NTNU – Trondheim
Norwegian University of
Science and Technology

The impact of outages on the profitability of HVDC-cables between the Nordic area and the continent using the EMPS model

Christian Sørum Melaaen

Master of Energy Use and Energy Planning
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Supervisor: Magnus Korpås, ELKRAFT
Co-supervisor: Stefan Jaehnert, ELKRAFT

Norwegian University of Science and Technology
Department of Electric Power Engineering

Problem description

As analyses have predicted and reality has shown, the integration of large amounts of renewable energy sources (RES) in the European power system reduces the profits of conventional power plants significantly. However, due to the intermittence of RES, sufficient conventional power plants or other flexibility options are required as back-up to ensure system adequacy and a reliable operation of the power system.

The Nordic and especially the Norwegian hydro-based power production is in a favourable position to provide at least parts of the required generation back-up capacity for RES situated in continental Europe. In order to provide this, sufficient transfer capacity needs to be available. However, for the HVDC-cables it is observed that outages occur rather regular and could remain for long periods. During such events, back-up capacity could not be provided.

The aim of the master project is to assess the impact of HVDC-cable outages on exchange and the value of providing back-up generation capacity to continental Europe. Cable outages shall thereby be modelled with the help of EMPS, including the expectation for outages in the operation optimization of the power system.

Sub-tasks:

- Implement cable outage scenarios in a detailed dataset for Northern Europe
- Run cable outage scenarios for Northern Europe
- Assess the value of capacity provision taking into account cable outages

Supervisor: Prof. Magnus Korpås, NTNU

Co-supervisor: Stefan Jaehnert, NTNU

Preface

This master thesis is written at Norwegian University of Science and Technology, NTNU, Faculty of Information Technology, Mathematics and Electrical Engineering, Department of Electric Power Engineering, in spring 2015.

The master thesis is given by NTNU and contains power market simulations with focus on HVDC-cable outage between the Nordic synchronous area and the European continent.

All simulations provided in this report are performed by the *EMPS (*EFIs Multi-area Power-market Simulator), and the data set used is provided by NTNU from SINTEF Energy.

Nomenclature is presented in the end of the report.

I would like to thank my supervisor Magnus Korpås for important feedback and explanations, as well as guidance throughout the entire master thesis work. I would also like to thank my co-supervisor Stefan Jaehnert for vital information and help regarding EMPS-modelling and market behaviour.

Christian Sørum Melaaen

Summary

This master thesis investigates sudden HVDC-cable exchange limitations between thermal-based and hydro dominated areas from a market perspective. Thermal-based areas are based on fossil-fired units in combination with large amounts of wind and solar energy. This power production structure resembles Germany.

The power market simulator used is EMPS (EFIs Multi-area Power-market Simulator), which is a well-known simulation tool throughout the Nordic area. The simulation uses historical water inflow and weather measurements for 75 climatic years, giving a wide range of different outcomes. The outage analyses are mainly done in a data set developed by SINTEF resembling the North-European power system configuration in year 2030.

The EU has agreed upon extensive objectives regarding reduction in greenhouse gas emissions. The energy sector is changing towards more Renewable Energy Sources (RES). The challenge is that RES is not able to accomplish the same flexibility as conventional power plants provide. Flexible hydropower production from Norway intends to support intermittence of RES and contribute to security of supply. Exchange capacity from Norway to continental Europe is provided through HVDC-cables. This report shows the impact of HVDC-cable outages on North-European power prices.

Statistical data shows that HVDC-cable disturbance outages occur. Disturbance outages are forced outages limiting the cross-border power exchange. The average cable unavailability due to such outages is 2.4 weeks per year. The cable investigated is the planned cable connecting Norway to Germany, Nord.Link, with a capacity of 1.4 GW. Outages are modelled annually from the beginning of the first week in each simulated climatic year. There is a higher probability of stressed operation in winter time, due to high load combined with lower solar production, and this season is assumed to be a critical period for outages.

The results show that a three-week outage of Nord.Link has close to no impact on the average price in Germany for all 75 simulated years. However, during power capacity shortage, the price increases significantly. Power capacity shortage comes with low wind and solar production combined with high consumption, and demand is met by use of expensive flexible load. It is seen that the highest price in Germany reaches 900 EUR/MWh at worst. This is 200 EUR/MWh higher than if Nord.Link had been available.

German consumers are most affected during outage on Nord.Link. In this study, a three-week outage reduces the consumer surplus in Germany by 60 MEUR in the worst year due to the significant increase in prices. However, the mean loss in consumer surplus for all climatic years is less, being close to 8 MEUR. The results also discover that there is not the outage length that is critical regarding consequences, but the initial power situation in the affected period. A fifteen-week outage of Nord.Link on average costs German consumers 30 MEUR, while a two-week outage during power capacity shortage exceeds 50 MEUR.

The results show that transmission cable outage gives the same consequences in consumer surplus in Germany as power production outage for the same capacity. Additionally, the fault-statistics are in favour of cables. Cross-border capacity should therefore be included in

foreign Capacity Remuneration Mechanism (CRM). CRM pays for installed capacity to support intermittence of renewables, making power supply capacity more profitable.

Furthermore, Norway becomes a more secure source of supply in the future due to more interconnections, making it possible to import energy in dry years to store water in reservoirs.

HVDC-cable exchange between the Nordic area and the European continent improves security of supply, and is in line with EUs target of a clean and strongly interconnected power system. The value of providing back-up capacity to the continent is high because the power exchange will reduce continental prices significantly during power capacity shortage, reducing the electricity bill for consumers.

Sammendrag

Masteroppgaven analyserer konsekvenser av HVDC-kabel utfall mellom termisk-basert kraftsystemområde i Nord Europa og vannkraft-dominert område i Norge fra et markedsperspektiv. Det termisk-baserte området er basert på produksjonsenheter som benytter fossilt brennstoff i kombinasjon med store mengder vind og sol energi. Denne produksjonsstrukturen kjennetegner Tyskland.

Kraftmarkedssimulatoren som er benyttet er EMPS (Samkjøringsmodellen), som er et velkjent simuleringsverktøy i de nordiske landene. Simuleringsverktøyet bruker historiske tilsig- og værmålinger for 75 klimatiske år, noe som gir en stor bredde av ulike resultater. Utfallsanalysene er hovedsakelig gjort i et datasett utviklet av SINTEF for det nord-europeiske kraftsystemet i år 2030.

EU har satt seg omfattende mål i forhold til reduksjon av drivhusgasser. Energisektoren endres mot mer fornybare energikilder. Utfordringen er at fornybare energikilder ikke har den samme tekniske fleksibiliteten som konvensjonelle kraftverk har. Fleksibel vannkraftproduksjon fra Norge kan støtte uregelmessig produksjon av fornybar energi, og dermed bidra til økt forsyningssikkerhet. Kraftutveksling mellom Norge og kontinentet skjer gjennom HVDC-kabler. Denne rapporten viser hvilke påvirkning HVDC-kabel utfall har på nord-europeiske kraftpriser.

Statistisk data viser at det forekommer driftsforstyrrelser på HVDC-kabler. Driftsforstyrrelser er utilsiktede utfall som begrenser utvekslingsmulighetene. Gjennomsnittlig er kabler utilgjengelige 2.4 uker per år som følge av driftsforstyrrelser. Den planlagte 1.4 GW kabelen mellom Norge og Tyskland, Nord.Link, er basis for analysen. Årlige utfall er modellert fra begynnelsen av første uke i hvert simulerte klimatiske år. Det er en større sannsynlighet for produksjonsknapphet på vintertid som følge av høy last kombinert med lavere produksjon fra solenergi, og det er derfor antatt at utfall på denne tiden er kritisk.

Resultatene viser at et tre-ukers utfall av Nord.Link har liten påvirkning på gjennomsnittsprisen i Tyskland for alle de 75 simulerte årene. Ved utfall i perioder med produksjonsknapphet øker imidlertid prisene betydelig. Produksjonsknapphet kommer som følge av lav produksjon av vind- og solenergi kombinert med høy last. I slike tilfeller dekkes kraftetterspørselen av kostbar fleksibel last. Resultatene viser at de høyeste prisene i Tyskland når 900 EUR/MWh på det verste. Dette er 200 EUR/MWh høyere enn hvis Nord.Link hadde vært tilgjengelig.

Tyske forbrukere er mest berørt som følge av utfall av Nord.Link. Dette studiet viser at et tre-ukers utfall reduserer konsumentoverskuddet i Tyskland med 60 MEUR i det verste året som følge av en betydelig økning i priser. Derimot er det gjennomsnittlige konsumentunderskuddet for alle klimatiske år kun 8 MEUR. Resultatene avdekker også at det ikke er utfallslengden som er kritisk med tanke på konsekvenser, men produksjonsknappheten i den berørte perioden. Et femten-ukers utfall av Nord.Link koster i gjennomsnitt tyske forbrukere 30 MEUR, mens et to-ukers utfall under produksjonsknapphet kan overstige 50 MEUR.

Resultatene viser at transmissionskabelutfall gir tilsvarende konsekvenser som utfall av kraftproduksjon med lik kapasitet for konsumentoverskudd i Tyskland. I tillegg er feilstatistikken i favør kabler. Derfor bør utvekslingskapasitet på kabler være med i andre lands kapasitetsmekanismer. Kapasitetsmekanismer betaler for installert kapasitet for å støtte uregelmessig produksjon fra fornybare energikilder. Deltakelse øker lønnsomheten for kraftproduksjonsanlegg.

Resultatene viser også at Norge i fremtiden vil bli en sikrere energikilde som følge av flere utlandsforbindelser. Det er fordi Norge kan importere energi i tørre år for på den måten spare vann i egne reservoarer.

Energiutveksling mellom det nordiske området og det europeiske kontinentet forbedrer forsyningssikkerheten i tillegg til å tilfredsstille EUs mål om ren energi og et sterkt sammenkoplet nett. Verdien av å tilby fleksibel kapasitet til kontinentet er høy fordi kraftutvekslingen vil redusere prisene på kontinentet betydelig ved kapasitetsknapphet, noe som videre vil redusere elektrisitetsregningen for forbrukerne.

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1. Introduction

The EU has agreed upon extensive objectives regarding reduction in greenhouse gas emissions. Within 2030, the domestic reduction in emission should at least be 40 % compared to 1990 levels (European Commission, 2015). A great part of the reduction is addressed to the energy sector.

To reduce greenhouse gas emissions, fossil-fired units are unwanted. The counter part is Renewable Energy Sources (RES), which are implemented in vast numbers by help of subsidies. The majority of RES is wind and solar energy. However, this change in energy mix challenges security of supply of electricity due to the intermittent and unpredictable supply of power plant feedstock. The correlation between wind and solar production and demand do not necessarily meet. In 2013, almost 40 % of the installed generation capacity in Europe was RES power (ENTSO-E, 2014). Installed capacity with great amounts of such sources will result in some very high prices in order to obtain balance between production and demand.

To avoid lack of production, available flexible capacity is preferred before use of load shedding. Energy-only market (EOM) as well as current policy challenge this. In EOM, producers bid *amounts* of energy to specific prices. The only payment is for the actual production in energy. The merit order effect occurs as RES has close to zero marginal cost and are first to be dispatched. Fossil-fired units need to pay for fuel, which RES do not. Additionally, CO_2-emission is costly and the CO_2-price is expected to increase in the future. The merit order effect drives prices down, reducing the utilization time of fossil-fired units. This makes them less profitable (or even non-profitable). The power system, however, needs flexible capacity to support the intermittence of RES.

A Capacity Remuneration Mechanism (CRM) is a measure to keep capacity within the system to ensure that there is enough installed capacity. Participants of CRM are paid for their installed capacity on top of any production. This increases their revenue.

However, capacity does not necessarily only come from domestic production, but can also be provided by cross border exchange. Through the Guidance Package, the European Commission *requires* that CRM is to be open for foreign participation for other Member States (European Commission). Beside national initiatives, owners of cross-border capacity want to be included in CRM in order to increase their revenue. This is the case for NSN, connecting Norway to Great Britain. Statnett would like the cable to be a part of Great Britain's capacity auction. This would compensate for their contribution to security of supply. This is also in line with the European Commission's target for the Internal Energy Market (IEM), which aim to coordinate and strongly interconnect the European system.

The purpose of CRM is to ensure system adequacy, so it seems logical that all kind of flexible capacity is included. However, there are some major topics up for discussion. There are always producers supplying the cable with power. How should cable owners and producers coordinate their supply making sure power is available when needed? What happens if there is lack of power on both sides? And what kind of penalty is reasonable if the cable is out of service?

This report intends to reveal consequences regarding unpredictable outages of cross-border capacity between hydro dominated and thermal-based areas with vast amounts of RES from a market perspective. Production outage is also evaluated and compared to cable outage. This is done in order to see if the source of capacity has an impact on the consequences for outage.

2. Power market theory

This chapter gives information that should be known in order to understand the results. The chapter is divided into two main parts: Description of electricity markets and description of the power market simulator EMPS. The first part involves explanation of market functions as well as an introduction of different market solutions. The second part introduces the simulation tool used for all simulations, EMPS (EFIs Multi-area Power-market Simulator).

2.1 Electricity market

The aim of the section is to introduce important knowledge of how the electricity market settles, as well as information about different market solutions.

2.1.1 Market dynamics

The price is set at the equilibrium where producers are willing to sell and consumer to pay known as the market cross, illustrated by p* in Figure 2.1. With marginal pricing, producers bid their marginal production cost into the market, usually with hourly resolution. At the intersection, the price is set for the hour and the amount determined.

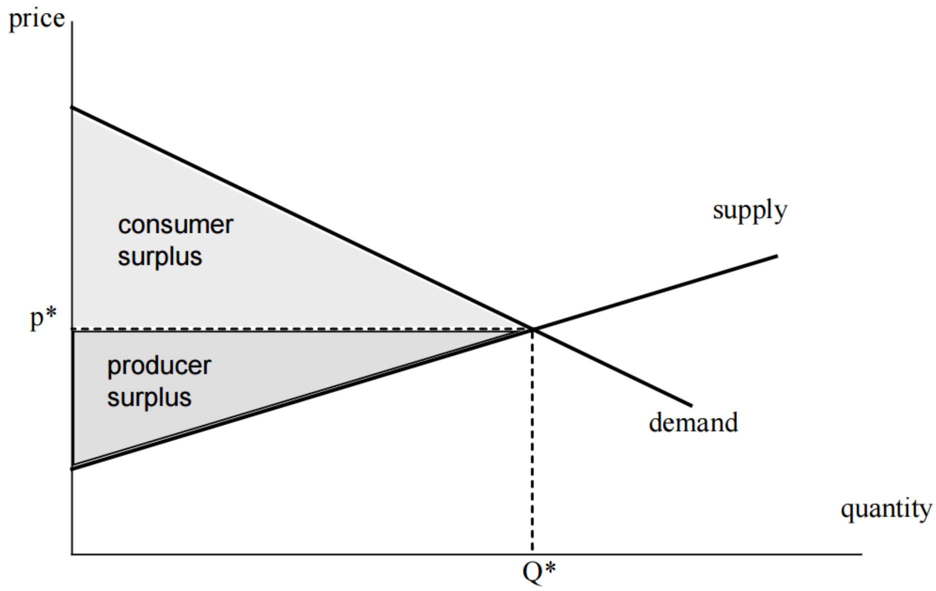


Figure 2.1: Market cross including consumer and producer surplus (Doorman, TET4185 Power markets - Micro economics, 2013).

In Figure 2.1, producer surplus is the grey area beneath p*, and Consumer Surplus above. Simplified, the sum of producer and consumer surplus for all areas in the evaluated system gives the socio-economic surplus. More advanced, socio-economic surplus consists also of change in water level during the evaluated period, transmission loss and congestion rent. Socio-economic surplus is used to evaluate consequences from a system perspective, taking into account various stakeholders like producers, consumers and system operators.

The demand curve presented in the figure above is rather flat, i.e. highly elastic. This means that consumers adjust their consumption when prices change.

However, electricity consumers do not always really see price signals. This means that when there are less power production available and prices rise, it is not obvious that consumers reduce their power consumption. Figure 2.2 gives a more realistic demand slope. If the market cross now change, the quantity of demand does not vary significantly.

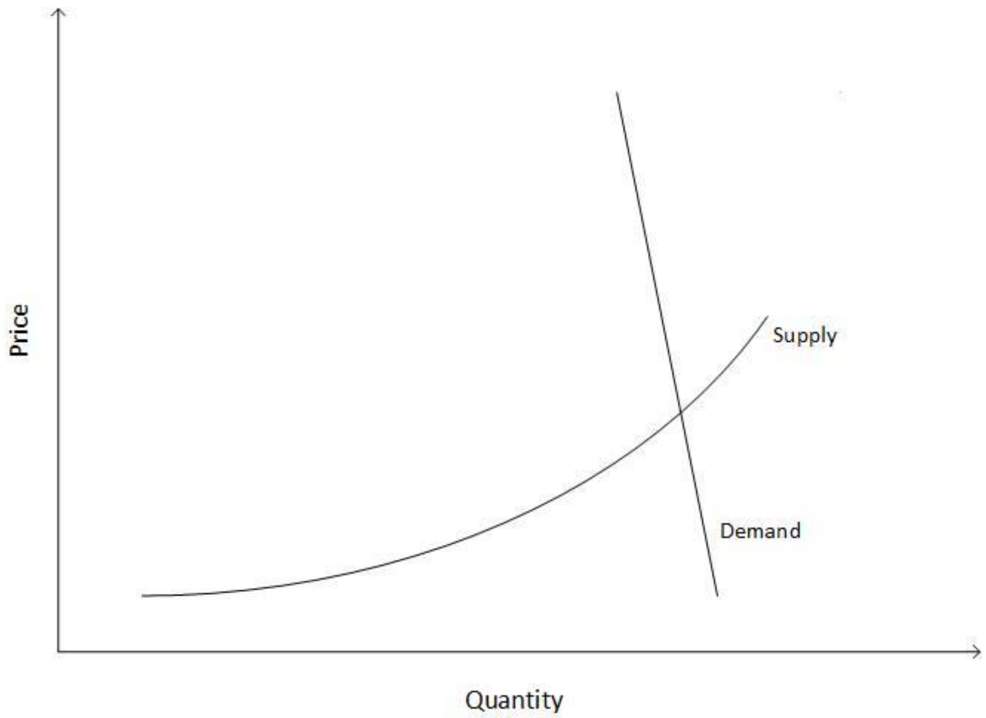


Figure 2.2: Market cross illustrating less elastic demand.

This steepness of the curves does affect how much consumer and producer surplus changes if the price vary. The demand curve is steeper than the supply curve. This means that a change in price affects consumer surplus *more* than producer surplus, since the change in area is greater.

RES share of the total power consumption increases, as seen in Figure 2.3. For the future, more renewables are expected to enter the power system in order to reach climatic goals set by the EU. The installed capacity mix is changing towards being less flexible.

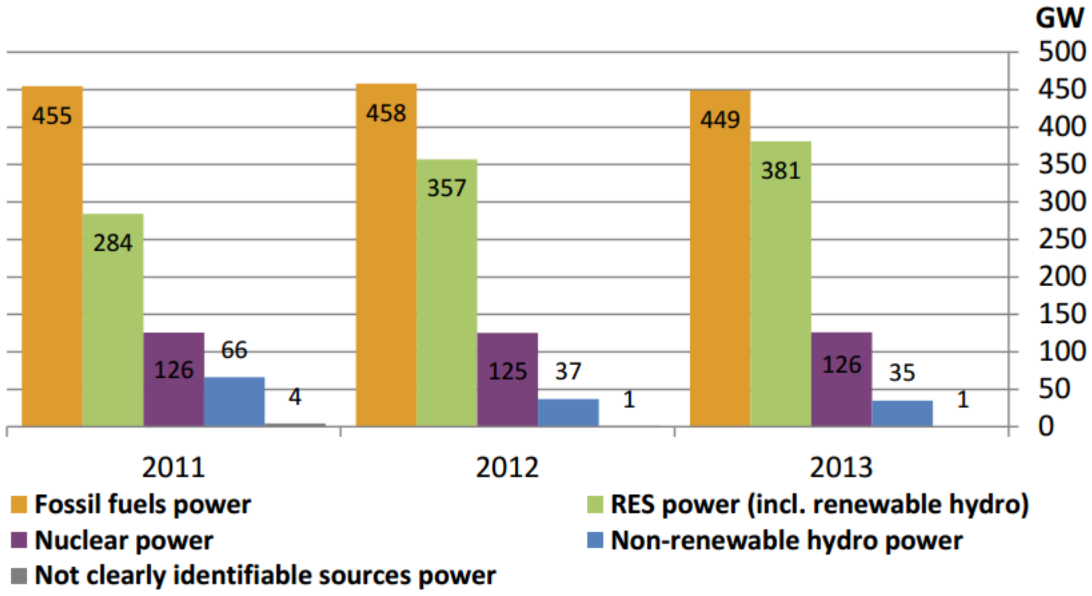


Figure 2.3: Net generation capacity evolution in Europe (ENTSO-E, 2014).

The capacity mix affects the supply curve slope. In a power system greatly influenced by RES, there will be a shift in supply curve to the right, as illustrated in Figure 2.4. RES have low marginal cost due to free fuel, and is located at the very left in the supply curve. The low marginal cost refers to the actual power production cost of producing one extra unit of energy. As illustrated in Figure 2.4, the extra RES supply reduces the price as the market cross shifts to the right. The most expensive unit without RES (first market cross) is no longer producing.

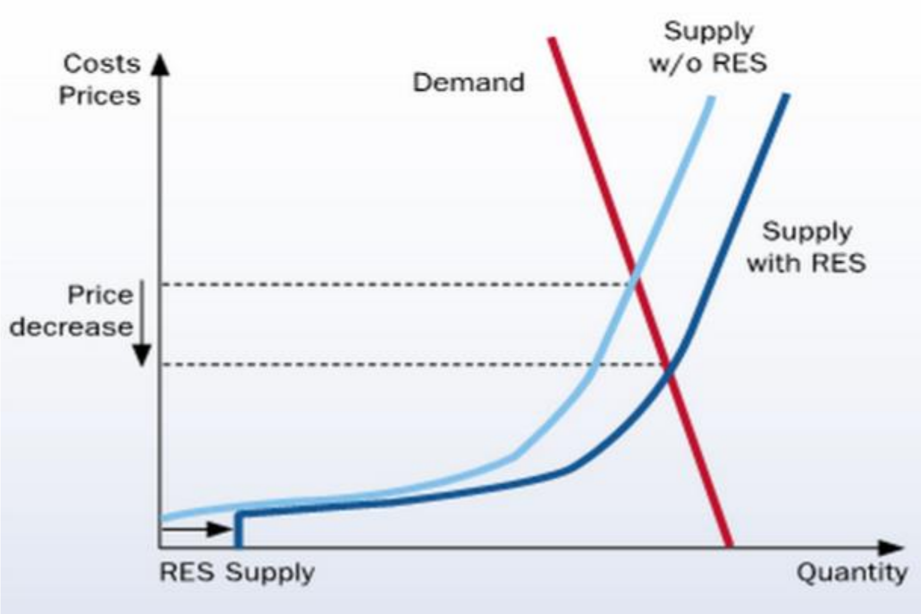


Figure 2.4: Market cross with and without renewables (Benedettini, 2015).

A disadvantage of RES is the uncertainty of when wind and solar energy are available. This intermittence of RES means that the arrow indicating the extra production in Figure 2.4, often turns. When the previous additional quantity from RES is no longer available, the high priced unit will now again be wanted in order to meet demand.

Periods with high prices indicate power capacity shortage. Production units with high marginal cost are active, drawing prices up. When demand reaches the capacity limit of the peak generator, prices often increase rapidly. The peak generator is the unit in the system with highest marginal cost. If demand is above the capacity of the peak generator, there is need for flexible load or load rationing. Flexible load is load that is disconnected stepwise at high prices, contractual pre-determined with the system operator. Rationing is involuntary load shedding (very high price) as a last measure to keep system in operation.

The peak capacity is illustrated in Figure 2.5. Here, supply curve is the MC-curve (Marginal Cost). K_{max} shows the capacity limit of all available capacity. At the very edge of the peak generator, the supply curve is totally elastic, i.e. vertical. No matter how far the price increase, the quantity supplied is unchanged. There are no more available capacity, so all quantity wanted by demand exceeding the capacity limit need to be fulfilled by use of flexible load or load rationing.

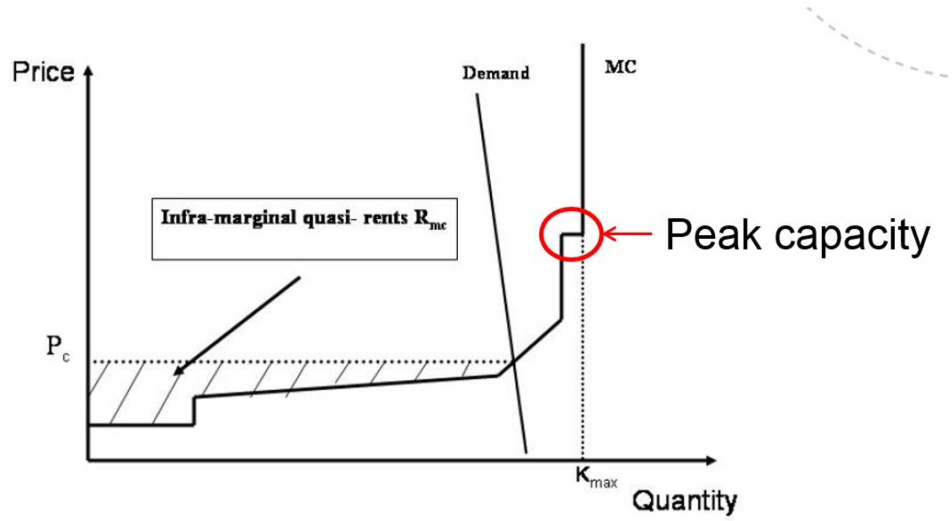


Figure 2.5: Short run marginal cost pricing (Joskow, 2006).

Scarcity pricing could occur during power capacity shortage. Production capacity is exceeded and prices are determined by demand. This way, also the peak generator is able to make money (return of investments). In Figure 2.6, scarcity rent is the area between the marginal cost of the peak generator and the intersection of supply and demand.

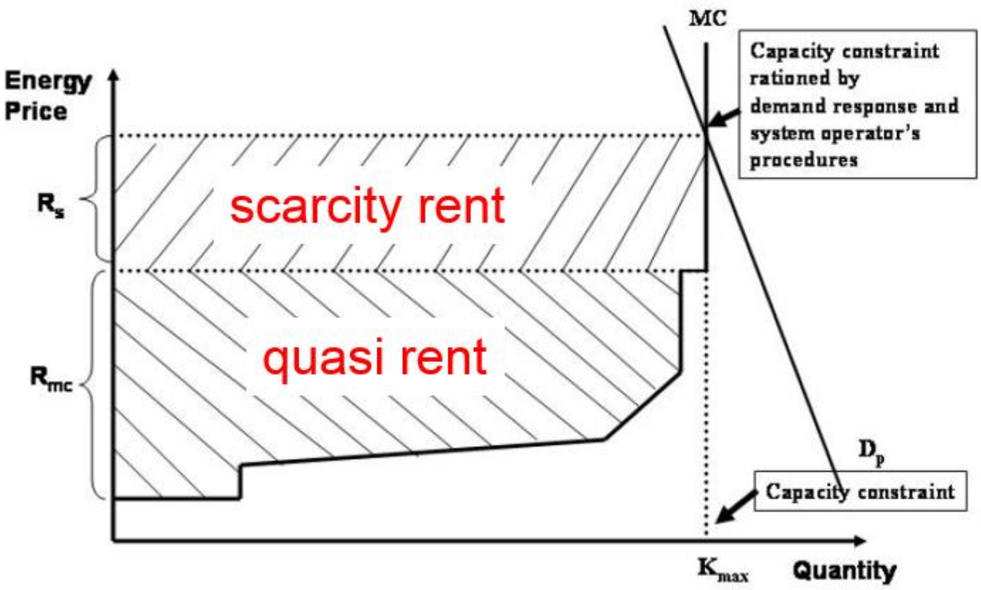


Figure 2.6: Electricity pricing with power capacity constraint (Joskow, 2006).

Area pricing is one method to handle power congestions, i.e. technical transmission bottlenecks. This is illustrated for a system consisting of two “price areas” in Figure 2.7. If they were totally disconnected, i.e. no exchange capacity, the price in area A would be 75, and in B 125 NOK/MWh. If a transmission link with capacity of 100 MW is connected between the areas, the price increases in area A to 100, and reduces in area B to 100. It is exactly enough capacity to have equal price in both areas. However, if the capacity were less than 100 MW, there would be price differences due to the bottleneck.

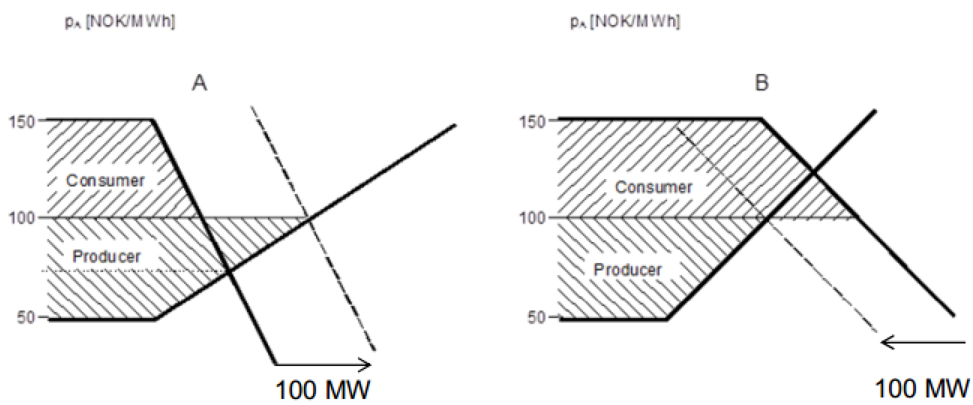


Figure 2.7: Exchange between two price areas (Doorman, TET4185 Power markets - Grid access & Congestion Management, 2013).

