ECN

Discussion paper

Generation Capacity Investments and High Levels of Renewables

The Impact of a German Capacity Market on Northwest Europe

Özge Özdemir
Jeroen de Joode
Paul Koutstaal
Marit van Hout

May 2013
ECN-E--13-030

Acknowledgement

This study has been conducted for Dutch Ministry of Economic Affairs. We would like to thank Benjamin F. Hobbs (JHU and Scientific Advisor, ECN), Gerard Doorman (NTNU), and Francisco Munoz (JHU) for their comments and valuable feedback on the modelling and results of the analysis presented in this paper. The project is registered at ECN under project number 5.1974. The contact person for this study is Özge Özdemir (ozdemir@ecn.nl).

Abstract

Presently, Northwest European centralised electricity markets are designed as 'energy-only' markets. In an energy-only market, the price received for electricity produced is set by the marginal generation unit. Potentially, the designs of these markets could leave the owners of these units with 'missing money': i.e. money that is required to recover investment cost. Further, increasing penetration of renewables could exacerbate this problem. Of all the different options available to tackle the 'missing money' problem, capacity mechanisms have attracted most of the attention in recent policy debates in Europe.

This paper contributes to ongoing policy discussions by providing a quantitative analysis of the phenomena of 'missing money' and capacity mechanisms in Northwest Europe. Our analysis shows that in the case of energy-only markets with a much higher penetration of intermittent electricity sources such as wind and solar PV, the 'missing money' problem may be aggravated, because operating hours for peak and mid-merit order capacity will be considerably reduced. Furthermore, unilateral introduction of capacity mechanisms in integrated electricity markets can have considerable impacts on cross-border electricity flows and investment decisions. Stand-alone introduction of a capacity market in Germany will likely result in higher investments in Germany at the expense of lower investments outside Germany and an increase in net exports from Germany. A possible advantage of a unilateral capacity mechanism in Germany may be a reduction in super-peak prices in the larger market area. Thus, neighbouring countries may have the possibility to free ride on the increase in flexible capacity in Germany. However, this advantage is conditional and depends on sufficient availability of interconnection capacity necessary to be able to use this reserve capacity. Otherwise, security of supply might be more at risk if the German capacity mechanism results in less capacity investment within a country, especially if the transmission capacity is insufficient or the need to draw upon reserve capacity occurs simultaneously in the larger market area.

Contents

1 Introduction

Before liberalization of electricity markets in both the US and Europe, electricity production and distribution was a public utility and the investments in new plants were based upon long-term plans drawn up by governmental or government-backed organizations. With liberalization, electricity production and investments in generation capacity has become the responsibility of companies who have to make sufficient profits on the electricity market. Initially, when liberalization was introduced in Europe and in the US in the late eighties and nineties of the former century, policy makers held the view that energy-only spot electricity markets would provide sufficient incentives for investment in new generation capacity. Therefore, no additional measures were put in place to stimulate investments. However, the large need for both replacement and new capacity investments in many countries and recent experience with energy-only markets have led policy makers to question whether these markets will provide sufficient incentives for investments or whether additional policy measures would be needed to ensure sufficient investments and thereby security of delivery in electricity markets.

Parallel to the policy debate, there has also been considerable attention in the scientific literature for the question whether investors can recoup their investments in these liberalized electricity markets. According to this literature, an optimal energy-only market would, in principle, allow investors in peak capacity to earn sufficient revenues during peak hours. Important conditions for such an optimal energy only market are prices which are allowed to rise to the point where consumers would prefer to be disconnected instead of paying this price (the value of lost load, VOLL) and sufficient flexibility in demand to react to high prices ([1], [2]). However, these conditions are not necessarily met in real energy-only markets, as has been extensively explained by ([1], [3], [4]). Consequently, investors in especially peak-capacity will not recoup their investment costs from their revenues on the electricity market, the so-called 'missing money' problem.

The scientific literature and recent policy discussions in the US and Europe seem to indicate that there is indeed a problem with investments in new generation capacity in energy-only markets. In California, for example, the need for new flexible fossil-fuelled capacity has been identified by the state's Independent System Operator, yet there is concern that there are inadequate investment incentives to provide that capacity [5]. In Europe, there has been an overcapacity of generation inherited from the pre-liberalisation era. Now, an increasing share of intermittent renewables in electricity generation and a decommissioning of a substantial share of capacity has put the issue to the foreground since it may indeed exacerbate the 'missing money' problem and reduce the investment incentives for new back-up generation capacity. This has been the subject of recent studies (e.g., [6], [7]) which have assessed the impact of increasingly large amounts of wind and solar PV in the Northwest European electricity system on investment incentives in back-up generation capacity. A main outcome of [6] is that with high penetration of the intermittent renewables such as wind and solar, the operating hours and scarcity rents for peak and mid-merit order capacity will be considerably reduced. Consequently, in the *short term*, the existing peak and mid-merit order units gain inadequate revenues to recover their fixed costs since these units generate in less hours. In the *long term*, this problem may create a disincentive for investment in new generation capacity, which is a problem if there is not excess capacity.

There are a number of options available to address the 'missing money' problem, such as improving demand response and price signals. The price signals in power markets can be improved to make investments more profitable, for example by means of allowing prices to rise to VOLL when operating reserves are short or system operators take out-of-market actions during scarcity conditions. As an alternative option to tackle the 'missing money' problem aggravated by increasing shares of renewable, capacity mechanisms have attracted considerable attention in recent policy debates in Europe. Some countries have actually introduced capacity mechanisms, such as Ireland and Spain (capacity payments) and Sweden & Finland (strategic reserves), while other countries (Germany, UK, France) consider the introduction of such mechanisms. So far, the discussion has focussed on national, unilateral mechanisms for one country only, while electricity markets have become more integrated over recent years and extend over more than one country. A similar situation is also observed in the US, where spot markets fall under federal (FERC) jurisdiction, but capacity markets are the responsibility of the states ([8]).

This paper contributes to ongoing policy discussions by providing a quantitative analysis of the phenomena of 'missing money' and capacity mechanisms in Northwest Europe. First, we analyse the impact of an increasing amount of intermittent renewable electricity generation in Northwest Europe on investment incentives for back-up capacity. Thereafter, we analyse what the impact could be on the Northwest European market of a hypothetical (but realistic) situation that Germany unilaterally implements some form of capacity mechanism. For the analysis, we use a model of European electricity market, COMPETES model[1], which is briefly described in Section 2. Literature on the actual impact of introducing national capacity mechanisms in Europe on neighbouring markets is rare, especially quantitative analysis (e.g., [9] and [10]). [11] give a qualitative explanation of how a German capacity market could affect its neighbouring countries.

[1] The mathematical formulation and several applications of the model are presented in (Hobbs & Rijkers, 2004), (Lise & Hobbs, 2005), (Ozdemir, et al., 2008), (Ozdemir, et al., 2009), (Lise, et al., 2010).

