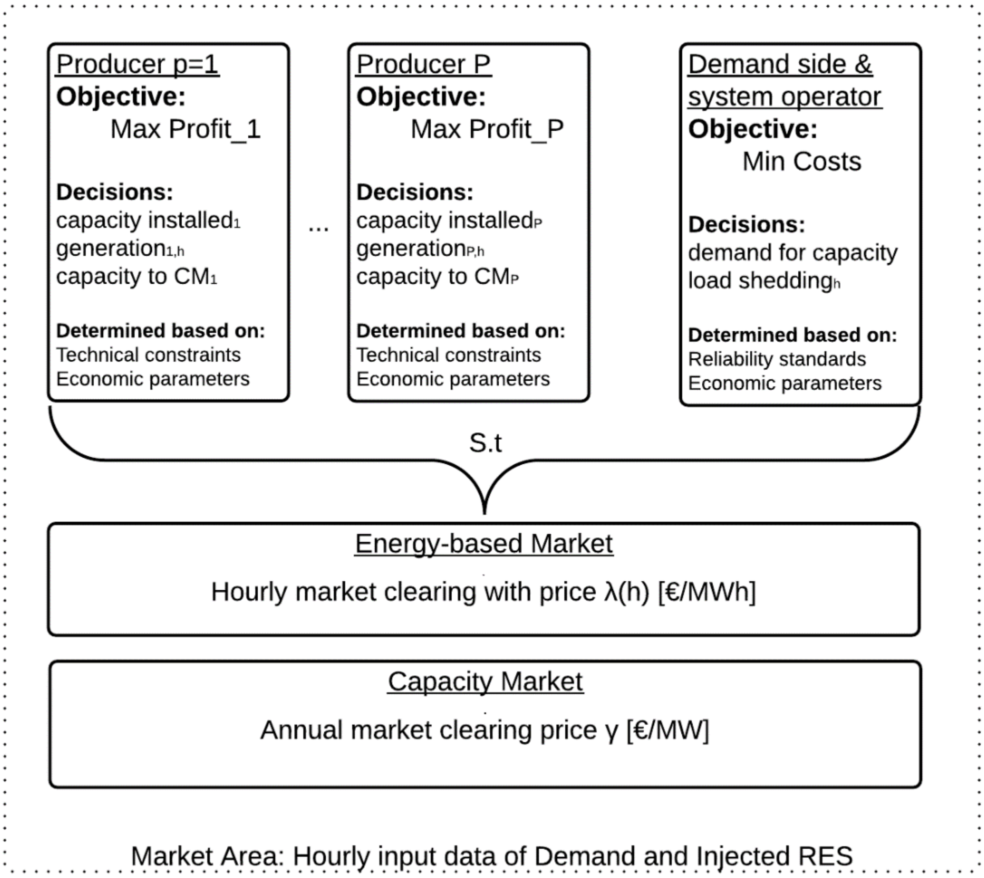

Figure 3.1: Design 2: Power Market Model including Capacity Market (CM) [23]

Figure 3.2 differs from Figure 3.1 with the producers being categorized in two groups: flexible producers, represented by f, and non-flexible producers, represented by b. As for Design 2 does the producers maximize their profit individually, here does the objective function for producer f and producer b differ since they receive different prices in the capacity market. The demand side in Design 3 have two new decision variables, demand for flexible capacity and demand for other capacity (referred to as dem^{base} in nomenclature). One new reliability standard is introduced for the demand-side and SO, namely flexible capacity adequacy, which states how much flexible capacity should be installed as a share of maximum demand.

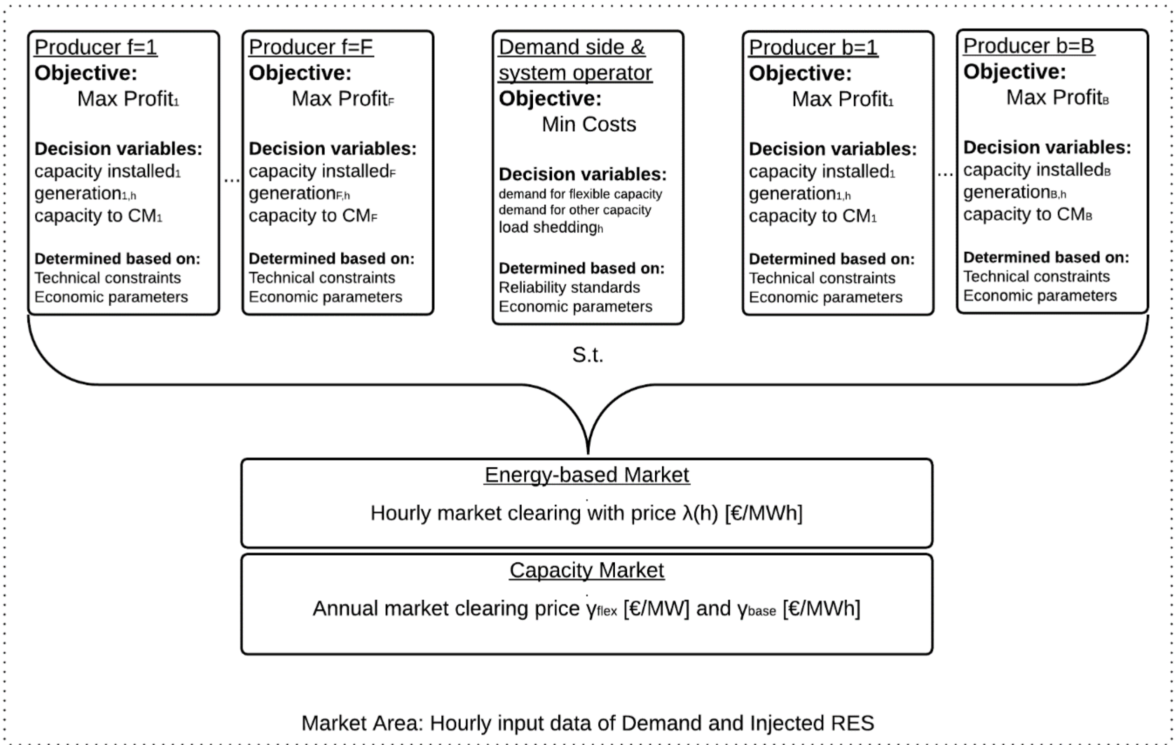

Figure 3.2: Design 3: Power market model including the two-priced Capacity Market

The following sections will present the mathematical relationships between the objective functions and constrains. First the producer objective function will be presented with its constraints, followed by the demand side/SO objective function and its constraints, and in the end the constraints representing the energy-based market and capacity market will be given. Note that the objective functions presented below are not actually a part of the model, as complementary problems do not contain objective functions. Only equations on complimentary form (e.g. equation 3) are included in the model. The step by step mathematical derivation of complementary KKT-condition from the original optimization problem can be found in the Appendix.

3.2.1 Profit maximizing producers

In equation 7 the objective function for producers in Design 1 is shown. The profit (Z_p) are the revenue from the hourly energy-based market, i.e. electricity price times generated power ($\lambda_h * gen_{p,h}$), minus variable costs from generation ($VC_p * gen_{p,h}$) and annual fixed costs from installation of capacity, ($FC_p * cap_p^{inst}$). In Design 2 is the revenue from the capacity market, shown in equation 8, added to the objective function. I.e. capacity price multiplied with capacity made available by producer (p) to the capacity market is added to equation 7.

[D1]:

$$Max\ Z_p = \sum_{h=1}^{H} \big((\lambda_h - VC_p) * gen_{p,h}\big) - FC_p * cap_p^{inst} \tag{7}$$

[D2]:

$$+ \gamma * cap_p^{cm} \tag{8}$$

Equation 9 and equation 10 are the objective functions for the two categories of producers in Design 3, namely flexible producers (f) and non-flexible producers (b). The profit maximizing functions (Z_f) and (Z_b) are the same as for Design 2 except that the price in the capacity market differs. Flexible producers are paid both the flexible price (γ^{flex}) and the secondary price (γ^{base}), hence their revenue from the capacity-based market will be sum of the two prices times the capacity they make available to the capacity-based market (cap_f^{cm}).

The revenue from the capacity market for non-flexible producers (b) is the secondary capacity price (γ^{base}) times capacity made available to the capacity-based market (cap_b^{cm}).

[D3]:

$$Max\ Z_f = \sum_{h=1}^{H} \big((\lambda_h - VC_f) * gen_{f,h}\big) - FC_f * cap_f^{inst} + (\gamma^{flex} + \gamma^{base}) * cap_f^{cm} \tag{9}$$

[D3]:

$$Max\ Z_b = \sum_{h=1}^{H} \big((\lambda_h - VC_b) * gen_{b,h}\big) - FC_b * cap_b^{inst} + \gamma^{base} * cap_b^{cm} \tag{10}$$

3.2.1.1 Generation Limits

Producers cannot generate more electricity than their installed capacity allows. Equation 11 is applied in Design 1 and 2. The equation is the same also in Design 3 except there exists two of it, one for flexible producers (f) and one for non-flexible producers (b).

[D1], [D2], [D3]*:

$$\forall p, h:\ 0 \leq -gen_{p,h} + cap_p^{inst} \perp \mu_{p,h} \geq 0 \tag{11}$$

The dual variable ($\mu_{p,h}$) takes a value over zero if the generation unit is fully used, i.e. if the unit generation their max capacity. It can be seen as an hour-based, technology-specific generation scarcity rent, expressed in €/MWh.

3.2.1.2 Capacity Limits

The capacity limit constraint, shown in equation 12, applies to the capacity market, hence Design 2 and 3. In Design 3 there exists two versions of this equation, one for flexible producers (f) and one for non-flexible producers (b). The equation limits the capacity each producer can make available to the capacity market, cap_p^{cm}, which cannot exceed their installed capacity, cap_p^{inst}.

[D2], [D3]*: $$\forall p:\ 0 \leq -cap_p^{cm} + cap_p^{inst} \perp \phi_p \geq 0 \qquad (12)$$

The dual variable (ϕ_p) takes a value when the producer makes all installed capacity available to the capacity market, it is a scarcity rent for capacity on annual basis expressed in €/MW.

3.2.1.3 Optimal Generation and capacity

Equation 13 represents the optimal generation of each producer every hour of the year. It is derived from the Lagrange function of the producers' profit maximizing problem, by differentiating the Lagrange function on the generation variable ($gen_{p,h}$).

[D1], [D2], [D3]*: $$\forall p,h:\ 0 \leq -\lambda_h + VC_p + \mu_{p,h} \perp gen_{p,h} \geq 0 \qquad (13)$$

The equation shows that generation by a producer is only stimulated if the hourly energy-based price (λ_h) is high enough to cover variable costs and the scarcity rents of generation ($\mu_{p,h}$). This equation is applied in all designs. In Design 3 there exists two versions of this equation, one for flexible producers (f) and one for non-flexible producers (b).

[D1]: $$\forall p:\quad 0 \leq FC_p - \sum_{p=1}^{P} \mu_{p,h} \perp cap_p^{inst} \geq 0 \qquad (14)$$

[D2],[D3]*: $$\forall p:\ \ 0 \leq FC_p - \sum_{p=1}^{P} \mu_{p,h} - \phi_p\ \perp\ cap_p^{inst} \geq 0 \tag{15}$$

Equation 14 is the optimality constraint for the installed capacity of each producer. It is derived from producers' profit maximizing Lagrange function, by differentiating on the capacity installed-variable (cap_p^{inst}). The equation shows that installation of capacity is only justified if the fixed costs (FC_p) are covered by revenues from the energy-based market, through high enough accumulated scarcity rents of generation.

Equation 15 is applied in Design 2. It shows that fixed costs can be covered by income from both the hourly based energy market, through the sum of scarcity rents of generation ($\mu_{p,h}$), and the annual capacity market, through scarcity rent of capacity (ϕ_p). Equation 15 is also valid for Design 3 except that there exists two versions of it, one for flexible producers (f) and one for non-flexible producers (b).

3.2.2 Demand side and SO

The objective of the demand side and the SO is to achieve a certain standard of reliability at minimum costs. Equation 16 shows the costs for the demand side and SO in Design 1, consisting of the costs of load shedding. In this model the maximum electricity price (P^{Max}) is used to value load shed. The difference between maximum market electricity price and actual electricity price (λ_h) times amount of load shed, represent the costs for the demand side of load shedding.

[D1]: $$Min\ C = \sum_{h=1}^{H} \big((P^{Max} - \lambda_h) * ls_h\big) \tag{16}$$

[D2]: $$+\gamma * dem^{cm} \tag{17}$$

[D3]: $$+ (\gamma^{flex} + \gamma^{base}) * dem^{flex} + \ \gamma^{base} * dem^{base} \tag{18}$$

In Design 2 the part shown in equation 17 is added to equation 16. Here an additional cost is added, namely the amount system operator pays for available capacity in the system. This is the capacity market price (γ) times demand for capacity (dem^{cm}).