2.1.2 Market solutions

The power market should give the right price signal to all stakeholders, i.e. providing an efficient and reliable power system. Recently, the development towards a production mix with more renewables creates *merit-order effect* in an Energy-Only Market (EOM). Merit-order effect is to prefer low marginal cost energy sources. This affects the utilization time of conventional power plants due to their higher marginal cost.

EOM and capacity mechanisms

In EOM, producers bid *amounts* of energy to specific prices. The only payment is for the actual production in energy. However, the marginal cost for different production types differ. Wind and solar have very low marginal cost (no fuel cost, only operational cost), and will produce as long as resources are available. Fossil-fired units are assumed to have no resource restriction, but higher marginal cost and start/stop issues. The “no resource assumption” means that all wanted fuel (coal, oil, gas etc.) is available.

A variety of factors result in financial challenges for thermal power plants, known as “missing money”. The merit order effect is one of them. It reduces the operation hours for thermal generators. This reduces, or even eliminates their profit, making them financial insecure. However, in a power system, flexible capacity is a necessity, which intermittent renewables physically cannot fulfil. The market must provide the right price signals to keep enough flexible production (back-up capacity) in the system, or incentivise new investments.

Capacity Remuneration Mechanism (CRM) objective is to provide security of supply. CRM aim to ensure that there is enough installed capacity in the system to meet peak electricity demand in the future. This is called system adequacy. Such mechanism pays for *capacity (MW, kW)* outside the normal power market on top of any power they produce. The mechanisms intend to be technology neutral, but with certain criteria like minimum size. This opens for participation for generation types as fossil-fired units, nuclear, hydropower, renewables and flexible consumers. The main difference between EOM and CRM is illustrated in Figure 2.8.

EOM	CRM
Profits from **kWh** sold	Profits from **kWh** sold and **kW** installed

Figure 2.8: Main difference between EOM and CRM

The cost of CRM is given to the consumers, as they are the only ones to utilize electricity. However, this extra payment benefits security of supply as well as extinguishes missing money issue for producers. CRM is then an expensive solution but might be preferred instead of involuntary load shedding and unstable system operation.

CRM status for Europe

The implementation and characteristics of such mechanisms differ. Figure 2.9 shows status for CRM in Europe as of 2014.

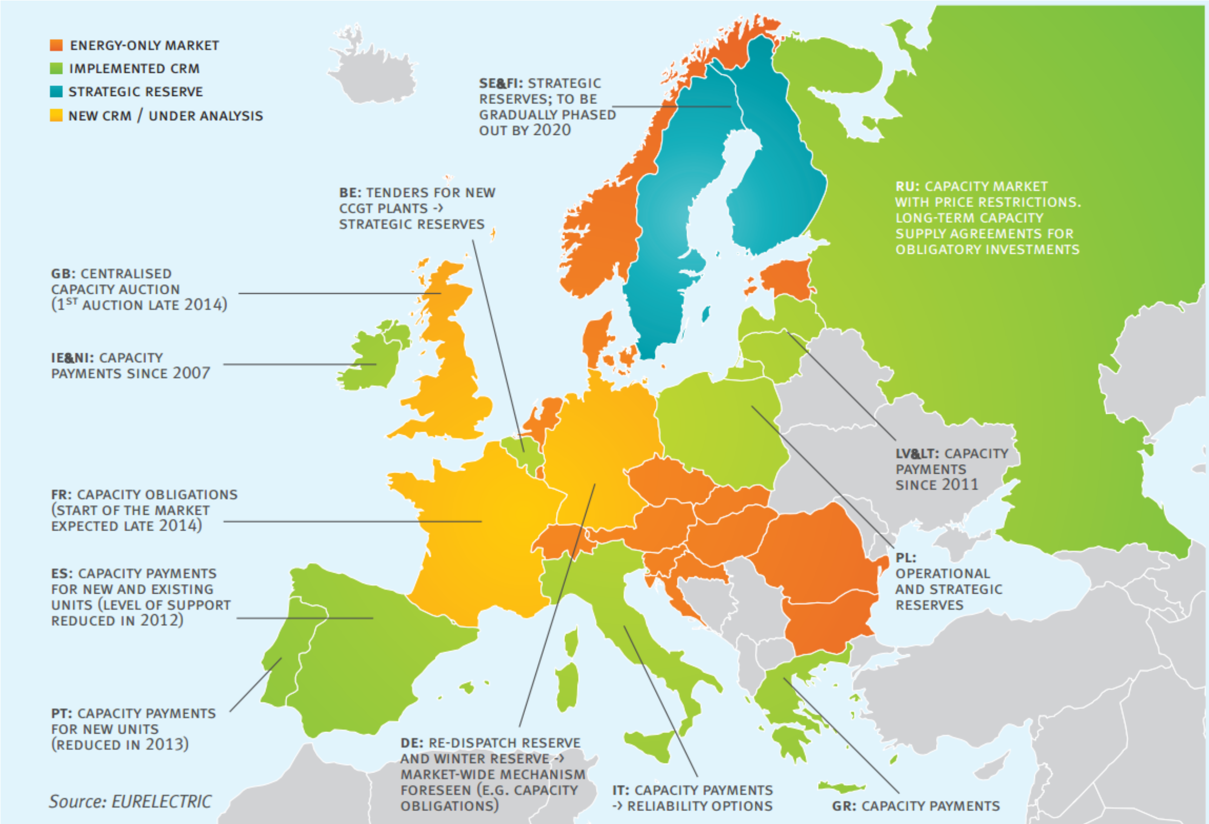


Figure 2.9: Implementation of CRM in Europe, as of June 2014 (EURELECTRIC, 2014).

The CRM used in Great Britain (GB) is capacity auction. The auction is a sub-category of capacity markets. The first auction was December 18, 2014. The needed capacity to ensure that peak demand is met for 2018/19 is estimated up front. Producers bid their capacity, promising the capacity will be available when needed. The reverse auction drives prices down and the cheapest capacity wins contracts. (Department of Energy & Climate Change, 2015)

Most renewables are ineligible to participate in the capacity market. In GB, renewables cannot enter the capacity market until support from other subsidies (Renewable Obligation/Contracts for Difference) is expired. They also need to fulfil the size-criterion. However, fossil-fired, nuclear, CHP and demand-side response are included. (Allen & Overy, 2013)

There is still a discussion if capacity mechanism should be implemented in Germany.

Norway has no capacity issue. Energy-only market is therefore sufficient.

Cross-border participation in CRM

CRM participation could also go beyond national borders. This would optimise cross border capacity, as well as compensate for their contribution to security of supply. Through the Guidance Package, the European Commission *requires* that CRM is to be open for foreign participation for other Member States (European Commission). This is also in line with the

European Commission’s target for the Internal Energy Market (IEM), which aim to coordinate and strongly interconnect the European system (European Commission, 2015).

Eurelectric, representing 3,500 companies in power generation, distribution, and supply in Europe, agrees with the European Commission on inclusion of cross-border participation in CRM. (EURELECTRIC, 2013). Despite of this, the design of such participation seems to meet challenges.

For the first capacity market auction in GB, it was not possible for foreign participation. This was due to complexity of interaction with the European market. The Government’s view was that “it is not appropriate for interconnectors to participate directly in a capacity market as interconnectors are primarily transmission infrastructure and therefore do not directly provide capacity”. However, GB is committed through the European Commission to work on a solution for this in the future. (Allen & Overy, 2013)

Allen & Overy suggests certain criteria that need to be fulfilled before allowing foreign participation. One solution is to let foreign power producers participate directly into the GB capacity market. Issues raised are then how to ensure that the plant actually delivers power to GB during stressed operations. Additionally, the plant should only receive capacity payment from one CRM at the time, it need to fulfil size-criterion and provide energy when needed. Another issue is whether the foreign capacity should reserve physical transmission rights. (Allen & Overy, 2013)

Eurelectric has also some proposals for cross-border participation. The main lines are that all participations must fulfil the same requirements and rules. It should only be allowed to participate in one CRM at a time. There should not be any cross-border capacity reservation for CRM. This final proposal means that the participation of CRM should not affect any other market involvements. Capacity can participate in other markets, like day-ahead, intraday and balancing markets, without any restrictions due to the participation of cross-border CRM. (EURELECTRIC, 2013)

Eurelectric propose models for cross-border participation. The main question is who is to be allowed to participate: the producers or the interconnector. Eurelectric also identifies that the product delivered vary. Should availability be paid for, or the actual delivery. The different proposals are presented in Figure 2.10. (EURELECTRIC, 2014)

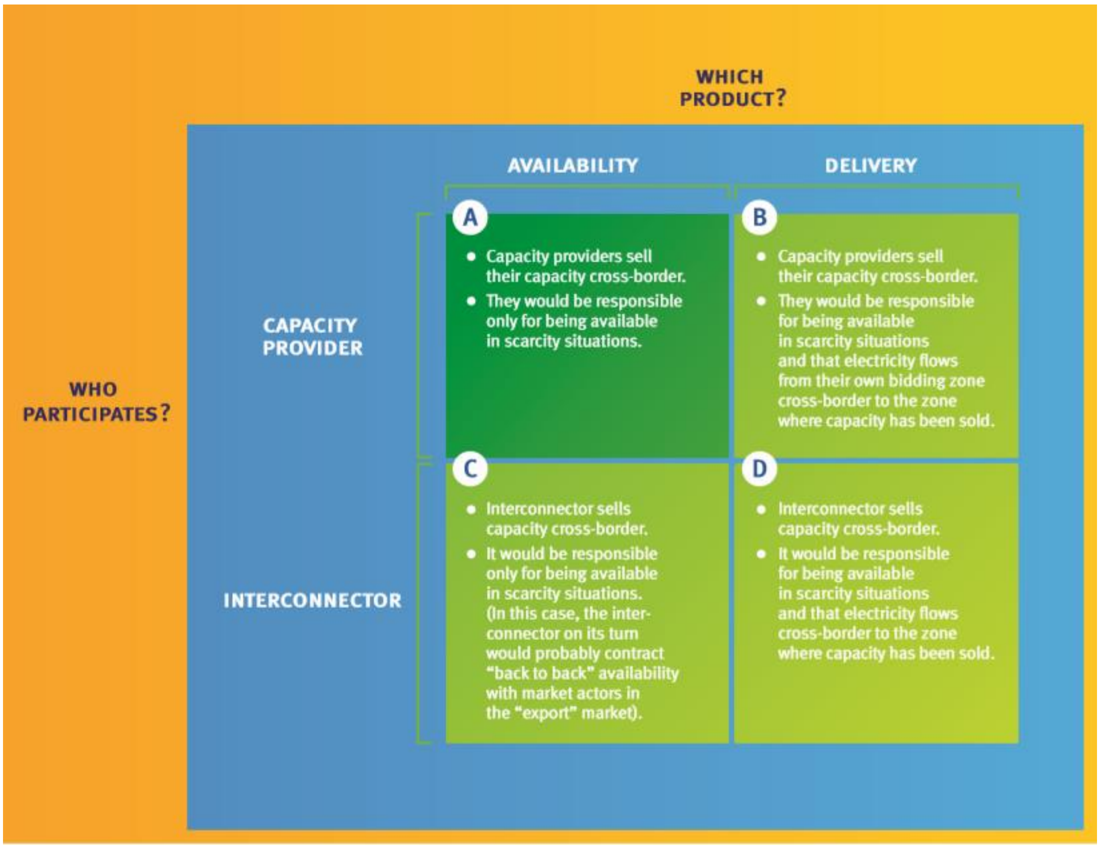


Figure 2.10: Options for cross-border participation in capacity markets (EURELECTRIC, 2014).

Eurelectric supports Model A from Figure 2.10. Their argument is that this model minimizes market distortion, and guarantees producers to participate, not regulated entities. Eurelectric do not see such participation as beneficial because interconnectors then compete with market participants, like generators, flexible consumer etc. Interconnectors will only profit from congestion rent in this model, i.e. price difference between areas. Model B and D might influence the merit order, as delivery is the product. This means that forced delivery outside the merit order might be preferred, distorting energy markets. Model C has the drawback of participation of the interconnector (EURELECTRIC, 2014).

Penalties for not providing obliged capacity

There should be penalties if the participants of CRM do not provide the desired capacity. Allen & Overy proposed that capacity participants are penalised if they do not fulfil its obligation given a 4-hour notice in advance of a stressed situation. The penalty is based on the amounted obligation and the value of lost load (rationing price) minus imbalance charge during the period of stress. Despite of this, exception from penalty could be valid if there are technical failures in the transmission grid: "where there is unmet demand or voltage reduction because of failures or deficiencies in the transmission or distribution systems, capacity market penalties will not apply" (Allen & Overy, 2013).

2.2 Power market simulator

The power market simulator used in this report is EMPS, developed by SINTEF Energy Research. EMPS is a well-known simulation tool used within the Nordic area, providing market analysis and price forecasts among other.

The data set used is developed by SINTEF, and intend to resemble the power system structure in year 2030. The data set is extensively described in a TWENTIES report evaluating possibilities of Nordic hydropower generation flexibility and transmission capacity expansion to support the integration of Northern European wind power production (Farahmand, Jaehnert, Aigner, & Huertas-Hernando, 2013). The only difference from the 2030 grid presented in the master thesis is that the offshore power grid is removed. This offshore grid connected intended wind farms in the North Sea together, providing additional exchange possibilities.

For comparison reasons, a data set for 2010 is used. This data set is also developed by SINTEF and is presented extensively in the Twenties report referred to above (Farahmand, Jaehnert, Aigner, & Huertas-Hernando, 2013).

2.2.1 EMPS main principles

The power market simulator run a data set with a given installed capacity. The power system evaluated in this report is for year 2030 except of one comparison to a data set for 2010. Given this system, different climatic years from historical records are run. Variations in inflow, precipitation, solar, wind etc. can then be evaluated for a specific data set. There are 75 climatic years that are simulated. This is recorded from year 1931 to 2005.

The simulation tool optimizes with respect to socio-economic surplus. EMPS aim to optimise the use of water resources, taking uncertain inflow and thermal production into account. Water has an opportunity cost, i.e. the water used today cannot be used tomorrow. The opportunity cost, known as the water value gives the water a marginal cost, used for production planning in a system containing different production units (SINTEF, 2012).

The simulator is divided into a strategy phase and simulation phase. First, the strategy computes water values for hydro areas, creating a long term strategy of utilizing the reservoir. Then, the simulation takes different climatic years into account, verifying the strategy determined.

In order to emphasize variability in wind and solar production, sequential resolution is used instead of weekly. Each sequence is 2 hours during the weekdays and 4 hours in the weekend. Each week consists then of 72 sequences.

EMPS is a transport model, i.e. there are no underlying power flow. Each country is divided into areas, and the data set has 56 areas in total included, resembling Northern Europe and its interconnections. Exchange at the borders of the data set is modelled by a fixed exchange based on historical data. This way, also exchange outside the simulated areas are taken into account. AC transmission limitation is included in the model by a reduced transmission capacity factor of 0.7 (Farahmand, Jaehnert, Aigner, & Huertas-Hernando, 2013).

2.2.2 Allocation and aggregation

In EMPS, hydro areas can be modelled both with aggregated and allocated production. An illustration of the aggregation is shown in Figure 2.11. Usually, hydro areas are first aggregated in the strategy part, before the production is allocated to each plant in the simulation part. There are also a connection between these modules, ensuring that the optimal strategy on aggregated level is possible when allocating it to each plant as well. However, this allocation is time consuming. Therefore, under some circumstances, it is beneficial to solve everything on aggregated level. However, this leads to loss of some details as coupling between reservoirs. Thermal areas are always modelled on aggregated level.

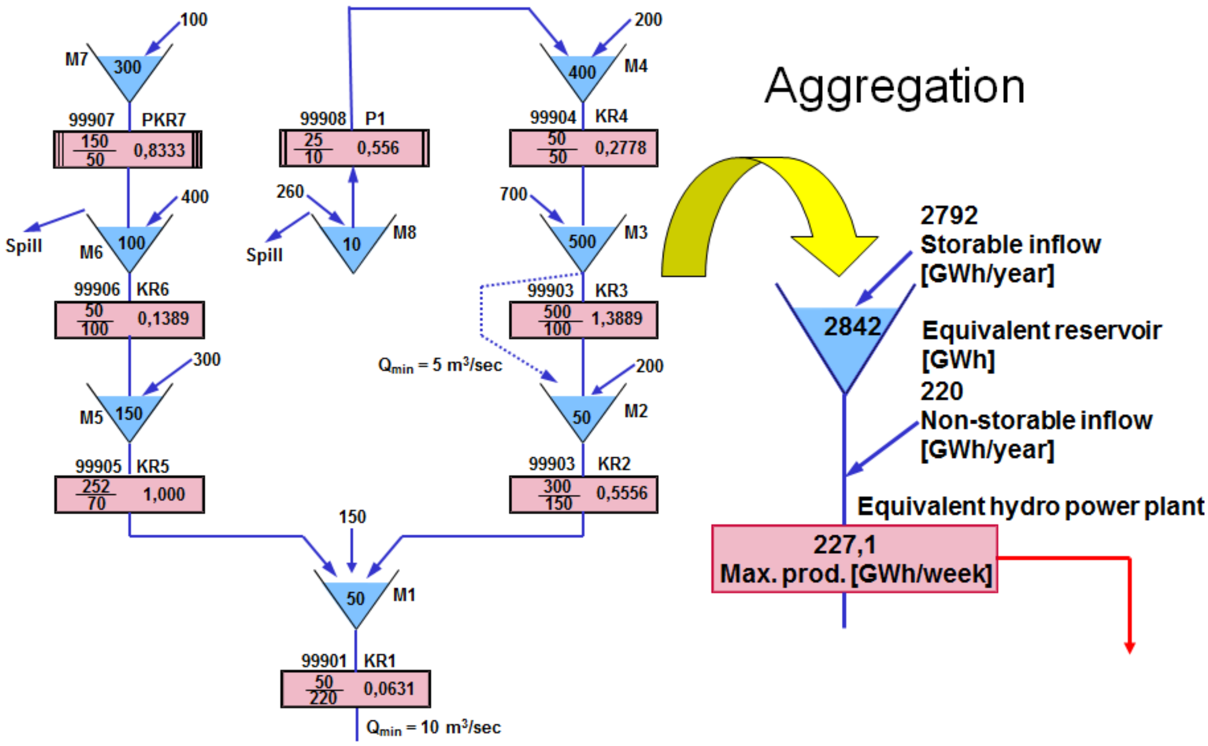


Figure 2.11: Aggregation of hydro areas [user manual EMPS].

2.2.3 Rationing and flexible load

Rationing is performed when load is disconnected involuntarily due to lack of power production. The price of involuntary load shedding should correspond to the loss for consumers if electricity is unavailable. The price for rationing is set to be 3000 EUR/MWh in the model. This is significantly higher than the most expensive production unit (136.5 EUR/MWh). This method shows how the involuntarily part is taken into account. Producers will always try to produce energy when the price rises so high – even if the need for power is only for short periods.

Flexible load is included between the most expensive production unit and rationing. Like production units, flexible load has stepwise resolution with different amounts to different prices.

2.2.4 Thermal power production

Fossil fuel is assumed constant in cost, but with CO_2-price increasing from 13 to 44 EUR/ton for year 2010 and 2030 respectively, following current policy.

A "cold start" could last up to several days, depending on the production source. Start-up costs in thermal-based areas should therefore be included to adapt to the real situation. Then, the marginal cost of thermal units does not just take fuel cost into account, but also emphasizing start and stop cost.

If the area price for one hour is below the marginal cost, the unit would, without start-up cost included, be shut down during this hour and started again the hour after. However, if the start-up cost is included, the area price can be below the marginal cost and the production unit continue producing, as long as the deviation is less than the start-up cost.

If this extra cost is included, the prices are more volatile due to more power production than necessary in some hours, and less in others, i.e. producers are not willing to turn off for certain low-priced hours, and require higher price to turn on.

Regarding EMPS, including start-up increases the calculation time significantly.

For the market cross, including start-up cost interrupts the merit order. In the real power market, this cost could be taken into account through "block-bids", which are bids into the spot market that goes over several hours.

2.2.5 Exchange capacity from Norway to continental Europe

In 2010, the total exchange capacity was 1.6 GW, 0.7 GW NorNed and 0.9 GW at Skagerrak 1-3 respectively. This capacity is expected to increase. Figure 2.12 shows the expected exchange capacity development from the Nordic synchronous area in 2020. Skagerrak 4 (0.7 GW) was commissioned in December, 2014. It is decided to build 1.4 GW connecting Norway to Germany (Nord.Link) and the link is expected to be commissioned in 2018. It is also decided to build 1.4 GW connecting Norway and Great Britain (NSN), which is expected to be commissioned in 2020 (Statnett SF, 2013). Additionally, NorNed II with 0.7 GW is included in the data set for 2030. This increases the total HVDC-cable exchange capacity from Norway by 4.2 GW.

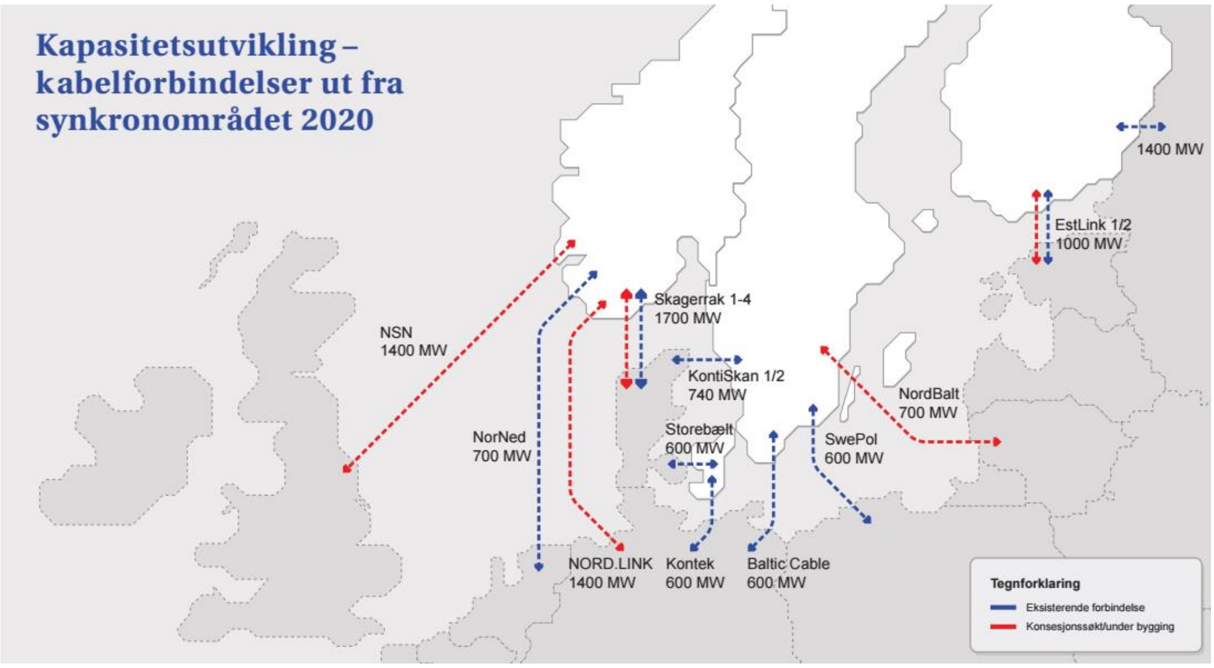


Figure 2.12: Capacity development from the Nordic synchronous area 2020. (Statnett SF, 2013).

3. Transmission cable and production outage study

This chapter consists of statistical unavailability data for HVDC-cables and different types of power plants as well as a description of the outage modelling.

3.1 Unavailability statistics

The following sections present unavailability statistics for HVDC-cables and production units.

3.1.1 HVDC-cables

The European Network of Transmission System Operators for Electricity (ENSTO-E) develops yearly HVDC-statistics for cables connected to or within the Nordic synchronous area. A sub-group of ENTSO-E named Regional Group Nordic collects the following statistics. The group has participations from Transmission System Operators (TSO) in all Nordic countries.

HVDC is preferred to transfer energy over great distances in front of HVAC. This is mainly due to no reactive power loss, as well as smaller cross section needed to transfer equal amounts of power.

Figure 3.1 allocates the links geographically for 2014. In total, 15 cables, with a technical exchange capacity of 70.5 TWh/year are connected. The exchange capacity *to* the Nordic synchronous area is 6.6 GW. (Regional Group Nordic, 2014)

Figure 3.1: HVDC-cables overview connected to or within the Nordic Synchronous area. (Regional Group Nordic, 2014).

Figure 3.2 presents the utilization of HVDC-links separated by unavailable, transmission and technical capacity not used. The entire pillar is E_{max}. E_{max} is the maximum energy that can be transferred including losses.

Statistics from 2012 and 2013 are used, due to the recently more consistent reporting (statistics for 2014 are not published yet). EstLink 2 was commissioned in 2014, so statistics for this link is left out.

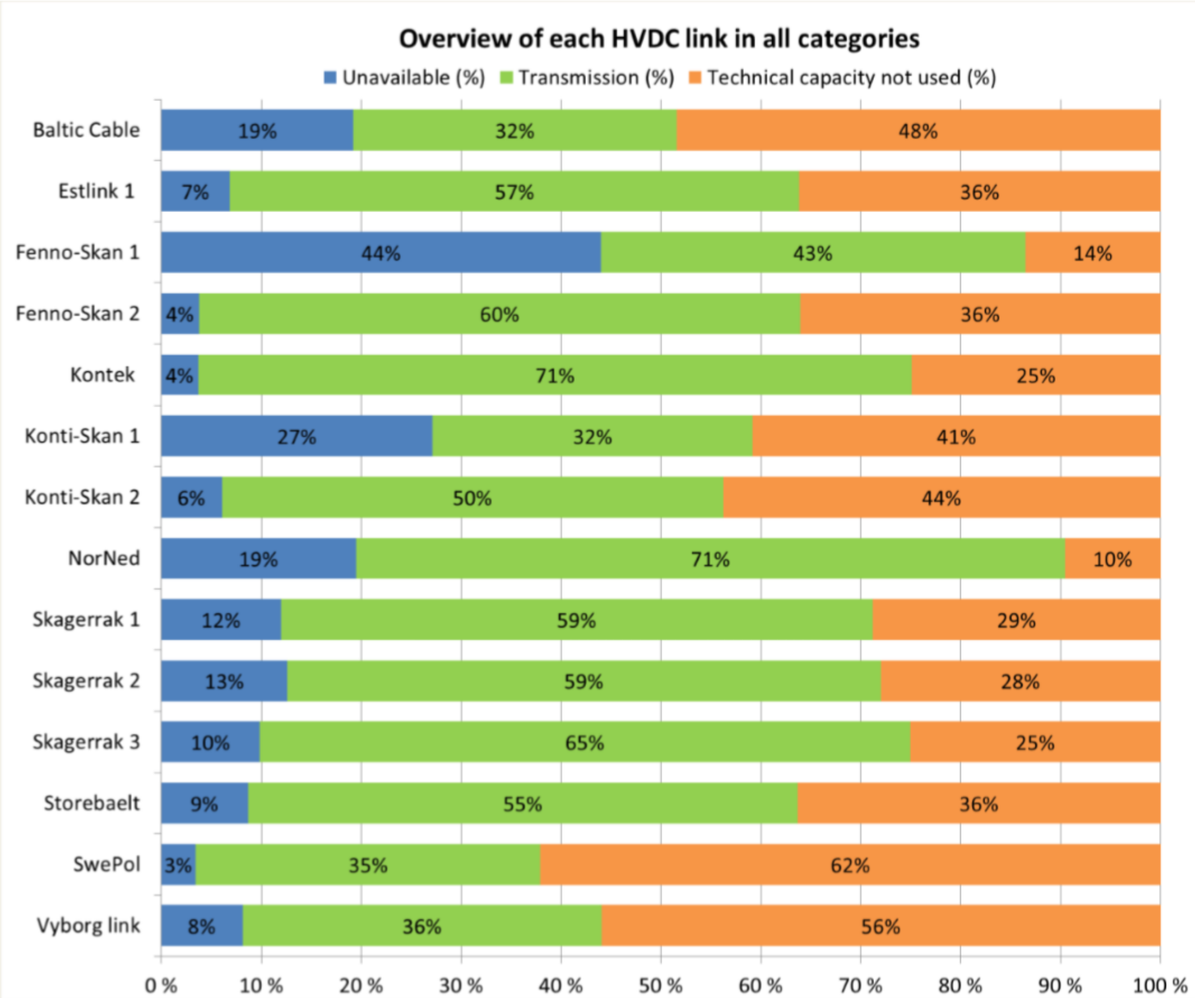


Figure 3.2: Annual overview of HVDC-links in 2013 (Regional Group Nordic, 2014).

E_U is used to identify unavailable exchange capacity. E_U is the affected transfer capacity multiplied with the time of unavailability. In 2013, the E_U on average for all links was 13.2 %. The corresponding statistics for 2012 was 11 %. (Regional Group Nordic, 2013) Combined, the average E_U is 12.1 %.

Subcategories of *unavailable* are disturbance outage, maintenance, other outage and limitations. Disturbance outage is defined as "forced or unintended disconnection or failed reconnection as a result of faults in the power grid". (Regional Group Nordic, 2013) Often, a forced unplanned outage is a valid description. Limitation is usually referring to the events in the interconnected AC-grid that affect the exchange capacity.

The share of subcategories for unavailability varies. In addition to disturbance outage, maintenance of the link including its stations and limitation in AC-grid are major factors. Limitation in AC-grid is often a result of maintenance or upgrading here. Both of these categories are usually possible to perform at suited time in order to reduce consequences.

Figure 3.3 shows subcategories of the figure above for NorNed, split over the year. The unavailable exchange capacity in 2013 was 19 %. The majority of the unavailable capacity was due to disturbance outage, and small parts due to limitation and maintenance of the cable. Limitations on NordNed are usually caused by maintenance or work in the interconnected AC-grid. Limitations and maintenance of the cable are therefore usually predictable, and can be carried out on suited time. The figure below shows that both are greatly influencing the exchange on late summer – a period that usually do not depend so much on exchange capacity due to low load.