In Section 3, we explore the 'missing money' problem in the Netherlands for the year 2020 where the share of intermittent renewables increases in Europe according to the targets reported by [12] based on National Renewable Energy Action Plans (NREAP) of the EU member states. Our analysis shows that the increase in intermittent electricity generation capacity increases the variability in the contribution of electricity produced by gas-based units to the Dutch electricity system on both an hour-to-hour and day-by-day basis. The increased volatility leads to a lower number of full load-hours for this type of units. The order of magnitude of this effect in terms of full load-hours lies in the range of -55 to -75% for gas-based units in mid-merit and peak hours, respectively, while the generation units operating in the super-peak hours are hardly operating at all. This points to an increase in the amount of ''missing money''. The resulting gap to cover investment costs of these units can increase significantly depending on their position in the merit order (with 36 till 72%).[2]

We analyse the cross-border impact of the unilateral implementation of a capacity mechanism in Germany in Section 4.[3] We compare the outcomes of two possible market designs in Germany for 2020; (1) an energy-only market with VOLL pricing implemented in all the European member states including Germany and (2) a forward capacity market unilaterally implemented in Germany while the other countries continue to have energy-only markets. In the forward market assumed in Germany, the regulator sets a reserve margin (peak capacity – peak load) and generators located in Germany receive a capacity payment. We assess the effects on the Northwest European electricity markets in terms of generation capacity investments, production levels, cross-border flows, and prices. Our analysis shows that stand-alone introduction of a capacity market in Germany will result in higher investments in Germany at the expense of lower investments outside Germany and an increase in net exports from Germany. Introduction of a unilateral capacity mechanism in Germany will reduce super peak prices in the larger market area, thereby increasing consumer surplus. Neighbouring countries can free ride on the increased flexible capacity in Germany. However, this advantage is conditional on sufficient availability of interconnection capacity necessary to be able to use this reserve capacity. Otherwise, security of supply might be reduced, given less capacity investments in neighbouring countries when transmission capacity is insufficient or a simultaneous need in reserve capacity occurs in the larger market area.

[2] These results corroborate the findings of [6] which is based on a comparable approach and confirm that gas-based generation units may not be able to recover investment costs in a future electricity system with a higher level of intermittent renewable energy sources.

[3] Discussions on how the design of the capacity market in Germany should be is beyond the scope of this paper. Assuming a well-designed capacity market and perfect competition, we aim to observe the long-term impacts of a unilaterally implemented forward capacity market in Germany on the Northwest Europe; in particular in the neighbouring countries such as the Netherlands.

2

Methodology and Assumptions

COMPETES[4] is an economic electricity market model of Europe which covers EU countries and some non-EU countries as given in **Figure 1**. Every country is represented by one node, except for Luxembourg which is included in Germany, and Denmark is split in two nodes due to its participation in two non-synchronous networks. The model assumes an integrated EU market where the trade flows between countries are constrained by “Net Transfer Capacities (NTC)” reflecting the ten year network development plans (10YNDP) of ENTSO-E ([13]).

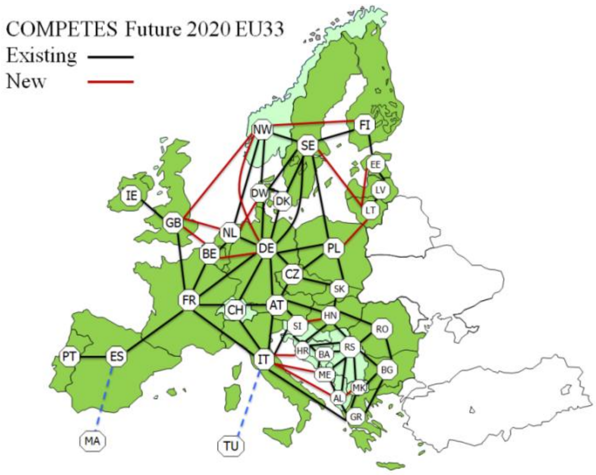


Figure 1: Geographical coverage in COMPETES and the representation of the network according to ten year network development plan of ENTSO-E [13] until 2020

[4] COMPETES is developed by ECN in corporation with B.F. Hobbs, who is a professor with the Department of Geography and Environmental Engineering of the Johns Hopkins University, Baltimore, USA and Scientific Advisor to ECN. References documenting formulations and applications of COMPETES include [14], [30]- [32].

Next, we briefly describe static and dynamic versions of the model which are used to address the following research questions respectively:

1. What is the impact of more intermittent RES in the Netherlands on generation capacity investment incentives?
2. What is the impact of Germany unilaterally implementing some form of capacity mechanism on the Northwest Europe?

2.1 Modeling operation of wholesale electricity markets with intermittency

The first research question is analysed by using the static COMPETES model which simulates operation (for fixed generation capacity) within a competitive European market. The static model includes wind and solar intermittency and simulates each hour in a year, taking into account the cross-border transmission limitations. Under perfect competition, the model is formulated as a Linear Program (LP), which is equivalent to the mixed complementarity problem derived from models of generator, TSO, and arbitrageur behaviour in an integrated EU market (e.g., [14]). The LP model minimizes total generation and load-shedding costs (i.e., 10.000 euro/MWh [1]) subject to electricity market constraints such as:

- *Power balance constraints:* These constraints ensure demand and supply is balanced at each node at any time.
- *Generation capacity constraints:* These constraints limit the maximum available capacity of a generating unit. These also include derating factors to mainly capture the effect of planned and forced outages to the utilization of this plant.
- *Cross-border transmission constraints:* These limit the power flows between the countries for given NTC values.

Given the specific levels of demand and the characteristics of supply and transmission limits, competitive solution of COMPETES specifies the least-cost/social welfare maximizing allocation of production and transmission for all the countries and the competitive prices calculated at each node represent the locational marginal prices. The least-cost allocation of production implies that the conventional generation technologies and the flexible renewable technologies (e.g., biomass and waste) are dispatched according to their marginal costs and positions in the merit order for each country. Furthermore, pre-calculated hourly intermittent RES and hydro generation are taken as a must-run generation by the model.

2.2 Modeling generation capacity investments

For this study, the COMPETES model is modified by incorporating endogenous conventional generation capacity investments, so in that sense it can be characterized as a dynamic model. The installed capacities of renewables and nuclear are taken as exogenous since the investments/ decommissioning for these technologies are assumed to be policy driven.[5]

We consider a two-stage set up similar to [15], [16] and [17]. Investors of conventional generators give their investment decisions in a mix of new technologies in the first stage (i.e., 2010) and their generation is dispatched in future electricity markets in the second stage. The year 2020 is taken as a representative year for the operation of future electricity markets in the second stage.

[17] shows that, under perfect competition assumption, the two-stage competitive equilibrium of generation investments in energy-only electricity markets or electricity markets with a forward capacity market can be found by solving an equivalent optimization problem which is an LP. Thus, the dynamic COMPETES model[6] is still formulated as an LP in which the objective function minimizes the overall investment and system operating costs. The investment cost includes annual investment cost of new conventional generation capacities and the system operation cost consists of the annual generation operating cost and the cost of energy not served. The constraints are defined similar as in Section 2.1, except maximum available conventional generation capacity is allowed to expand if it is optimal to do so.

For given variability of demand and renewable generation in 2020 and the nuclear investment/ decommissioning plans, the dynamic model calculates perfectly competitive equilibrium of new conventional generation investment levels in European member states, minimizing the total generation investment and system operating cost while taking into account the exogenous cross-border trading capacities between the countries. The variability of demand and intermittent renewable generation are captured by using 1000 sampled hours generated from 8760 hours by using an importance sampling method (e.g., [18], [19], [20] for similar approaches). The following notation is used to formulate the investment decisions of conventional generators in energy-only and forward capacity markets.

Parameters

$\mathrm{k} \in \mathrm{K}$ Set of conventional generating technologies

OC_{ki} Overnight cost of technology k at node i

AI_{k} Annual investment cost of technology k at node i

5 We implicitly assume that energy prices will be too low to support investment in renewable without subsidy; as a result, the amount of investment will be determined by policies that allocate subsidies such as renewable energy credits or feed-in tariffs.