For Design 3 the part presented in equation 18 is added to equation 16. The costs from the capacity market is divided in two parts, one for available flexible capacity and one for non-flexible available capacity. These are the price paid to flexible producers ($\gamma^{flex} + \gamma^{base}$) multiplied by demand for flexible capacity and the price paid to non-flexible producers (γ^{base}) multiplied by demand for other capacity (dem^{base}).

3.2.2.1 Short-term Operational Security of Supply: Load Shedding

The load shedding constraint shown in equation 19 gives a maximum limit of how much load shedding is allowed. The reliability standard of maximum load shedding share (RS^{LS}) of total demand sets an upper limit of the decision variable of load shedding (ls_h). This constraint is applied in all designs.

[D1], [D2], [D3]:
$$0 \leq RS^{LS} * \sum_{h=1}^{H} DEM_h - \sum_{h=1}^{H} ls_h \perp \alpha \geq 0 \tag{19}$$

The dual variable (α) only takes a value when the load shedding variable is equal to maximum allowed load shedding share of total demand. If load shed variable is higher than equation 19 allows, α will be adjusted until the condition is fulfilled. When α increases is the maximum electricity price (P^{MAX}) increased. This is further explained by equation 23.

3.2.2.2 Long-term Capacity Adequacy: Capacity Reserve Margin

The constraint presented in Equation 20 creates the value of variable dem^{cm}, which represents the demand for capacity. There is an opportunity to set a reserve margin (RS^{CAP}) above the max demand (DEM^{MAX}).The constraint is applied in Design 2.

Equation 21 is applied in Design 3, and represent the total demand for capacity. Demand for capacity is divided in demand for flexible capacity (dem^{flex}) and demand for capacity in general (dem^{base}). An additional constraint is included in Design 3, given in equation 22. This constraint represents the demand for flexible capacity.

The dual variable (β) included in both Design 2 and 3 represents the marginal cost of reserve margin. It takes a value when demand for capacity equals the wanted reserve margin.

[D2]: $$0 \leq dem^{cm} - RS^{CAP} * DEM^{MAX} \perp \beta \geq 0 \quad (20)$$

[D3]: $$0 \leq dem^{flex} + dem^{base} - RS^{CAP} * DEM^{MAX} \perp \beta \geq 0 \quad (21)$$

3.2.2.3 Flexible capacity adequacy

Equation 16 is special for Design 3. It ensures that the demand for flexible capacity (dem^{flex}) is grater or equal to a share of the total demand ($RS^{FLEX} * DEM^{MAX}$). The reliability standard of flexible capacity (RS^{FLEX}) is a parameter that can be varied.

[D3]: $$0 \leq dem^{flex} - RS^{FLEX} * DEM^{MAX} \perp \delta \geq 0 \quad (22)$$

The dual variable (δ) represents the marginal cost of a flexible capacity standard.

3.2.2.4 Optimal load shedding and demand for capacity

Optimal amount of load shedding from the demand side / SO is shown in equation 23. The equation is derived from the Lagrange function of demand sides' minimization problem, differentiating on variable of load shedding (ls_h). This constraint is applied in all designs. The equation ensures that if there is load shedding, the electricity price (λ_h) is at least at level of maximum electricity price (P^{MAX}). If there is more load shedding than equation 19 allows (i.e. $\alpha \geq 0$), α is added to the electricity price. This represents a case where the maximum electricity price is set too low to ensure short-term reliability.

[D1], [D2], [D3]: $$0 \leq P^{MAX} - \lambda_h + \alpha \perp \mathrm{ls}_h \geq 0 \quad (23)$$

Equation 24 is applied in Design 2, and represents optimal demand for capacity. It ensures that there is only a demand for capacity it the marginal cost of reserve margin (β) is smaller or equal to the capacity price (γ).

[D2]: $$0 \leq \gamma - \beta \perp dem^{cm} \geq 0 \tag{24}$$

[D3]: $$0 \leq \gamma^{base} - \beta \perp dem^{base} \geq 0 \tag{25}$$

Equation 25 represents optimal demand for non-flexible capacity in the capacity market for Design 3. There will only be a demand for non-flexible capacity when the capacity price paid to non-flexible producers (γ^{base}) is higher than the marginal cost of capacity reserve margin (β).

Equation 26 is applied in Design 3, and represents optimal demand for flexible capacity in the capacity market. It ensures that the there is only a demand for flexible capacity if the capacity price ($\gamma^{flex} + \gamma^{base}$) paid to flexible producers is higher or equal to the sum of marginal cost of reserve margin (β) and marginal cost of flexibility standard (δ).

[D3]: $$0 \leq \gamma^{flex} + \gamma^{base} - \beta - \delta \perp dem^{flex} \geq 0 \tag{26}$$

3.2.3 Energy-based Market:

Equation 27 is an equality constraint balancing the energy in the system. Total generated power, consisting of conventional generation ($gen_{p,h}$) plus injected variable RES (INJ_h^{solar} and INJ_h^{wind}), has to meet total demand. Injected solar and wind power will be treated as free-of-use energy sources, which means if RES power is available it will enter the market. Option of load shedding (ls_h) and production shedding (ps_h) is included in the model. Load shedding gives the SO the opportunity to cut off some of the load in times of scarcity of generated power. Production shedding is appropriate when the total variable RES production is larger than the demand. Equation 27 is applied in Design 1 and 2. While equation 28 is applied in Design 3. The only difference from equation 27 is that there are two generation variables in equation 28, one for flexible producers ($gen_{f,h}$) and one for non-flexible producers ($gen_{b,h}$).

[D1],[D2]: $$\forall h: \sum_{p=1}^{P} gen_{p,h} + INJ_h^{SOLAR} + INJ_h^{WIND} = DEM_h + ls_h - ps_h \tag{27}$$

[D3]:

$$\forall h: \sum_{f=1}^{F} gen_{f,h} + \sum_{b=1}^{B} gen_{b,h} + INJ_h^{SOLAR} + INJ_h^{WIND} = DEM_h + ls_h - ps_h \quad (28)$$

Production shedding constraint is given in equation 29. If injected RES ($INJ_h^{SOLAR} + INJ_h^{WIND}$) is larger than the demand, the production shedding variable gets a value which balance the equation. This constraint is applied in all designs.

[D1],[D2],[D3]:

$$\forall h: 0 \leq DEM_h + \ ps_h - INJ_h^{SOLAR} - INJ_h^{WIND} \perp \ ps_h \geq 0 \quad (29)$$

3.2.4 Capacity-based market:

Volume-based capacity constraint given in Equation 30 is applied in Design 2. Total capacity available to the capacity market, cap_p^{cm}, must be bigger than the demand for capacity. This equation can also be called capacity balance, it represents the capacity market in a similar way to how equation 27 represents the energy-based market. The capacity-based price, which is the dual variable (γ), is generated from this equation.

[D2]:

$$0 \leq \sum_{p=1}^{P} cap_p^{cm} - dem^{cm} \perp \gamma \geq 0 \quad (30)$$

Equation 31 and 32 represents the capacity market in Design 3. These are the two equations that creates a capacity market with two prices. The flexible capacity balance is given in equation 31. This sum must be binding if the flexible capacity price (γ^{flex}) should have a value. In other words if there is offered more flexible capacity in the capacity market than there is demand for the price for flexible capacity will be zero. If that is the case, Design 3 works exactly the same way as Design 2, as a traditional capacity market with a uniform capacity price to all producers.

[D3]:

$$0 \leq \sum_{f=1}^{F} cap_f^{cm} - dem^{flex} \perp \gamma^{flex} \geq 0 \quad (31)$$

Total capacity balance for Design 3 is given in equation 32. This equation must be binding to give the secondary capacity price a value. In other words, if there is offered more total capacity (flexible and non-flexible) in the capacity market than there is demand for, the secondary capacity price will be zero. If that is the case, non-flexible producers are paid no capacity-based remuneration, only flexible producers are paid remuneration, through the flexible capacity price (γ^{flex}).

[D3]:
$$0 \leq \sum_{f=1}^{F} cap_f^{cm} + \sum_{b=1}^{B} cap_b^{cm} - dem^{flex} - dem^{base} \perp \gamma^{base} \geq 0 \tag{32}$$

A final note on the two equations above (31 and 32), a crucial element which decides if these two equations are binding is the flexible capacity reliability (RS^{FLEX}). If it is set "too low", meaning it is set at a level of flexible capacity that would have been installed anyway (i.e. without a flexible capacity standard), equation 31 will be non-binding, while equation 32 will be binding. If it is set "too high" there will be installed so much flexible capacity that the demand for total capacity will be lower than total capacity available to the capacity market, hence equation 32 will be non-binding while equation 31 is binding.

3.3 Data description

This section will present the system and data the above described model will be tested on. The system will represent the power market in one country, where four generation technologies in addition to intermittent RES are considered, namely nuclear, coal, CCGT and OCGT power plants. The following sections will describe input data for demand side and SO, RES and costs for producers. Finally, the processing of the output data is presented.

Input data:

- Time series of demand for every hour in a year. [MW]
- Injected solar and wind power. [MW]
- Annually fixed cost for installation of capacity for producers. [€/MW]
- Hourly variable cost for generating power for producers. [€/MWh]
- Reliability standards. [%]
- Price cap of energy-based price [€/MWh]

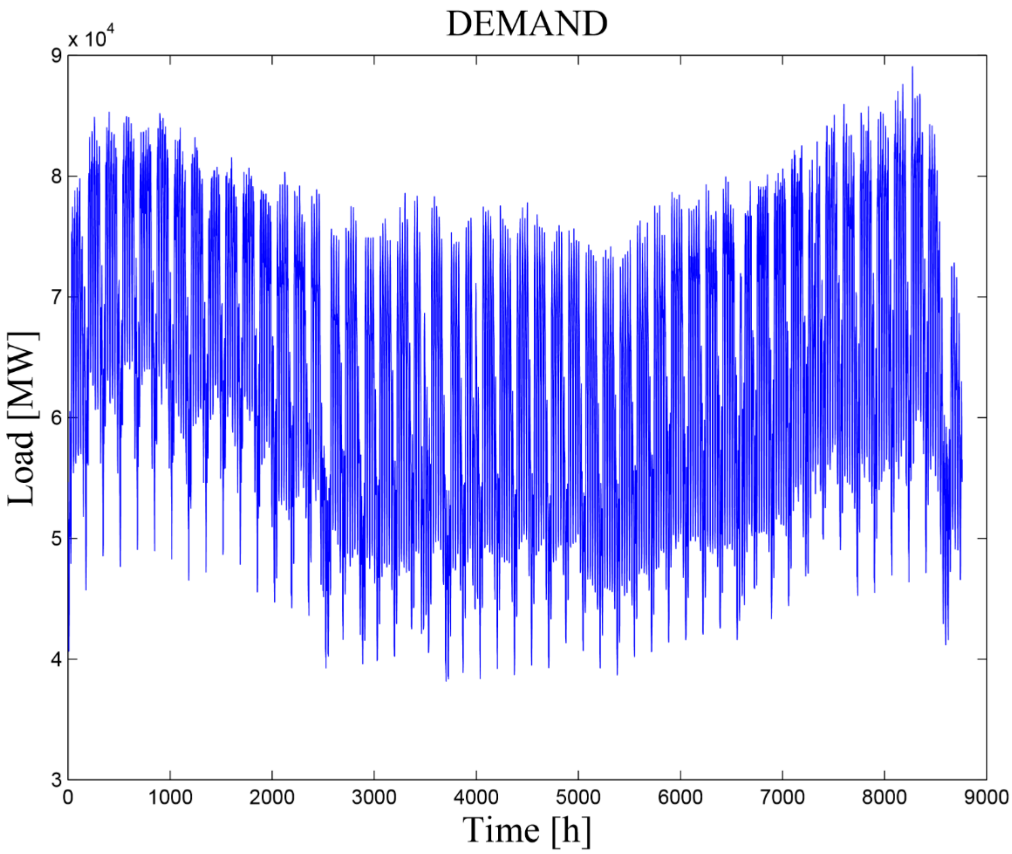

Figure 3.3: Demand for all hours of the year, with load given in MW

3.3.1 Demand-side and RES Data

Time series of demand and injected wind and solar power represents German power market in 2030. The times series are collected from reference [25] and [26]. The German power market is represented as one node. Only onshore wind power is considered. The time series contain data for every hour of the year 2030. The 2030-German power market has a large production of both solar power and wind power, which is why it is chosen as a test system in this thesis.

The demand minus the injected wind and solar power create residual demand. The demand and residual demand are shown in Figure 3.3 and Figure 3.4 respectively. From the figures it can be seen that the demand profile has more of a pattern, consisting of days and weeks, than the residual demand. The residual demand is what the power producers in the model need to meet with their generation to sustain the energy-balance in the system.