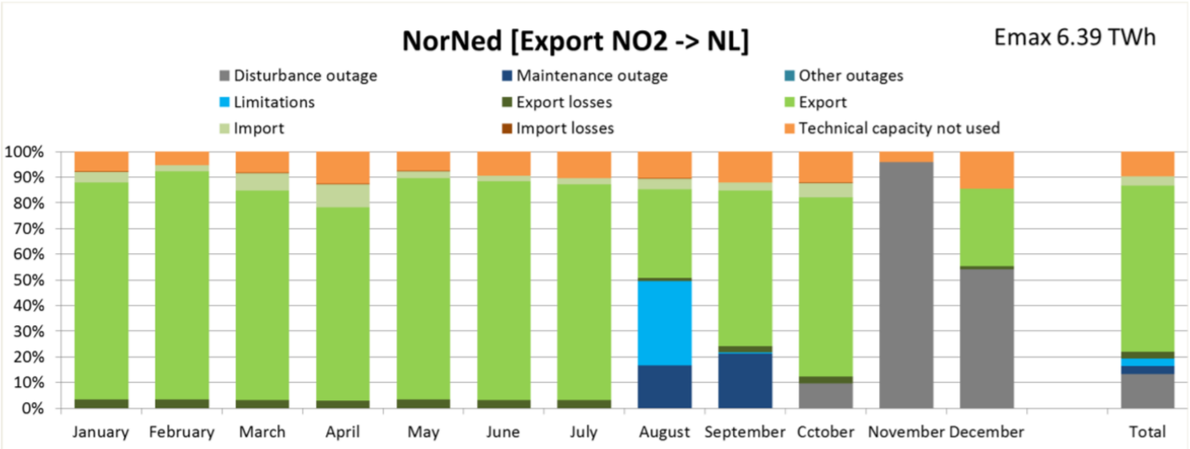


Figure 3.3: Share of energy on NorNed divided over the year (Regional Group Nordic, 2014).

Figure 3.4 and Figure 3.5 presents the unavailability (E_U) of all cables in 2012 and 2013 caused by disturbance outage in percent of E_{max}. There were some extensive outages in the evaluated years, affecting Fenno-Skan 1 and 2, the Baltic cable and NorNed. The highest E_U caused by disturbance outage did reach 25 % of the annual E_{max}. This resembles 13 weeks with no exchange capacity. These events confirm that outages might restrain the exchange capacity significantly.

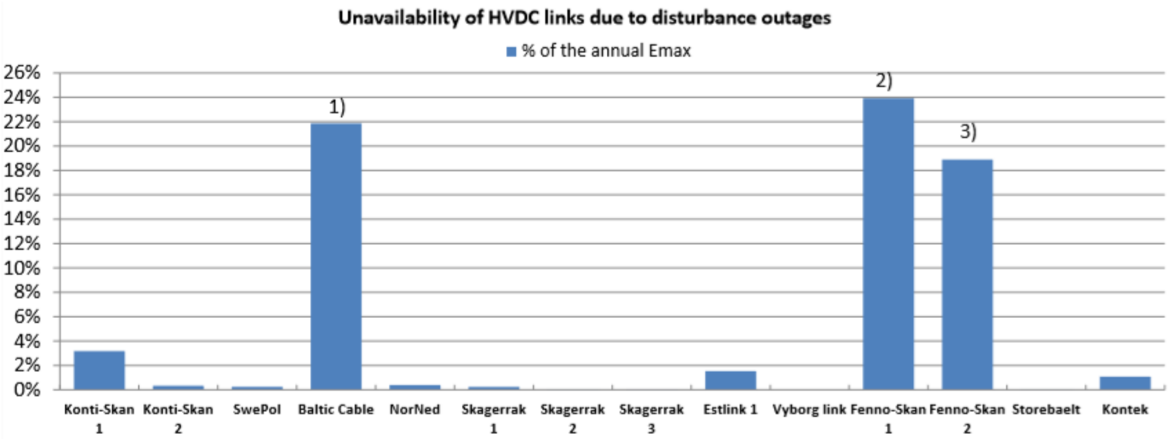


Figure 3.4: Unavailability due to disturbance outages in 2012 (Regional Group Nordic, 2013).

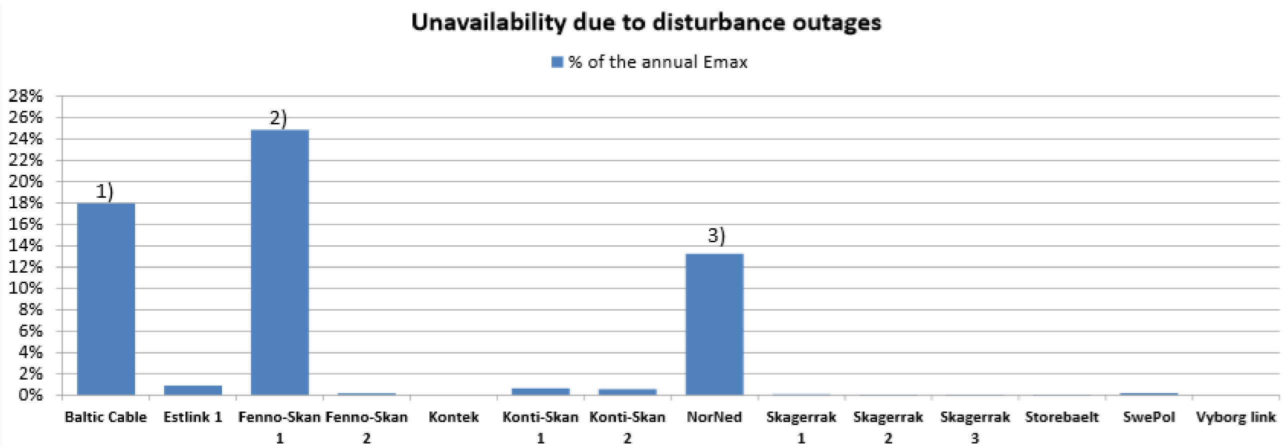


Figure 3.5: Unavailability due to disturbance outages in 2013 (notice the change in x-axis compared to previous figure) (Regional Group Nordic, 2014).

The average E_U caused by disturbance outages in the period 2012-2013 was 4.7 %. Converted to weeks this is 2.4 weeks/year per cable. The number of disturbance outages varied between 0 and 14, with an average of 4 events. (Regional Group Nordic, 2013; Regional Group Nordic, 2014)

Tree numbers from the HVDC-cable statistics are referred to later in the report. These are the average E_U of 12.1 % (6 weeks), the average E_U caused by disturbance outage of 4.7 % (2.4 weeks) as well as the highest E_U caused by disturbance outage of 25 % (13 weeks).

3.1.2 Power production units

There are several sources of statistical data for production units and their unavailability. In this report, statistics from ENTSO-E and EURELECTRIC are considered.

Statistics from ENTSO-E

ENTSO-E delivers yearly statistics and adequacy of the European power system, including specific statistics for production units. ENSTO-E represents 41 TSOs from 34 countries across Europe. (ENTSO-E, 2014)

Table 3.1 presents the power balance for *December* in 2011, 2012 and 2013. *Outages*, a sub category of *Unavailable Capacity* gives the capacity in [GW] unavailable due to an outage. ENTSOE defines outages as forced outage, which is in line with RGN's definition of disturbance outage. The amount is relatively constant, about 2.4 % of Net Generation Capacity (NGC) on average. This number is found by using the average unavailable capacity caused by outage for December in the period 2011-2013, and dividing it by the NGC in the same period. However, the amount is on aggregated level, and does not reveal the production source details.

Table 3.1: ENTSO-E power balance for December 2011-2013 (ENTSO-E, 2014).

GW	2011	2012	2013	Change 2013 to 2012	
				Absolute value (MW)	%
Net Generating Capacity	**935.5**	**978.6**	**992.4**	**13.9**	**1.4%**
Fossil fuels power	454.8	458.4	449.1	-9.2	-2.0%
Nuclear power	125.7	125.4	126.3	0.9	0.7%
RESs power (incl. renewable hydro)	284.3	357.1	381.2	24.1	6.7%
Non-renewable hydro power	66.1	36.8	35.0	-1.9	-5.1%
Not clearly identif. energy sources power	4.5	0.9	0.8	-0.1	-9.6%
Unavailable capacity	**270.6**	**327.0**	**327.9**	**0.9**	**0.3%**
Non-usable capacity	189.4	230.5	235.0	4.5	2.0%
Maintenance & overhauls	30.2	36.0	39.0	3.0	8.4%
Outages	20.0	27.6	22.9	-4.7	-17.0%
System services reserve	31.1	32.9	31.0	-1.9	-5.9%
Reliable Available Capacity	**664.9**	**651.6**	**664.6**	**13.0**	**2.0%**
Load	**473.5**	**481.3**	**475.4**	**-6.0**	**-1.2%**
Remaining Capacity	**191.4**	**170.3**	**189.2**	**18.9**	**11.1%**
Exchanges	**-2.2**	**-1.1**	**-0.1**	**1.0**	**-91.6%**
Imports	51.2	46.1	59.6	13.5	29.2%
Exports	53.4	47.2	59.7	12.5	26.5%

Figure 3.6 presents sub categories of unavailable capacity during 2013 on a European level. The share of outages compared to NGC seems rather stable over the year. Outages vary between 2.3 % and 3.2 % (between 22.5 and 31.8 GW respectively) of NGC over the year.

(ENTSO-E, 2014) The figure also reveals that *maintenance & overhauls* provide a significant share of the unavailable capacity for production units.

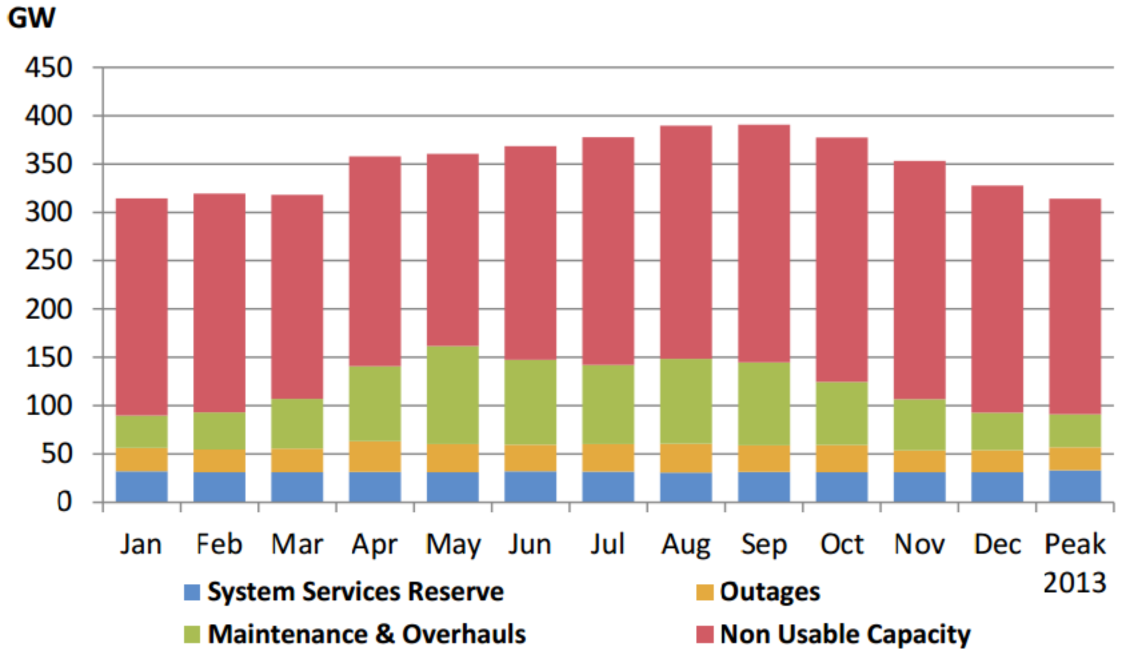


Figure 3.6: Unavailable capacity and its structure overview in 2013 (ENTSO-E, 2014).

Statistics from EURELECTRIC

The Union of the Electricity Industry (EURELECTRIC) represents participants of the electricity industry within Europe, as well as some countries outside the continent. (EURELECTRIC, 2012)

Their report *Power Statistics & Trend 2012* provides more detailed unavailability statistics for production units than ENTSO-E. The detail level separates fossil-fired units from other production sources.

EURELECTRIC divides unavailability into two sub categories: planned and unplanned unavailability. The relation is shown in Figure 3.7. Planned unavailability means that the unavailability was determined more than 4 weeks in front of the event. This category can be resembled to “maintenance” in statistics for cable outages developed by Region Group Nordic. Unplanned unavailability is detainable less than 4 weeks in front of the event. Further, the sub categories “postponable” or “not postponable” are determined by whether it can be detained by 12 hours or not.

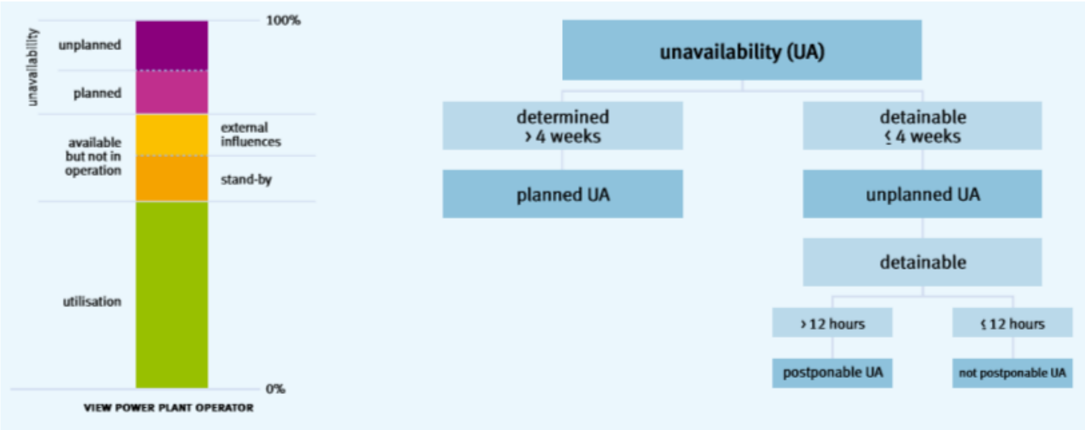


Figure 3.7: Definitions of availability and utilisation of power plants (EURELECTRIC, 2012).

The category used for disturbance outage in cable statistics developed by Regional Group Nordic (ENTSO-E) and production statistics developed by EURELECTRIC do not entirely fulfil each other. However, it is assumed that unplanned unavailability that are *not* postponable resembles disturbance outage (forced outage) in the cable statistics.

Table 3.2 shows availability and unavailability of fossil-fired units for the period 2002 to 2011. The gathered statistics are from Austria, Czech Republic, Germany, France, Italy, Netherlands, Poland and Portugal - representing a total net capacity of 788.8 GW.

Table 3.2: Availability statistics of fossil-fired units 2002-2011 (EU countries AT, CZ, DE, FR, IT, NL, PL, PT) (EURELECTRIC, 2012).

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	02-11
Number/Unit Years	237	239	247	249	249	252	250	239	244	248	2,454
Capacity (gross) (MW)	73,585	75,543	80,122	80,942	79,538	80,672	80,368	75,882	80,015	82,104	788,770
Time Availability (%)	83.3	87.7	87.0	86.8	86.8	85.9	84.2	83.3	83.5	83.4	85.7
Time Utilisation (%)	60.3	61.9	61.7	62.4	63.7	66.7	61.7	62.4	59.5	59.2	62.0
Energy Availability (%)	87.2	85.4	84.3	84.2	83.4	83.3	82.4	80.7	82.3	81.7	83.5
Energy Unavailability (%)	12.8	14.6	15.7	15.8	16.6	16.7	17.6	19.3	17.7	18.3	16.5
planned part (%)	7.2	6.9	8.0	8.7	9.3	8.7	9.5	10.4	10.6	9.7	8.9
unplanned part (%)	5.6	7.7	7.7	7.1	7.3	8.0	8.1	8.9	7.0	8.6	7.6
postponable (%)	1.0	1.1	1.2	1.4	1.6	1.3	1.4	2.1	1.5	1.7	1.4
not postponable (%)	4.6	6.7	6.57	5.7	5.7	6.7	6.7	6.8	5.6	7.0	6.2
Energy Utilisation (%)	51.0	53.1	52.7	53.2	52.9	55.2	51.0	51.8	50.3	49.4	52.1

Fossil-fired units are unavailable due to unplanned not postponable events 6.2 % of total on a ten-year average. This corresponds to an annualised outage of 3.2 weeks.

3.2 Outage simulation

Nord.Link, the intended 1.4 GW connection between Norway and Germany, is used to investigate outage. However, the exact link investigated is not that important. The importance is that outage is modelled on a link between hydro dominated and thermal-based areas consisting of much wind and solar. This is due to the different production structures. These areas can utilize each other as the correlation between available resources are not that strong. If an outage then reduce the exchange capacity, the consequences are more visible than if the production structures on both sides were equal.

3.2.1 Outage modelling

All transmission outages simulated in this report are unexpected, i.e. not included in the strategy part. This is done by using the strategy computed for the system without outage, and then implement an outage directly in the simulation part. This way, producers do not know about the outage before the very moment it occur. For hydro areas, this affect planned production and water levels.

The same approach is done for production outage: Strategy is computed without any outage, while the simulation take the outage into account. Two gas power plants in Germany with a total capacity of 1.4 GW are closed for a specific period. Their marginal cost were 61.8 and 64.5 EUR/MWh. This is medium prices for such units in the data set for 2030.

Only one yearly outage is implemented with a certain duration in each simulation. This outage lasts for the exact same period each of the 75 climatic simulated years. The number of outages (split in several periods over the year) is not important. The importance is whether capacity is available when needed. This is during tight operations. Therefore, all evaluated outage periods start at the beginning of the first week each year. The chance of power capacity shortage is greater because load is relatively high at this time.

3.2.2 Outage length

The average energy unavailable caused by disturbance outage for 2012-2013 was 4.7 % of E_{max} per cable. This resembles an annualized outage period of 2.4 weeks. The main simulation for transmission outage uses then 3 weeks outage length due to the weekly outage resolution in the model.

However, some cables did experience greater reduction in exchange. The highest unavailability caused by disturbance outage exceeded 25 % of E_{max} on yearly basis. This resembles 13 weeks with loss of exchange capacity. Such long run events are taken into consideration in sensitivity analysis. The longest modelled transmission outage lasts for 15 weeks.

3 weeks outage is the outage length for fossil-fired production units. This is due to two factors: First, fossil-fired production units were found to have an historical annualized

outage period of 3.2 weeks. Secondly, it makes the results directly comparable to the main exchange outage period.

4. Results

The results intend to show consequences of transmission and production outages in order to evaluate the importance of their individual availability.

The first section provides assumptions for the following results. Further, the result chapter is divided into three main parts:

- Transmission cable outage
- Power production outage
- Impact of including start-up cost for thermal power plants

Table 4.1 shows the content of the three main sections. The sections are presented in the same order as listed below, starting from the left top, and going vertically down.

Table 4.1: Overview of the chapter

Extensively investigated	Transmission cable outage	Production outage	Start-up cost included
EOM – Worst year	X	X	X
EOM – Median year	X		
CRM – Worst year	X		

Transmission outage is the most extensive section including analysis of different market solutions, i.e. different amounts of thermal capacity installed. Each response is extensively documented. This is done to provide information of the model, as well as verifying the results.

The *Production outage* section includes outage of thermal power production with the same capacity as the transmission cable. It shortly presents consequences in price and surpluses for various stakeholders.

Impact of including start-up cost for thermal power plants section evaluates the impact of start-up cost in the simulations. Start-up cost is left out in all previous simulations because these calculations are very time consuming. This section evaluates the validity of all the simulations that do not consider this extra cost.

In the end of the result chapter there is a comparison between prices in Norway for power system configurations in 2010 and in 2030. These simulations are performed to see how Norwegian prices are affected by the expected increase in exchange capacity to continental Europe.

4.1 Assumptions

All simulations are done in EMPS mainly with a data set for year 2030. The last section, however, uses a data set for 2010. The model and its data set are presented in section 2.2.

All outages affect the intended cable Nord.Link, interconnecting Norway and Germany. Further information of the outage modelling is presented in section 3.2.

The outage simulations are divided into two parts: Energy-Only Market (EOM) and Capacity Remuneration Mechanism (CRM). CRM is modelled as increased thermal capacity in Germany. A detailed explanation of these market solutions are presented in section 2.1.2.

Furthermore, the first five weeks of the year are extensively analysed. This is a critical period due to higher chance of stressed situations, i.e. lack of power production. The beginning of the year has high load and usually lower production, especially from solar energy.

The analyses are done for the *worst year* with high prices and the *median year* with a normal price level. Both years are chosen from the yearly average price in Germany from the system without any outage. Given the data set of 2030, the worst year is the climatic year of 1973, and the median 1981.

Each outage starts from the beginning of week 1. Each week consists of 168 hours, and one year is 8760 hours.

All prices are weighted prices, i.e. the price of the system values the amount of energy in each price area. In this way, a small area with high prices does not have large impact on the average prices.

All socio-economic surpluses and consumer surpluses presented are yearly surpluses.

4.2 Transmission cable outage

The simulations intend to reveal market consequences for cable outages that limits the exchange between hydro- and thermal-based areas.

Table 4.2 shows the three parts of the transmission cable outage section. The sub-sections are presented in the same order as listed below, starting from the top, and going vertically down.

Table 4.2: Overview of the transmission outage section

Extensively investigated	Transmission cable outage
EOM – Worst year	X
EOM – Median year	X
CRM – Worst year	X

4.2.1 Energy-only market - worst year

The first part gives an overview of the worst year power situation in the system. Consequences in prices and surpluses of various stakeholders appear in the end of this section.

Load

Figure 4.1 shows the firm load in Germany for the first five weeks (840 hours). The load is relatively low up to hour 170 because of the holydays, with daily fluctuations caused by the day/night consumption, as well as lower load in the weekends. The load then reaches 100 GW. The day/night difference is about 25 % of the total load. The capacity of 1.4 GW of Nord.Link is small compared to the peak load (1.4 %).

It should be mentioned that the load in Germany follows a yearly unchanged pattern for all 75 simulated years.

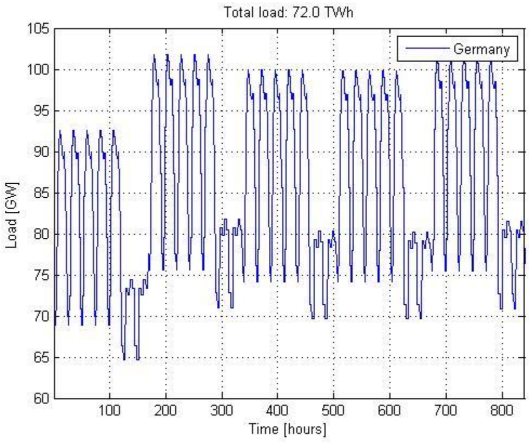


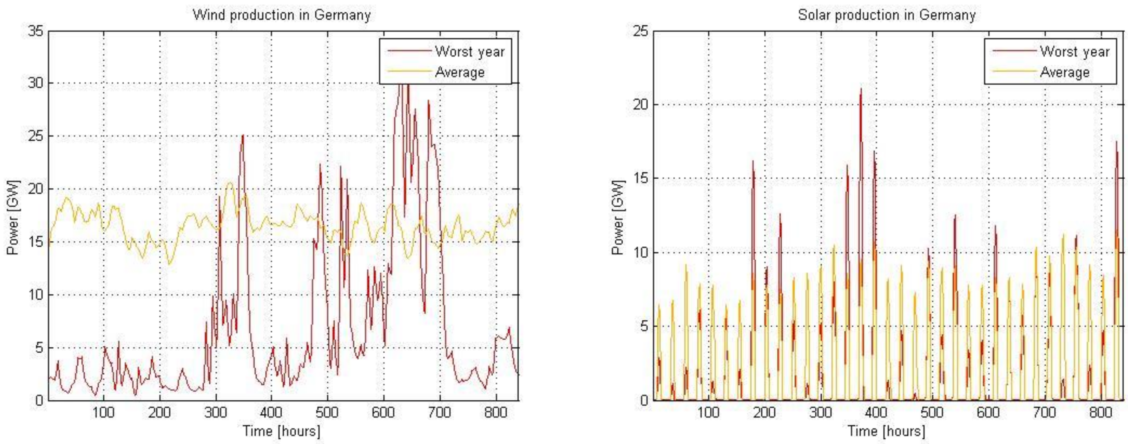
Figure 4.1: ***Firm load*** *the first five weeks in Germany.*

Wind and solar power production

Figure 4.2 (1) shows wind production on average and in the worst year in Germany for the first five weeks. Overall, the worst year has low wind production compared to the average of all 75 simulated climatic years. Still, there is great volatility, and power production vary between 1 and 30 GW in this period. At its maximum, production from wind has a share of almost 1/3 of the peak load in Germany.

Figure 4.2 (2) emphasizes the intermittence of solar production. Production in the worst year varies between 0 and 21 GW, with evident daily fluctuations. However, also the average goes down to zero production at night.

When comparing the figures, it is clear that only coincidences decide the amount of wind and solar energy. It is evident that a system dominated by such units needs sufficient back up generation to avoid power capacity shortage.



(1) (2)

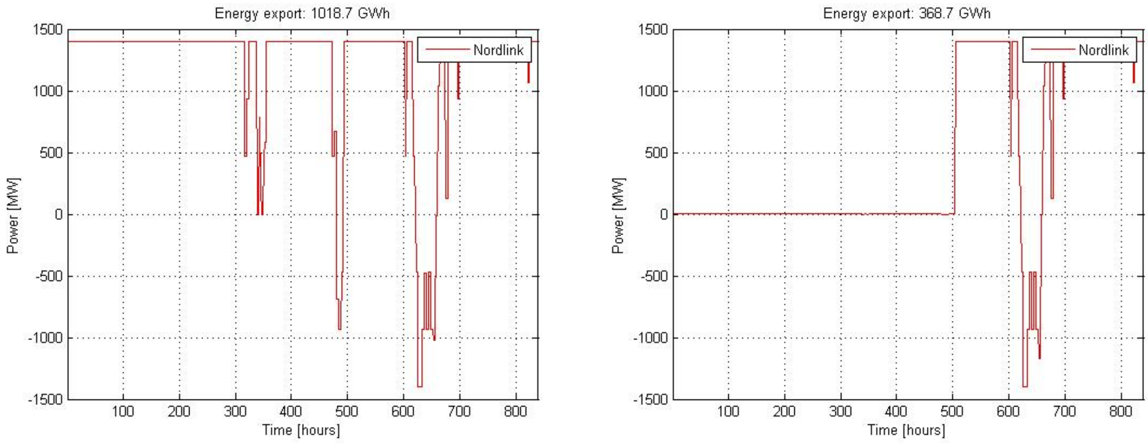
Figure 4.2: ***Production*** *in the first five weeks in* ***Germany*** *from (1) wind and (2) solar energy.*

Exchange

Figure 4.3 (1) shows that Nord.Link, with its capacity of 1.4 GW, usually exchange power *from* Norway to Germany these first five weeks in the worst year. However, when wind production is high and the load in Germany low, the flow turns.

Three specific periods sticks out: around the hours 330, 490 and 620. When comparing these figures to the previous figures for Germany, hour 330 has high wind, low solar and high load. The exchange is close to zero. At hour 490, the wind is high, solar is medium, but load is low. The exchange has turned, and Norway imports energy. At the final peak, hour 620, wind is at its peak with almost 30 GW, solar is low, and load is low. At this point, the capacity is used to exchange power from Germany to Norway. It seems to be a strong correlation between wind production and exchange to Norway.

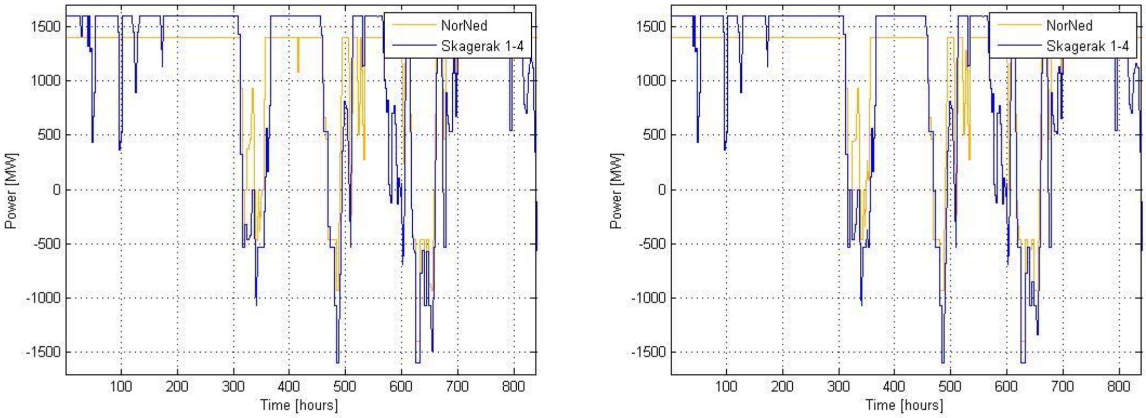
However, when outage occurs for three weeks, as confirmed in Figure 4.3 (2), the link is unavailable and the previous net export from Norway is reduced. Given these results, it is assumed that the outage gives higher prices in Germany.



(1) (2)

*Figure 4.3: **Exchange on Nord.Link** referred to Norway the first five weeks in the worst year with (1) no outage and (2) 3 weeks outage of Nord.Link.*

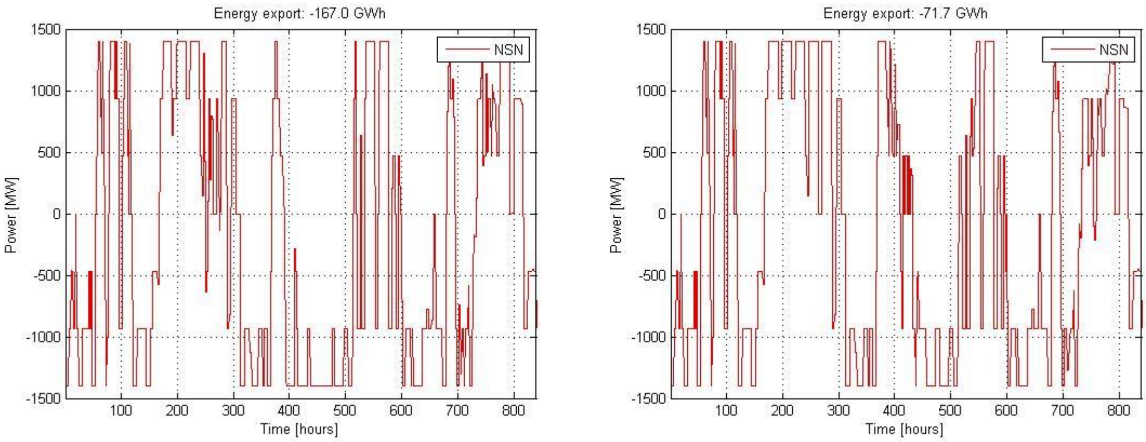
When outage occurs on Nord.Link, rerouted power flow through other links could be assumed to cover the loss of one link. However, this does not seem to be the case. Figure 4.4 shows exchange on NorNed and Skagerrak 1-4, respectively connecting Norway to the Netherlands and west-Denmark. There are close to no visible changes in exchange when outage occurs on Nord.Link.