6 The dynamic model is deterministic. The outcomes of the model does not reflect investment decisions under uncertainties (e.g., fuel prices, regulation uncertainties) in the electricity system. However, the methodology used here may also be applied, albeit with slight modifications, when uncertainties in the electricity system are taken into account (see [17]).

r_k Discount rate of technology k
df_k Derating factor of technology k
R Predetermined capacity margin in Germany
TC_{GER} Total existing derated capacity in Germany

Variables

G_{ki} New generation capacity technology k
CMP Capacity market price in Germany
SR_{ki} Annual scarcity rent of technology k at node i

Generation investments in energy-only markets

In case of energy-only markets, the perfectly competitive equilibrium of new conventional generation investments represents the least cost generation portfolio in Europe where prices are allowed to rise to the VOLL of 10.000 euro/MWh [1] in case of scarcity situations.

The investors maximize the expected value of their long-term profit while choosing their capacities at the first stage. The long-run marginal profit of an investment depends on the annual scarcity rent (per MW) SR_{ki}, earned in the electricity market at the second stage (resulting from the wholesale market revenues minus operating costs). Thus, SR_{ki} is endogenously determined as an outcome of the operation of wholesale markets[7]. The risks are taken into account via risk adjusted discount factors. Specially, the two-stage investment model requires converting the overnight costs into the annual investment cost by using a standard formula (see Chapter 1-3 of [1]):

$$\mathrm{AI}_k = \mathrm{OC}_k \sum_{t=1}^{T^k} \frac{1}{(1+r_k)^t},$$

where T^k is the economic lifetime of plant k. The solution of the dynamic model satisfies the following optimality condition for capacity investments of each conventional generation technology:

$$0 \leq -\mathrm{SR}_{ki} + \mathrm{AI}_{ki} \quad \perp \quad G_{ki} \geq 0, \; (1)$$

where the ⊥ ("perp") symbol indicates pairwise complementarity between generation capacity investment and the long-run marginal profit of the investment. The complementarity condition Eq.(1) implies that if the annual scarcity rent, SR_{ki}, received from the wholesale market by investing in new generation capacity offsets its annual investment cost, AI_{ki}, then the corresponding investment takes place. Otherwise, if annual investment costs exceed the scarcity rent, no investment is made. This complementarity condition is both the first order condition for optimization of investment in COMPETES and the first order condition for a profit maximizing investor.

Generation investments with forward capacity requirements

Discussions on capacity mechanisms in Germany are still continuing, it is not certain whether some form of capacity mechanism will be introduced and, if so, which type of

[7] Annual scarcity rent corresponds to the dual variable of the generation capacity constraint in spot market.

mechanism. Given the focus of this analysis on the general effects that may prevail from such an initiative, it is assumed that a forward capacity auction (i.e. a capacity market) is introduced in Germany that aims to realize sufficient reserve capacity within German borders. In such an auction, a central institution in Germany sets a target for minimum capacity level C* and buys generation capacity in advance on a long term basis (i.e. via forward contracts). The capacity target is calculated based on a predetermined reserve margin criterion R* and expected peak demand level in 2020: *C*=(1+R*)Peak_Demand*. In the model, the demand for the generation capacity in Germany is represented by imposing a lower bound, *C*,* on the installed capacity in Germany which needs to be fulfilled in 2020. We assume that the reserve capacity target R* in Germany is set at 15%. It is widely recognized that the level of firmness (the so-called “capacity credit”) of intermittent energy sources to contribute to the capacity target level is quiet limited[8]. Following [6], we assume that capacity credits for wind and solar power generation are 5% and 0% respectively. The contribution of thermal generation capacities in the capacity target are also derated for their unavailability based on historical data of forced and planned outages.

The existing and new generators in Germany, which contribute to achieve the minimum target level, earn the capacity price set by the forward capacity market. The equilibrium capacity price is set endogenously in the model by the target capacity constraint Eq.(2) and the optimality condition Eq.(3) for the new generation capacity investments in Germany. Thus besides Eq.(1) satisfied by new generation capacity investments in other countries with energy-only markets, the new generation capacity investments and the capacity market price in Germany satisfy the following optimality conditions:

$$0 \;\le\; -C^{*} + TC_{GER} + \textstyle\sum_{k^*} df_k * G_{kGER} \perp \mathrm{CMP} \;\ge 0, \quad (2)$$

$$0 \;\le\; -\mathrm{SR}_{kGER} \; - \mathrm{CMP} * df_k + \; \mathrm{AI}_{kGER} \perp G_{kGER} \ge 0. \quad (3)$$

In the above conditions, Eq.(2) (which can be interpreted as a market clearing constraint for the capacity auction) implies that there is a positive capacity price only if the existing capacity is less than C* and thus new generation capacities are built to contribute to the target level. Furthermore, Eq.(3) (interpretable as the first-order condition for a profit-maximizing generation investor) implies that the investments in a conventional generation technology in Germany take place if the sum of the capacity price received from capacity market and the annual scarcity rent received at the wholesale market offset its annual investment cost. The bids of new generation capacities will be equal to the missing margin from the wholesale market at equilibrium. Consequently, capacity price at equilibrium will be equal to the accepted bid with the highest missing margin (e.g. peak unit) which is the solution of the dynamic model.

The details of representing a capacity market in a mathematical modeling framework can be found in [16] and [17]. The solution of the modified model again represents the least-cost generation portfolio which satisfies the specified reserve capacity requirement in Germany.

8 The wind capacity credit in percent of installed wind capacity is reduced at higher wind penetration levels. According to [32], the relative capacity credit is approximately 5-8% per cent at high wind penetration levels that we assume for Germany (e.g., 45 GW of wind).

2.3 General input data assumptions

The input data of COMPETES involves wide-range of generation technologies (see Appendix A). The generation type, capacity, and the location of existing generation technologies up to 2010 are based on WEPPS 2010 [21]. The assumptions for 2020 are taken from scenarios of IRENE-40 project (see [22], [23]) and are briefly summarized below:

a) All scenarios of [22] use same assumptions at year 2020 in which "20-20-20" targets are assumed to be achieved. RES penetration levels and the corresponding generation capacities in EU are based on NREAP ([12])
b) Hourly wind data values are estimated from 2004 profiles given by [24] and hourly solar data is estimated from the profiles given by [25].
c) Electricity Consumption levels for EU member states change by an average annual growth rate of 0.8%. The future hourly load curves are calculated based on the 2010 monthly and hourly historical data given by ENTSO-E, which have been adjusted to capture the changes in total energy demand.
d) 17.5 GW and 6.6GW of nuclear are assumed to be decommissioned in Germany and UK respectively by 2020.
e) Cross-border trading capacities in 2020 reflect the transmission capacity investments given in 10TYNDP prepared by ENTSO-E ([13]).
f) Gas and coal prices are assumed to be same for all countries at values 8.4 €'2010/GJ and 3.5 €'2010/GJ respectively. Carbon price is 15.8 €'2010/GJ.
g) Value of Lost Load (VOLL) is 10.000 €/Mwh ([1]).

Finally, the assumptions made regarding the development of conventional generation capacity are somewhat different in the two analyses:

- For the analysis of the first research question (see Section 3), conventional generation capacities in 2020 are taken as exogenous in line with the 2020 values of IRENE-40 scenario [23].
- For the analysis of the unilateral introduction of a capacity mechanism in Germany (see Section 4), 2010 generation capacities are taken as an initial point and the conventional generation capacity investments between 2010-2020 are calculated endogenously by the model by using the methodology presented in Section 2.2. The assumptions for the endogenous generation capacity investments are described below.

2.4 Assumptions for generation capacity investments

For the analysis of the unilateral introduction of a capacity mechanism in Germany, we use dynamic COMPETES model to calculate the conventional generation capacity investments between 2010-2020. Old coal and gas-based generation are assumed to be decommissioned based on their commissioning year and economic lifetime (see Table

1). Annual investment costs for new generation capacities are estimated based on their overnight costs and economic lifetime by using a 10% discount rate.