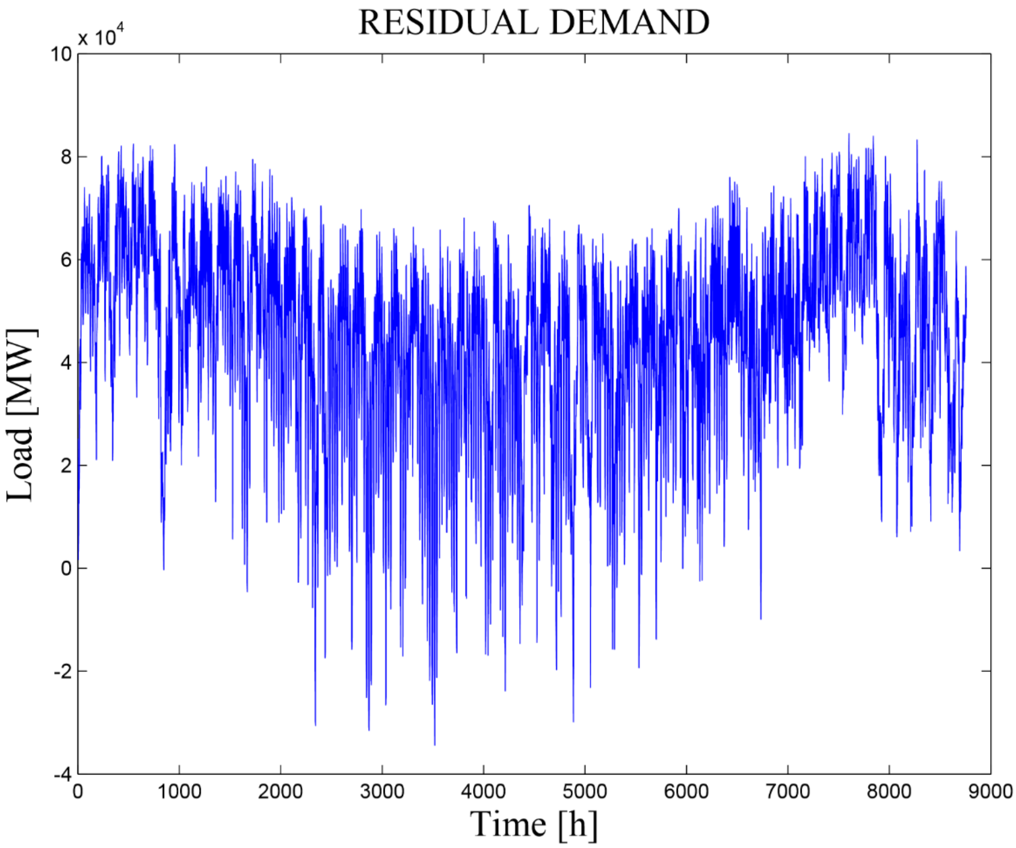

Figure 3.4: Residual demand for all hours of the year with load given in MW.

The demand side sets the price cap, referred to as P^{MAX} in the model. The price cap is set to 3000 €/MWh, which is a value of lost load (VoLL) taken from [27]. The model contains three reliability standards set by the demand side/SO, namely capacity reserve margin above max demand (RS^{CAP}), maximum load shedding share of total demand (RS^{LS}) and flexibility capacity share of maximum demand (RS^{FLEX}). These can be seen in Table 3.2.

Table 3.2: Values of Reliability Standards

Reliability Standard	Value [%]
$\mathbf{RS^{CAP}}$	110
$\mathbf{RS^{LS}}$	0.034
$\mathbf{RS^{FLEX}}$	50

Capacity reserve margin is, as in [23] set to 110 %, which means total installed capacity should be 10 % higher than peak demand. Maximum load shedding share in as [23] set to 0.034 %, which means that no more than 0.034 % of total demand can be shed. Flexible capacity share is a reliability standard developed during this thesis, and will only be included in Design 3. It is set to 50 %, which means that the amount of flexible capacity installed must be equal or greater than 50 % of peak demand. The value of flexible capacity share needs to be varied depending on which generation technologies are considered flexible. In the base case of this thesis OCGT and CCGT generation will be considered as flexible technologies.

3.3.2 Producer data

Paper [28] is used as reference for variable and fixed costs for the four types of thermal generators considered in this thesis.

Design 1: producers, p: Nuclear, Coal, CCGT and OCGT.

Design 2: producers, p: Nuclear, Coal, CCGT and OCGT.

Design 3: - Flexible Producers, f: CCGT and OCGT.

- Non-flexible Producers, b: Nuclear and Coal.

Each of the four generation technologies will be considered as one company, here called producers, which will maximize its own profit. The annual fixed cost and hourly variable costs can be seen in Table 3.3. The fixed cost are calculated to represent one year of simulation.

Table 3.3: Costs for different generation technologies [28]

	Fixed Costs [€/MW]	Variable Costs [€/MWh]
Nuclear	280 000	3
Coal	72 000	35
CCGT	41 000	48
OCGT	16 000	150

3.3.3 Data handling

Figure 3.4 show how data have been handled in this study. The input data, given above, are read from Microsoft Excel into the model described in section 3.2, which is written in GAMS.

The GAMS program gives the output data, given below, back into a excel file. The output data are either plotted directly in Excel or imported to MATLAB if editing of the output data is needed create plots.

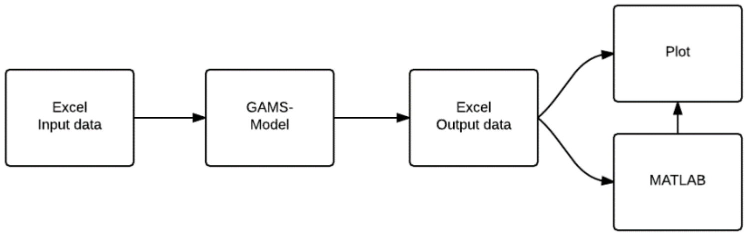

Figure 3.5: Data handling.

Output data of the GAMS model:

- Generated power of each producer in every hour of the year [MWh]
- Capacity Installed of each producer [MW]
- Load shedding [MWh]
- Production shedding [MWh]
- Capacity made available to the capacity market by each producer [MW]
- Energy-based price [€/MWh]
- Capacity-based prices [€/MW]
- The other dual variables presented in nomenclature

Results calculated from the output data in MATLAB:

- Revenues for each producer from Energy-based market [€]
- Revenues for each producer from Energy-based market [€]
- Total revenue for each producer [€]

4 Results & Discussion

In this section the results of the simulation of the model given in section 3.2, tested on the data given in section 3.3, will be presented as the base case of this thesis. The results of the three different designs, shown below, will be compared with the focus on investigating how the different market designs influence the different generation technologies. Topics that will be presented and discussed are, energy-based and capacity prices, installed capacity, load shedding and revenues of producers. Section 4.5 presents sensitivity analyses of four number of cases.

- Design 1 [D1]: Energy-only market
- Design 2 [D2]: Volume-based capacity market
- Design 3 [D3]: Volume-based capacity market with two prices

4.1 Prices

Prices from the energy-based market and the capacity market in the three designs will be presented in this section.

4.1.1 Energy-based prices

Below is the price duration curves of the three designs presented in Figure 4.1. The graphs show for how many hours a year the energy-based prices are at certain levels. All three graphs are quite similar with some exceptions. The energy-based prices are equal to producers' variable costs of generation throughout the year. Except for 5 hours in Design 1, where maximum price is reached as load shedding occur. This can be seen with the green line in Figure 4.1, where the price rise to 3000 €/MWh. For the rest of the year is the price duration curve for Design 1 and 2 the same. In Design 2 and 3 the highest value of the energy-based price is 150 €/MWh, which is equal to the production cost of OCGT. This shows that the remuneration from the capacity market in these designs make the need of energy-based price spikes redundant.

The price duration curve for Design 3 shows a longer period of the year with price of 48 €/MWh than Design 2 and Design 1, which is showed by the blue line in Figure 4.1. The reason for this is that CCGT generators operate more instead of coal generators in Design 3 compared to Design 2. The reason for this will be explained through long term marginal costs (LTMC) functions for the different generation technologies in section 4.2.

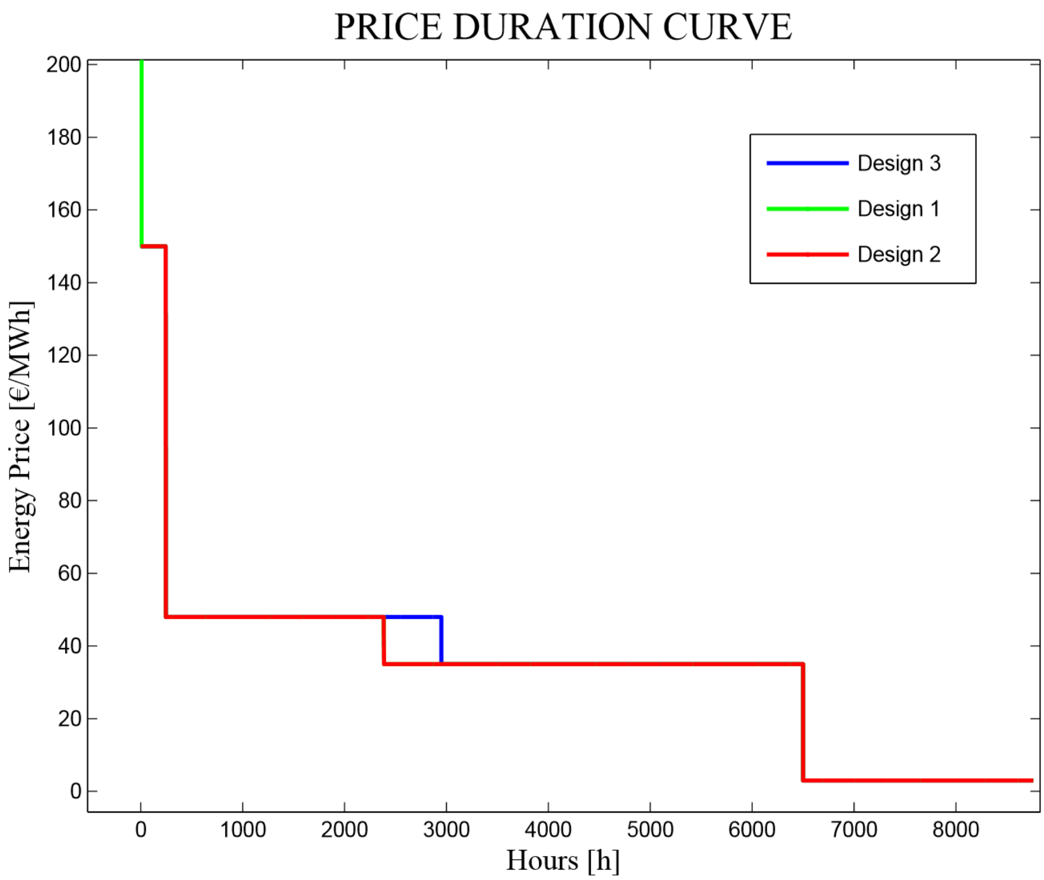

Figure 4.1: Price Duration Curve for Design 1 (green), Design 2 (red) and Design 3 (blue). Green and blue curve hides behind red curve, where they are not shown.

As can be seen in Table 4.1, there is a higher average energy-based price in Design 1 than Design 2 and 3. This is because of the price-spikes in times of load shedding as was discussed above. Reason why the average price in Design 3 is higher than Design 2 is the increased amount of hours of CCGT in generation, as seen in Figure 4.1.

Table 4.1: Average Energy-based prices:

Design 1	34.9634 €/MWh
Design 2	33.1369 €/MWh
Design 3	33.9745 €/MWh

4.1.2 Capacity-based prices

The capacity price is the remuneration each producer is paid for every MW capacity they make available to the capacity market. In Design 2 is the capacity price equal to the cost of installing one more MW of the technology with the lowest fixed costs. This is 16000 €/MW, which is the fixed costs of OCGT. As can be seen in Figure 4.2 this price is paid to all types of generation technologies.