(1) (2)

*Figure 4.4: **Exchange on NorNed and Skagerrak 1-4** referred to Norway the first five weeks in the worst year with (1) no outage and (2) 3 weeks outage of Nord.Link.*

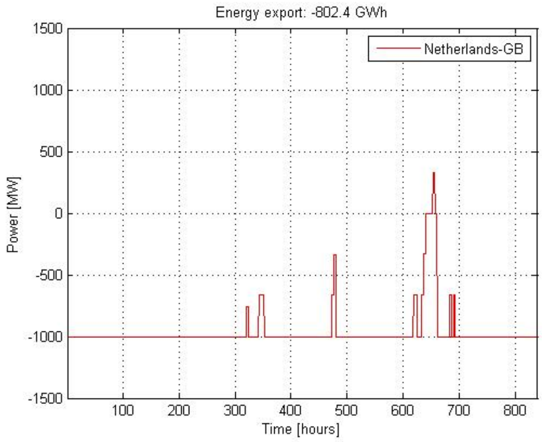
Figure 4.5 shows power exchange on NSN for the first five weeks of the worst year. NSN connects Norway to Great Britain. When outage of Nord.Link occurs, it is observed that more energy is transferred from Norway to Great Britain. The energy export referred to Norway increases by 95 GWh when outage occurs on Nord.Link.



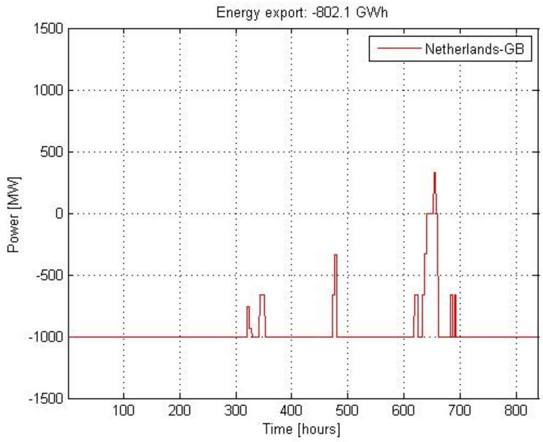
(1) (2)

*Figure 4.5: **Exchange on NSN** referred to Norway the first five weeks in the worst year with (1) no outage and (2) 3 weeks outage of Nord.Link.*

However, as Figure 4.6 shows, there is a great congestion on the link between Netherlands and Great Britain. The rated exchange capacity towards continental Europe is full in the worst year. The outage of Nord.Link cannot be compensated by extra power flow through Great Britain. This also explains the extra flow on NSN. It is not due to the desire of more power import to continental Europe. It is desired to export power from Norway.



(1)



(2)

*Figure 4.6: **Exchange on Netherlands-GB** referred to Netherlands the first five weeks in the worst year with (1) no outage and (2) 3 weeks outage of Nord.Link.*

There are also links from Denmark to Germany and Sweden to Germany (Baltic cable). These cables follow the same pattern as the presented links above: There are close to no visible changes in exchange when outage occurs on Nord.Link, because their capacity is already exploited in hours with power capacity shortage on the continent. The power flow from Denmark and Sweden to Germany are presented in Appendix A.

It is clear that if transmission cable outage occurs in hours with power capacity shortage on the continent, there is not necessarily available capacity on other links to cover the loss of power exchange.

Flexible load

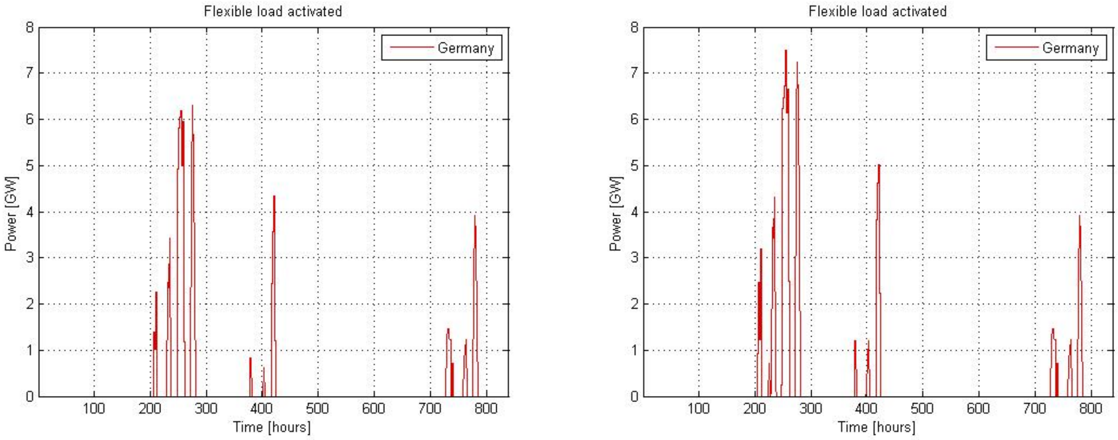
Flexible load is used to compensate for power production shortage. 136.5 EUR/MWh is the marginal cost of the most expensive production unit in Germany. When prices exceed this, all available production units produce their rated capacity.

Figure 4.7 (1) shows activation of flexible load in Germany without outage of Nord.Link for the first five weeks in the worst year. The use of flexible load is high between hours 200-300, peaking 6 GW at highest value. These periods have low wind, medium solar and high load. The distinct fluctuating peaks are due to the day/night consumption.

Overall, it seems to be a strong correlation between wind energy and use of flexible load. The only low wind period without use of flexible load is up to hour 200 (first week). Here, flexible load is not necessary due to the low load caused by the holidays.

Figure 4.7 (2) shows the use of flexible load in Germany with Nord.Link out for three weeks. The direct consequence is 1.4 GW unavailable exchange capacity. Comparing these figures to each other, this amount is possible to recognize. The very high peaks around hours 200-300 increase by approximately 1.4 GW when Nord.Link is out. The spikes around hour 400 increase by 0.6 GW. However, the price peaks between hours 700-800 do not seem to change at all. This is due to Nord.Link is put in operation after hour 504 (three weeks).

Knowing that use of flexible load is expensive, these figures indicate that the price in Germany is high, and that the outage makes prices even higher.

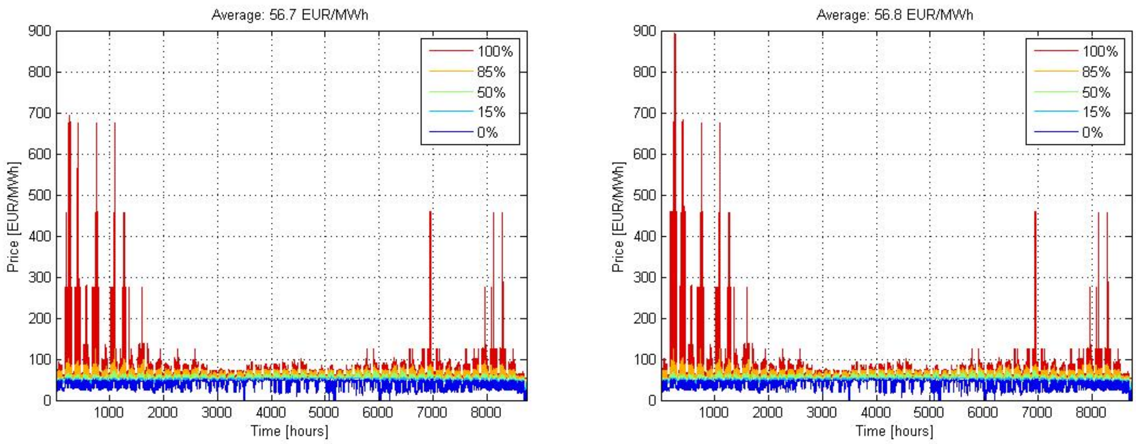


(1) (2)

*Figure 4.7: **Flexible load** in Germany the first five weeks in the worst year with (1) no outage and (2) 3 weeks outage of Nord.Link.*

Prices

Figure 4.8 shows price percentiles for all 75 climatic years in Germany (1) without outage, and (2) with 3 weeks outage of Nord.Link. The average price is close to unchanged, even though there is a noticeable rice in the 100.percentile during the outage period (up to hour 504). However, the prices seem relatively unchanged throughout the year, emphasizing a lack in capacity, not an energy issue. If there were an energy issue, higher production in one period would affect the next, as there would be a change in available resources (e.g. stored water). In thermal areas, there are no such resource issue as nothing is stored, and the availability of resource is infinite (gas, oil, coal, etc.). Higher use in one period does not change the availability of resource in the next, and not the price.



(1) (2)

*Figure 4.8: **Price percentiles in Germany** with (1) no outage and (2) 3 weeks outage of Nord.Link.*

Figure 4.9 shows prices in the first five weeks of the worst year in Germany. Due to lack of power production, prices in certain hours are far above the marginal cost of any production unit (136.5 EUR/MWh), confirming activation of expensive flexible load. Overall, the price pattern fits the flexible load pattern well. When large amounts are activated, prices increase accordingly.

Spikes during the outage period (up to hour 504) rises noticeable when comparing the figures below. However, spikes after this period are unchanged. This confirms that power production in Germany *during* the outage period does not affect the power production after.

For periods with power capacity shortage, 1.4 GW exchange capacity is important. The lack of power in the worst year rises peak prices to 900 EUR/MWh (about 9 NOK/kWh) and the average price by 7.7 EUR/MWh.

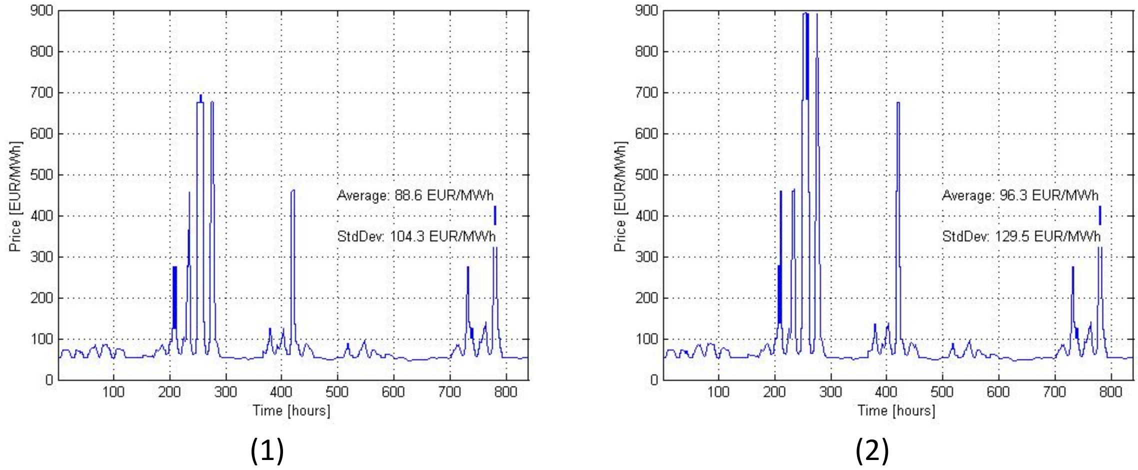
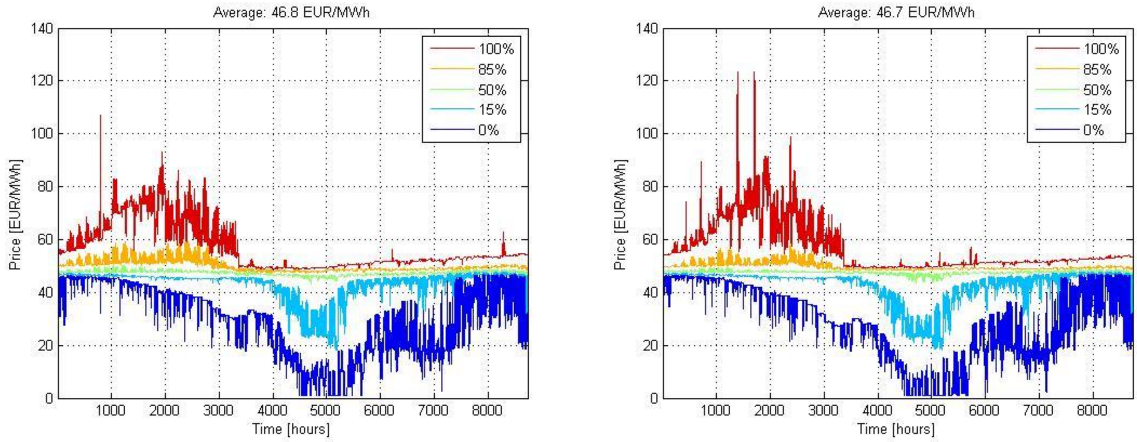


*Figure 4.9: **Prices in Germany** the first five weeks in the worst year with (1) no outage and (2) 3 weeks outage of Nord.Link.*

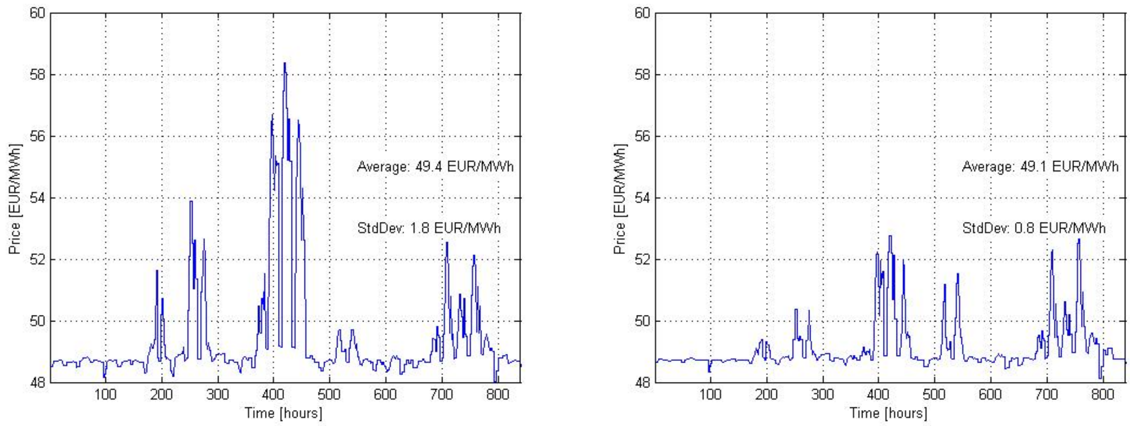
Figure 4.10 shows price percentiles in Norway for all 75 climatic years. Some new price peaks exceeding 120 EUR/MWh occur *after* the three-week (lasts until hour 504) outage of Nord.Link. Some dry years suffer from unavailable exchange in the first three-weeks, resulting in lower reservoir level during the year and higher prices. However, the average price due to Nord.Link outage reduces by 0.1 EUR/MWh for all 75 climatic years.



(1) (2)

*Figure 4.10: **Price percentiles in Norway** with (1) no outage and (2) 3 weeks outage of Nord.Link.*

Figure 4.11 shows prices in Norway for the first five weeks of the worst year (in Germany). When outage occur, the direct link between Norway and Germany is unavailable, slightly reducing the five-week average price in Norway, as well as reducing some high peaks. The source of income from Germany is no longer available, resulting in lower price. Equally, the reservoir level increase due to lower production, and increasing water also reduce the prices. However, it is clear that the outage of Nord.Link for the worst year gives no significant consequence in Norway.



(1) (2)

*Figure 4.11: **Prices in Norway** the first five weeks in the worst year with (1) no outage and (2) 3 weeks outage of Nord.Link.*

Great Britain is not strongly connected to the continent illustrated by the great price difference in Figure 4.12. However, Germany, Belgium and the Netherlands are strongly interconnected. Still, prices are overall highest in Germany. Such strong interconnected areas are challenged by the domino effect: If one area suffers, the other areas follow. The outage of Nord.Link rises prices in several countries, including Denmark.

The resolution in Figure 4.12 is not necessary correct below 60 EUR/MWh. All dark blue areas have prices below this, but the resolution is chosen this way to visualize changes in high price areas.

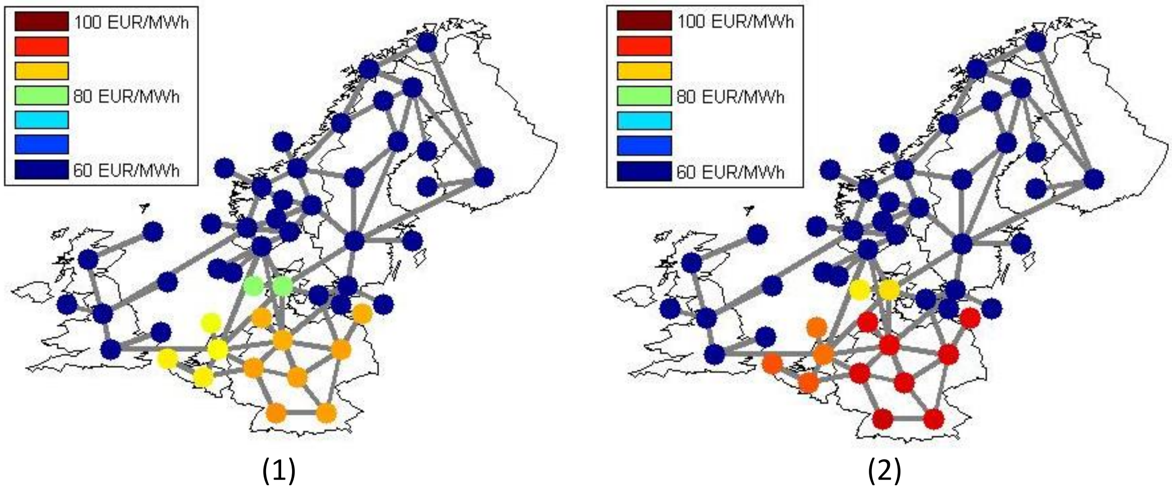


*Figure 4.12: **Area prices** the first five weeks in Northern Europe in the worst year with (1) no outage and (2) 3 weeks outage of Nord.Link.*

Surplus of various stakeholders

The simulation tool optimizes with respect to socio-economic surplus. The optimization is interrupted when system changes occur. Figure 4.13 presents a sensitivity analysis showing the relation between outage length of Nord.Link and change in socio-economic surplus for the system. The outage length varies between 1 and 15 weeks. The highest amount of energy not transferred caused by disturbance outage on HVDC-cables in the period 2012-2013 did reach 25 % of the annual E_{max}. This represents 13 weeks of no exchange.

It should be repeated that each outage starts at the beginning of week 1.

Figure 4.13 confirms that the power situation when outage occurs is highly critical. *The mean* socio-economic surplus of all years has a linear relation between length and reduced surplus. The linear relation indicates that on average, the time of outage is not important, but the length decides the consequences. For the worst year however, the relation is more logarithmical, indicating that the time of limitation is highly important. Outage in the two first weeks gives a steep reduction in socio-economic surplus. This is due to the great increase in prices at continental Europe as shown in Figure 4.12. The trend-line seems to flat out when outage in the worst year exceeds five weeks, and is close to parallel to the mean of all years from this outage length and further. This is because outage of Nord.Link does not affect prices on the continent as much as it did in the beginning of the year.

The cost of an outage of Nord.Link for the system can be seen in the figure below. For instance, a three-week outage cost the society 5 MEUR in the worst year, and a mean cost of 1.2 MEUR for all 75 climatic years.

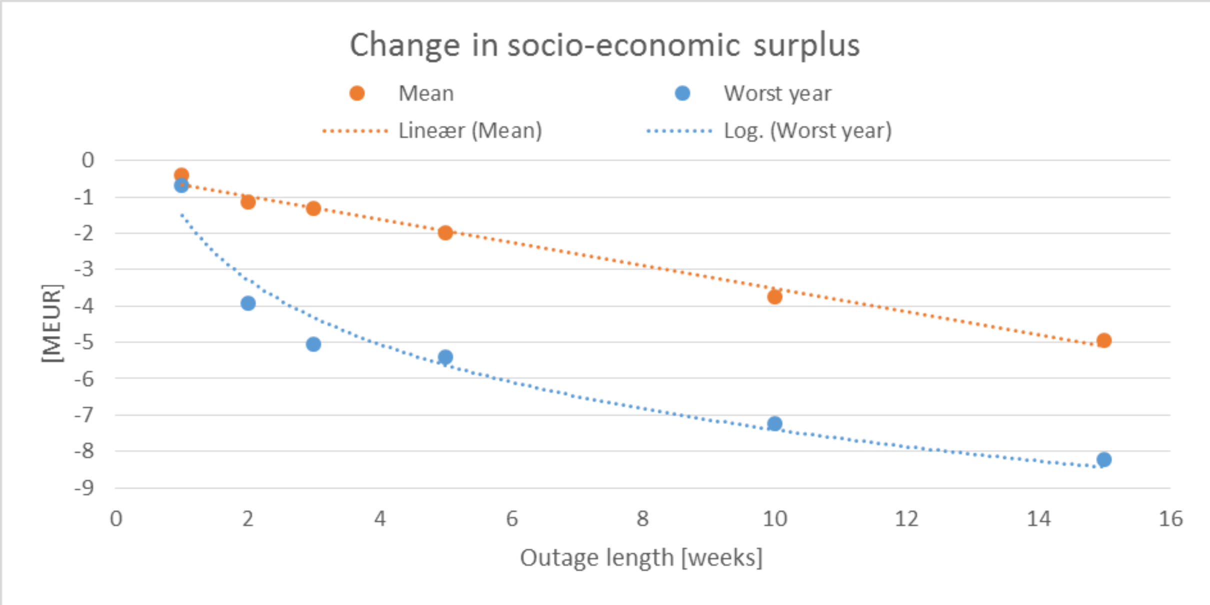


Figure 4.13: Change in ***socio-economic surplus*** *compared to the no-outage scenario.*

The simplified reason of why the socio-economic surplus reduces when prices increase is that consumer surplus reduces *more* than producer surplus increase. Taking the basic illustration of consumer and producer surplus (see Figure 2.1) into account, what is happening when prices increase is that the market cross moves. Due to the steeper demand curve, consumer surplus is then reducing more than producer surplus increase, and the net change in socio-economic surplus is negative.

The consumers suffer when prices rise. Figure 4.14 presents the change in consumer surplus in Germany with respect to outage length. As seen in the figure, outage in the first week gives close to no consequence. Two weeks, however, gives a reduction in consumer surplus in Germany of 50 MEUR in the worst year. A five weeks outage increases the loss in consumer surplus by over 90 MEUR in the worst year, while it stays below 20 MEUR on average.

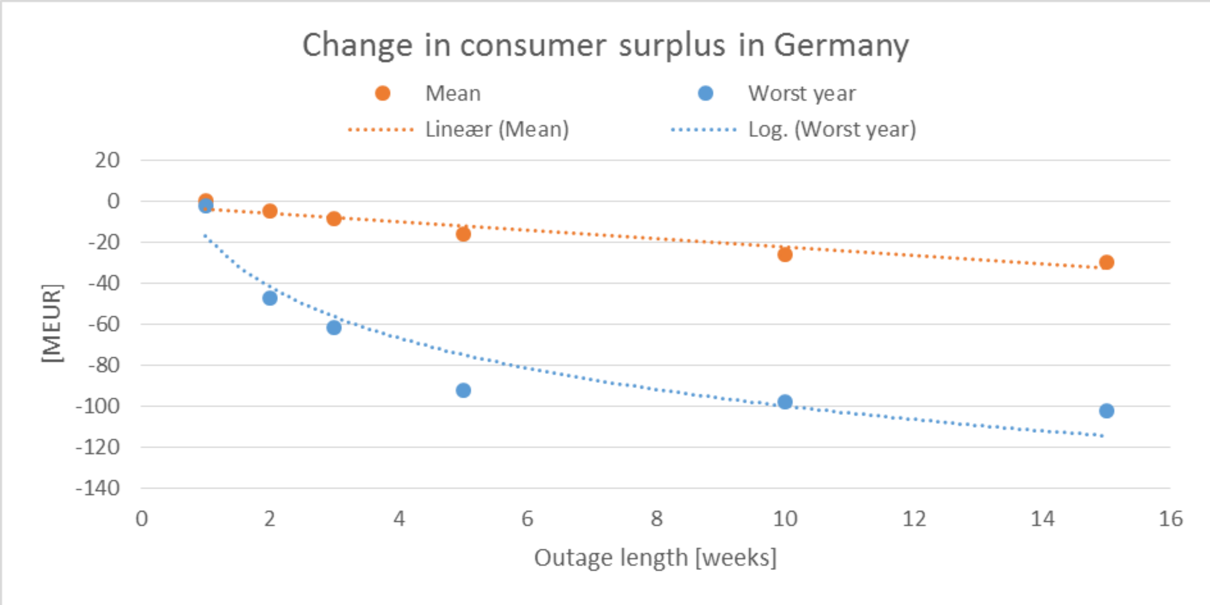


*Figure 4.14: Change in **consumer surplus** in **Germany** compared to the no-outage scenario.*

Loss of 1.4 GW exchange capacity during power capacity shortage will cause severe consequences for consumers in Germany, while the consequences on system level (socio-economic surplus) are small.

4.2.2 Energy-only market – median year

The worst simulated year did experience some very high prices as presented in the previous section. The following analyses illustrate variations for the median year of the 75 climatic simulated years. The median year is the climatic year of 1981 and is supposed to illustrate a normal year.

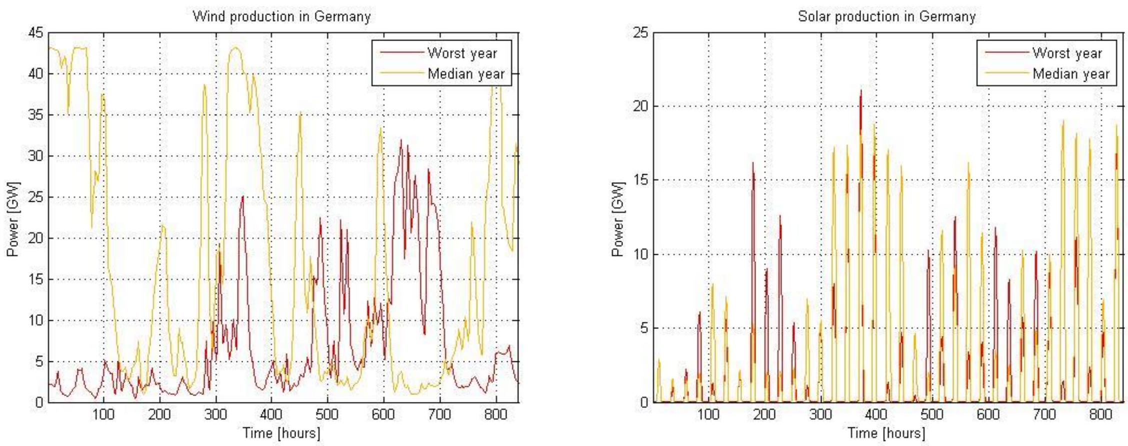
It should be repeated that the firm load in Germany follows a specific yearly pattern, i.e. do not vary between years. The pattern for the first five weeks is presented in Figure 4.1.

Wind and solar production

Figure 4.15 (1) shows wind production in Germany in the first five weeks for the worst and median year. Even in the median year, wind production fluctuates greatly, varying between 2 and 43 GW. At some periods, the wind production is close to the same level as in the worst year.

Figure 4.15 (2) shows the same presentation for solar power production. It is more production in the median year than the worst. However, the variations are still extensive, varying between 0 and 19 GW.

When comparing power production patterns from both sources, the distinct randomness of energy supply is clear. The period with highest wind production (up to hour 100) has the lowest solar production. Around hour 150, both sources have low active capacity, providing about 5 GW in total. However, between hours 300-400, the production from both sources are high, reaching close to 60 GW. This is about 60 % of the peak load in Germany.



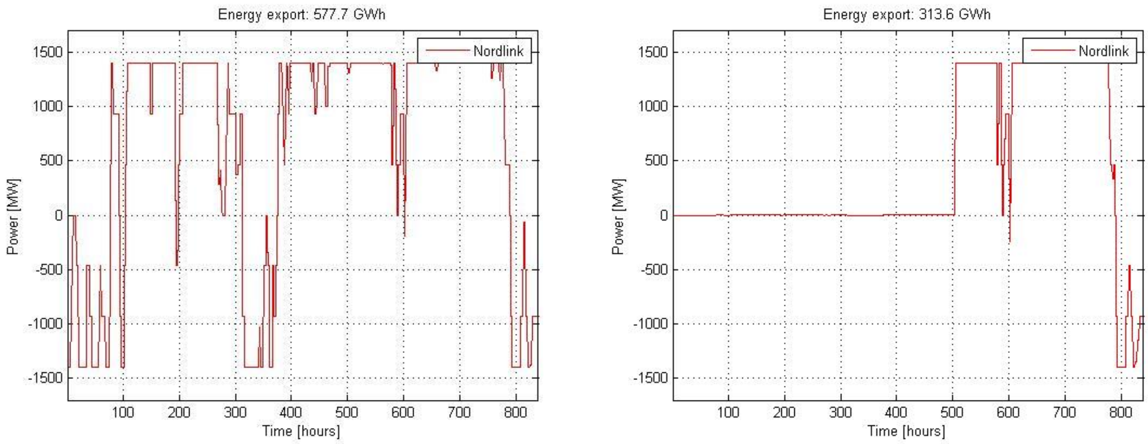
(1) (2)

*Figure 4.15: (1) **Wind-** and (2) **solar production** in Germany.*

Exchange

Figure 4.16 presents the exchange on Nord.Link for the median year. In the no-outage scenario, the exchange pattern fits well with the wind production in Germany. There is maximum export from Norway when wind production is low, and opposite when the production is high.