Table 1: Assumptions for new generation capacity investments[9]

Generation Technology		Overnight Costs [€/kW]	Economic Lifetime	Efficiency
COAL	**PC**	1425	40	37%
COAL	**IGCC**	2050	40	45%
COAL	**CCS**	3700	40	38%
LIGNITE	**PC**	1625	40	36%
GAS	**CCGT**	725	30	60%
GAS	**GT**	425	30	43%
GAS	**CCS**	1400	30	53%
OIL	**-**	750	30	47%

[9] Note that we assume the same capacity and fuel costs in all countries. Only the efficiencies of existing generation capacity differ. Thus, the generation capacity investments in our analysis are entirely driven by availability of sites and strong cross-border transmission connections in countries.

3

Incentives for generation capacity investments in energy-only markets with high penetration of renewables

Long term planning of power generation capacity do not only suffer from market imperfections but also from uncertainties in the short-term (e.g., day ahead and real time) operation of electricity markets. Besides regulatory uncertainties (e.g., market design, environmental regulations), the high volatility in electricity prices increases the risk involved in investing new generation capacity. In an energy-only electricity market without significant demand response, a high penetration of intermittent renewables tends to increase the volatility of electricity prices, reduce market price levels during most hours of the year, and decrease the overall capacity utilization of flexible conventional power plants (e.g., [26]). This may aggravate the 'missing money' problem in particular for flexible conventional resources which are needed as a back-up capacity to maintain a certain level of system reliability in case intermittent resources are not available.

By using a static version of the European electricity market model COMPETES (described in Section 2.1), we analyse the impact of adding additional wind and solar PV-based capacity in Northwest Europe in the period between 2010 and 2020 on the operation of gas-based units in the Netherlands. Figure 2 gives an overview of the assumed generation capacity developments in the Netherlands and Germany. According to figures reported on in NREAPS, the increase in wind and solar PV based electricity generation capacity in the Netherlands and Germany between 2010 and 2020 in total could amount to about 64 GWe of installed capacity, which is equivalent to about one third of the total installed capacity in these countries in 2010.[10] This corresponds to a 30% increase in the share of RES generation in the total consumption of the Netherlands of which 22% is from intermittent renewables. Based on these figures, we analyse how the dispatch of generation units in the Netherlands changes over time for an average year since the COMPETES model simulates an 'average year' whereas the utilization of power plants may be higher (or lower) in an extreme year with low (high) wind generation or high (low) demand levels.

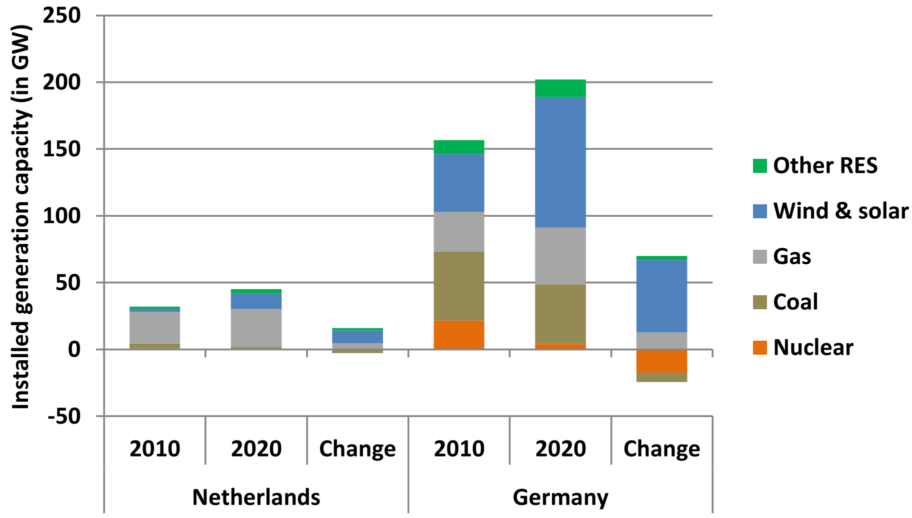
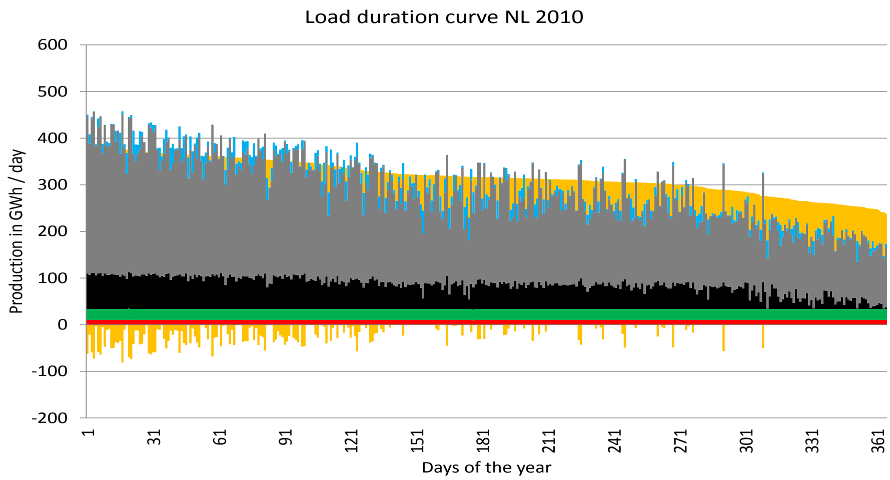
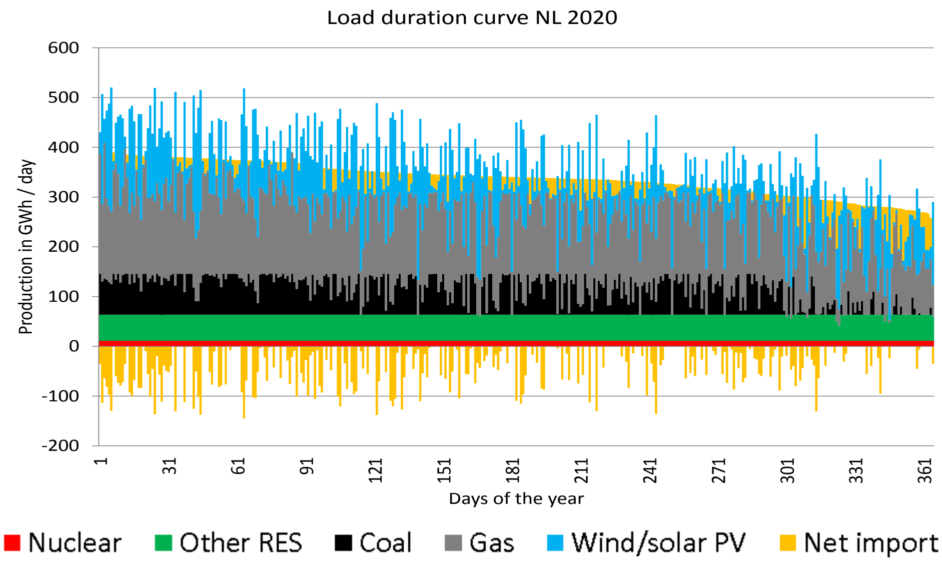


Figure 2: Production capacity development Netherlands and Germany (2010-2020) based on IRENE-40 data (see Section 2.3)



(a) Situation in 2020 with a low level of intermittent RES

[10] In fact, renewable shares in Germany have already grown at an even higher pace then is assumed in our calculations.