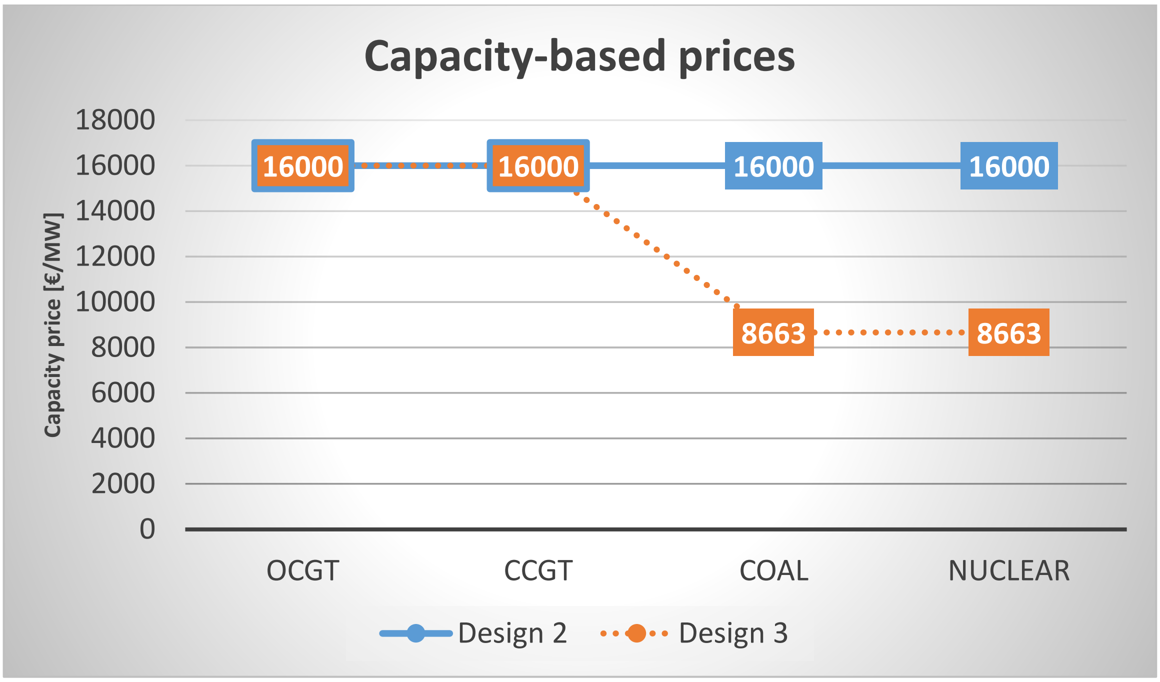

Figure 4.2: Capacity-based prices for the four generation technologies in Design 2 and 3.

The results of Design 3 show two prices in the capacity market, as can be seen in Figure 4.2. The capacity price paid to flexible producers for each MW capacity they make available to the capacity market is the sum of the two dual variables from Equation 31 and 32 (γ_{flex} and γ_{base}), expressed in section 3.2.4. This sum is equal to the cost of installing one more MW of the technology with the lowest fixed costs. The capacity price paid to non-flexible producers is the dual variable created by Equation 32, referred to as the secondary capacity price (γ_{base}).

With flexible reliability margin (RS^{FLEX}) set to 0.5 the flexible capacity price (γ_{flex}) becomes 7337 €/MW. The secondary capacity price (γ_{base}) is 8663 €/MW. This means the price paid to flexible producers is 16000 €/MW, which is the sum of γ^{flex} and γ^{base}. Compared to Design 2 the price paid to flexible producers (OCGT and CCGT) is the same, while the price paid to non-flexible producers (Nuclear and Coal) is lowered from 16000 €/MW to 8663 €/MW, as can be seen in Figure 4.2. This is a reduction by 45.9%.

4.2 Installed capacity and load shedding

Figure 4.3 shows the total amount of installed capacity in the three designs. The stacked piles indicate how much capacity are installed of each type of generation technology.

Total installed capacity is the same for Design 2 and 3 (97966 MW) while it is somewhat smaller for Design 1 (82475 MW). Design 2 and 3, contrary to Design 1, fulfill the wanted reliability standard of 10% reserve margin above maximum demand (red line in Figure 4.3). The energy-only market does not even install enough firm capacity to cover peak demand (showed with black line in Figure 4.3). The reason for this can be a combination between the injected RES not being considered as firm capacity and that the market does not produce high enough prices for producers to install adequate capacity (as was presented in section 2.3.1).

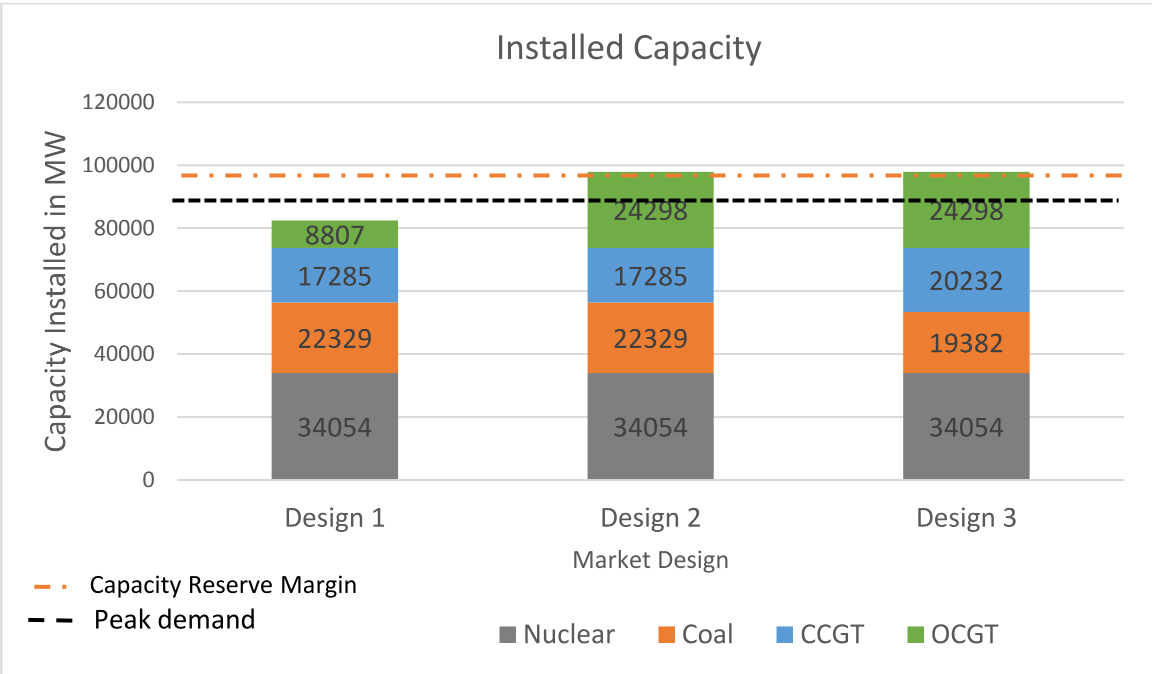

Figure 4.3: Installed capacity of the four types of producers for Design 1, Design 2 and Design 3.

In Design 2 and 3 the gap to the capacity reserve margin is filled with capacity from OCGT. Therefore Design 2 and 3 fulfill the requirement of capacity markets to give incentive to invest to reach adequate capacity. As a result of sufficient capacity being installed in Design 2 and 3, there is no load shedding.

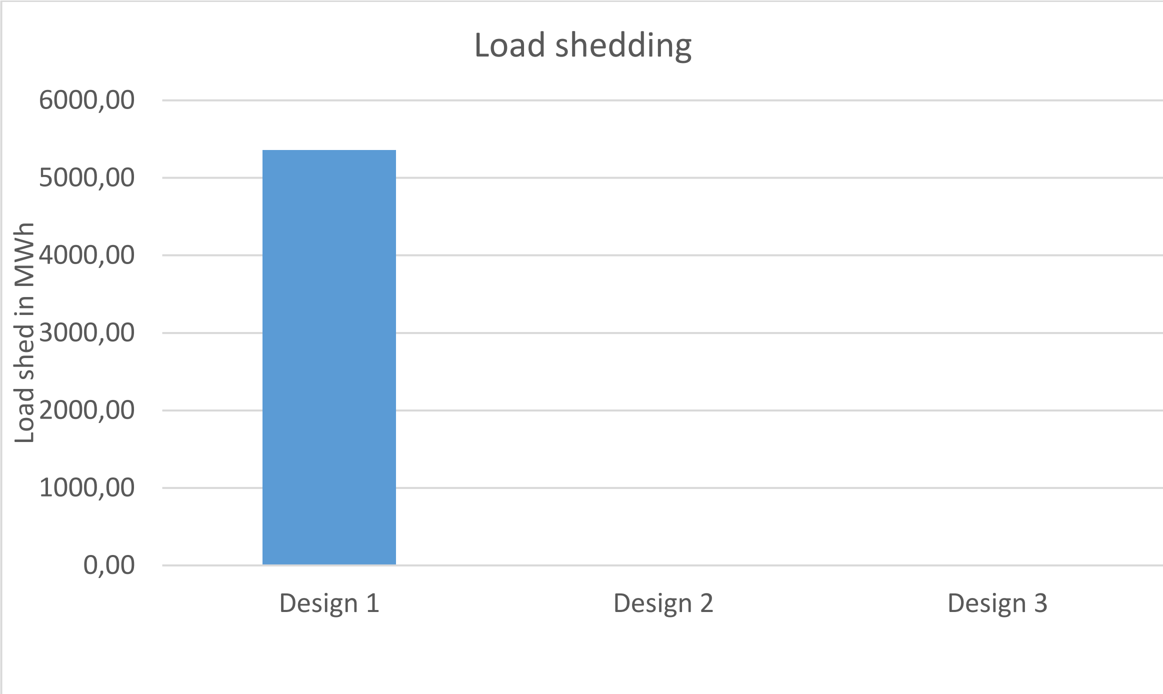

Figure 4.4: Load shedding

In Design 1 on the other hand, there are 5355.31 MWh of load shed during the simulated year, as can be seen in Figure 4.4. This equals 0.00096 % load shed of total demand, which is well below the reliability standard of maximum load shedding of 0.0034 %. Further discussion why no load is shed in Design 2 and 3 can be found in case 2 and 3 in section 4.5, and in section 4.6.

The difference in Figure 4.3 between Design 2 and 3 is installed amount of capacity of Coal and CCGT. Design 3 has more CCGT capacity and equally less coal capacity installed compared to Design 2. To explain this difference it is necessary to take a look at the LTMC of the generation technologies.

Below are the LTMC functions of installing 1 MW of capacity for the four different types of generation technologies, presented in Figure 4.5. The functions show the relationships of fixed and variable costs of the four generation technologies. The Figure show three important intersections:

- **Intersection 1:** It can be seen that for 245 hours the blue line, representing the LTMC of OCGT, is lower than the green line, representing CCGT. That means for loads exceeding 245 hours CCGT will be a more cost-efficient alternative than OCGT.
- **Intersection 2:** The same can be seen in the intersection between the green line (CCGT) and the red line, representing the LTMC of coal generation. For loads exceeding 2384 hours there will be cost-efficient install and run coal generation instead of CCGT.

- **Intersection 3:** The intersection between the red (coal) and the black line, representing total costs of nuclear generation, gives that there will be costs-efficient to install and run nuclear generation instead of coal when the load exceeds 6500 hours. It can be noted, that if the base load do not exceed 6500 hours, then no nuclear capacity will be installed. This can happen if injected RES is increased, so that the residual demand becomes zero (or less) for a large amount of hours.

The LTMC are highly connected with the price duration curves, presented in Figure 4.1. The given hour at each intersection discussed above, is the same hour the price duration curves drop. E.g. after 245 hours the price duration curve drops from 150 €/MWh to 48 €/MWh, that is when the LTMC functions of OCGT and CCGT intersect.

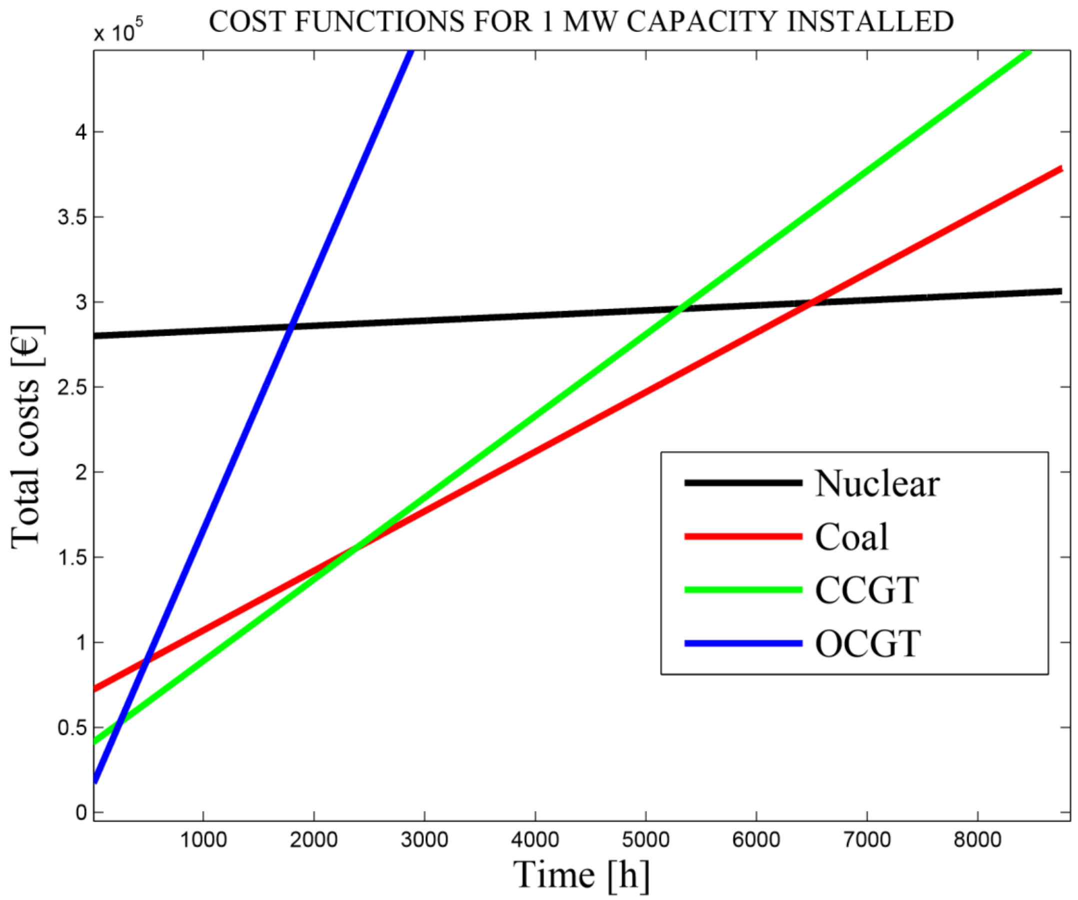

Figure 4.5: LTMC functions for the four generation technologies.