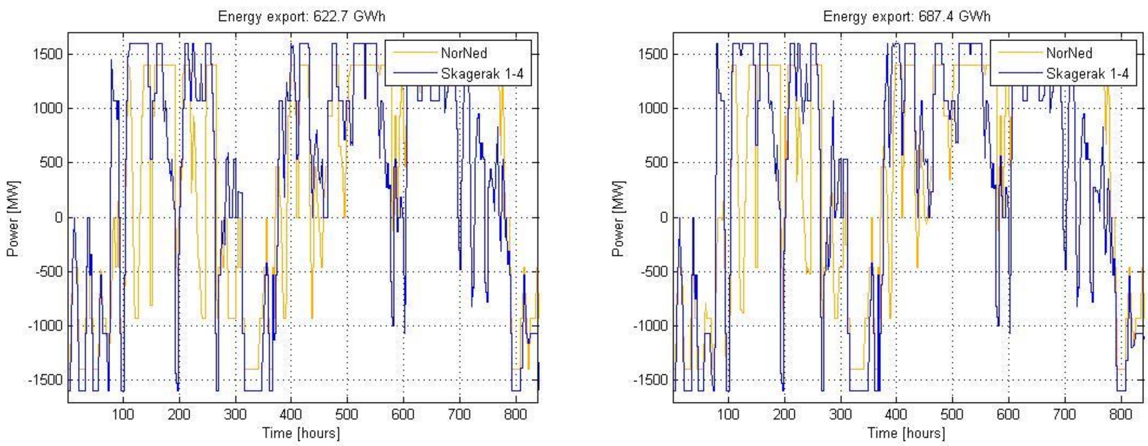
The net export from Norway is less in the median year compared to the worst year (see Figure 4.3), reduced from 1018.7 to 577.7 GWh for these five weeks.



(1) (2)

*Figure 4.16: **Exchange on Nord.Link** the first five weeks in the median year with (1) no outage and (2) 3 weeks outage of Nord.Link.*

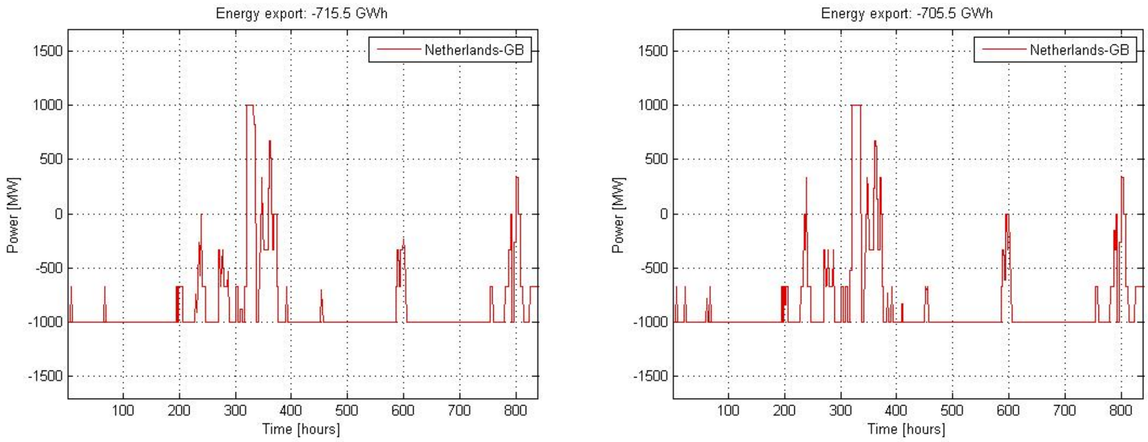
In the median year, some exchange will be rerouted when outage of Nord.Link occurs. Figure 4.17 shows the flow on NorNed and Skagerrak 1-4 without (1) and with outage (2) of Nord.Link. The energy export the first five weeks rises from 622.7 to 687.4 GWh, i.e. increased flow towards continental Europe. However, the loss of Nord.Link do not seem to be covered by increased power flow on other interconnections, as they are at its maximum in many hours already in the no-outage scenario.



(1) (2)

*Figure 4.17: **Exchange on NorNed and Skagerrak 1-4** the first five weeks in the median year with (1) no outage and (2) 3 weeks outage of Nord.Link.*

Figure 4.18 shows exchange from Netherlands to Great Britain. In high priced hours on the continent, the exchange capacity is at its maximum even in the no-outage scenario. The total amount of exchange are close to unchanged when Nord.Link is out, only increasing the net power flow towards the continent by 10 GWh for these five weeks.



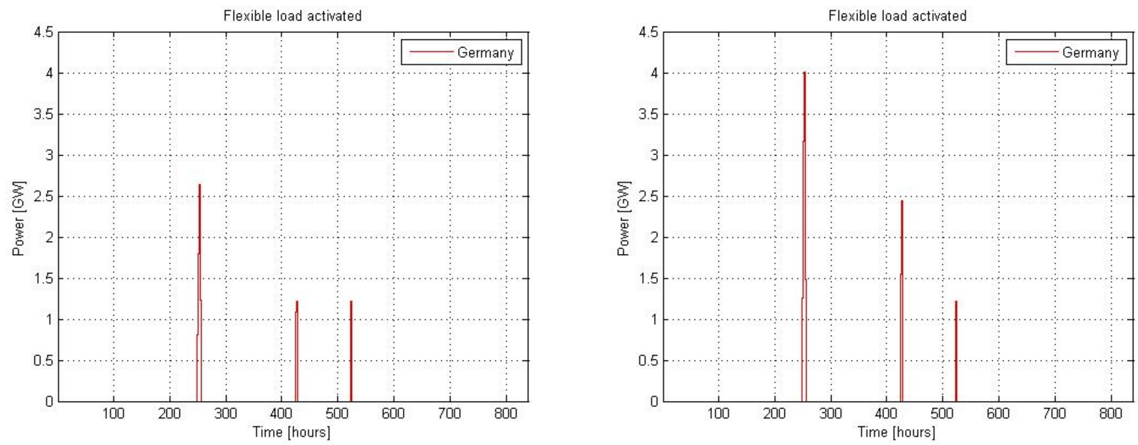
(1) (2)

*Figure 4.18: **Exchange on Netherlands-GB** the first five weeks in the median year with (1) no outage and (2) 3 weeks outage of Nord.Link.*

Flexible load

Figure 4.19 shows the use of flexible load in Germany these five weeks for the median year. It confirms the very edge of power capacity shortage in some hours, even in a “normal year”. The spike in Germany at hour 250 and 420 rises by 1.4 GW when outage occurs - the exact capacity of Nord.Link. The spike at hour 520 would be expected to rice equally if the outage lasted that long (online from hour 504). Instead, it remains unchanged.

At hour 250, both wind and solar production is very low, resulting in the highest peak of flexible load. The power production situation is the same between hours 600-700, but Figure 4.2 (2) confirms that the firm load in this period is low, resulting in no need of flexible load.



(1) (2)

*Figure 4.19: **Flexible load** in the median year with (1) no outage and (2) 3 weeks outage of Nord.Link.*

Even in the median year, a three-week outage of Nord.Link increases the use of flexible load noticeable. In critical hours, the prices are high in Germany and capacity on other links already used, limiting the possibility of rerouted power flow. The intermittence of wind- and solar production could challenge the system balance even in a normal year. It is clear that having available exchange capacity is important.

Prices

The German prices for the median year are volatile, as shown in Figure 4.20, but still far less than the worst year (see Figure 4.9). During the outage, a new spike exceeding 450 EUR/MWh occurs around hour 410. The loss of 1.4 GW from Nord.Link, about 1.5 % of the consumption, rises the price quickly due to the need of more expensive flexible load. The amount is not that great, but in a situation with power capacity shortage, the consequences even in a normal year could be significant in some hours. Despite of the distinct rise in certain hours, the average price for the first five weeks rises by 2.4 EUR/MWh.

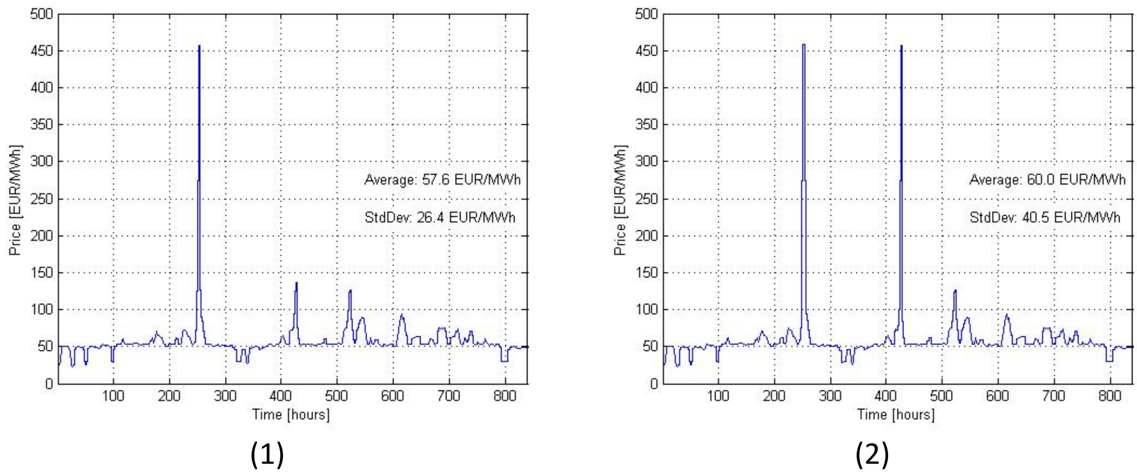


*Figure 4.20: **Prices in Germany** the first five weeks in the median year with (1) no outage and (2) 3 weeks outage of Nord.Link.*

4.2.3 Capacity remuneration mechanism – worst year

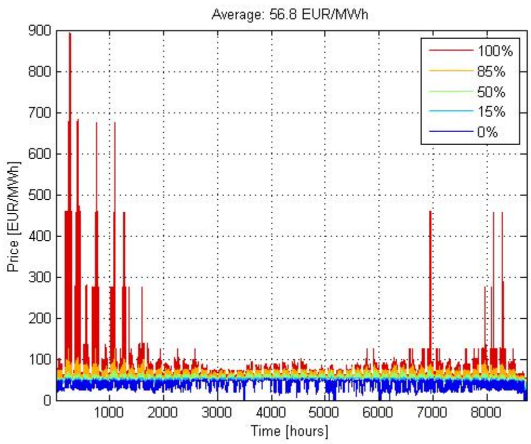
If CRM is included, there is no longer an energy-only market. CRM leads to a higher amount of thermal capacity installed. In periods with high load combined with low wind and solar production, this extra installed capacity could prevent use of flexible load. More capacity available does also reduce the prices as the marginal cost of the system reduces (cheaper than flexible load). The aim of this section is to see how consequences change when there is increased installed capacity in the system.

The CRM evaluated provides 18.5 GW extra thermal capacity in Germany, with an annualised investment and maintenance cost of 70 EUR/kW (considers discount rent). The extra cost for the system adds up to 1295 MEUR. This amount of extra capacity is not necessarily realistic; the importance is that the peak load is covered. There is interesting to see what influence such mechanism has regarding prices. The same approach as with Energy-Only Market (EOM) is used to see variations for the worst year.

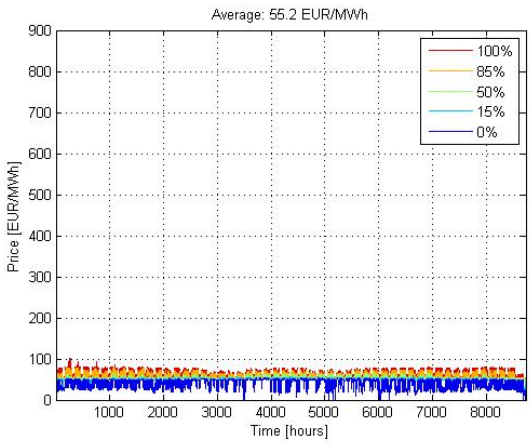
It should be mentioned that it was no new calibration of the model when including this extra capacity. A calibration affects the utilization of hydro reservoirs. However, it is expected that this gives no consequences in Germany, as the calibration mainly affects hydro areas.

Prices

Figure 4.21 compares a three-week outage of Nord.Link with EOM and CRM. With CRM, high price peaks are eliminated. However, the average price of all 75 climatic years only changes slightly, decreasing from 56.8 to 55.2 EUR/MWh with CRM.



(1)



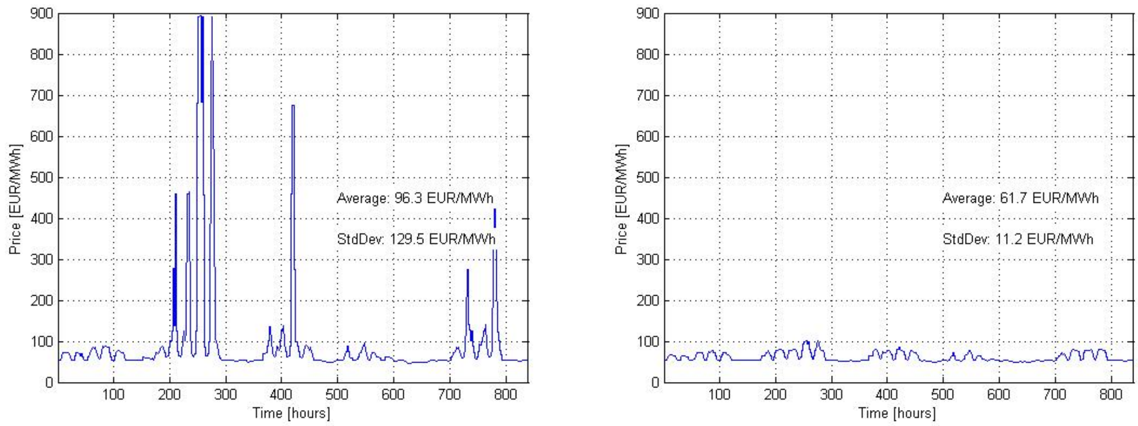
(2)

*Figure 4.21: **Price percentiles in Germany** with 3 weeks outage of Nord.Link with (1) EOM and (2) CRM.*

Further analysis reveals that the average price in Germany over 75 climatic years does not change whether Nord.Link outage occurs or not with CRM. This is no surprise considering that the price on average only increased by 0.1 EUR/MWh with EOM (see Figure 4.8).

Figure 4.22 compares prices in Germany the first five weeks of the worst year for the two market solutions with outage of Nord.Link. CRM reduces the volatility as well as the average price in Germany compared to EOM. The average price in Germany with EOM reaches 96.3 EUR/MWh, while it stays below 62 EUR/MWh with CRM. In addition, the standard deviation is reduced by a factor of 10.

Further analysis reveals that there are no use of flexible load in Germany when CRM is included, explaining the avoidance of high peak prices.



(1) (2)

*Figure 4.22: **Prices in Germany** the first five weeks with **3 weeks outage** of Nord.Link in the worst year with (1) EOM and (2) CRM.*

Appendix B presents prices in Norway for both EOM and CRM in Germany, as well as exchange on Nord.Link. The results reveal that the volatility in both countries is lower with CRM in Germany, and that the export from Norway is reduced by almost 50 %. This is due to the lower prices in Germany.

The results show that outage of Nord.Link gives no significant consequences in Germany with CRM - not even in the worst year. Power capacity shortage is avoided.

Surplus of various stakeholders

CRM require investment costs for the extra thermal capacity installed as well as maintenance cost. This additional cost must be taken into account when comparing socio-economic surplus for different market solutions.

The extra capacity of 18.5 GW caused by CRM is an assumption, equally to the investment and maintenance cost of 70 EUR/kW. To make the result more robust, a sensitivity analysis taking into account +/- 30 % estimate of the annualised cost is included. The estimated cost would then be in the range between 49 EUR/kW and 91 EUR/kW, giving a total cost of respectively 906.5 and 1683.5 MEUR.

Figure 4.23 shows socio-economic surplus for EOM and CRM. The socio-economic surplus favourites EOM. CRM with its original additional cost (70 EUR/kW) reduces the mean socio-economic surplus by 1351 MEUR. The solution of CRM is expensive for the system as the socio-economic surplus drops. Even with the -30 % estimate of extra cost, socio-economic surplus for EOM is far greater.

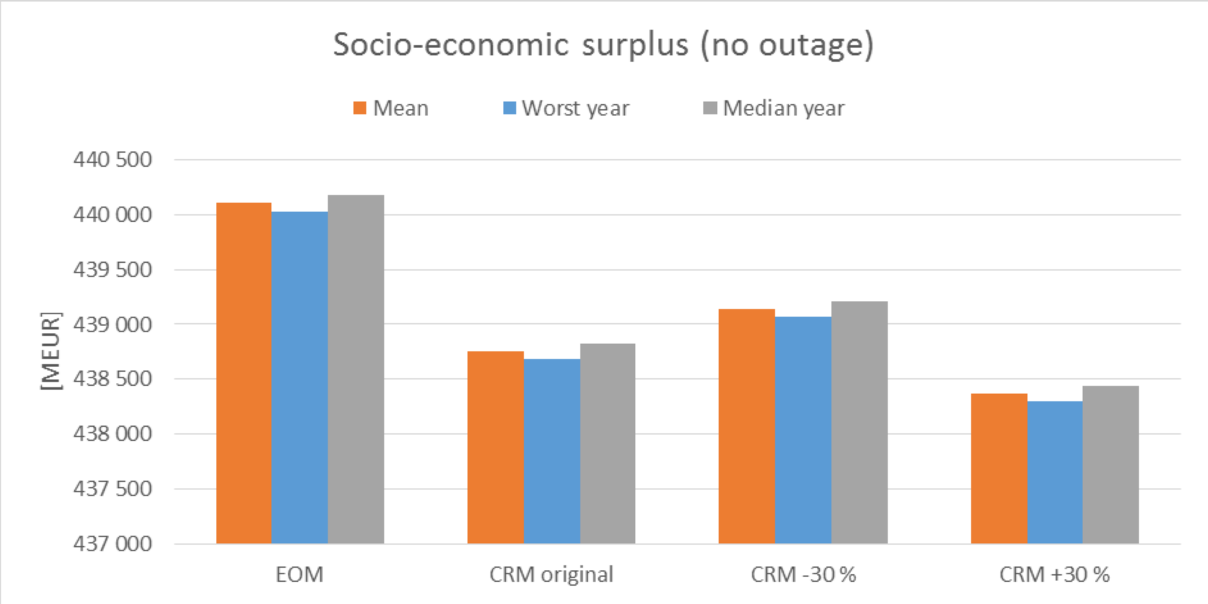


*Figure 4.23: **Socio-economic surplus** comparing EOM to CRM with a +/- 30 % range of annualised cost.*

The socio-economic surplus is higher for EOM than CRM in all evaluated years. This is the case even *without* the additional investment and maintenance cost included. However, that seems not correct. More capacity installed would, as mentioned, reduce the system cost (when neglecting the additional investment and maintenance cost) as flexible load is more expensive. This should have led to lower price and higher socio-economic surplus. Since the model was not calibrated with CRM, this affects prices, and further surpluses. However, the consequences following calibration issue are expected to be small compared to the difference in surplus between the two market solutions. This means that these figures give the bigger picture when comparing EOM to CRM.

The response in surplus for the median year are random. Due to the series simulation, outage in previous years affects the amount of water stored. This will further influence the water value and the amount of production in following years. The median year are included to see a possible response in a normal year, emphasizing variability. The median year is therefore too variable, and should not be representative to analyse expected surplus for a normal year.

Figure 4.24 shows the same presentation as above for consumer surplus in Germany. All extra capacity is installed in Germany, which means that the additional cost is allocated to consumers there. Consumers indirectly pay the costs for extra capacity through their electricity bill.

From the figure, it is clear that consumers are most affected by CRM. The mean deviation in consumer surplus varies between 1745 MEUR and 527 MEUR in favour of EOM. CRM provides a higher electricity bill for consumers than in an energy-only market.

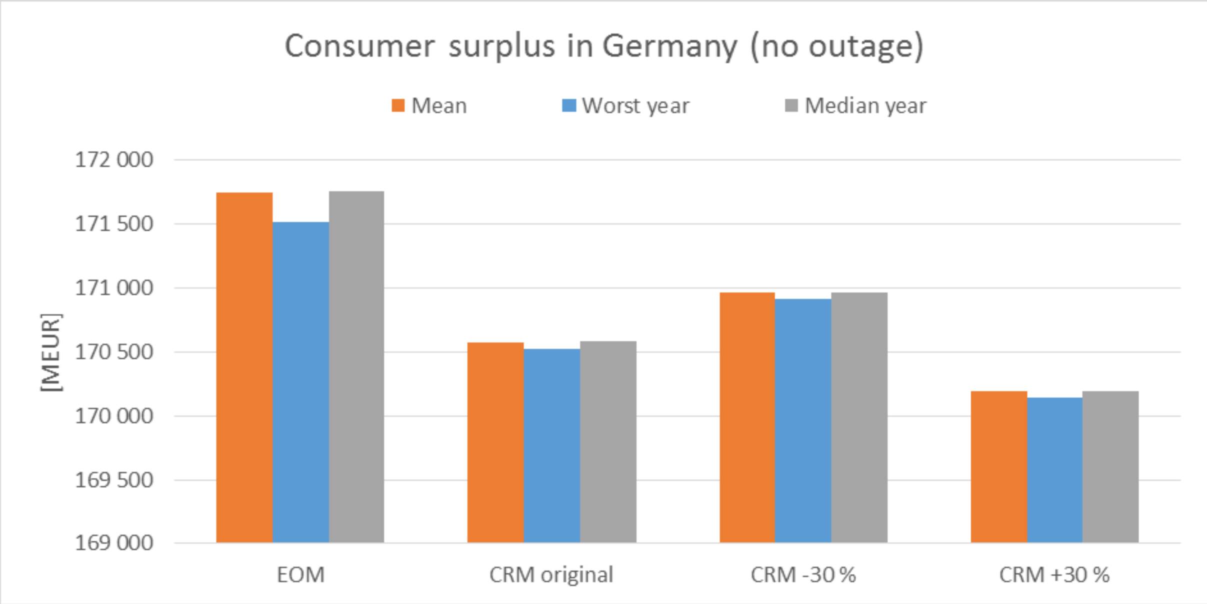


*Figure 4.24: **Consumer surplus in Germany** comparing EOM to CRM with a +/- 30 % range of annualised cost.*

Figure 4.25 shows the change in socio-economic surplus comparing a three-week outage to the no-outage scenario for both market solutions. Here, calibration issue is no problem as it is the *change* that is analysed.

The effect of investing in more capacity is clear. With EOM, the consequences are volatile. For the worst year, the reduction in socio-economic surplus is over five times greater than with CRM. The extra installed capacity in Germany through CRM makes the entire system more robust, keeping prices steady resulting in small changes in socio-economic surplus.

The counter intuitive rise in the median year for EOM can be explained by the higher reservoir filling in Norway when outage occur, allowing more production throughout the year. This increases the surplus, even though the price in Norway becomes somewhat lower during Nord.Link outage.

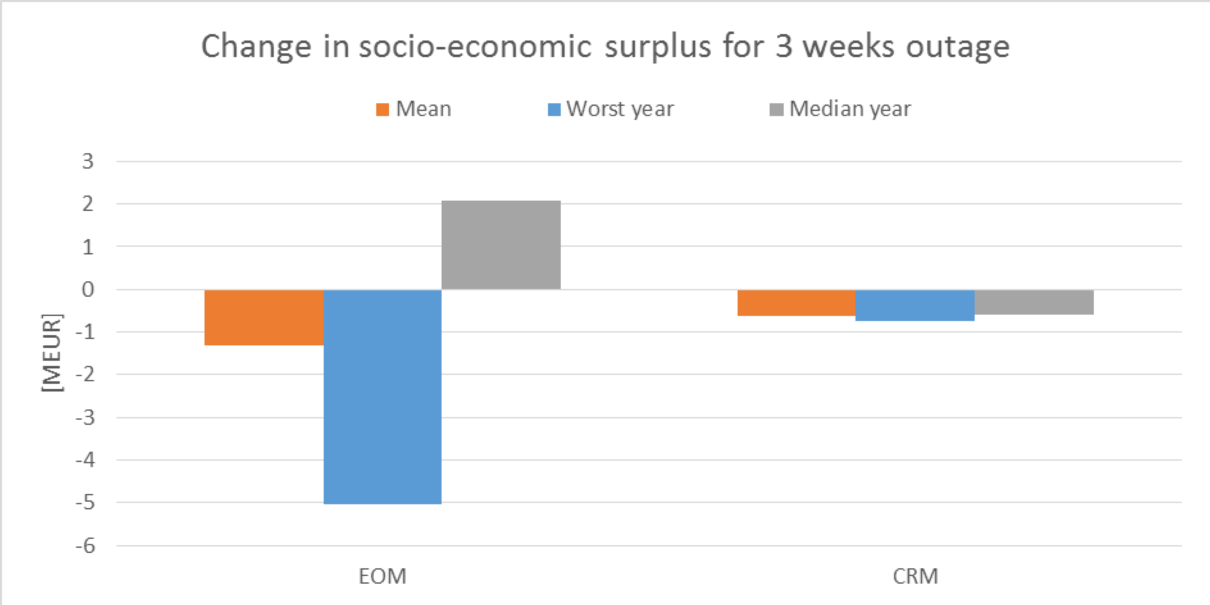


*Figure 4.25: **Change in socio-economic surplus** for EOM and CRM for 3 weeks outage of Nord.Link referred to the no-outage scenario.*

The cost of outage for consumers in Germany is shown in Figure 4.26. The variations between each evaluated case is significant. Due to the steep demand (almost inelastic), a small change in price changes the consumer surplus significantly, explaining the vast numbers.

For the worst year, the loss in consumer surplus exceeds 60 MEUR for an EOM. With CRM, the loss reaches only 4 MEUR. For the mean of all years, the loss in consumer surplus for CRM is almost negligible, while the loss exceeds 8 MEUR with EOM.

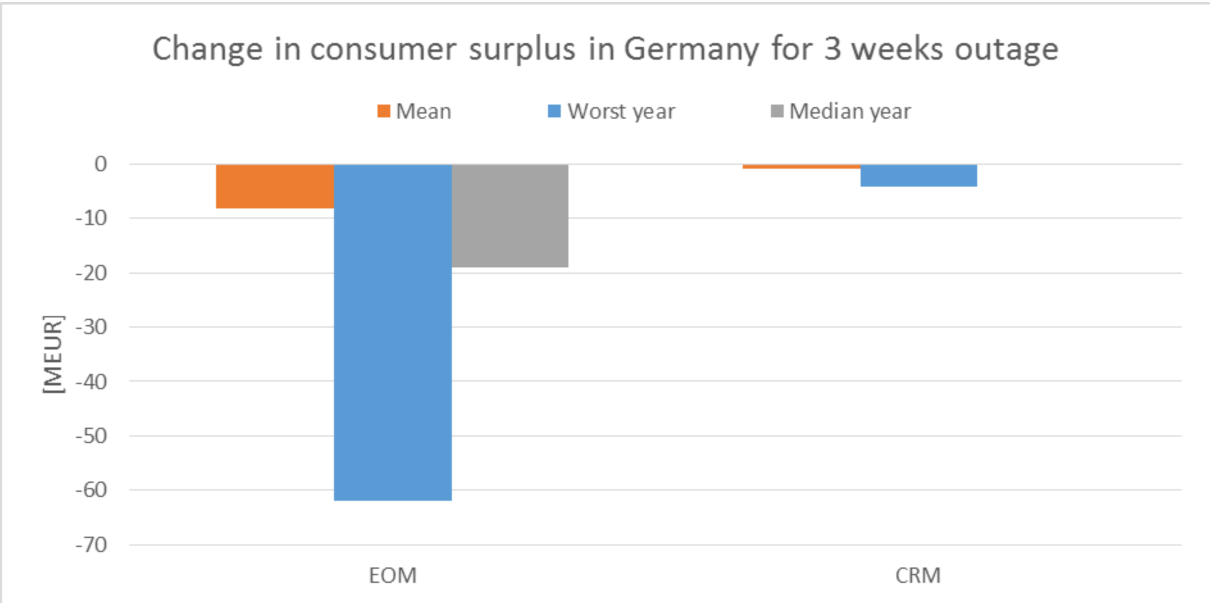


*Figure 4.26: **Change in consumer surplus in Germany** for EOM and CRM for 3 weeks outage of Nord.Link referred to the no-outage scenario.*

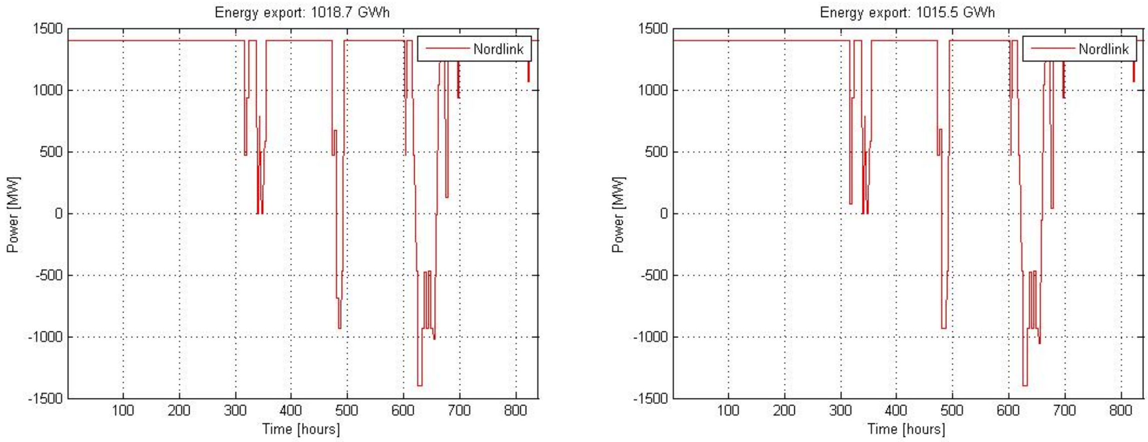
It is evident that CRM is costly for consumers, but the inclusion of more capacity makes prices stable. A three-week outage in an energy-only market at worst time increases the yearly loss in consumer surplus by a factor of 15 compared to if extra capacity is installed.