(b) Situation in 2020 with a high level of intermittent RES

Figure 3: The impact of penetration of intermittent renewables on the volatility of conventional power generation (Source: ECN COMPETES calculations)

As wind and solar PV-based electricity has marginal costs that are close to zero, the increase in such capacity over time increasingly pushes more expensive generations units -such as coal and gas-based units- out of operation during specific hours of the year (see Figure 3 below). In Figure 3, the blue bars indicate the increase in the contribution from wind and solar PV in the electricity mix, whereas the grey bars illustrate how the contribution of gas-based units throughout the hours and days of the year becomes more volatile between 2010 and 2020. The increase in intermittent electricity generation capacity increases the variability in the contribution of gas-based units to the Dutch electricity system from hour-to-hour to day-by-day basis (in terms of electricity produced). The increased volatility leads to a lower number of full load-hours for this type of units. This makes it more difficult for investors in these units to recover their investment over time, as the contribution margin per MWh produced is reduced.[11] This points to an increase in the amount of ''missing money'.' The order of magnitude of this effect in terms of full load-hours lies in the range of -55 to -75% for gas-based units in mid-merit and peak hours, respectively while generation units operating in the super-peak hours are hardly operating at all. The resulting investment gap for these units can consequently increase significantly (with 36 till 72%).

Figure 4 illustrates the increase in the 'missing money' problem in terms of required and actual revenue per kWe of installed capacity using output data from the static COMPETES model simulation. The required revenue per kWe installed capacity needed

[11] The contribution margin (in Euro/MWh produced), also called "gross margin", is defined as the difference between the revenue from electricity production and the variable cost of producing electricity. In order to remunerate the cost of investing in generation capacity, the contribution margin of the average MWh produced over the lifetime of the generation unit needs to be positive. When the contribution margin is insufficient to recover cost there is a 'missing money problem' for the assumed generation capacity levels.

to recover both operational and investment costs for each year that the unit is in operation depends on the capacity factor of operation – which is related to the number of full load-hours. The reduction in full load hours of a gas-based generation unit between 2010 (left) and 2020 (right), implies a lower capacity factor (from 70% to 19%) and requires a higher amount of required revenue per kWe of installed capacity during the whole lifetime of operations. The figure depicts the variable cost and total cost of operating, as well as the actual revenue received. Confronting the variable cost with the actual revenue shows that there is a positive contribution margin in both years, but that the contribution margin is significantly reduced, and below the replacement cost of capacity. Consequently, the gap in investment cost recovery (per kWe of installed capacity) increases as illustrated by the difference between the total operating cost and the actual revenue in 2010 and 2020.

The impact on conventional gas-based generation capacity (in terms of operating hours and financial performance) may differ across different gas-based technologies. This is because different types of gas-based units may have different positions in the merit order. In addition, there are two different effects of intermittency on the ‘missing money’ problem, depending on the position of generator in the merit order. First, the ‘missing money’ problem of peak generators such as gas turbines is exacerbated by reducing their full load hours substantially. Second, mid-load generators (e.g., CCGTs or CHPs) will become marginal units for more hours a year (for example, when there is a substantial generation from wind energy). Not only will this decrease their total full load hours, it also increases the number of hours that they are in effect the marginal generation unit (and thus receive no additional margin on top of marginal costs).

This suggests that as a result of high penetration of renewables, conventional power plants in an energy-only market are likely to have higher missing margin and fewer hours to cover their capital costs. In the long-run, this may reduce the incentives to invest in new generation capacity or increase the risk premium for generation investments as discussed by [4]. This also implies that the conventional generation investments assumed in the modelling of this section, which are sufficient as a back-up capacity with high intermittent renewables, will probably not be optimal. At optimal values of generation capacity investments, lower investment levels and higher price spikes are likely to be observed during scarcity hours which are needed for peak generators to cover their investments costs. In the dynamic energy-only COMPETES used in the next section, we calculate the optimal generation capacity investments under two different market designs (e.g., VOLL pricing and capacity market) where we observe these price spikes in case of VOLL pricing.

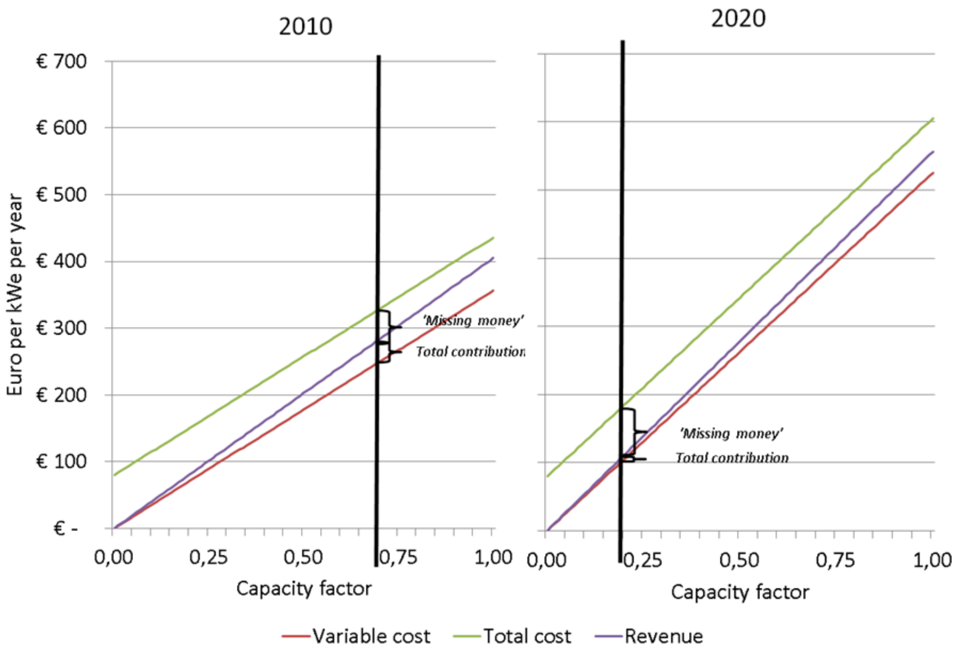


Figure 4: Illustration of the impact of an increase in intermittent electricity generation capacity in Northwest Europe between 2010 and 2020 on the business case of a gas-based power plant in the Netherlands. The impact is measured in terms of required and actual revenue per kWe of installed capacity given the capacity load-factor of operations.[12]

[12] The price of energy is assumed to be X Euro/kWh (the slope of the revenue line), while the marginal fuel cost is Y Euro/kWh (slope of red and green lines). The green line is offset vertically from the red line by the capital cost.

4

Impact of unilateral introduction of a national capacity mechanism in Germany on Northwest Europe

The ‘missing money’ problem and its increased magnitude due to high intermittent renewable generation has increased the fear in some European countries that there will be insufficient investments in new generation capacity. Ongoing discussions in Germany suggest a possible implementation of a capacity mechanism which provides funding for capacity investments in addition to the revenue realized by selling electricity. Unilateral introduction of a national capacity mechanism in Germany may impose benefits and costs upon the larger power market area, depending on the type of capacity mechanism introduced and its specific design.

In our analysis, we assume unilateral introduction of a forward German capacity market with a reserve capacity target of 15%. By using the dynamic COMPETES model with investment methodology described in Section 2.2, we assess the cross-border effects in Northwest Europe by simulating generation capacity investments, imports and exports, and perfectly competitive prices compared to an energy-only market. In contrast to Section 3, the impact of energy-only or capacity markets on conventional generation investments are determined endogenously.

4.1 The shift of generation capacity investments to Germany

One of the main impacts of implementing a unilateral capacity mechanism in Germany is on the generation investment incentives in the neighbouring countries. In an energy-only market with transmission congestion, investments in generation capacity take place in those countries and locations that are closest to the demand centres and offer the best siting conditions (e.g., proximity to grid for interconnection or nearby presence of waterways, fuel and capital cost differences over locations etc.). Since we assume the same capacity and fuel costs in all countries, the generation capacity investments in our analysis in case of an energy-only market are entirely driven by the availability of strong cross-border connections, the amount of decommissioned base load capacity, and the level of intermittent renewable penetration. The introduction of a capacity mechanism may encourage national investment in new generation capacity at the expense of generation investment across the border compared to an energy-only market which we also observe in our simulations.