To explain why CCGT are more in production in Design 3 than Design 2 the producers' capacity remuneration has been subtracted from the LTMC functions. This is justified by the fact that all producers make all their installed capacity available to the capacity market. In

Design 2 all generation technologies are paid the same remuneration per MW capacity installed, hence subtracting the remuneration from the capacity market will not affect the intersection between the LTMC functions.

In Design 3 on the other hand, there is a difference between the remuneration paid to flexible and non-flexible producers, which can be seen in Figure 4.2. Subtracting the capacity remuneration from the LTMC functions the intersection point between the functions of CCGT and coal move up and to the right, as can be seen in Figure 4.6. This figure is a zoom of Figure 4.5, but also showing the LTMC functions subtracted the capacity remuneration per MW installed capacity, with the dotted lines. The intersection of the dotted lines shows that for loads up to 2949 hours that there will be more efficient to install and run CCGT than Coal, compared with the original intersection, valid for Design 2, at 2384 hours. This is the reason why more CCGT (and less coal) is installed and operated in Design 3 compared with Design 2.

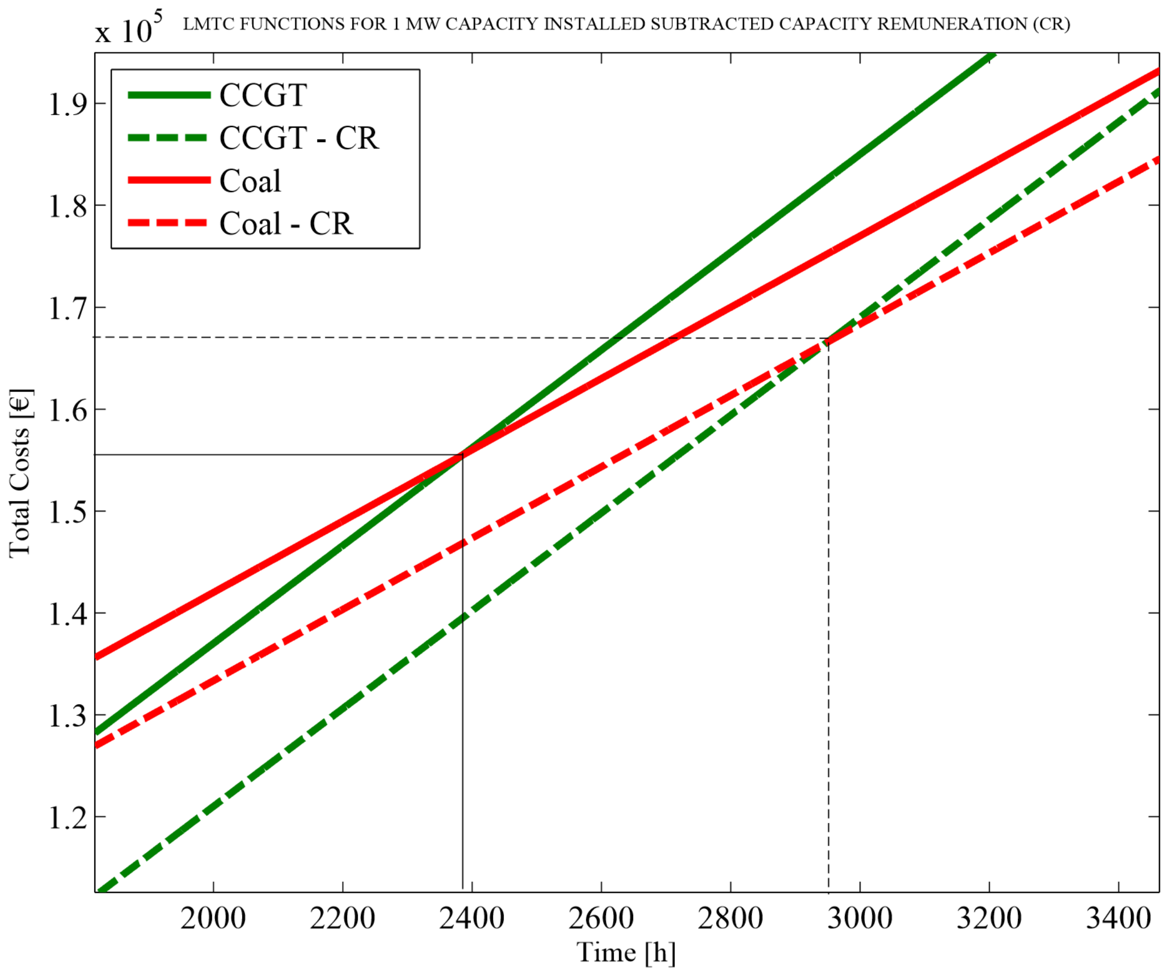

Figure 4.6: Design 3: Intersection of LTMC functions of CCGT and Coal subtracted capacity remuneration.

4.3 Revenues

In this section the revenues for producers are presented for the different designs. The purpose is to compare the market designs to each other, and how the market designs effect the revenue for each generation technology, total revenues, and the origin of the revenues; from the energy-based market or the capacity market.

4.3.1 Total Revenues

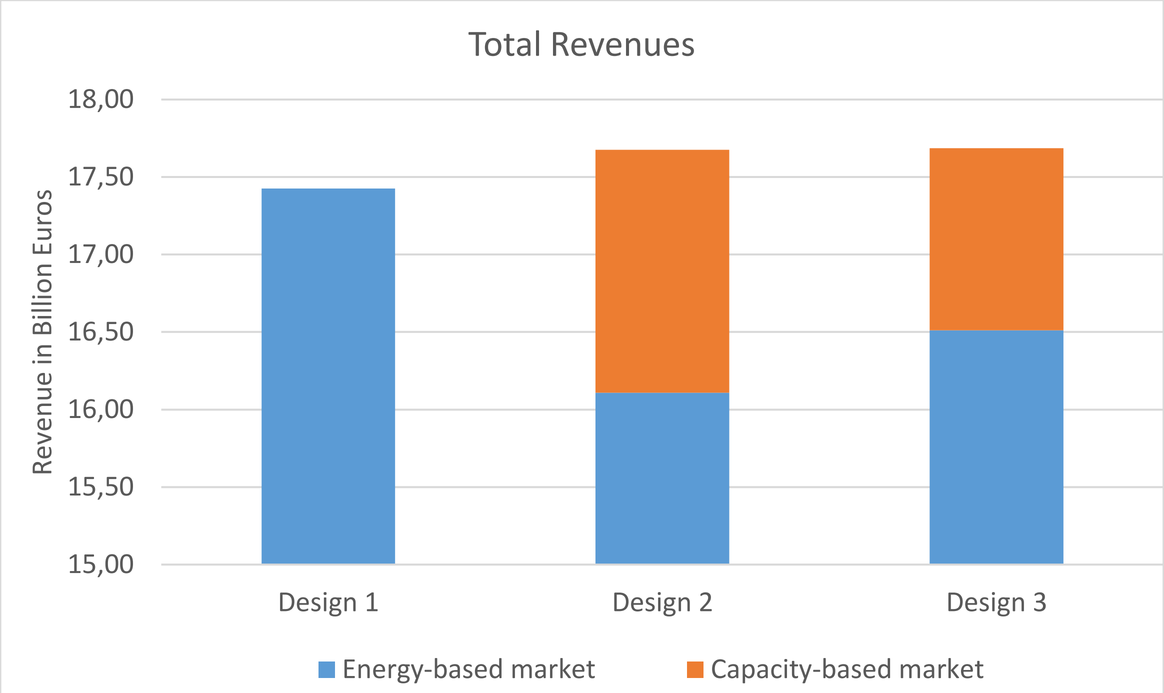

Figure 4.7: Total revenues for all producers combined for Design 1, Design 2 and Design 3.

Figure 4.7 shows total revenue for all producers combined for the three different market designs. It can be seen that there are not large differences in the total revenue between the three designs. Total revenue for Design 2 and 3 are equal, an increase by 1.42 % compared with Design 1. This backs up what found in [23], that capacity markets are not a source of large increase in producer revenue, but rather a shift in revenue, from energy-based to capacity-based revenues.

The stacked piles indicate the origin of the total revenue. The revenue from the energy-only market in Design 1 is 8.19 % and 5.57 % higher than Design 2 and Design 3 respectively. While there are no capacity market revenue for producers in Design 1, producers in Design 2 and Design 3 respectively get 8.87 % and 6.65 % of their total revenue from the capacity market.

The reason for less revenue originating from the capacity market in Design 3 compared with Design 2 is the lower capacity-based price paid to nuclear and goal generation, as shown in Figure 4.2. The reason for the increase in revenue from the energy-based market in Design 3 compared with Design 2 is higher energy-based prices, because of more generation of CCGT.

Despite that the revenues vary between the designs, the profit of each producer is zero. This is because the model assumes perfect competition. All revenues of producers are used on either installation or production costs.

4.3.2 Energy-based revenues

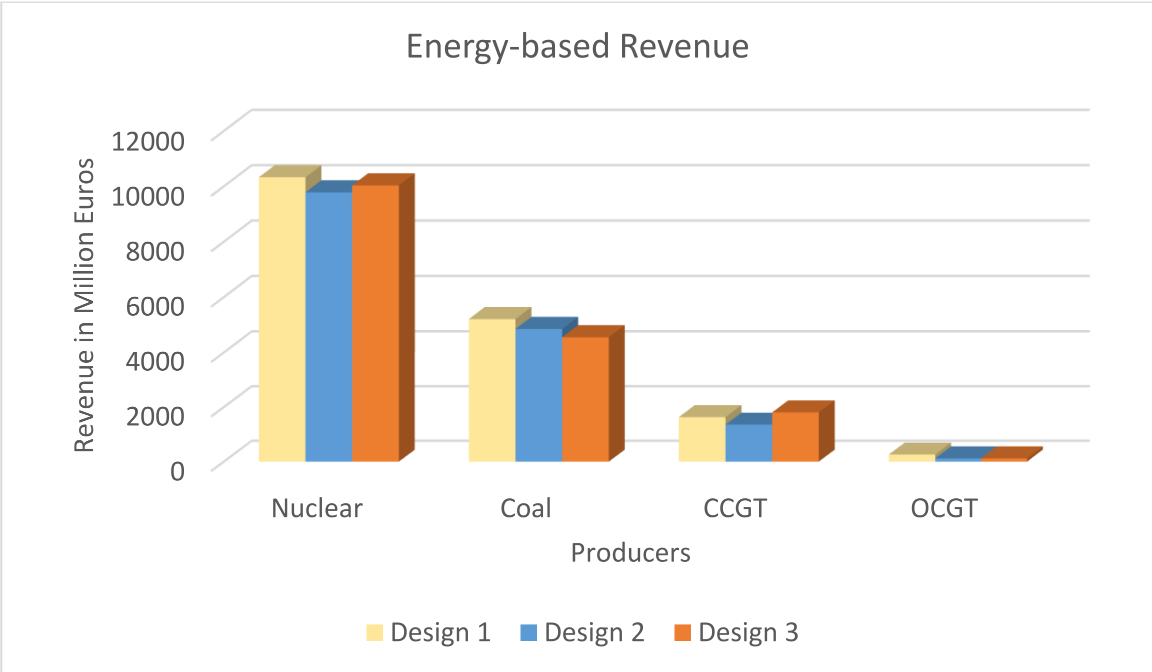

Figure 4.8: Energy-based revenue for each of the four generation technologies for the three market designs.

In Figure 4.8 the energy-based revenue for each of the four generation technologies are shown. For all three market designs the load factor is decisive for the size of the energy-based revenue. Nuclear is the generation technology with most generating hours in the year. After that comes Coal and then CCGT. OCGT are only used in peak load hours. Therefore nuclear has clearly the largest revenue from the energy-based market for all designs, followed by coal, CCGT and OCGT in declining order.

For all producers, except CCGT, the energy-based revenues are highest in Design 1. The reason for this is that Design 1 has the highest average energy-based price, caused by the price spikes in times of scarcity, which do not occur in the two other designs. This results in that all producers have higher energy-based revenue in Design1 compared with Design 2.