Transmission cable outage is expensive for consumers in continental Europe if it occurs during power capacity shortage. In a CRM-solution, stressed situations are avoided because there are enough spare capacity to prevent extensive use of flexible load, and the consequences of exchange outage are low.

4.3 Power production outage

As statistical data presented in section 3.1.2 confirms, production units are also affected by forced outages. This section intend to reveal consequences of such events. The simulation uses outage of 1.4 GW thermal capacity in Germany. CRM is not analysed since Germany then has enough capacity installed to avoid high prices. Similar to transmission outage, the power plants are set to be unavailable annually from the beginning of the first week. The outage duration is set to be three weeks, which is in line with the ten-year fault statistics of fossil-fired units.

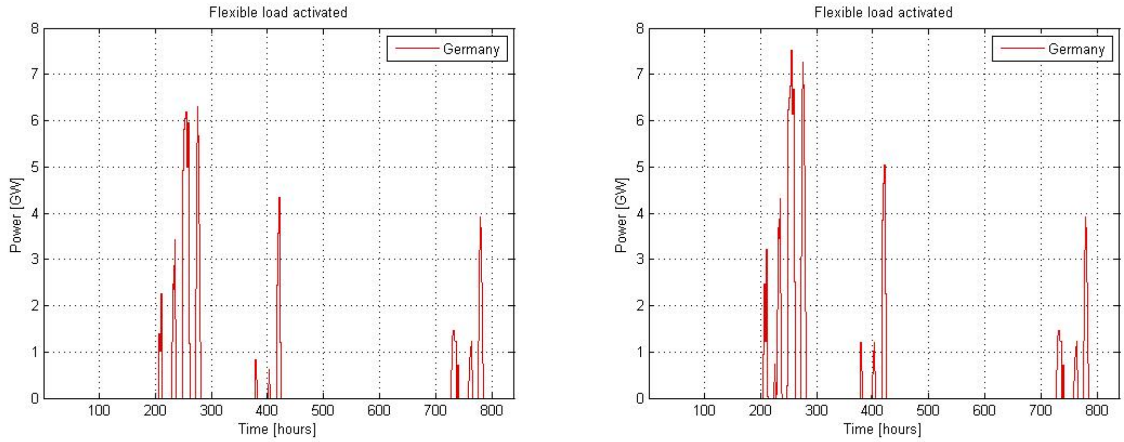
Figure 4.27 shows power exchange on Nord.Link in the worst year. The change in power flow due to outage of thermal capacity is marginal. This means that the outage of power plants is not covered by increased power flow on Nord.Link.



(1) (2)

Figure 4.27: ***Exchange on Nord.Link*** *referred to Norway the first five weeks in the worst year with (1) no outage and (2) 3 weeks outage of 1.4 GW thermal power plants.*

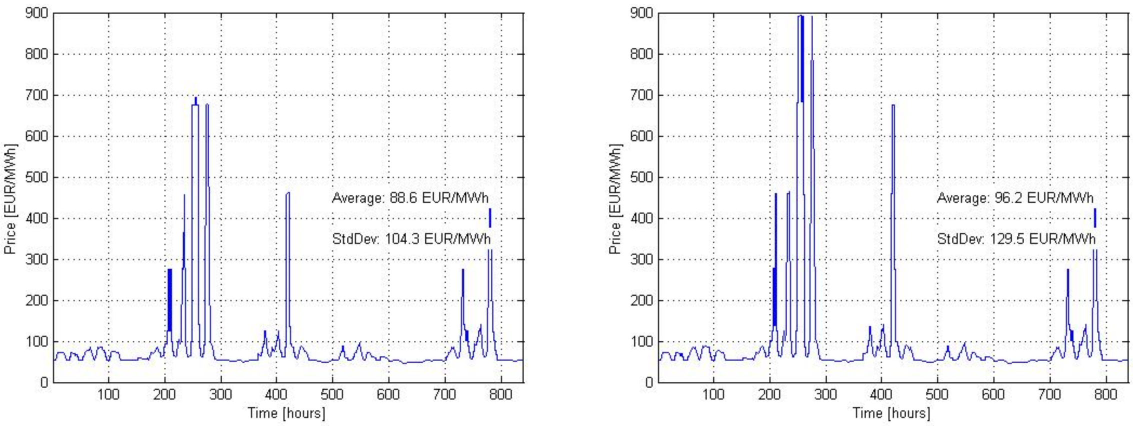
Figure 4.28 shows flexible load activated in Germany in the worst year. The flexible load spikes increase when the thermal power plants are out of service. The import from Norway is at its maximum during all hours with use of flexible load – even before the outage.



(1) (2)

*Figure 4.28: **Flexible load** the first five weeks in the worst year with (1) no outage and (2) 3 weeks outage of 1.4 GW thermal power plants.*

Figure 4.29 shows prices for the worst year in Germany. The lack of 1.4 GW thermal power production increases the prices noticeable. The average price increases by 7.4 EUR/MWh, and very high price peaks reach 900 EUR/MWh. The prices rise due to extensive use of flexible load.



(1) (2)

*Figure 4.29: **Prices in Germany** the first five weeks in the worst year with (1) no outage and (2) 3 weeks outage of 1.4 GW thermal power plants.*

Figure 4.30 shows change in consumer surplus in Germany with 3 weeks outage of 1.4 GW thermal power production. The mean of all 75 climatic years shows a reduction of 8.5 MEUR. The worst year, however, exceeds a loss in consumer surplus of 60 MEUR. The consequence of 1.4 GW less power production capacity is significant during power capacity shortage.

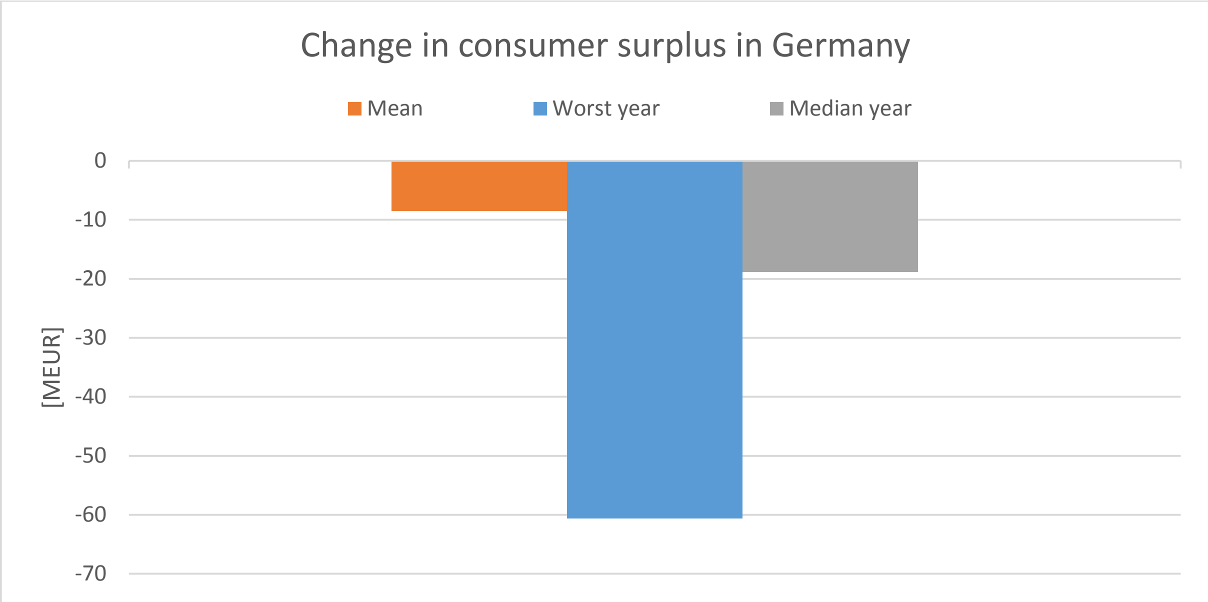


Figure 4.30: Change in consumer surplus in Germany with 3 weeks outage of 1.4 GW thermal power production.

4.4 Impact of including start-up cost for thermal power plants

Including start-up cost for thermal power plants extends the simulation time significantly, and has been left out in all previous simulations. The purpose of this section is to consider the impact of including this extra cost.

It should be mentioned that the model is not calibrated when including start-up cost. Such calibration takes several weeks. Calibration mostly affects the utilization of hydro reservoirs. In a system at size of Northern Europe, it is assumed that such calibration does not have a significant impact of the results. The calibration used without start-up cost included is therefore used also here.

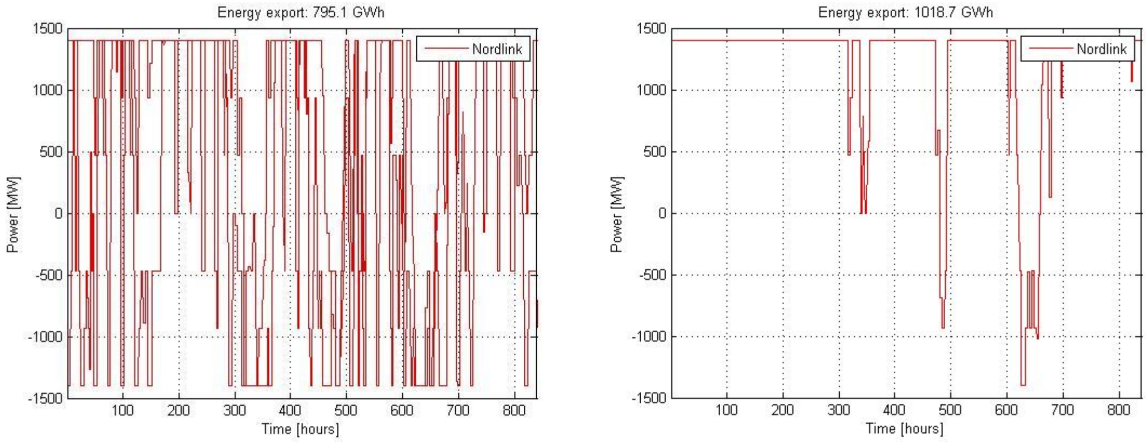
4.4.1 Allocated versus aggregated hydropower plants

Including start-up cost in the simulation with allocated production are very time consuming, taking about 20 hours per simulated climatic year. All simulations including start-up costs are performed on aggregated level to solve the equations faster. Aggregated level means that all reservoirs and hydropower plants in each area are aggregated into one unit (see illustration in Figure 2.11).

The comparison between “allocated level” and “aggregated level” is presented in Appendix C. The results show that there is no change in prices for thermal-based areas. However, the volatility reduces noticeable in hydro-based areas, and the average price reduces somewhat. Nevertheless, there is no difference in results on system level. This means that each comparison between *allocated level* and *aggregated level including start-up cost* is a direct comparison of the system with and without start-up cost.

4.4.2 Simulations with and without start-up cost

Figure 4.31 shows exchange on Nord.Link with and without start-up cost included in the simulation. It is clear that the exchange pattern is more varying when start-up cost is taken into account. The fluctuations are changing because thermal units now have to include start-up cost in the production planning. The planners must evaluate whether to continue production during hours with lower price than their marginal cost just to be ready for the next hour with higher price, or to stop. When start-up cost is neglected, the unit can start and stop rapidly without financially issues.



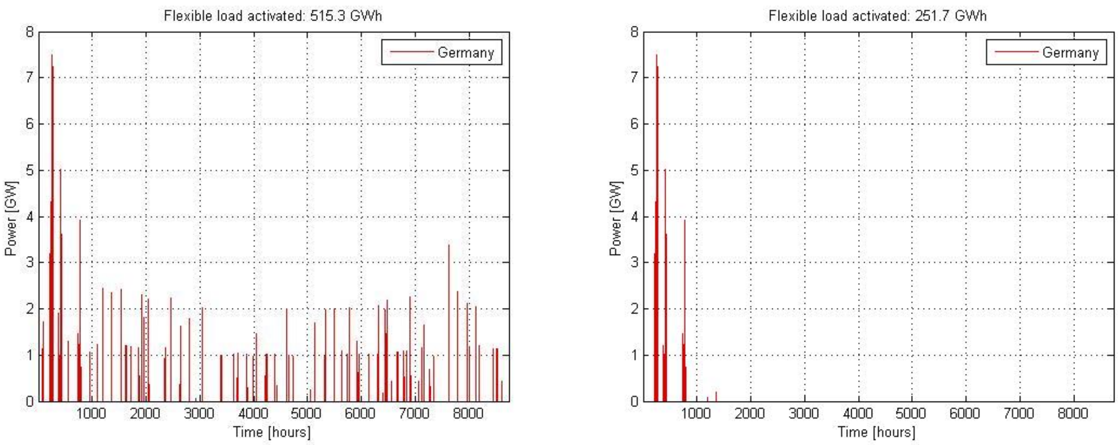
(1) (2)

*Figure 4.31: **Exchange on Nord.Link** referred to Norway the first five weeks in the worst year for EOM (1) with start-up cost and (2) without.*

The net export from Norway for this period is reduced by approximately 20 % when start-up cost is included.

The use of flexible load is also affected by this extra cost. Figure 4.32 (1) shows use of flexible load throughout the worst year with and without start-up cost included. There is an evident different. When start-up cost is included, use of flexible load appears throughout the whole year - not only in the first five weeks. This is explained by power producers reluctance to turn on power plants when high price only appear for some hours. Demand is met by use of flexible load instead of turning on extra production.

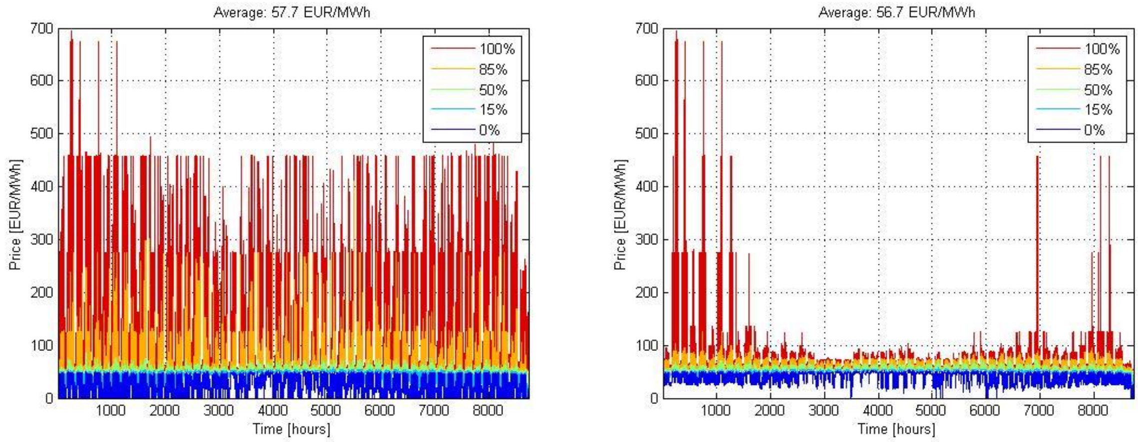
An important observation is the size of the high peaks in the beginning of the year. They do not change whether start-up cost is included or not. This is hours with so high price that any power production is turned on anyway. The highest prices in simulations without start-up cost are then assumed to be equal to those simulations where start-up cost is considered.



(1) (2)

*Figure 4.32: **Flexible load in Germany** over the worst year with 3 weeks outage of Nord.Link for EOM (1) with start-up cost and (2) without.*

Figure 4.33 presents prices in Germany with and without start-up cost included. Start-up cost increases the volatility. Both higher prices as well as lower are seen throughout the year. Without start-up cost, the price pattern is more narrow. However, the average price of all 75 climatic years increases by only 1 EUR/MWh when including start-up cost.



(1) (2)

*Figure 4.33: **Price percentiles in Germany** for EOM (1) with start-up cost and (2) without.*

The low prices occur because of thermal power plants reluctance to turn off during short low-price periods. When including start-up cost, this extra cost is also included to the variable cost (fuel cost) in order to decide when to produce. In some hours, the price is below the marginal cost of the thermal unit. The cost for stopping and starting up need to be higher than the deviation between marginal cost (fuel cost, efficiency) and price over the period in order to stop. If opposite, the unit will produce at its minimum capacity, typical 25 % of rated, until the price exceeds the marginal cost again. The same evaluation is done in hours with lack of capacity. The units do not turn on if the start-up cost is higher than the deviation between marginal cost and price over the time. This explains the arrival of new peaks throughout the year in Figure 4.33 (1).

Figure 4.34 shows prices in Germany for the first five weeks of the worst year. Including start-up cost reduces the average slightly as well as increasing the volatility. Some new price peaks occur due to the reluctance to turn on capacity for specific hours. However, the highest peaks do not change, and the impact of including start-up cost is low.

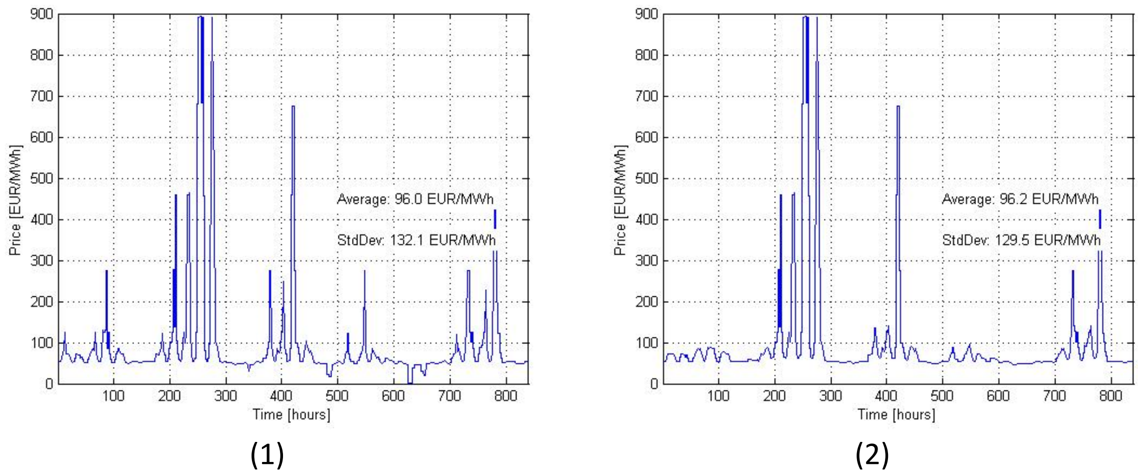


*Figure 4.34: **Prices in Germany** in the worst year for EOM with 3 weeks outage of 1.4 GW thermal power production (1) with start-up cost and (2) without.*

The same figure as above for transmission cable outage is presented in Appendix D. Additionally, change in utilisation time and profit margin for fossil-fired units are shown. The conclusion is that all units earn more and run longer with start-up cost included.

Figure 4.35 shows the change in consumer surplus in Germany for a three-week production outage with and without start-up cost included. The mean vary between a loss in consumer surplus of 8 and 8.5 MEUR, respectively with and without start-up cost. The worst year vary between 64 and 61 MEUR. Overall, the impact of including start-up cost is small.

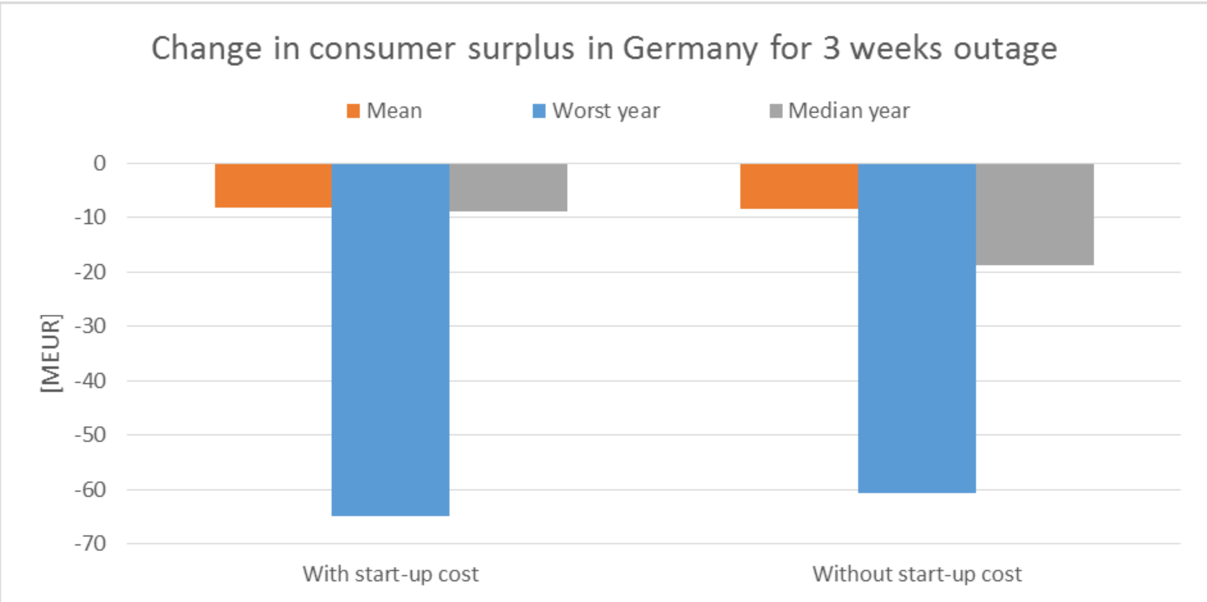


*Figure 4.35: **Change in consumer surplus** for production outage in EOM with and without start-up cost.*

The results from this section verify that German consumers suffer when capacity outage occurs – no matter if start-up cost is included. Including start-up cost gives more volatile prices. Nevertheless, the highest peaks and the change in consumer surplus are close to unchanged.

4.5 Prices in Norway in 2010 and 2030

The intension of this section is to show how the prices in Norway are expected to change between 2010 and 2030. In this period, the number of cables between Norway and North Europe will be increased by four, providing increased exchange capacity of 4.2 GW. These results are further used in the discussion part to evaluate the security of supply from Norway to continental Europe.

Figure 4.36 shows price percentiles in Norway for 2010 and 2030. It is seen that the average price increases by 2 EUR/MWh. The average price is slightly higher in 2030 because Norway is connected to the continent by more cables. However, the price peak is significantly higher in 2010 than 2030, exceeding 130 EUR/MWh at the worst time. The price peak in 2030 is reduced by 50 EUR/MWh compared to 2010.

The water inflow to the reservoirs has a great impact on the power price in areas dominated by hydropower. The high prices in Norway for 2010 are caused by lack of exchange capacity in the driest years.

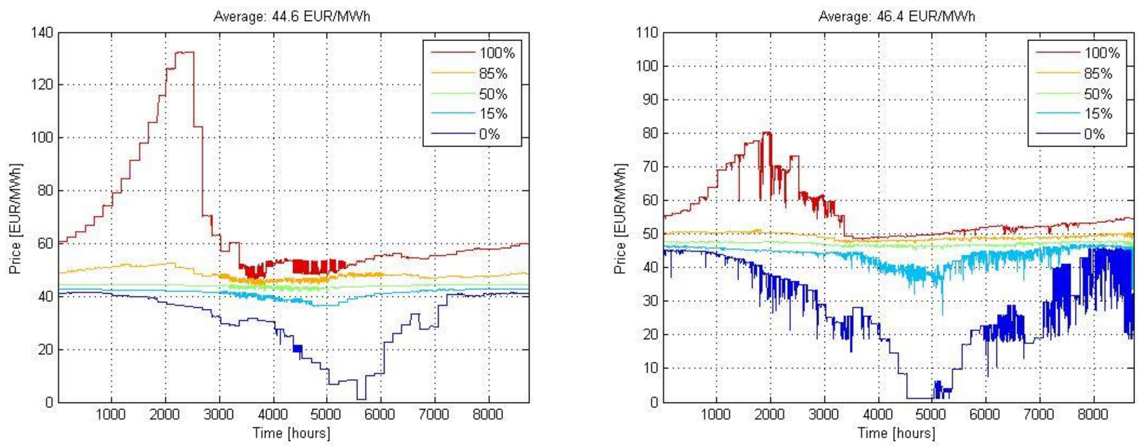


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*Figure 4.36: **Price percentiles in Norway** for EOM in (1) 2010 and (2) 2030.*

5. Discussion

This chapter is divided into three main parts:

- Discussions of main results
- Benefits of market participation for cross-border capacity
- Validity of results

Discussion of main results section collects the main findings in the report and draws conclusions. The aim is to compare and discuss these results in order to evaluate the consequence of forced outages from a market perspective.

Benefits of market participation for cross-border capacity section evaluates participation of foreign capacity into CRM and considers possible system solutions.

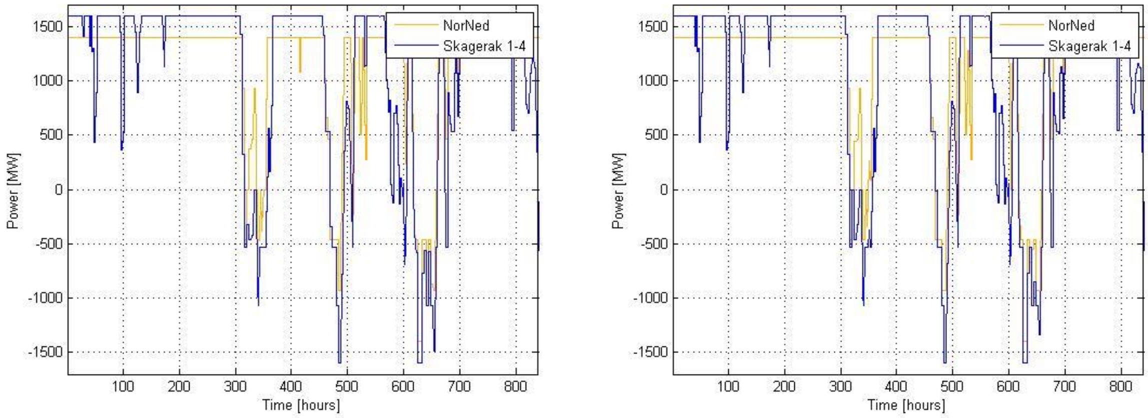
Validity of results section comments on simplifications and assumptions made in the thesis, emphasizing the effects on the presented results.

5.1 Discussions of main results

This section collects and compares the main results from simulations done in this master thesis.

5.1.1 Transmission cable outage is expensive for consumers in continental Europe if it occurs during power capacity shortage

Figure 5.1 shows power flow on NorNed and Skagerrak 1-4 (1) without and (2) with outage of Nord.Link. There are close to no change in power flow. Due to the relatively strong grid interconnection on the continent, prices in North-West European countries are high at the same time. In such situations, when capacity is highly needed, it cannot be expected that outage of one link can be compensated by increased power flow in others. The direct consequence of outage on Nord.Link during power capacity shortage is 1.4 GW less power supply to Germany.



(1) (2)

*Figure 5.1: **Exchange on NorNed and Skagerrak 1-4** referred to Norway the first five weeks in the worst year with (1) no outage and (2) 3 weeks outage of Nord.Link.*

The results show that a three-week outage of 1.4 GW exchange capacity has close to no impact on the average price in Germany for all 75 climatic years. However, in the worst year, which is the originally highest priced year in Germany, the price increases significantly. Lack of power production requires use of expensive flexible load, resulting in high price spikes. During these circumstances outage of exchange capacity has a significant impact on the power price.

Figure 5.2 shows prices in Germany the first five weeks of the worst year. The highest price peak in Germany is 700 EUR/MWh when Nord.Link is available. This is a period with close to no wind and solar production, and demand is met by extensive use of flexible load. However, the highest price peak rises further by 200 EUR/MWh during outage of Nord.Link, increasing the average price by 7.7 EUR/MWh. The rise in prices makes it more expensive to consume electricity, affecting consumer surplus in Germany greatly.

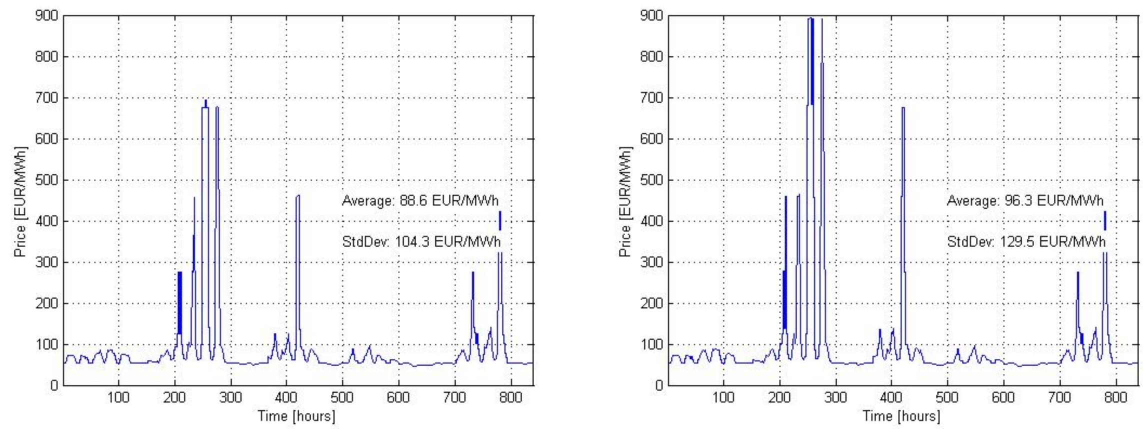


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*Figure 5.2: **Prices in Germany** the first five weeks in the worst year with (1) no outage and (2) 3 weeks outage of Nord.Link.*

Outage of 1.4 GW exchange capacity in a system at 100 GW as Germany, is not much. Despite of that, a three-week outage of Nord.Link might increase the average price in Germany by 2.4 EUR/MWh for the first five weeks in a normal year.

Norway is also affected by the outage of Nord.Link, but far less than Germany. The highest price peak for all 75 climatic years due to a three-week outage reaches 122 EUR/MWh, while the average price reduces by 0.1 EUR/MWh. The new price peaks occur *after* the outage period and is caused by the lower reservoir level in the first three weeks due to less exchange possibilities. However, the worst year in Germany is a year with normal prices in Norway.