In an energy-only market, the optimal generation investments are somewhat lower than the assumed exogenous generation capacity investments in Section 3 (see **Figure 5**). Endogenous generation investments are mostly in relatively cheaper baseload or mid merit technologies (e.g., lower fuel price and/or higher efficiency) to replace the decommissioned capacity which are rather high in Germany and UK; in particular in nuclear and coal-based generation capacity. Furthermore, at optimal generation capacity investments, prices are higher during scarcity hours which are needed for new generators to cover their investments costs (see Section 4.3).

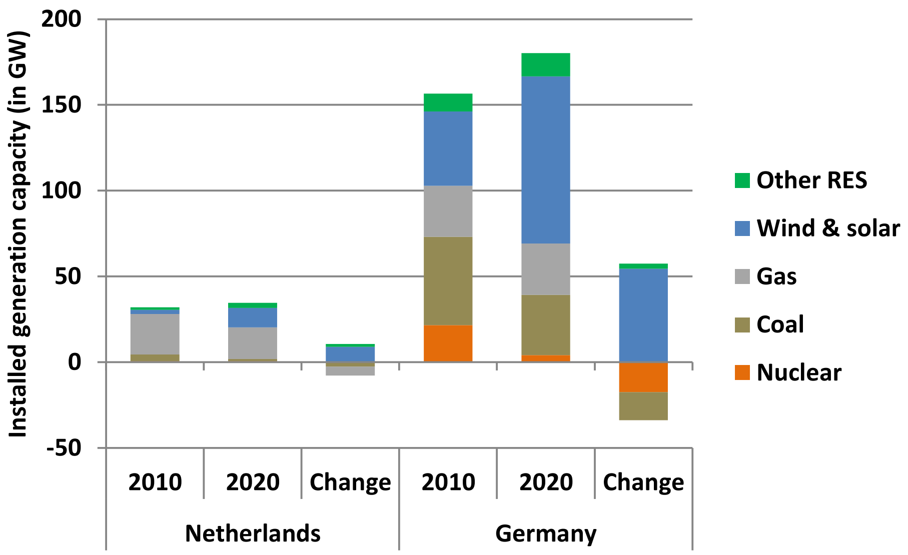


Figure 5: Optimal (endogenous) generation capacity development in the Netherlands and Germany (2010-2020) in an energy-only market with VOLL pricing

Figure 6 illustrates the total generation capacity investments in Germany and the other countries in the Northwest Europe excluding Germany[13] in case of an energy-only electricity market (w/o CM) and an electricity market with a German forward capacity market (w CM). Most of the investments in new generation capacity are observed in Germany and UK to replace the decommissioned capacity; in particular nuclear. There are also significant gas-based power capacity investments in the Netherlands. These are to some extent to replace the old retired capacity but also to provide flexibility to the neighbouring countries such as Belgium and Germany since the Netherlands is exporting electricity to these countries during peak hours. Availability of strong interconnections with the neighbouring countries allows the total capacity built in the Netherlands to be lower than if these capacities were built in the neighbouring countries individually.

A German capacity market increases investments in flexible gas-based capacity in Germany at the expense of investment in such units in the other Northwest European countries. This is explained by the fact that the introduction of a capacity mechanism leads to significant reduction in super-peak prices and moderate reduction in peak prices in most of the Northwest European countries (see Section 4.3). Since the introduced capacity auction does not allow for foreign bid and generators in neighbouring countries can cover their capital costs from mainly super-peak and peak prices in the wholesale market, new generation capacity is shifted from these countries to Germany where they receive compensation for the gap from the capacity market. In particular, significant amount of gas turbines are built in Germany since they have lower capital costs and hence provide least cost reserves.

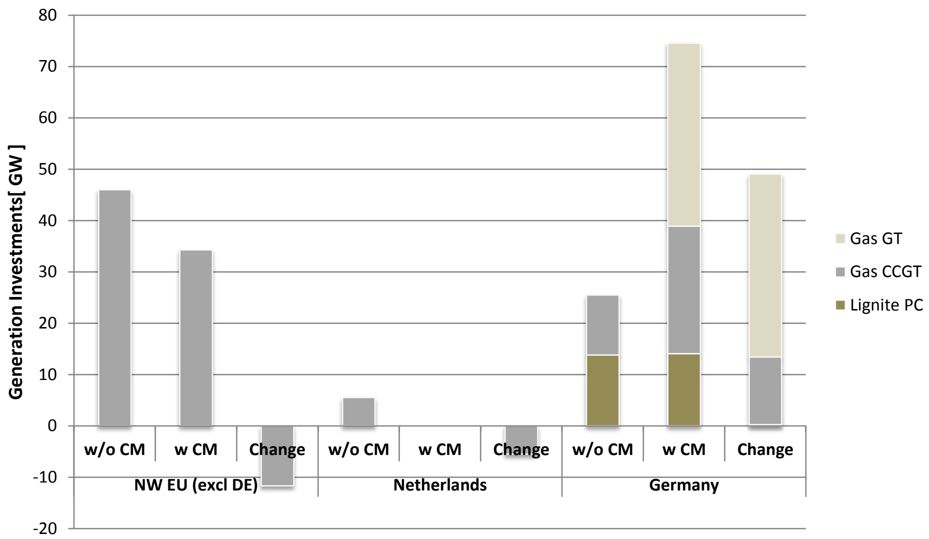


Figure 6: Optimal generation capacity investments in Northwest Europe

The most significant effect is observed in the Netherlands where all the new gas CCGT units are shifted from Netherlands to Germany. As a consequence, gas-based production in Netherlands decreases significantly (see **Figure 7**) with 40% whereas the gas-based production in Germany increases with 66%. This has also implications on import-export flows between Netherlands and Germany which is elaborated in Section

13 i.e., Netherlands, Belgium, France, UK, Norway, Sweden, and Denmark.

4.2. The total gas-based production in the Northwest Europe excluding Germany also decreases with 13% which is mainly due to the decrease in gas-based production in the Netherlands and the UK.

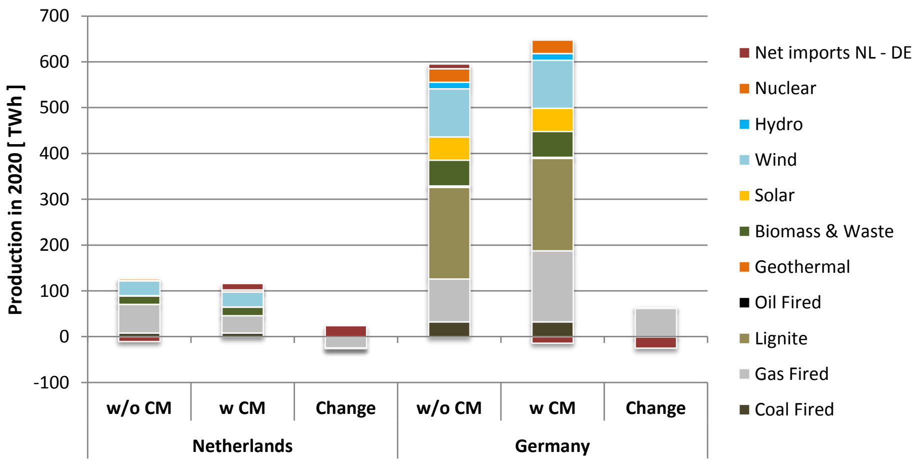


Figure 7: Generation-mix in the Netherlands and Germany with and without a national capacity market in Germany