For all producers, except coal, the energy-based revenues are lowest for Design 2. This is because the average energy-based prices are the lowest in Design 2. The reason why revenues are lower for coal producers in Design 3 than in Design 2 are less installed coal capacity. Similarly is the revenue of CCGT in Design 3 higher than both Design 1 and 2 because of more installed CCGT capacity and more CCGT operating hours. Energy-based revenues for OCGT are similar for Design 2 and 3, because in the hours OCGT are operating are the energy-based prices the same for these two designs, as can be seen in the price duration curve (Figure 4.1).

4.3.3 Capacity-based revenues

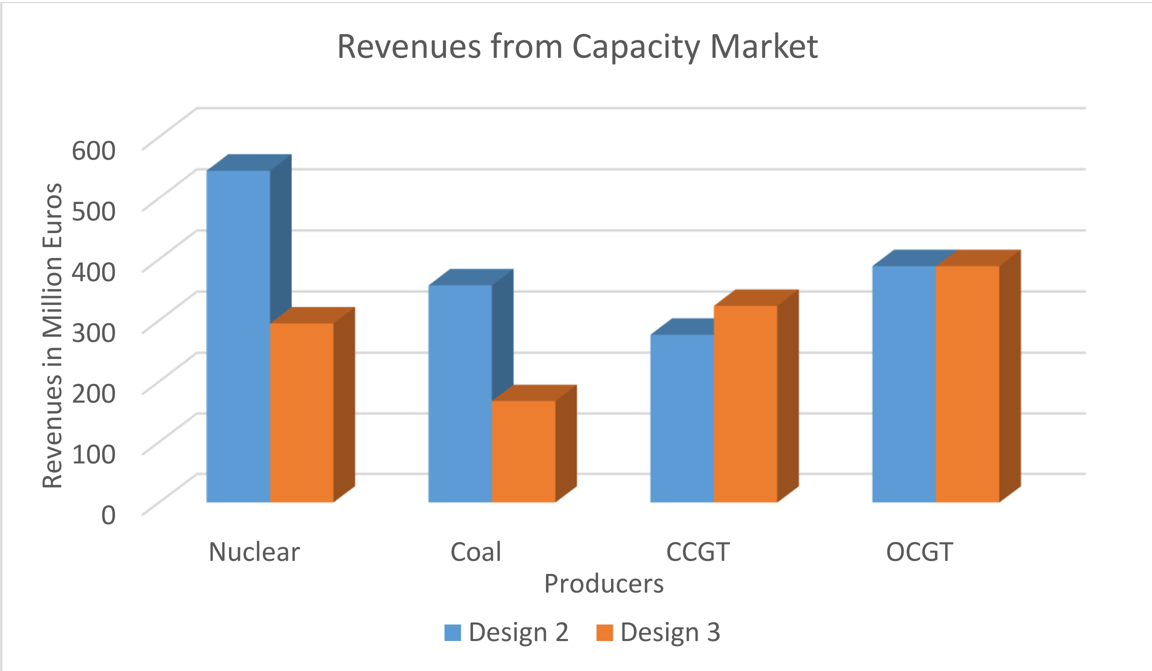

Figure 4.9: Capacity-based revenue for each of the four generation technologies for the three market designs.

Figure 4.9 shows the revenues from the capacity-based market for the producers in Design 2 and 3. There is no capacity-based market in Design 1, hence no capacity-based revenues. For both designs all producers make all their capacity available to the capacity market, therefore the revenues from the capacity market are strongly connected with installed capacity.

Comparing Design 2 and 3 it can be seen that there is a large reduction in capacity-based revenue for nuclear and coal generating producers in Design 3. Revenues for nuclear producers are reduced with 45.86 %. Installed nuclear capacity is the same in Design 2 and 3 so the reason for the decline is the reduced capacity-based price, shown in Figure 4.2. Revenues for coal producers are reduced with 53.00 %. This decline is caused by both the reduced capacity-based price and reduction in installed coal capacity.

Capacity-based revenue for CCGT producers increases by 17.03 % in Design 3 compared with Design 2. As Figure 4.2 show are both CCGT and OCGT paid the same capacity price in Design 2 and 3, so the increase in capacity-based revenue for CCGT is caused by increased installed CCGT capacity. Revenue for OCGT producers is the same in Design 2 and 3, because of the same capacity-based price and installed capacity.

Capacity-based revenues are among the most interesting topics in this thesis, as it reveals the different market designs' remuneration of capacity. Even though the capacity-based price is not higher for flexible producers in Design 3 than Design 2, is it clear that Design 3 gives a market advantage for flexible producers, which is the intension of the MPCM presented in section 2.3.4. That the non-flexible producers are paid less remuneration for their capacity, will be a market incentive to rather invest in flexible capacity. As a result, this study of Design 3 shows an increase in CCGT-capacity (which here is defined as a flexible producer) and decrease in coal-capacity (which here is defined as a non-flexible capacity). This can be a sign of that Design 3 might actually be an efficient market design to promote flexible capacity in power systems in a market based way.

4.4 Comparing results with the working paper [23] and project work [24]

Since Design 1 and 2 are reproduced from the working paper [23] it is natural to compare the results. Also the project work [24] of a fellow student uses these designs. In this thesis it is used other in-data than in the working paper and the project work, therefore the results differ. But there are several trends that can be seen in the results presented above, and in the working paper and the project work. Some of these worth mentioning are:

- Small increase in total revenue comparing Design 1 with Design 2

Both the working paper and the project work found that there were hardly any increase in total revenue for producers comparing Design 2 with Design 1. This is similar to the results in this thesis, presented in section 4.3.1, which showed that the total revenue in Design 2 was 1.42 % higher than Design1.

- A shift in revenue from energy-based to capacity revenue in Design 2.

In the Design 2, the working paper found that 10.5 % of the total revenue originated from the capacity market, while the rest came from the energy-based market. A similar trend was found in the project work. The result in this thesis, presented in in section 4.3.1, found that 8.87 % of the total revenue originated from the capacity market.

- Capacity reserve margin is met in Design 2, but not in Design 1.

Both in the working paper and the project work, Design 2 reaches the reserve margin of 10 % above max demand. Design 1 do not even install enough capacity to meet maximum demand. This is similar to the results in this paper, presented in section 4.2.

4.5 Sensitivity analyses

This section presents sensitivity analyses of four cases. Some left-hand-side parameters are varied, which will work either as a relaxation or a restriction of the model. The sensitivity analyses can show how the models function, tested on other data than the base case.

4.5.1 Case 1: Flexible capacity reliability standard

This case applies for Design 3. As mentioned in section 3.2.4 the value of the reliability standard of flexible capacity (RS^{FLEX}) is important for how Design 3 works, this is because RS^{FLEX} are important to determine the demand for flexible capacity. If RS^{FLEX} is set "too low" more flexible capacity will be installed than there is demand for, and there will be given no extra remuneration to flexible producers (since equation 31 is not binding), hence Design 3 will act the same way as Design 2. If RS^{FLEX} is set "too high" only flexible producers are remunerated, as the total installed capacity exceeds the total demand for capacity. This can be seen by varying the reliability standard of flexible capacity. In the base case RS^{FLEX} was 50 %.

Case 1a: RS^{FLEX} is set to 30 %, i.e. installed flexible capacity must at least be 30 % of maximum demand. The capacity price becomes 16000 €/MW for all producers. This leads to all results, including installed capacity and revenues, being the same as for the base case of Design 2.

Case 1b: RS^{FLEX} is set to 60 %, i.e. installed flexible capacity should at least be 60 % of maximum demand. The capacity price paid to flexible producers becomes 16000 €/MW. The price paid to non-flexible producers becomes zero, since the total capacity available to the capacity market is larger than the total demand for capacity, and hence equation 32 will not be binding. In this scenario will installed capacity be as can be seen in Table 4.2:

Table 4.2: Design 3: Installed capacity for remuneration only to flexible producers in MW:

Nuclear	Coal	CCGT	OCGT
34053.6	16088.02	23526.07	29909.93

Due to the restriction from the flexible capacity reliability standard of flexible installed capacity being 60 % of total demand, the installed flexible capacity must be raised by 8906.0 MW compared with the base case. This is covered by both a rise in CCGT and OCGT, while there is a decrease in installed capacity of Coal of 3294.4 MW. The revenues for the flexible producers increase since more capacity is installed. The revenues of the non-flexible producers decrease since the revenue from the capacity market is completely gone. The coal plant also experience decrease in revenue due to decrease in operational hours.

Case 1a and 1b show the importance of setting the correct value of RS^{FLEX} to create a two priced capacity market. Still, if RS^{FLEX} is set “too low” or “too high” this case show that Design 3 works, either as a traditional capacity market or as a “flexible-only capacity market”.

4.5.2 Case 2: Maximum price

This case applies for all three designs. Decreasing the maximum price (i.e. the VoLL) parameter can possibly increase load shedding. A lower maximum price is a relaxation of the model. Setting the maximum price at 1000 €/MWh results in an increase in load shed in Design 1 from 5355.31 MWh to 23789.87, but still beneath of the maximum level of load shedding. The increase in load shedding result in a small change in installed peak load capacity. As can be seen in Table 4.3 installed capacity of all generation technologies is the same except a reduction of OCGT capacity by 17.3 %. This case shows that as the load shedding increases the need for peak load generation decreases.

Table 4.3: Design 1: Installed capacity. P^{Max} is reduced from 3000 €/MWh to 1000 €/MWh:

P^{Max} [€/MWh]	Nuclear [MW]	Coal [MW]	CCGT [MW]	OCGT [MW]
3000	34053.60	22329.14	17284.95	8807.68
1000	34053.60	22329.14	17284.95	7282.12

In Design 2 and 3, the reduction of the maximum price does not result in load shedding. Hence this case for Design 2 and 3 have equal results as for the base case. This case show that there is installed sufficient capacity in Design 2 and 3 prevent load shedding even with such a significant reduction in VoLL.

4.5.3 Case 3: Reliability standard: capacity reserve margin

This case applies for Design 2 and 3. The reliability standard of reserve margin is set to 100 %, which means that there will be no reserve margin above maximum demand. The results for the installed capacity of both designs are shown in Table 4.4.

Table 4.4: Installed capacity in case without reserve margin.

	Nuclear [MW]	Coal [MW]	CCGT [MW]	OCGT [MW]	Total [MW]
Design 2	34053.6	22329.14	17284.95	15392.31	89060.0
Design 3	34053.6	16088.02	23526.07	21003.93	89060.0

Table 4.4 shows that the installed capacity decreases in both Design 2 and 3. In both designs are the reduction in capacity caused by less OCGT being installed. Total installed capacity in this case equals total demand. Still, it is no load shedding in either of the designs. This shows that the capacity reserve margin in the base case resulted in an overinvestment in capacity for Design 2 and 3.

The reason for this can be explained by that injected RES is treated as non-firm capacity. The capacity reserve margin constraint only considers firm capacity, which means there must be installed conventional capacity equal maximum demand plus the reserve margin. I.e. the constraint do not take residual demand in to account. The problem with overinvestments in capacity caused by the reserve margin constraint can be solved by treating the RES as partly firm capacity. A parameter of firmness level of the injected RES can be included in the model, e.g. this could for example be a low percentage of the maximum RES injected in the model. Inclusion of injected RES as partly firm capacity will be further discussed in section 4.6.

4.5.4 Case 4: Coal included as flexible producer

This case applies to Design 3. The thesis does not intend to draw the line of what is a flexible producer. Coal power plants have some flexible capabilities as they can ramp production, at least more than nuclear power plants [29]. Including coal power plants as flexible producers in the model together with CCGT and OCGT, gives the installed capacities shown in table below:

Table 4.5: Design 3: Installed capacity with coal included as a flexible producer. In MW:

Nuclear	Coal	CCGT	OCGT
31171.0	25211.74	17284.95	24298.31

For the first time of all cases presented there can be seen a drop in installed capacity of nuclear power plants. The reason for this is the capacity prices paid to Coal, CCGT and OCGT compared to Nuclear, shown in table below:

Table 4.6: Design 3: Capacity prices to different generation technologies. In €/MW:

Nuclear	Coal, CCGT, OCGT
6080	16000

The reduction in nuclear capacity is cover by coal capacity. Because of the higher remuneration to the coal power plants compared to nuclear, there is a shift in intersection 3, discussed in section 4.2. The shift results in that coal are more economical to run for a longer period of the year compared to nuclear power. This is similar to the shift that can be seen between Coal and CCGT in Figure 4.6.

This case shows that the two-priced capacity market model developed in this thesis can be applied on other definition of what is flexible producers. It will be up to the applier of the model to decide which generation technologies that should be promoted.

4.6 Potential of the two-priced capacity market model

The results that have been presented, show that Design 3 can be used to promote flexible resources. This can be said on the basis of the model is successful in paying flexible producers higher capacity price than non-flexible sources, resulting in that more flexible capacity being installed in Design 3 compared to Design 1 and 2.