It is evident that transmission cable outage might cause a significant impact on power prices on the continent. The consequence of outage depends greatly on the initial power situation when outage occurs, and *not* necessarily the outage length. This is also the case for the worst year as seen in Figure 5.2. Some price spikes increase by 200 EUR/MWh during outage of Nord.Link. Others do not rise at all.

Loss of 1.4 GW exchange capacity during power capacity shortage will cause severe consequences for consumers in Germany, while the consequences on system level are small. For comparison, a three-week outage of Nord.Link costs consumers in Germany 60 MEUR, while the loss in socio-economic surplus is only 5 MEUR.

Figure 5.3 shows change in consumer surplus versus outage length. The trend-line for the worst year is very steep up to three weeks outage of Nord.Link. Then, it slowly becomes parallel to the trend-line of the mean of all 75 climatic years. This is because outage of Nord.Link does not affect prices in Germany as much as it did in the beginning of the year.

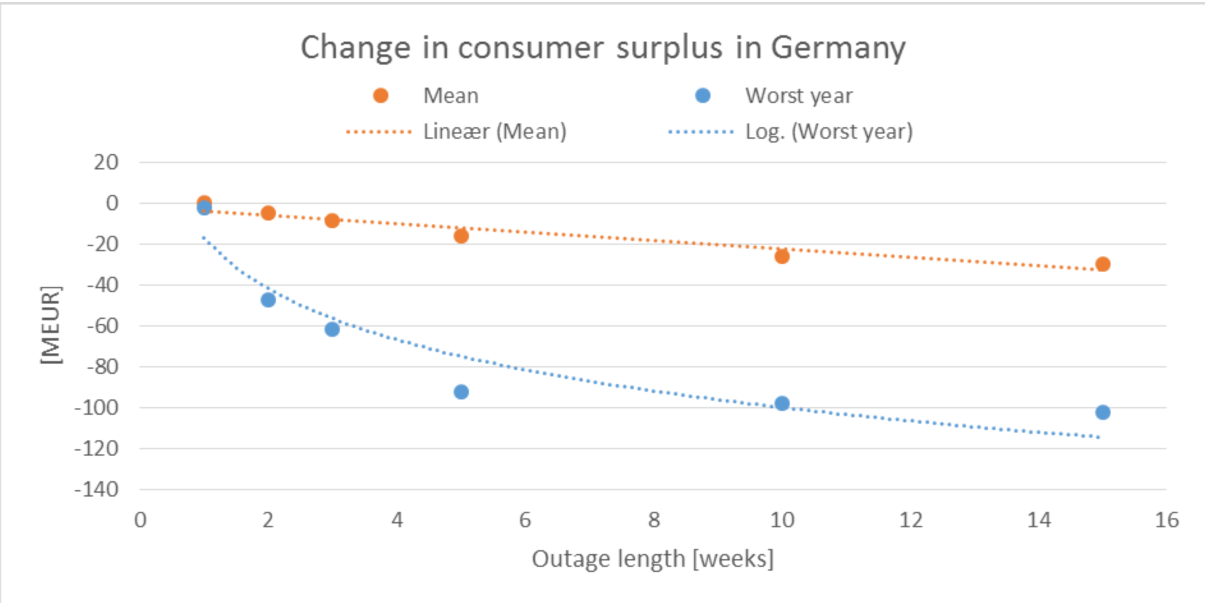

*Figure 5.3: **Change in consumer surplus in Germany** compared to the no-outage scenario.*

The loss of *not* providing back-up power exchange is evident. A two-week outage of Nord.Link costs German consumers close to 50 MEUR if it occurs during power capacity shortage. Nevertheless, the mean loss in consumer surplus of all 75 climatic years for a fifteen-week outage does not exceed 30 MEUR. The sensitivity analysis presented in the figure above reveals that transmission cable outages might provide a significantly higher electricity bill for consumers if it occurs when exchange capacity is needed.

The loss in consumer surplus presented in Figure 5.3 is evaluated to be rather optimistic. If the flexible load simulated was closer to the real system, each step should have been larger in power load (MW). This means that more load would have been disconnected, and prices increased further. In addition, consumers react to changing prices in the model. This is not necessarily realistic, especially not for short term changes in supply, because consumers do not really see the price changes.

Due to the domino-effect on the continent caused by the great interconnected grid, the loss in consumer surplus in Germany is only a part of the total loss in consumer surplus. The outage of Nord-Link rises prices in several countries on the continent, as presented in Figure 5.4. The value of providing back-up power exchange capacity to continental Europe is high because available transmission capacity leads to lower power prices for consumers.

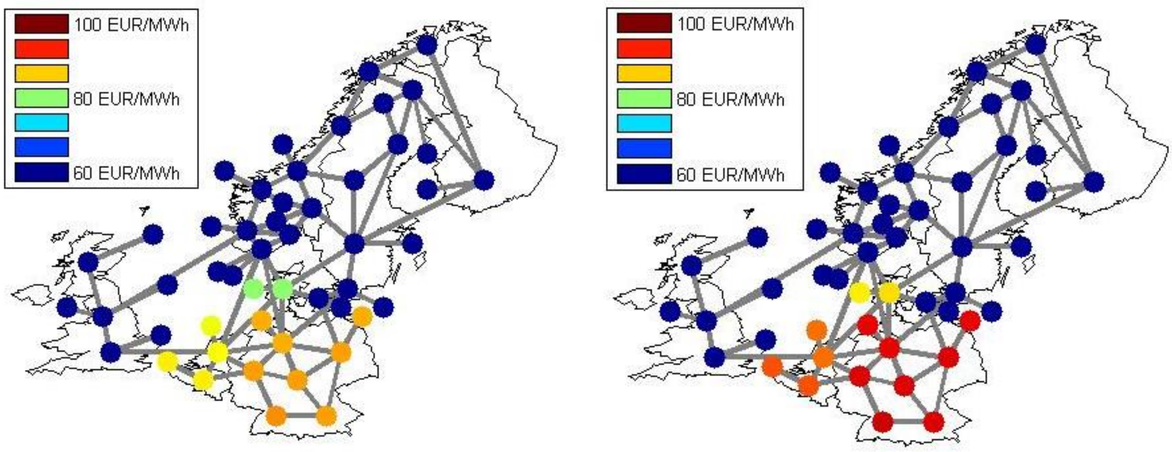

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*Figure 5.4: **Area prices** the first five weeks in Northern Europe in the worst year with (1) no outage and (2) 3 weeks outage of Nord.Link.*

However, the consequence of transmission outages depends greatly on the market solution in Germany. Capacity remuneration mechanism (CRM) ensures that there is enough installed capacity to cover peak load. CRM makes the system robust, avoiding power capacity shortage and very high prices.

The analysis shows situations with a high stable electricity bill (CRM) or electricity bill with great variations (EOM). CRM will almost eliminate all peaks in Germany, providing stable prices, but may give high losses in consumer surplus. The losses are caused by extra investment and maintenance cost for new power plants. These costs are indirectly paid by consumers as part pf the electricity price. Despite of that, power price response from an outage of Nord.Link has low impact in a market solution with CRM. The loss in consumer surplus for a three-week outage goes from exceeding 60 MEUR in EOM, to 4 MEUR in CRM, as shown in Figure 5.5. This is because there will be enough spare capacity installed in the system to avoid use of expensive flexible load in a CRM-solution.

The question is then how much consumers are willing to pay over time to avoid short-term variations.

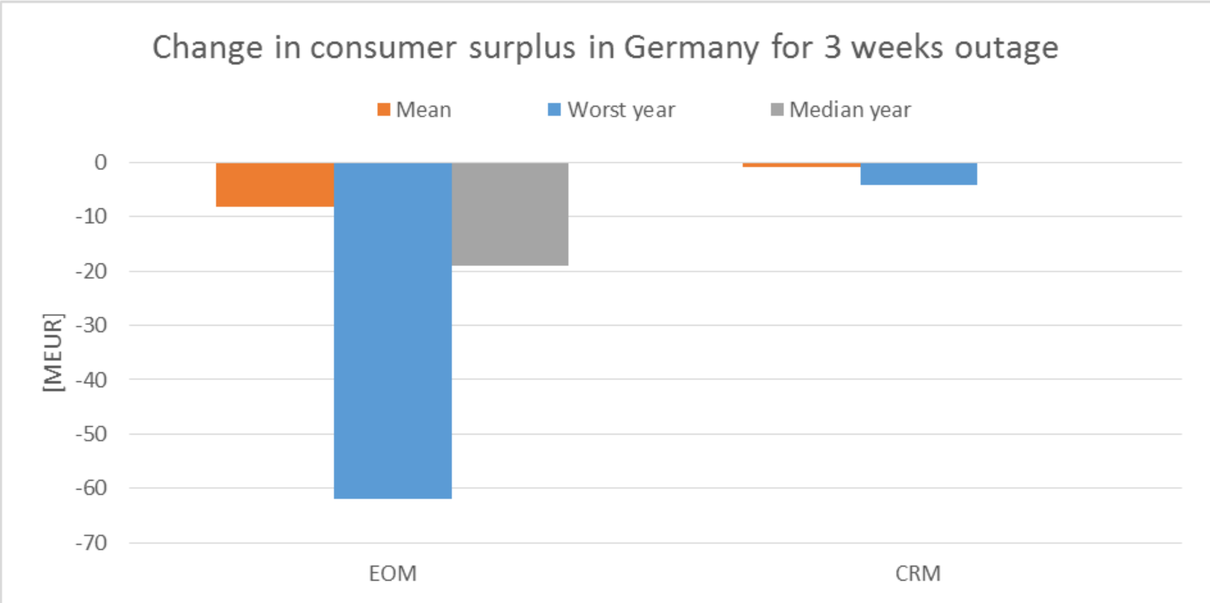

*Figure 5.5: **Change in consumer surplus in Germany** for EOM and CRM for 3 weeks outage of Nord.Link referred to the no-outage scenario.*

5.1.2 Production outage gives identical consequences as transmission cable outage

Figure 5.6 shows prices in Germany for the worst year, comparing outage of production and outage of transmission cable. The results give close to no difference in price pattern, i.e. the power capacity source is indifferent. This is expected. All available capacity is active as the marginal costs of any power production plant are far beneath the price peaks in such high price periods.

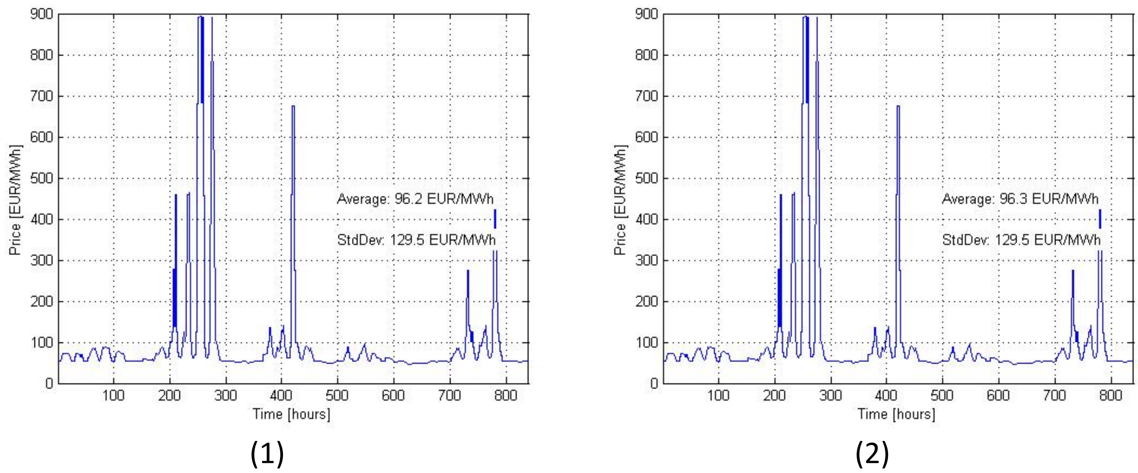

*Figure 5.6: **Prices in Germany** in the worst year for EOM with 3 weeks outage of 1.4 GW (1) thermal power production- and (2) transmission capacity.*

Figure 5.7 shows prices in Germany for the worst year with start-up cost included, presented equally as the figure above. Including start-up cost in the simulations is very time consuming. This should be included in thermal-dominated areas to emphasize their extra cost of start/stop. Despite of this, the results that include start-up cost give approximately the same loss in consumer surplus in Germany as when it is left out.

Including start-up cost affects prices as they become more volatile. Both higher and lower prices are seen throughout the year caused by producers reluctance to turn on/off due to this extra start-up cost. However, in critical hours, all capacity is used due to the very high prices, and consequences are seen to be equal to when the start-up cost is left out. The previous presented results are valid, even though start-up cost is left out of the simulations.

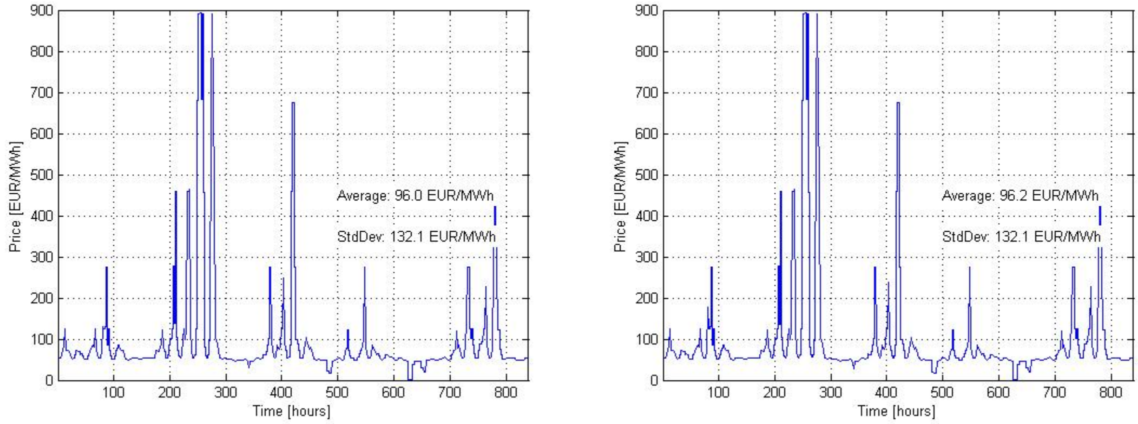

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*Figure 5.7: **Prices in Germany** in the worst year for EOM **with start-up cost** included with 3 weeks outage of 1.4 GW (1) thermal power production- and (2) transmission capacity (to be found in Appendix D).*

Figure 5.8 shows changes in consumer surplus in Germany when comparing power production and transmission cable outage. The difference in mean of all 75 climatic years varies with 0.5 MEUR, and the loss in consumer surplus for both cases exceeds 60 MEUR in the worst year. The consequence for consumers is negligible whether the capacity outage is production or transmission cable.

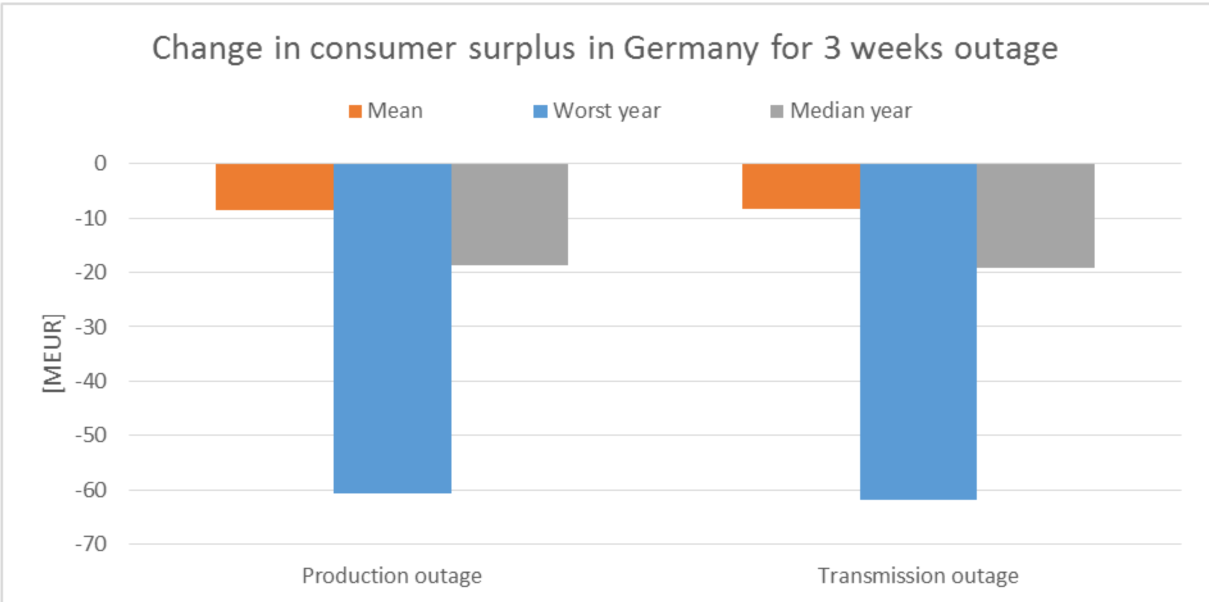


*Figure 5.8: **Change in consumer surplus in Germany** for 3 weeks outage of production- and transmission capacity.*

These discoveries confirm that the power capacity source is not important. The importance for German consumers is that *capacity* is available.

5.2 Benefits of market participation for cross-border capacity

This section intends to justify foreign participation in capacity remuneration mechanism (CRM). It focuses on the benefits of including hydro-dominated areas like Norway in such mechanism. The main hypotheses to be discussed follow below:

- HVDC-cables have less forced outages than fossil-fired units
- Prices are not influenced by the unavailable capacity type
- Norway becomes a more secure source of supply
- CRM may reduce profit for cable owners

5.2.1 HVDC-cables have less forced outages than fossil-fired units

The basic statistical data for this discussion is presented in section 3.1.

On average, unavailability stood for 12.1 % of the potential exchange on HVDC-cables for the period 2012-2013. Except disturbance outages, cable limitations and maintenance usually have a significant share of this category. Limitations are often a result of maintenance in the interconnected AC-grid. The two sub-categories of unavailability have in common that they are both usually predictable and can be carried out at suited time. They are therefore not assumed to be critical in respect to have capacity available in predefined, critical periods.

Energy not transferred on HVDC-cables due to disturbance outages, was 4.7 % on average in the period 2012-2013. The ten-year average of unavailability due to unplanned non-postponable events was 6.2 % for fossil-fired power plants. The statistical data on forced outages is in favour of HVDC-cables.

Since the categories are not entirely harmonised, and the evaluated periods are not identical, it could be difficult to draw a conclusion. Despite of that, the categories seem to complement each other as they both cover forced outages.

5.2.2 Prices are not influenced by the unavailable capacity type

The results shown in section 5.1.2 reveal that the consequences of outage are equal whether there is transmission cable outage or power production outage. This means that the capacity source is not important with respect to change in prices. All available capacity is producing its rated power during stressed situations.

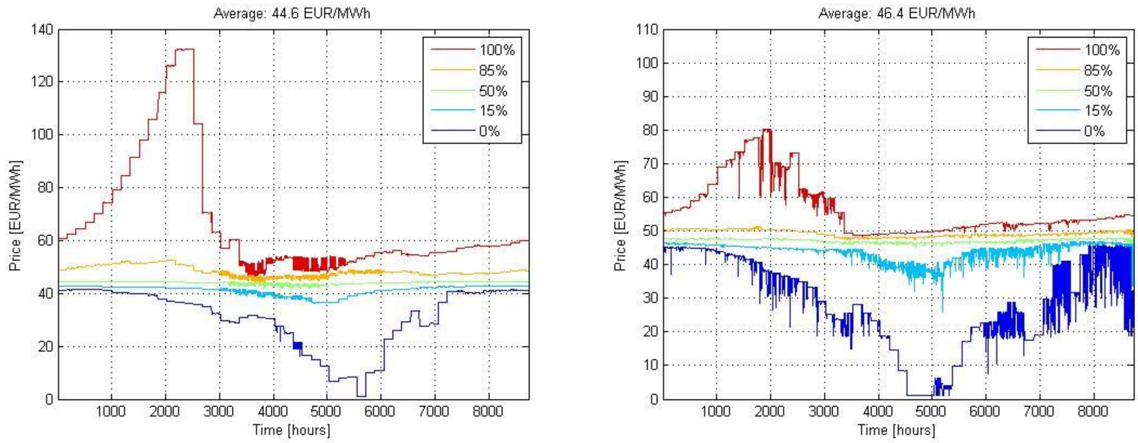
5.2.3 Norway becomes a more secure source of supply

High prices are a result of power production shortage. The Norwegian power production is dominated by hydropower. The inflow of water to the reservoirs is therefore critical in respect to power prices in Norway.

The impact of variations in water inflow on prices in Norway will be reduced with increased exchange capacity. In dry years, i.e. low inflow of water to reservoirs, Norway can import energy in order to store water. In 2010, the total HVDC exchange capacity from Norway was

1.6 GW. It is expected that the HVDC exchange capacity from Norway will rise by 4.2 GW until 2030 compared to 2010 levels: 0.7 GW to Netherland (NorNed II), 1.4 GW to Germany (Nord.Link), 1.4 GW to Great Britain (NSN) and 0.7 GW to Denmark (Skagerrak 4).

Figure 5.9 shows Norwegian price percentiles for a power system in 2010 and the expected system configuration in 2030. In 2030, the price peaks are significantly reduced due to increased exchange capacity. The highest Norwegian price peak in 2030 is reduced by 50 EUR/MWh compared to 2010. Even in the worst year in Germany, prices in Norway will be normal. The consequences of dry years will be less in the future. This makes Norway a more reliable source of supply with respect to energy in critical periods.



(1) (2)

*Figure 5.9: **Price percentiles in Norway** in (1) 2010 and (2) 2030.*

5.2.4 CRM may reduce profit for cable owners

Norway utilizes its production flexibility; importing energy when prices on the other side of the cable are low, and vice versa. However, inclusion of CRM in foreign countries reduces the price volatility and may reduce cable utilization. This further reduces the profit for cable owners. Cable participation in CRM is a measure to increase the profit again. Cable owners are then paid for installed capacity as well as energy sold. Exclusion of cables from CRM will likely bring up questions regarding closing borders in order to protect flexibility. Incentives for investing in new cables will also be reduced.

Moreover, the participation of cross-border capacity could provide investment incentives for new exchange capacity as well as reinvestments in Norwegian hydropower plants.

5.2.5 Participation in and implementation of cross-border CRM capacity

Current policy has two main targets: cleaner energy sector and secure power supply. Great amounts of renewables are, and will be, implemented on the continent. However, renewables need sufficient back-up power generation due to its intermittence.

CRM is a technology neutral solution to ensure system adequacy. Technology neutral means that also fossil-fired units are included. CRM is criticized due to giving subsidies to polluting fossil-fired power plants, which is counter intuitive to current policy. Cross-border capacity does the same job as internal production in respect to system adequacy, and it is cleaner (if supplied by hydropower). Cross-border capacity does therefore fulfil both policy targets: It is cleaner and ensures security of supply. Additionally, cross-border capacity is sufficient even considering unavailability due to forced outages. On top of that, it will reduce the required domestic installed generation capacity.

All previous arguments points out that cross-border capacity should be included if capacity remuneration mechanism is implemented in foreign countries.

However, there are some differences between the capacity providers. The main difference between production capacity and cross-border capacity is that producers need to *supply* the cross-border capacity with power. This demands some predefined regulations between the system operator and producers.

During stressed operations on both sides of the link, both sides should be equally prioritized. There should be an agreement between producers supplying a cable and the cable owner in order to provide the contractual obligation at all conditions. The participation should benefit foreign producers as well as cable owners financially. If the generator is unavailable, or the cable owner does not fulfil its obligation of available capacity, there should be penalties. However, the penalty must not frighten participation of CRM, but still intensify necessary maintenance and upgrades for the owner to keep the link available in vulnerable periods. Splitting the payment of CRM between adequacy and firmness could be a solution. Adequacy aims to ensure that capacity is installed, while firmness aims to ensure enough *available* capacity, also in the worst periods. Some is paid when the capacity is installed to ensure adequacy. If parts of the payment of participation are connected to deliveries during critical, predefined periods, firmness could also be considered.

Cross-border capacity included in CRM is also in line with EUs target of a clean European power system, as well as a strong and interconnected power system to provide security of supply. If foreign participation is excluded, incentives of interconnection and reaching internal energy market will be difficult.

5.3 Validity of results

In all kind of simulations, it is important to be critical to the results as they do not necessarily fulfil every perspective of the issue. There are some important items that should be addressed. This section evaluates these shortly, giving assumptions of their impact on the presented results.

Areas outside Northern Europe are modelled with fixed exchange based on historical data with hourly resolution. These boundary conditions are set to reduce the calculation time. It is assumed that if the exchange was not fixed, more capacity could have been available during stressed situations. This would reduce the size of super peak prices.

Demand reacts immediately to price changes. This is an important issue, and is not realistic. Consumers do not see the price signals - especially regular consumers that are charged by monthly resolution. In periods with tight capacity, prices would increase and consequences would be higher.

Calibration issues appear in simulations with CRM and start-up cost. A calibration would utilize water resources even better. Therefore, a calibration is beneficial, improving the results. However, calibration of a model of this size takes several weeks.

Start-up cost are not included throughout the results, but compared at the end. The conclusion is that start-up cost increases the price volatility, as well as variations in exchange. However, at the most critical hours, the inclusion of start-up cost is not important. All available power production sources supply their rated power because of the high power price. Therefore, start-up cost has no impact on the super peak prices. The average price is also close to unchanged, as well as variations in surpluses.

Very high numbers in surpluses could question the accuracy of the model. For instance, the consumer surplus in Germany with EOM exceeded 171 500 MEUR. The worst change in surplus of a three-week outage was about 60 MEUR. This change in surplus is only 0.3 thousandth. However, the results seem logical and consistent.

Consumption in Germany has a yearly constant pattern in all the 75 climatic simulated years. This is not necessarily realistic. However, the real load variations are not expected to vary as much as for instance in Norway. This is because space heat takes up a significant share of the electricity consumption in Norway, and the amount depends greatly on winter temperature.

Constant fossil fuel price from today to 2030 is an assumption. It is assumed that the CO_2-price increases until 2030, making the total cost of producing energy from fossil-fired units higher. Additionally, change in fuel cost would affect the production. Variability in fuel cost could lead to greater price volatilities, which again would affect consequences of outages.

AC limitations are included, but only by a constant reduction factor of 0.7 reducing the transmission capacity. EMPS is a transport model, with no underlying power flow. A power flow tool would make the flow more realistic, but much more time consuming.

HVDC-cable and production statistics are not entirely harmonised. This means that the statistical database might use categories differently. This is an issue when comparing statistical data from different distributors. Despite of that, the categories seem to complement each other as they both cover forced outages.

6. Conclusion

This study highlights the impact of HVDC-cable exchange outages between the Nordic area and the European continent, in order to evaluate the value of providing back-up generation capacity from Norway to the continent.

The main findings are:

- Transmission cable outage is expensive for consumers in continental Europe if it occurs during power capacity shortage. Consequences of outage are not determined by the outage length, but the initial power situation and the market solution in the affected area.
- Outage of one link will not be covered by increased power flow in other interconnections during power capacity shortage. This is because these transmission cables already are fully exploited due to price differences during such circumstances.
- Cross-border capacity should be included in foreign Capacity Remuneration Mechanism (CRM) because transmission cable outage gives identical consequences as power production capacity outage at the continent. Additionally, Norway becomes a more secure source of supply in the future due to more interconnections, making it possible to import energy in dry years.

The results show that a three-week outage of 1.4 GW exchange capacity, has close to no impact on the average price in Germany for all 75 climatic years in an energy-only market. However, in the highest priced year, the price increases significantly. In this study, results have shown the highest price reaches 900 EUR/MWh in Germany during a three-week outage of Nord.Link. This is 200 EUR/MWh higher than if Nord.Link had been available. These price peaks are a result of extensive use of flexible load. Norway is also affected by the outage of Nord.Link, but far less than Germany. The highest price peak for all 75 climatic years reaches 122 EUR/MWh, while the average price reduces by 0.1 EUR/MWh.

Loss of 1.4 GW exchange capacity during power capacity shortage will cause severe consequences for consumers in Germany. Despite of that, the consequences on system level are small. For comparison, a three-week outage of Nord.Link costs consumers in Germany 60 MEUR, while the loss in socio-economic surplus is only 5 MEUR.

Simulations show that the outage length has low impact regarding power prices and consequences for consumer surplus in Germany. However, initial power situation when outage occurs is important. A two-week outage of Nord.Link costs German consumers close to 50 MEUR if it occurs during power capacity shortage. Nevertheless, the mean loss in consumer surplus of all 75 climatic years for a fifteen-week outage does not exceed 30 MEUR. The sensitivity analysis reveals that transmission cable outage will provide a significantly higher electricity bill for consumers in Germany if it occurs when exchange capacity is needed.

The amount of installed conventional power has a great impact on consumer consequences. Extra installed capacity could be ensured through additional payment to producers and flexible consumers through Capacity Remuneration Mechanism (CRM). If there is enough capacity installed to avoid price spikes, the highest loss in consumer surplus in Germany caused by a three-week outage of Nord.Link is only 4 MEUR. This is a loss reduction of 93 % compared to 60 MEUR in an energy-only market.

Outage of one link will not be covered by increased power flow in other interconnections during power capacity shortage. Exchange capacity in other links is fully used during stressed situations due to the price differences - even before outage of Nord.Link. The direct consequence of outage during such circumstances is 1.4 GW less power supply capacity to Germany.

The impact of variations in water inflow on prices in Norway will be reduced with increased exchange capacity. In future dry years, Norway can import energy in order to store water and the consequences of dry years will be less severe. The simulations show that the highest Norwegian price peak in 2030 will then be reduced by 50 EUR/MWh compared to 2010. This makes Norway a more reliable source of supply with respect to energy in critical periods.

From the case study, it is concluded that transmission cable outage gives identical consequences in price as power production outage in Germany. Additionally, the fault-statistics are in favour of transmission cables, and foreign participation in CRM should therefore be recommended. Cross-border capacity included in CRM is also in line with EUs target of a clean European power system, as well as a strong and interconnected power system to provide security of supply.

Furthermore, the value of providing back-up generation from Norway to continental Europe is high because the exchange capacity will reduce continental power prices significantly during power capacity shortage.