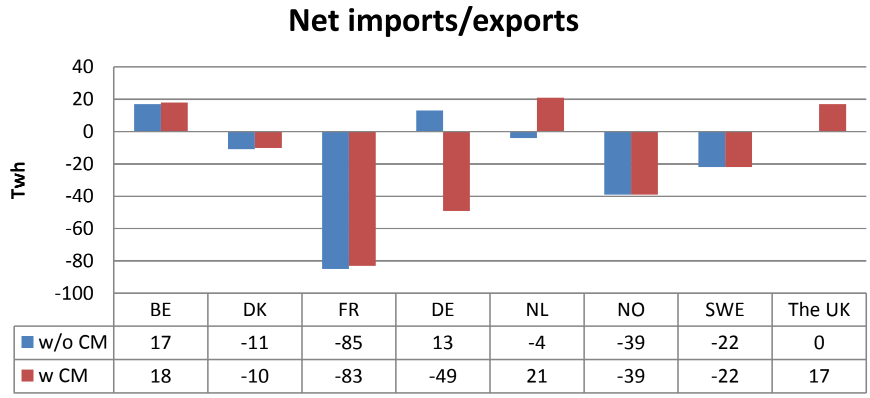
4.2 Germany is likely to become a net exporter and provide flexibility to the neighbouring countries

In an energy-only market, the Netherlands is a net-exporter since it provides flexibility to its neighbouring countries such as Belgium and Germany during peak hours. The same observation holds for Nord Pool countries which provide additional flexibility with hydro-based generation. Germany is a net importer in case of an energy-only market as illustrated in **Figure 8**.

Implementation of capacity mechanism results in installation of %15 reserve capacity in Germany. As a consequence, the capacity investments in neighbouring countries including Netherlands are reduced to achieve the least-cost generation portfolio within Europe. This implies that during most of the hours Germany has excess capacity to export to its neighbouring countries. Implementing a unilateral capacity mechanism makes Germany a net exporter from being a net importing country in an energy-only market.

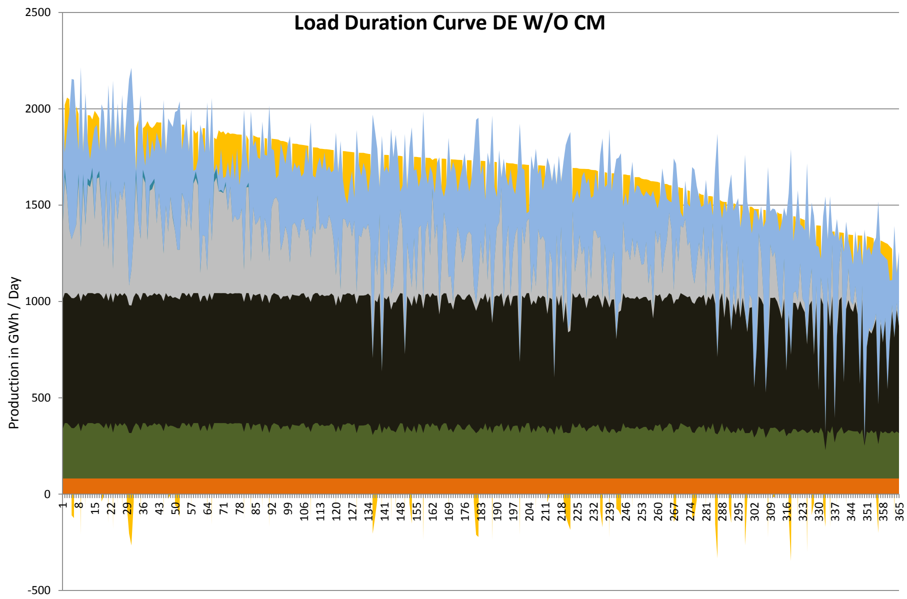
In addition, Germany provides its own flexibility against intermittency. In **Figure 9**, the blue bars indicate the increase in the contribution from wind and solar PV in the electricity mix, whereas the grey bars illustrate how the contribution of gas-based units throughout the hours and days of the year increases in Germany with the introduction of forward capacity market. The positive and negative values of orange bars indicate the net import flows to Germany and the net export flows from Germany, respectively. Net exports Germany increase with the introduction of capacity market. The exports are especially high when residual demand in the neighbouring countries (demand corrected for renewable supply) is high. Thus, most of the neighbouring countries increase their imports from Germany.

In Northwest Europe, the Netherlands is affected the most followed by the UK due to the decrease in generation capacity investments in these countries. Because of the decrease in gas-based capacity in the Netherlands, less electricity is produced in the Netherlands and less electricity is exported over the year. While providing flexibility to the neighbouring countries in case of energy-only markets, Netherlands becomes a net-importing country where the flexibility is mainly provided by imports from Germany.

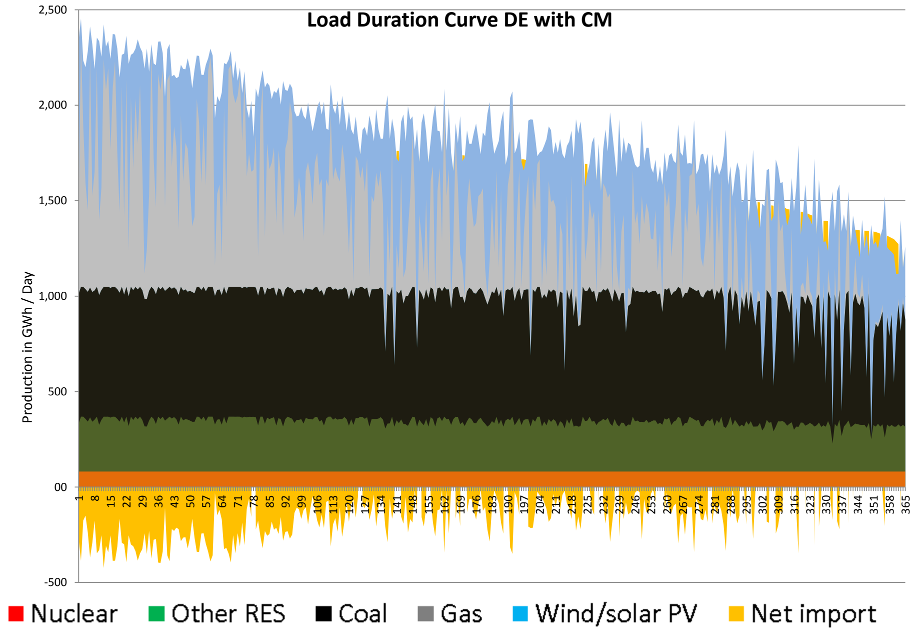


	BE	DK	FR	DE	NL	NO	SWE	The UK
w/o CM	17	-11	-85	13	-4	-39	-22	0
w CM	18	-10	-83	-49	21	-39	-22	17

Figure 8: Net imports/exports of the countries in North-West Europe with and without a national capacity market in Germany



(a) Load duration curve in Germany without a capacity market



(b) Load duration curve in Germany without a capacity market

Figure 9: Impact of a national capacity market in Germany on load duration curve and the net imports/exports

4.3 Free-rider effect on neighbouring countries

With introduction of a national capacity market in Germany, consumers in the Northwest Europe are likely to benefit from the reduction in wholesale energy prices. This induces a free-rider effect for neighbouring countries importing capacity subsidized by German consumers, which is a classic result from trade theory. As illustrated in **Table 2**, the most significant decrease is observed during super peak hours in the neighbouring countries since the corresponding reserve capacity is exported during these hours instead of load-shedding. While the reduction of super peak prices in some neighbouring countries may be significant such as Denmark and Norway (up to -97%) followed by the Netherlands, France, and Belgium (up to -54%), the reduction of super peak prices in UK is limited with only -13% decrease. In addition, slight decrease in peak hours may also be observed in these countries whereas off-peak prices are not affected and remain at similar levels. As a result of price reduction, the overall bill to consumers is likely to decrease which may be considered as the biggest possible advantage for the neighbouring countries. But, this advantage is conditional on the availability of reserve capacity from Germany and the presence of sufficient interconnection capacity necessary to be able to use this reserve capacity.