However, these results do not show the benefits of more flexible capacity being installed. Since flexible generators have better load following capabilities than non-flexible generators, a likely benefit would have been that Design 3 resulted in less load shedding than Design 2. In these results do not load shedding occur in either of Design 2 or 3. For this to happen two areas in the model need further development.

- Firstly, injected RES should be treated as partly firm capacity, instead of non-firm capacity. The constraint of capacity reserve margin only includes firm capacity. Therefore the capacity reserve margin constraint results in an overinvestment in capacity in Design 2 and 3, hence no load shedding.
- Secondly, ramping rates of generators should be included in the model. Without ramping rates flexible generators have the same operational constraints as non-flexible generators. I.e. Design 3 will have no advantage over the other designs in terms of load shedding, as long as the total capacity installed is equal.

In a power system with very high penetration of intermittent RES, it is necessary to have some level of flexibility amongst the conventional generators to meet residual demand. If the two points above can be included in the models of Design 2 and 3 and tested on a system with extreme values of intermittent RES there is likely that Design 3 will result in less load shedding than Design 2. This is of course if Design 3, as in these results, install a higher amount of flexible capacity than Design 2.

In that way, the further development of the model of the two-priced capacity market can give results showing benefits of a capacity market design promoting flexible generation technologies. This can provide information to the research field and policymakers to help constructing power market design fit to a future with high penetration of intermittent RES.

4.7 Summary

The results for the three market designs have been presented for a base case. In addition, sensitivity analyses of four cases are presented. Key points of the results are:

- It has successfully been created a capacity market that can treat flexible producers differently from non-flexible producers in a market-based way. Simulation of design 3 results in two capacity prices, one for flexible capacity and one for non-flexible capacity.
- Capacity reserve margin is reached in Design 2 and 3, which leads to that there is no load shedding. In Design 1 on the other hand, not even maximum demand is matched by installed capacity, hence load shedding occur 5 hours of the year.
- Despite that total installed capacity is equal in Design 2 and 3, there is more flexible capacity installed in Design 3 than Design 2. Reason for this can shortly be explained by that the capacity price paid to CCGT is higher than the secondary capacity price paid to coal producers. More generation of CCGT instead of generation of coal leads to slightly higher average energy-based price in Design 3 than Design 2.
- Total revenues for producers increased with 1.42 % in Design 2 and 3 compared with Design 1. Instead of a large increase in revenue there can rather be seen a shift in revenue from the energy-based market to the capacity market. The revenue from the capacity market makes the revenue from price spikes in the energy-based market redundant. Therefore, lower average energy-based price in Design 2 and 3 compared with Design 1.
- Capacity-based revenue is reduced with 45.86 % and 53.00 % for nuclear and coal producers respectively in Design 3 compared with Design 2. For CCGT, capacity-based revenue increases by 17.03 % while it is the same for OCGT, comparing the two designs. This shows that the two-priced capacity market can decrease the capacity-based revenue for non-flexible producers while maintaining the revenue for flexible producers compared with a single-priced capacity market.
- Sensitivity analyses show that the model works on other cases of data. Case 1 shows the importance of setting correct value for the flexible capacity reliability standard to create

a two-priced capacity market in Design 3. Case 2 shows that no load shedding occur in Design 2 and 3 even though the maximum price of electricity is heavily reduced, this do however cause more load shedding in Design 1. Case 3 discuss that treating RES as non-firm capacity in the reserve margin constraint might lead to an overinvestment in capacity both for Design 2 and Design 3. Case 4 shows that the model of Design 3 can be used to promote other types of generation than only CCGT and OCGT. It is up to the user to define which generations to be promoted.

- Even though the results of Design 3 show that it is installed more flexible capacity, the benefits of more flexible capacity are not shown through the results. If ramping rates of generators and injected RES as partly firm capacity are included in the model, it would have been possible to see a difference in load shedding comparing Design 3 with Design 2, if the models would be tested on cases with extreme enough amounts of intermittent RES.

5 Conclusion

In this thesis there has been developed an equilibrium market model of a power market including a two-priced capacity market, designed to promote flexible power generating capacity. Two other designs of the power market have been modeled, an energy-only market and a traditional single-priced capacity market. The three models have been referred to as Design 1, 2 and 3 in this thesis:

- Design 1 [D1]: Energy-only market
- Design 2 [D2]: Volume-based capacity market
- Design 3 [D3]: Volume-based capacity market with two prices

Design 3 has been based on a suggestion of a multi-priced capacity market (MPCM) presented as a part of a literature study in Part 2 of this thesis. A two-priced capacity market is a simplification of this suggestion, but the idea of giving flexible generation technologies an advantage in the power market over less flexible technologies is preserved.

Flexibility has in this thesis been used as a term describing high ramping rates and short start-up and shut-down time for generators. Four generation technologies have been included in the models. In Design 3 generators have been defined as either flexible or non-flexible. The base case of the model defines generators as follows:

- Flexible Producers: CCGT and OCGT
- Non-flexible Producers: Nuclear and Coal

Perfect competition amongst the producers has been assumed in the models. The transmission system is not considered. The models of the three designs have been tested on data of the German power market in 2030, with high levels of intermittent RES. The results of the simulations were presented in Part 4. Installed capacity, load shedding, energy-based and capacity based prices and revenues of generation technologies of the three designs, have been compared.

From the results, it can be said that it has successfully been modeled a two-priced capacity market, paying higher capacity price to flexible producers than non-flexible producers. The capacity prices, paid to the flexible and non-flexible producers for each MW of capacity they made available to the capacity market, became as follows in Design 3:

- Flexible producers: 16000 €/MW
- Non-flexible producers: 8663 €/MW

There has been shown that the two-priced capacity market gives the same incentive to invest in sufficient capacity as the traditional single-priced capacity market, as both designs reached the wanted capacity reserve margin. This was not the case with Design 1, where installed capacity was found to be lower than maximum demand. Hence, only Design 1 resulted in load shedding. Neither sensitivity analyses, with lower VoLL nor no reserve margin, resulted in load shedding in Design 2 and 3.

It has been discovered that, while the total amount of installed capacity in Design 2 and 3 was equal, more flexible capacity was installed in Design 3. The capacity market-based revenue of non-flexible producers was found to be reduced in the two-priced capacity market, while the revenues of flexible producers were either at the same level as Design 2 or increased depending on the type of producer.

On this basis it can be concluded that in this thesis, the first known model of a two-priced capacity market has successfully been constructed. It has been shown that the two-priced capacity market model indeed has the ability to give an advantage in the power market to flexible electricity producer over less flexible producers. This work has made a foundation of a model of the two-priced capacity market and additional development of the model should be done to further investigate benefits of the two-priced capacity market over traditional capacity markets.

5.1 Further work

In further development of the model of the two-priced capacity market, it will be essential to show the benefits of more flexible capacity being installed in Design 3 compared with Design 2. To achieve that, two areas of the model need to be developed:

- Injected intermittent RES as partly firm capacity: The model of Design 2 and 3 in this thesis treats injected intermittent RES as non-firm capacity, which can lead overinvestment in capacity, as explained in section 4.6. This can be avoided by treating it as a partly firm capacity.
- Ramping rates of generators: Without ramping rates flexible generators have the same operational constraints as non-flexible generators. Including ramping rates of generators will work as a stricter restriction of operation of the generators, possibly leading to more load shedding.

It will be interesting to compare the two designs after the inclusion of these two points in the model, especially by testing it on cases with extreme values of intermittent RES. The higher amount of flexible capacity in Design 3 should be better suited to meet the challenging demand, hence possibly leading to less load shedding.

Other areas of further development worth to mention:

- More nodes: To extend the model to several nodes and cross-border flow of electricity will make the model more realistic as all power markets in Europe are getting more integrated.
- Market power: Strategic behavior of producers, instead of perfect competition.
- Storage of electricity: E.g. battery storage or hydro power.

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Appendix A: Deriving KKT conditions

In this section is the complementary KKT conditions from the objective function with following constraints of flexible and non-flexible producers and the Demand side derived. This is section is valid for Design 3.

Producer optimization problem

Maximization problem for flexible producers.

[D3]:
$$Max\ Z_f = \sum_{h=1}^{H} ((\lambda_h - VC_f) * gen_{f,h}) - FC_f * cap_f^{inst} + (\gamma^{flex} + \gamma^{base}) * \ cap_f^{cm} \tag{33}$$

s.t.

[D3]:
$$\forall f, h{:}\ 0 \leq -gen_{f,h} + cap_f^{inst} \perp \ \mu_{f,h} \geq 0 \tag{34}$$

[D3]:
$$\forall f{:}\ 0 \leq -cap_f^{cm} + cap_f^{inst} \perp \ \phi_f \geq 0 \tag{35}$$

Converting the maximization problem into a minimization problem gives the following Lagrange function:

[D3]:
$$L_f = \sum_{h=1}^{H} ((-\lambda_h + VC_f) * gen_{f,h}) + FC_f * cap_f^{inst} - (\gamma^{flex} + \gamma^{base}) * \ cap_f^{cm} - \mu_{f,h}(-gen_{f,h} + cap_f^{inst}) - \phi_f(-cap_f^{cm} + cap_f^{inst}) \tag{36}$$

This gives the following KKT-conditions:

[D3]:
$$\frac{\partial L_f}{\partial gen_{f,h}} = -\lambda_h + VC_f + \mu_{f,h} \geq 0 \tag{37}$$

[D3]:
$$\frac{\partial L_f}{\partial cap_f^{inst}} = FC_f - \sum_{h=1}^{H} \mu_{f,h} - \phi_f \geq 0 \tag{38}$$

[D3]:
$$\frac{\partial L_f}{\partial cap_f^{cm}} = \gamma^{flex} + \gamma^{base} + \phi_f \geq 0 \tag{39}$$

Maximization problem for non-flexible producers:

[D3]: $$Max\ Z_b = \sum_{h=1}^{H} ((\lambda_h - VC_b) * gen_{b,h}) - FC_b * cap_b^{inst} + \gamma^{base} * cap_b^{cm} \tag{40}$$

s.t.

[D3]: $$\forall b,h:\ 0 \leq -gen_{b,h} + cap_b^{inst} \perp \mu_{b,h} \geq 0 \tag{41}$$

[D3]: $$\forall b:\ 0 \leq -cap_b^{cm} + cap_b^{inst} \perp \phi_b \geq 0 \tag{42}$$

Converting the maximization problem into a minimization problem gives the following Lagrange function:

[D3]: $$L_b = \sum_{h=1}^{H} ((-\lambda_h + VC_b) * gen_{b,h}) + FC_b * cap_b^{inst} - \gamma^{base} * cap_b^{cm} - \mu_{b,h}(-gen_{b,h} + cap_b^{inst}) - \phi_b(-cap_b^{cm} + cap_b^{inst}) \tag{43}$$

This gives the following KKT-conditions:

[D3]: $$\frac{\partial L_b}{\partial gen_{b,h}} = -\lambda_h + VC_b + \mu_{b,h} \geq 0 \tag{44}$$

[D3]: $$\frac{\partial L_b}{\partial cap_b^{inst}} = FC_b - \sum_{h=1}^{H} \mu_{b,h} - \phi_b \geq 0 \tag{45}$$

[D3]: $$\frac{\partial L_b}{\partial cap_b^{cm}} = \gamma^{base} + \phi_b \geq 0 \tag{46}$$

Demand side/SO optimization problem:

Demand side and SO optimization problem:

[D3]: $$Min\ C = \sum_{h=1}^{H} ((P^{Max} - \lambda_h) * ls_h) + (\gamma^{flex} + \gamma^{base}) * dem^{flex} + \gamma^{base} * dem^{base} \tag{47}$$

s.t.