7. Future works

Here are some proposals for further works:

- The model should be calibrated, both for CRM and start-up cost, in order to make the results more valid.
- Harmonised statistical data is wanted. This would improve the quality of comparing production and HVDC-cable fault-statistics.
- A sensitivity analysis of Norwegian prices and consumer surplus versus outage length is interesting. Some price peaks did occur due to a three-week outage of Nord.Link. How long outage of exchange capacity is acceptable before prices gets very high in Norway as well.

8. Nomenclature

Abbreviations

CRM – Capacity Remuneration Mechanism

EMPS - EFIs Multi-area Power-market Simulator

ENTSO-E – the European Network of Transmission System Operators for Electricity

EOM – Energy Only Market

EURELECTRIC – The Union of the Electricity Industry

HVAC – High Voltage Alternating Current

HVDC – High Voltage Direct Current

IEM – Internal Energy Market

NGC – Net Generation Capacity

RES – Renewable Energy Sources (assumed unregulated)

TSO – Transmission System Operator (Example: Statnett SF in Norway)

Definitions

Firm load – Fixed load, following a yearly pattern.

Flexible production – Technical flexible regarding controlling production both ways relatively quickly, i.e. increasing as well as decreasing power production. RES are by this definition not flexible.

Hydropower – Electricity generated by controllable hydro units.

Marginal cost – Refers to the actual power production cost of producing one extra unit of energy, and not the actual investment cost of the plant.

Power capacity shortage – Lack of energy production, which often results in high prices due to the need of expensive flexible load to meet demand.

Solar energy - Electricity generated by solar power plants.

Stressed operation/situations – refers to power capacity shortage. See definition above.

Thermal-based area – Areas dominated by fossil-fired units, in combination with large amounts of wind and solar. “Thermal-based area” resembles the production configuration in Germany.

Wind energy – Electricity generated by wind turbine units.

9. Literature

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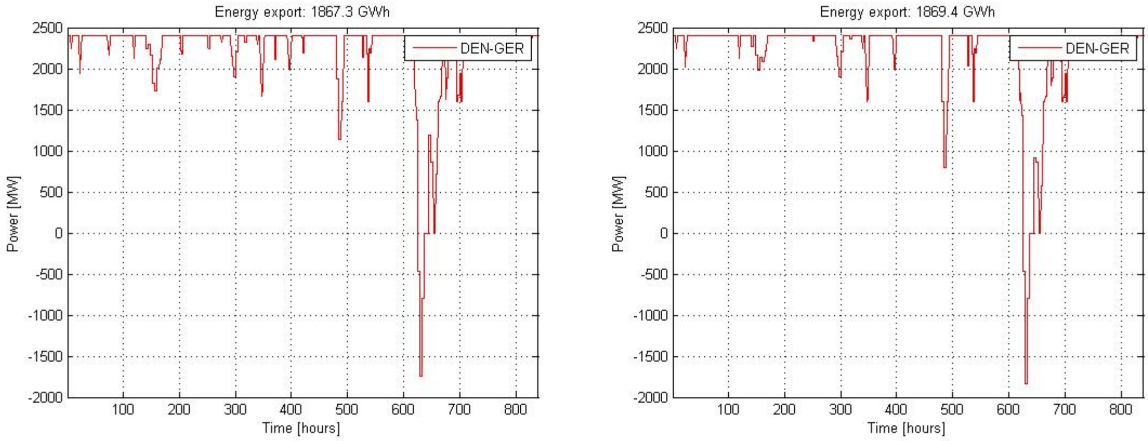
Appendices

Appendix A – EOM worst year

This section shows power flow from Denmark and Sweden to Germany in the worst year in an energy-only market. There are close to no visible changes in exchange when outage occurs on Nord.Link, because their capacity is already exploited in hours with power capacity shortage on the continent.

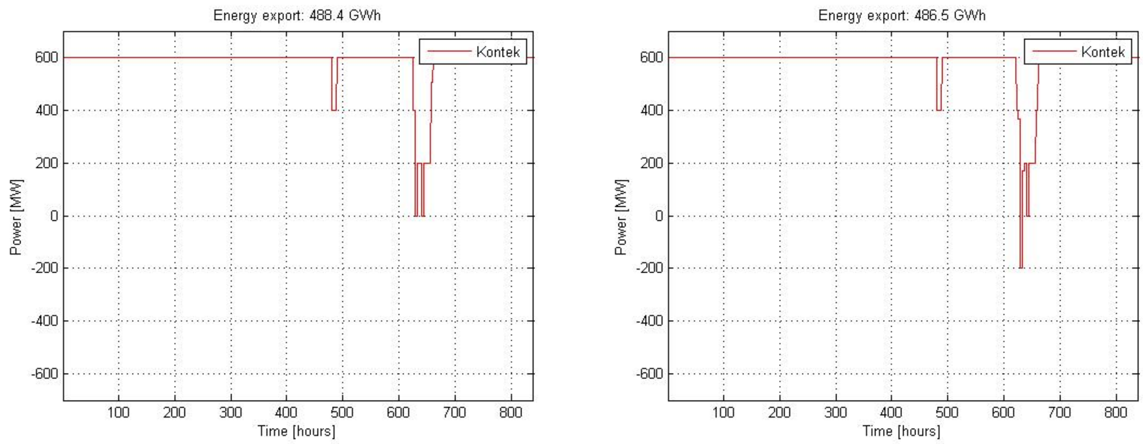
Denmark West – Germany:



(1) (2)

*Figure A.1: **Exchange on Denmark west-Germany** the first five weeks in the highest priced year in Germany with (1) no outage and (2) Nord.Link outage in the first 3 weeks of the year.*

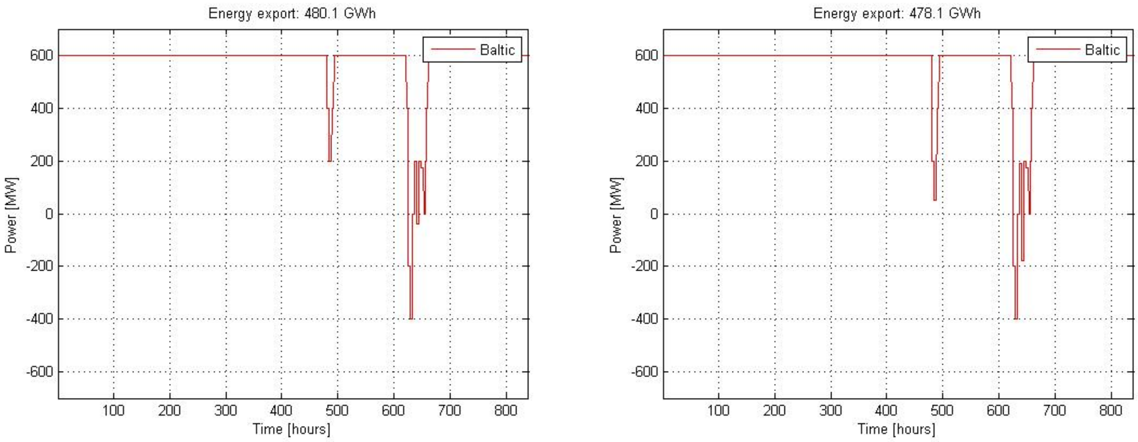
Kontek (Denmark East - Germany):



(1) (2)

*Figure A.2: **Exchange on Kontek** the first five weeks in the highest priced year in Germany with (1) no outage and (2) Nord.Link outage in the first 3 weeks of the year.*

Baltic cable (Sweeden - Germany):



(1) (2)

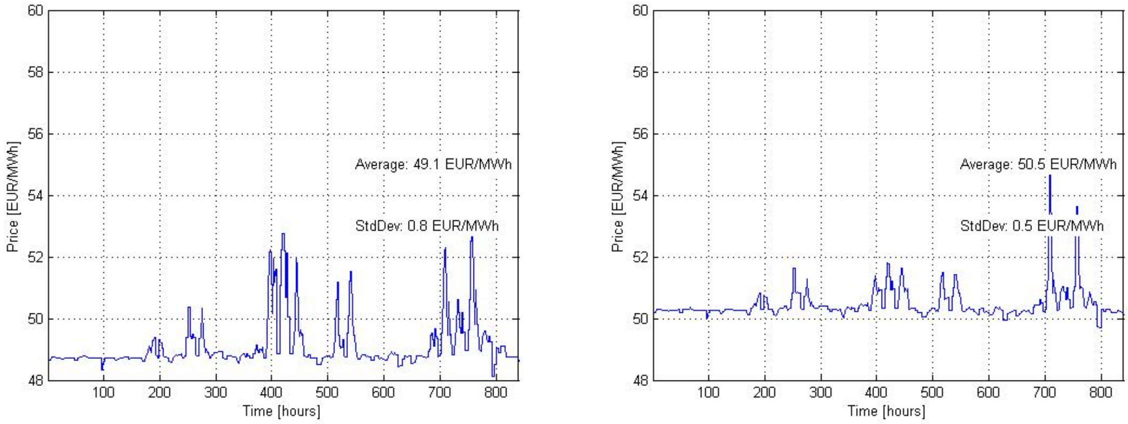
Figure A.3: ***Exchange on Baltic cable*** *the first five weeks in the highest priced year in Germany with (1) no outage and (2) Nord.Link outage in the first 3 weeks of the year.*

Appendix B – CRM worst year

This section shows prices in Norway and exchange on Nord.Link for a CRM-solution in Germany.

As seen in Figure A.4, the calibration in hydro production is not done (higher average price), i.e. do not utilize the reservoir fully. However, the average price is low compared to Germany.

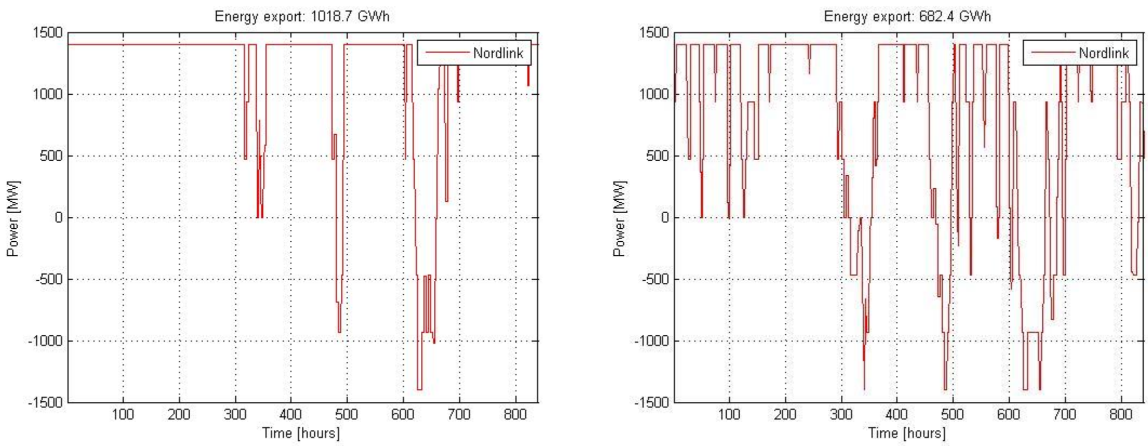
The price in Norway is slightly less volatile with CRM than EOM in Germany.



(1) (2)

*Figure A.4: **Prices in Norway** the first five weeks with **3 weeks outage** of Nord.Link in the worst year with (1) EOM and (2) CRM*

Figure A.5 compares the no-outage exchange on Nord.Link for the two market solutions. The amount of exported energy from Norway is reduced with CRM.

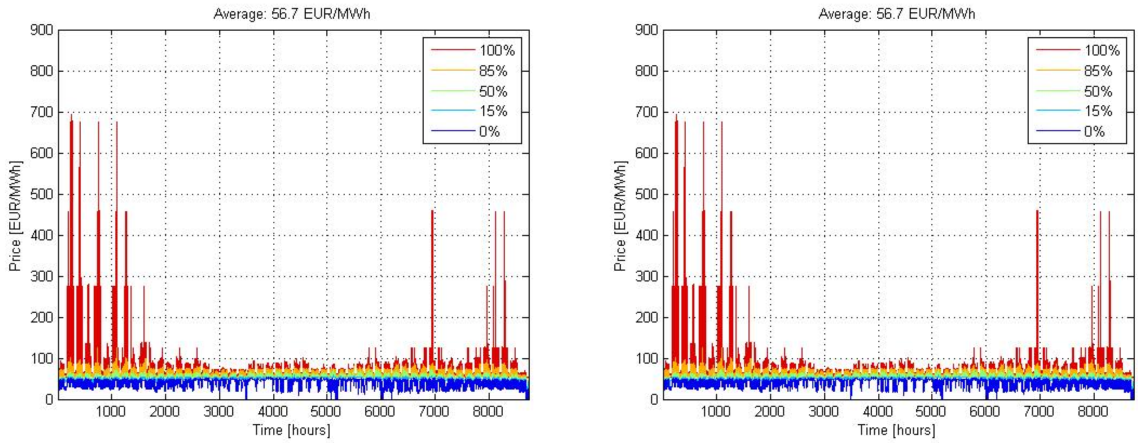


(1) (2)

*Figure A.5: **Exchange on Nord.Link** referred to Norway the first five weeks with **no outage** in the worst year with (1) EOM and (2) CRM*

Appendix C – Allocated versus aggregated simulation

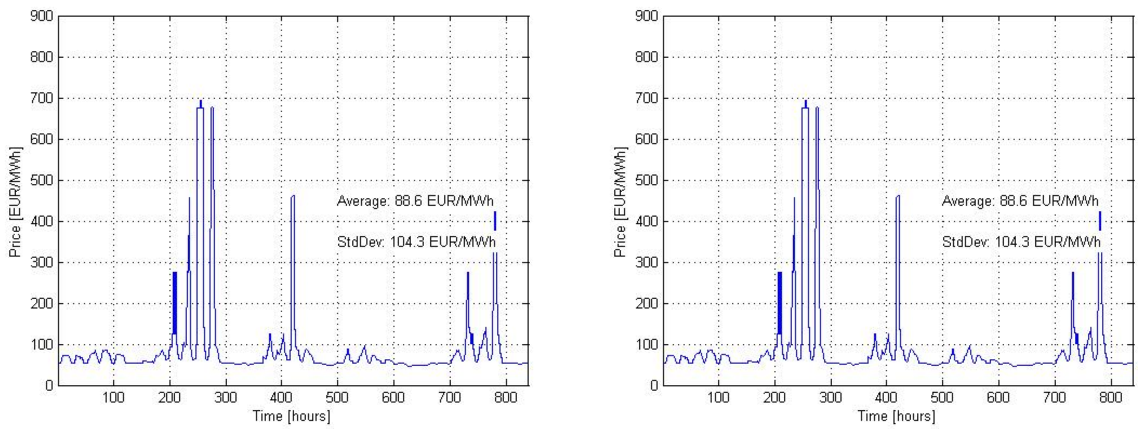
The differences between allocated and aggregated simulation are small, especially on the continent, which the following figures confirm. Allocation to specific plants are just done in hydro areas – never in thermal. This explains why the consequences are not visible in Germany. The impact of exchange is very low.



(1) (2)

*Figure A.6: **Prices in Germany** with EOM (1) allocated and (2) aggregated*

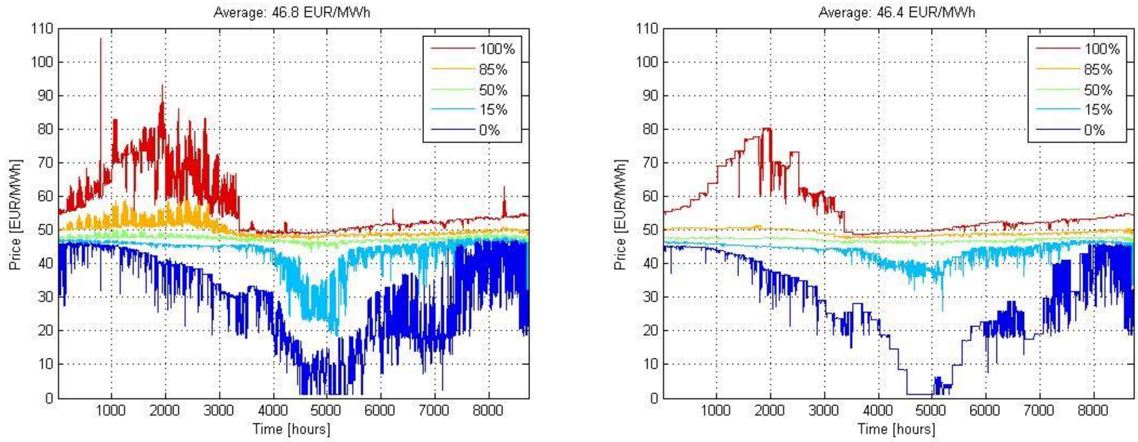
The worst year are also unchanged, as seen in Figure A.7.



(1) (2)

*Figure A.7: **Prices in Germany** for the worst year with (1) EOM (allocated) and (2) EOM (aggregated)*

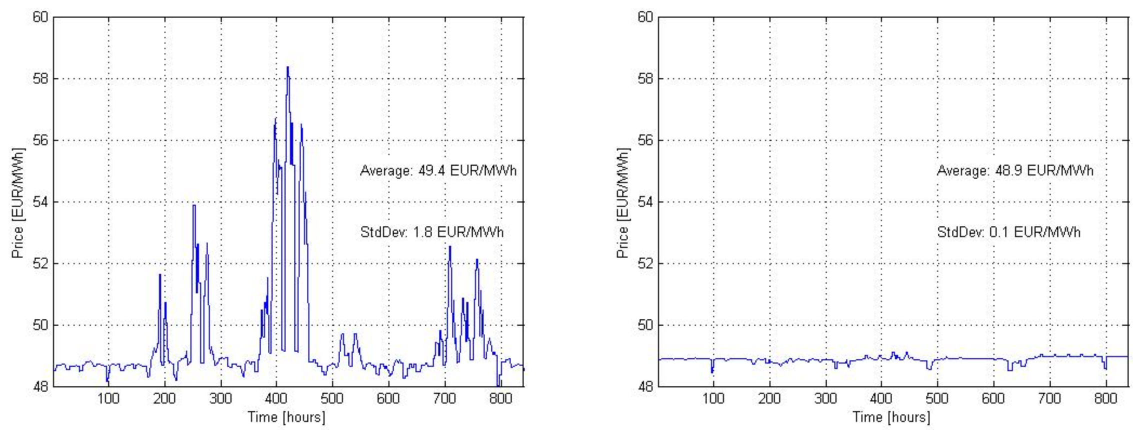
However, prices in Norway are changing somewhat, shown in Figure A.8. The volatility seem to disappear when aggregating the areas, even though both have sequential resolution. The average price reduces from 46.8 to 46.4 EUR/MWh for over the 75 climatic years simulated.



(1) (2)

*Figure A.8: **Prices in Norway** with EOM for simulation with (1) allocated and (2) aggregated hydro production*

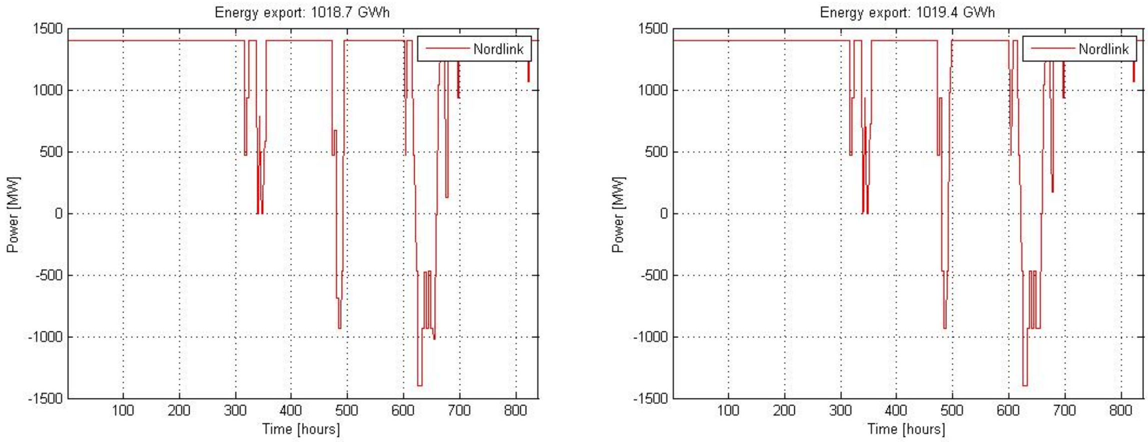
The change in volatility is significant for the worst year. However, the average price reduces just by 0.5 EUR/MWh.



(1) (2)

*Figure A.9: **Prices in Norway** for the worst year with EOM for simulation with (1) allocated and (2) aggregated hydro production*

Exchange on Nord.Link are not affected by the use of aggregated simulation.

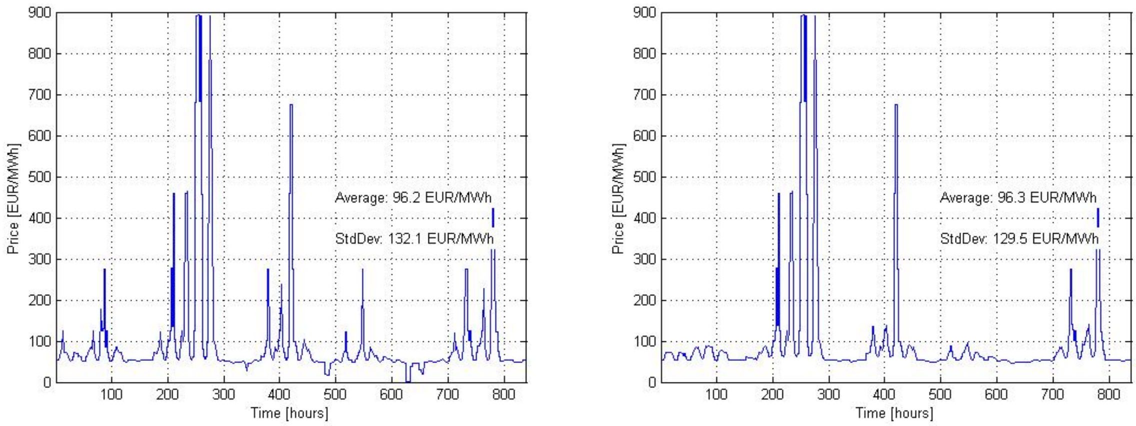


(1) (2)

*Figure A.10: **Exchange on Nord.Link** referred to Norway the first five weeks with EOM for simulation with (1) allocated and (2) aggregated hydro production*

Appendix D – Simulation with and without start-up cost

Figure A.11 shows prices in Germany for the first five weeks of the worst year with a three-week outage of Nord.Link. There are close to no impact of including start-up cost in the simulation in such high-price periods.



(1) (2)

*Figure A.11: **Prices in Germany** in the worst year for **EOM** with 3 weeks outage of Nord.Link (1) with start-up cost and (2) without.*

Table A.1 shows average profit for fossil-fired production sources with and without start-up cost included. When including start-up cost, the profit increases for all fossil-fired units, with an average about 10 EUR/MWh of all simulated years.

Table A.1: Average profit (1) with start-up cost and (2) without

Average profit:	EUR/kW	
Lignite:	108.60	108.60
Hard Coal:	57.14	57.14
Gas:	46.67	46.67
Oil:	12.80	12.80

(1)

Average profit:	EUR/kW	
Lignite:	94.14	94.14
Hard Coal:	46.78	46.78
Gas:	36.95	36.95
Oil:	7.98	7.98

(2)

Figure A.12 and Figure A.13 shows the annual margin and running hours for fossil-fired production sources, with and without start-up cost included. All units earn more and run longer with start-up cost included.

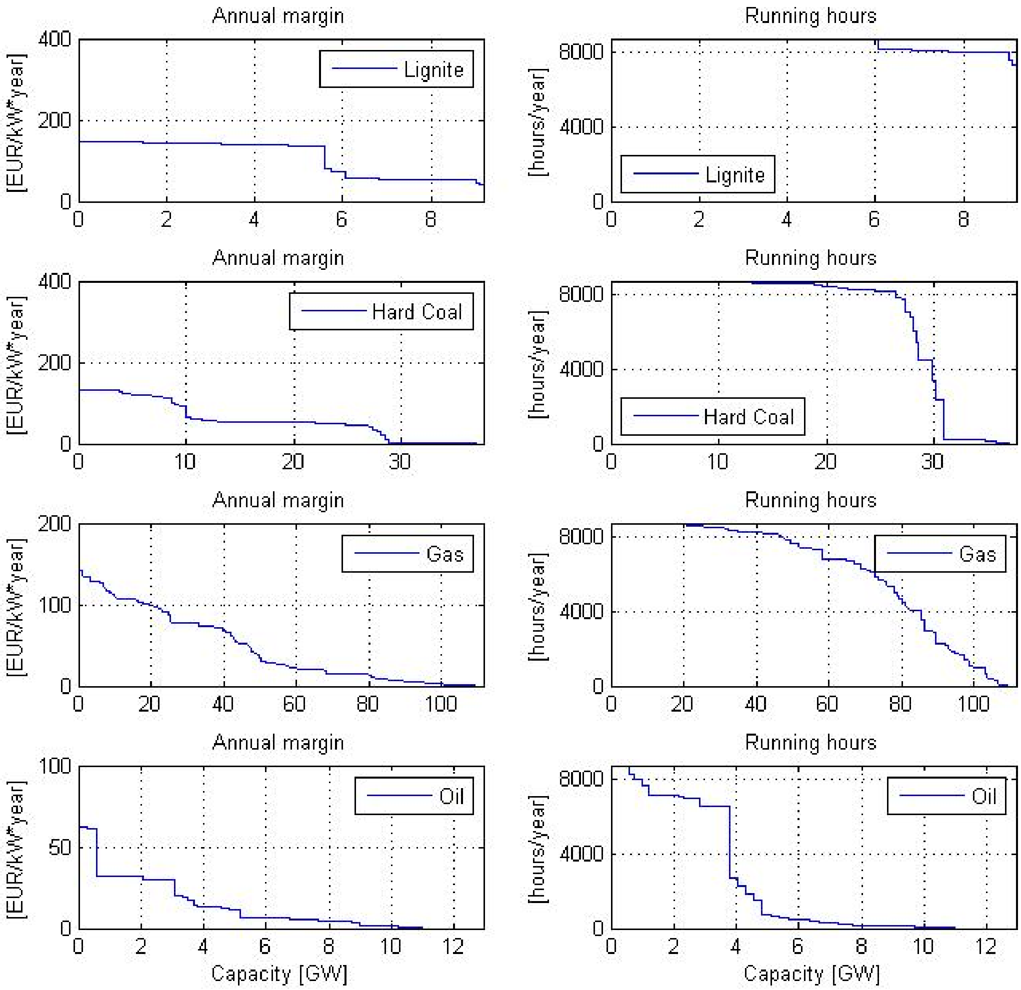


Figure A.12: Annual margin and utilization time with start-up cost for EOM

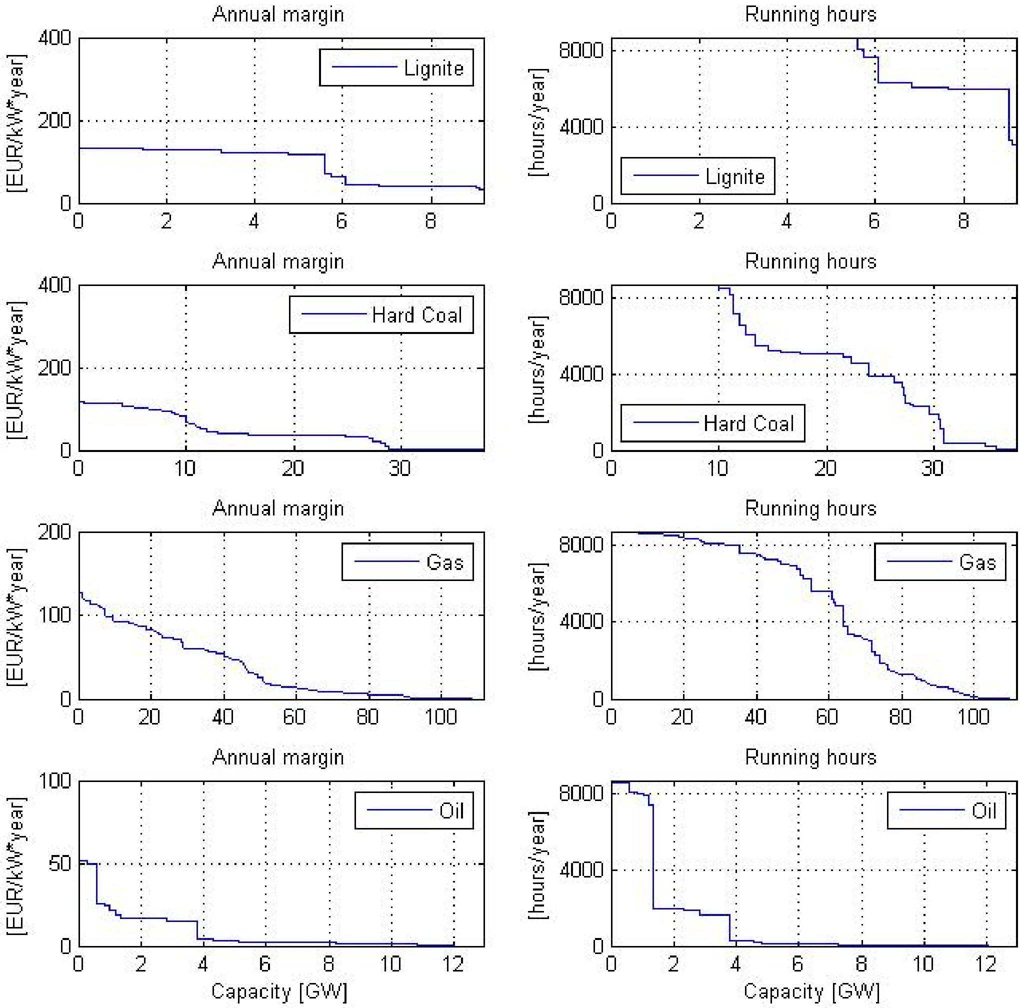


Figure A.13: Annual margin and utilization time without start-up cost for EOM