[D3]: $$0 \leq RS^{LS} * \sum_{h=1}^{H} DEM_h - \sum_{h=1}^{H} ls_h \perp \alpha \geq 0 \quad (48)$$

[D3]: $$0 \leq dem^{flex} + dem^{base} - RS^{CAP} * DEM^{MAX} \perp \beta \geq 0 \quad (49)$$

[D3]: $$0 \leq dem^{flex} - RS^{FLEX} * DEM^{MAX} \perp \delta \geq 0 \quad (50)$$

Lagrange function is as follows:

[D3]: $$L^{Demand} = \sum_{h=1}^{H}\big((P^{Max} - \lambda_h) * ls_h\big) + (\gamma^{flex} + \gamma^{base}) * dem^{flex} + \gamma^{base} * dem^{base} - \alpha(RS^{LS} * \sum_{h=1}^{H} DEM_h - \sum_{h=1}^{H} ls_h) - \beta(dem^{flex} + dem^{base} - RS^{CAP} * DEM^{MAX}) - \delta(dem^{flex} - RS^{FLEX} * DEM^{MAX}) \quad (51)$$

This gives the following KKT-conditions:

[D3]: $$\frac{\partial L^{Demand}}{\partial ls_h} = P^{Max} - \lambda_h + \alpha \geq 0 \quad (52)$$

[D3]: $$\frac{\partial L^{Demand}}{\partial dem^{flex}} = \gamma^{flex} + \gamma^{base} - \beta - \delta \geq 0 \quad (53)$$

[D3]: $$\frac{\partial L^{Demand}}{\partial dem^{base}} = \gamma^{base} - \beta \geq 0 \quad (54)$$

Appendix B: GAMS code

The gams code for the model of the power market including a two-priced capacity market (Design 3), is given below. Note that the dual variables, written in the nomenclature as Greek letters, are here written in Latin letters. E.g. γ is written "gamma" in the code.

```
*This GAMS-file models a power market including a two-priced capacity market.
*Mixed complementary problem (MCP) is used for this one-node model.
*Equilibrium market model of the energy-based market and the capacity market.
*Perfect competition amongst electricity producers is assumed.
*Producers maximize profit individually. Demand-side minimizes costs.

*Written by Petter Christiansen

*Defining Sets:
sets
F flexible producers /CCGT, OCGT/
B non-flexible producers /Coal, Nuclear/
H hours /hour1*hour8760/;

*Specifying maximum computation time [sec]:
option reslim = 100000000000;

*Defining parameters
Parameters
DEM(H) Energy demand,
INJ_WIND(H) Generated wind power,
INJ_SOLAR(H) Generated solar power

*Some parameter are assigned value directly:
DEM_MAX Maximum Energy Demand
/ 89060 /

P_MAX Maximum market price
/ 3000 /
RS_LS Reliability standard: load shedding
/ 0.0034 /
RS_CAP Reliability standard: reserve margin
/ 1.1 /

RS_FLEX Reliability Standard: required amount of flexible capacity in the sys»
tem
/ 0.5 /

FC1(F) Fixed costs of flexible producers f
/ CCGT           41000
  OCGT           16000      /

FC2(B) Fixed costs of non-flexible producers b
/  Nuclear        280000
   Coal            72000 /

VC1(F) Variable costs of flexible producers f
/ CCGT           48
  OCGT           150       /

VC2(B) Variable costs of non-flexible producers b
/  Nuclear        3
  Coal           35       /
;

*Loading data from excel of parameters not already assigned a value:
$CALL GDXXRW.EXE indata2.xls trace=3 par=DEM rng=a2 rdim=1 cdim=0
$GDXIN indata2.gdx
$LOAD DEM
$GDXIN
display DEM;
```

```

$CALL GDXXRW.EXE indata2.xls trace=3 par=INJ_SOLAR rng=Sheet2!a2 rdim=1 cdim=»
0
$GDXIN indata2.gdx
$LOAD INJ_SOLAR
$GDXIN
display INJ_SOLAR;

$CALL GDXXRW.EXE indata2.xls par=INJ_WIND rng=Sheet3!a2 rdim=1 cdim=0
$GDXIN indata2.gdx
$LOAD INJ_WIND
$GDXIN
display INJ_WIND;

*Defining variables:
VARIABLE
lambda(H) Energy-based price hour h;

POSITIVE VARIABLES
cap_inst1(F) total installed capacity of firm f,
cap_inst2(B) total installed capacity of firm f,
gen1(F,H) flexible generation output of firm f in hour h,
gen2(B,H) non-flexible generation output of base-load-firm b in hour h,
ls(H) load shed in hour h,
ps(H) production shedding in hour h,
cap_cm1(F) flexible capacity made available to cap market by firm f,
cap_cm2(B) non-flexible capacity made available to cap market by firm b,
dem_cm_flex demand for flex capacity in cap market,
dem_cm_base demand for non-flexible capacity in cap market,
alpha energy-based price adaption to fulfill load shed standard,
beta marginal cost of capacity reserve margin,
delta marginal cost of reliability standard of flexible capacity,
gamma1 flexible capacity price,
gamma2 secondary capacity price,
my1(F,H) scarcity rent of flexible Generation,
my2(B,H) scarcity rent of non-flexible Generation,
phi1(F) scarcity rent of flexible capacity,
phi2(B) scarcity rent of non-flexible capacity;

*Defining equations:
EQUATIONS
*Flexible producer-optimization-problem:
GENLIMIT1_my1(F,H) GENERATION LIMITS FOR EACH FIRM IN EVERY HOUR,
GENOPT1_gen1(F,H) OPTIMAL FLEXIBLE GENERATION FOR EACH FIRM IN EACH HOUR,
CAPLIMIT1_phi1(F) PRODUCER F CANNOT OFFER MORE CAPACITY TO MAREKT THAN INSTAL»
LED CAPACITY,
CAPOPT1_cap_inst1(F) OPTIMAL INSTALLED FLEXIBLE CAPACITY FOR EACH PRODUCER,
OFFEREDCAP1_cap_cm1(F) FLEXIBLE CAPACITY PRICE MUST BE GREATER THAN SCARCITY »
RENT OF FLEXIBLE GENERATION,

*Non-flexible producer-optimization-problem:
GENLIMIT2_my2(B,H) GENERATION LIMITS FOR EACH FIRM IN EVERY HOUR,
GENOPT2_gen2(B,H) OPTIMAL NON-FLEXIBLE GENERATION FOR EACH FIRM IN EACH HOUR,
CAPLIMIT2_phi2(B) PRODUCER F CANNOT OFFER MORE CAPACITY TO MAREKT THAN INSTAL»
LED CAPACITY,
CAPOPT2_cap_inst2(B) OPTIMAL INSTALLED NON-FLEX CAPACITY FOR EACH PRODUCER,
OFFEREDCAP2_cap_cm2(B) NON-FLEXIBLE CAPACITY PRICE MUST BE GREATER THAN SCARC»
ITY RENT OF FLEXIBLE GENERATION,

*Demand-side/TSO-optimization-problem:
LOADSHED_alpha LOAD SHEDDING CONSTRAINT,
```

```
SHEDOPT_ls(H) OPTIMAL AMOUNT OF LOAD SHEDDING,

DEMCAPACITY_beta TOTAL DEMAND FOR ALL TYPES OF CAPACITY IN CAPACITY MARKET,
DEMFLEX_delta DEMAND FOR FLEXIBLE CAPACITY IN THE CAPACITY MARKET,
GAMMALIMIT1_dem_cm_flex PRICE PAID TO FLEXIVBLE PRODUCERS MUST BE GREATER THA»
N MARGINAL COSTS OF RESERVE CAPACITY MARGIN AND RS OF FLEXIBLE CAPACITY,
GAMMALIMIT2_dem_cm_base SECONDARY CAPACITY PRICE MUST BE GREATER THAN MARGINA»
L COSTS OF RESERVE MARGIN,

*Energy-based market:
ENERGYBALANCE_lamda(H) ENERGY BALANCE EVERY HOUR,
PRODSHED_ps(H) PRODUCTION SHEDDING OF RES IF RES PROD GREATER THAN DEMAND,

*Capacity market:
CAPACITYBALANCE_gamma2 CAPACITY AVAILABLE IN CAPACITY MARKET MUST BE GRATER T»
HAN DEMAND,
FLEXBALANCE_gamma1 FLEX CAPACITY IN CAPACITY MARKET MUST BE GREATER THAN DEMA»
ND FOR FLEX CAPACITY;

*Expressing the equations:
*Flexible producers:
GENLIMIT1_my1(F,H).. -gen1(F,H) + cap_inst1(F) =G= 0;
GENOPT1_gen1(F,H).. -lambda(H) + VC1(F) + my1(F,H) =G= 0;
CAPLIMIT1_phi1(F)..cap_inst1(F)-cap_cm1(F)=G=0;
CAPOPT1_cap_inst1(F).. FC1(F) - SUM(H,my1(F,H))-phi1(F) =G= 0;
OFFEREDCAP1_cap_cm1(F)..-gamma1-gamma2+phi1(F)=G=0;

*Non-flexible producers:
GENLIMIT2_my2(B,H).. -gen2(B,H) + cap_inst2(B) =G= 0;
GENOPT2_gen2(B,H).. -lambda(H) + VC2(B) + my2(B,H) =G= 0;
CAPLIMIT2_phi2(B)..cap_inst2(B)-cap_cm2(B)=G=0;
CAPOPT2_cap_inst2(B).. FC2(B) - SUM(H,my2(B,H))-phi2(B) =G= 0;
OFFEREDCAP2_cap_cm2(B)..-gamma2+phi2(B)=G=0;

*Demand-side/TSO:
LOADSHED_alpha.. RS_LS*SUM(H,DEM(H)) - SUM(H,ls(H)) =G= 0;
SHEDOPT_ls(H).. P_MAX - lambda(H) + alpha =G= 0;
DEMCAPACITY_beta.. dem_cm_flex + dem_cm_base - RS_CAP*DEM_MAX =G= 0;
DEMFLEX_delta.. dem_cm_flex - RS_FLEX * DEM_MAX =G= 0;
GAMMALIMIT1_dem_cm_flex.. gamma1 + gamma2 - beta - delta =G= 0;
GAMMALIMIT2_dem_cm_base.. gamma2 - beta =G= 0;

*Energy-based market:
ENERGYBALANCE_lamda(H)..sum(F,gen1(F,H))+sum(B,gen2(B,H))+INJ_SOLAR(H)+INJ_WI»
ND(H)-DEM(H)+ls(H)-ps(H) =E= 0;
PRODSHED_ps(H)..  0 =G= INJ_SOLAR(H) + INJ_WIND(H)- DEM(H) - ps(H);

*Capacity-based market:
CAPACITYBALANCE_gamma2..SUM(F,cap_cm1(F)) +  sum(B,cap_cm2(B)) - dem_cm_flex »
- dem_cm_base =G= 0;
FLEXBALANCE_gamma1..sum(F,cap_cm1(F))- dem_cm_flex=G=0;


*Defining and solving model:
MODEL DESIGN_3 /
GENLIMIT1_my1.my1,
GENLIMIT2_my2.my2,
GENOPT1_gen1.gen1,
GENOPT2_gen2.gen2,
CAPLIMIT1_phi1.phi1,
CAPLIMIT2_phi2.phi2,
```

```
CAPOPT1_cap_inst1.cap_inst1,
CAPOPT2_cap_inst2.cap_inst2,
OFFEREDCAP1_cap_cm1.cap_cm1,
OFFEREDCAP2_cap_cm2.cap_cm2,

LOADSHED_alpha.alpha,
SHEDOPT_ls.ls,
DEMCAPACITY_beta.beta,
DEMFLEX_delta.delta,
GAMMALIMIT1_dem_cm_flex.dem_cm_flex,
GAMMALIMIT2_dem_cm_base.dem_cm_base

ENERGYBALANCE_lamda.lambda,
PRODSHED_ps.ps,

CAPACITYBALANCE_gamma2.gamma2,
FLEXBALANCE_gamma1.gamma1,
 / ;
*Reduce problem size by treating fixed variables as constraints:
DESIGN_3.holdfixed=1;
*Activate scaling of model:
DESIGN_3.scaleopt=1;
*Solves model by using Mixed complementary problem:
SOLVE DESIGN_3 USING MCP;

*Writing output-data to Excel:
execute_unload "result_MCP_two_priced_alt1_changed.gdx";
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N var=gen1 rng»
=gen1!a1';
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N var=gen2 rng»
=gen2!a1';
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N var=cap_inst»
1 rng=cap_inst1!a1';
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N var=cap_inst»
2 rng=cap_inst2!a1';
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N var=lambda r»
ng=lamda!a1';
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N var=ls rng=l»
s!a1';
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N var=ps rng=p»
s!a1';
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N var=cap_cm1 »
rng=cap_cm1!a1';
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N var=cap_cm2 »
rng=cap_cm2!a1';
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N var=dem_cm r»
ng=dem_cm!a1';
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N var=gamma1 r»
ng=gamma1!a1';
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N var=gamma2 r»
ng=gamma2!a1';
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N var=phi1 rng»
=phi1!a1';
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N var=phi2 rng»
=phi2!a1';
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N var=my1 rng=»
my1!a1';
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N var=my2 rng=»
my2!a1';
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N var=alpha rn»
g=alpha!a1';
```

```
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N var=beta rng»
=beta!a1';
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N var=delta rn»
g=delta!a1';
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N par=RS_FLEX »
rng=RS_FLEX!a1';
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N par=DEM rng=»
DEM!a1';
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N par=DEM_MAX »
rng=DEM_MAX!a1';
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N par=VC1 rng=»
VC1!a1';
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N par=VC2 rng=»
VC2!a1';
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N par=FC1 rng=»
FC1!a1';
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N par=FC2 rng=»
FC2!a1';
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N par=RS_LS rn»
g=RS_LS!a1';
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N par=RS_CAP r»
ng=RS_CAP!a1';
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N par=INJ_WIND»
 rng=INJ_WIND!a1';
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N par=INJ_SOLA»
R rng=INJ_SOLAR!a1';
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N par=RS_FLEX »
rng=RS_FLEX!a1';
execute 'GDXXRW result_MCP_two_priced_alt1_changed.gdx Squeeze=N par=P_MAX rn»
g=P_MAX!a1';
```