In Germany, there is significant reduction in wholesale energy prices of in most of the hours. Similar to the other countries, the biggest impact is observed for super peak prices with 98% decrease followed by peak prices with 5% decrease and a slight decrease in off-peak prices. However, on the other hand consumers in Germany also pay the costs due to the implementation of the capacity mechanism (i.e. the capacity price set by the capacity market for additional reserve capacity). This may increase the overall price for some consumers compared to the energy-only market depending on how the capacity payments are distributed over the year. For example, if the total capacity payments are distributed uniformly over the super peak and peak hours, then this may result in 54% price increase for peak consumers compared to energy only market whereas the super peak prices still remain 97% lower than the super peak prices in an energy-only market.

Table 2: Illustration of the impact on competitive wholesale prices and capacity price with and without a national capacity market in Germany

		Average super peak price [Euro / MWh]	Average peak price [Euro / MWh]	Average off-peak price [Euro / MWh]
% of hours in a year		0.1%	35.1%	65.8%
NW EU excl. Germany	**w/o CM wholesale**	4550	73	58
	w CM wholesale	2130	72	58
	Δ wholesale price	-53%	-1%	0%
Germany Wholesale Market	**w/o CM wholesale**	4560	72	58
	w CM wholesale	84	68	57
	Δ wholesale price	-98%	-5%	-1%
Germany Capacity market	**capacity price**	42	42	0
	w CM total price	126	111	57
	Δ total price	-97%	54%	-1%

4.4 Impact on the existing producers of neighbouring countries

The decrease in super peak prices also reduces the revenue of existing producers in the neighbouring countries. The degree of reduction in the revenues of existing producers may differ across countries and technologies. As mentioned above, some countries may have higher reductions in super peak prices. Furthermore, different types of technologies may have different positions in the merit order. The existing peak generators (e.g., gas turbines) in the neighbouring countries suffer the most with almost 50% reduction in their surplus from the wholesale market because their revenues mostly depend on the super peak and peak prices in the spot market and these generators cannot bid in the German capacity market. Coal-based generators and the more efficient gas-based generators (e.g., CCGT) also face reduction in their surplus between 16%-30%. There is also slight surplus decrease for nuclear and wind generators with 5% and 3% respectively. The reduction of producer surplus in the neighbouring countries is also the reason for the shift of new generation capacity from these countries to Germany where they receive compensation for the gap from the capacity market.

The generators in Germany receive additional revenues from capacity market. While surplus of peak generators increase by 20-25% with the introduction of the capacity market, the surplus of base-load generators do not change significantly.

5
Conclusions and Reflection

The phenomenon of the 'missing money' problem is not new. It is widely reported on in economic literature and it received attention in the first years of European electricity liberalization. The issue was removed from the agenda with the initial overcapacity in the market. Now, the issue is back at centre stage due to an increasing level of intermittent electricity production units in combination with a decommissioning of conventional production capacity. Quantitative model-based analyses in this study support the claim that even towards 2020 the expected increase in wind and solar-based generation capacity worsens the economics of gas-based generation technologies (CHP, CCGT, gas turbines). This may discourage investment and could potentially lead to a future lack of conventional, flexible, back-up capacity. This warrants additional policy measures in order to ensure that sufficient investments are undertaken in generation capacity and security of supply is not put at risk.

Some of the countries in Northwest Europe, such as Germany, consider introduction of capacity mechanisms as an option to address the 'missing money' problem. The discussion in these countries so far has mainly focussed on the national, unilateral mechanisms for one country only, while electricity markets have become more integrated over recent years and in many regional markets extend over more than one country. A unilateral introduction of a national capacity mechanism in Germany may pose benefits and costs for a larger power market area and it is important to be aware of the possible impact of its implementation on the other European markets; in particular on the neighbouring countries.

In this study, we have analysed the impact on generation capacity investment, electricity generation, market prices, and net/import exports in the Northwest Europe, assuming a perfectly competitive European electricity market and taking into account cross-border transmission constraints. The optimal market outcomes (e.g., generation capacity investments, generation, prices, and flows) in the Northwest European electricity market in 2020 have been compared for the case of a pure energy-only market in Northwest Europe and the case with implementation of a unilateral forward capacity market in Germany. Note that the magnitude of the impact illustrated in this analysis strongly depends on the type and design of the capacity market implemented in Germany and the corresponding assumptions (e.g., the target reserve margin, capacity credit for wind / solar PV, interconnection capacities, fuel and CO2 prices).

Unilateral introduction of capacity mechanism in a country can have mixed effects on welfare in the neighbouring countries. A specific cost that could arise for neighbouring markets is the crowding out of investment in national generation capacity. With a level playing field, investment in generation capacity takes place in those countries and locations that offer the best conditions. This could for example refer to the nearby presence of waterways (for the supply of solid fuels) or strong transmission network properties. Accordingly, also flexible back-up capacity should be located in those locations that can provide this capacity at least costs. The introduction of national capacity mechanisms may create an uneven playing field and may encourage national investment in new generation capacity at the expense of generation investment across the border. Due to the decrease in generation capacity at the cross-border and increase in flexible gas-based capacity in Germany, less electricity is produced in the neighbouring countries and Germany's exports to these countries increase. Thus neighbouring countries may not experience a materialization of investments that would be expected given its comparative advantages in a level playing field situation (i.e. without one country introducing a capacity mechanism). Furthermore, security of supply might be more at risk if less capacity investments are realized within a country, especially if the need for reserve capacity occurs simultaneous in the larger market area.

The introduction of a unilateral capacity mechanism induces a free-rider effect for neighbouring countries. This may be considered one of the biggest positive (external) effects of such a mechanism. The neighbouring countries free ride on the increase in (flexible) capacity in the country introducing a capacity mechanism. However, the advantage is conditional on sufficient presence of cross-border interconnection capacity and the degree of congestion on these interconnections.

To summarize, the impact of national capacity mechanisms exceeds national borders and affects the performance of the internal energy market because there will no longer be a level playing field in electricity generation across Europe. A relevant hypothesis is that if a capacity market is introduced, it is economically efficient to design it in such a way that also foreign electricity generating companies can participate as this would allow market parties to fully benefit from comparative advantages across countries and regions in Europe. To the extent that building capacity is more beneficial or less costly in some countries than others, the overall efficiency of the market for the EU is enhanced by allowing free trade in capacity. In a future study, we will compare these results with a situation in which there is a German capacity market that allows foreign entrants.

Bibliography

[1] S. Stoft, Power System Economics: Designing Markets for Electricity, Hoboken, NJ: Wiley, 2002.

[2] F. Schweppe, M. Caramanis, R. Tabers and R. Bohn, Spot Pricing of Electricity, Boston, MA: Kluwer Academic Publishers, 1988.

[3] P. Cramton and S. Stoft, "A capacity market that makes sense," *Electricity Journal,* vol. 18, no. 7, pp. 43-54, 2005.

[4] P. Joskow, „Capacity payments in imperfect electricity markets:need and design," *Utility Policies,* vol. 16, nr. 3, pp. 159-170, 2008.

[5] J. Bushnell, S. Harvey, B. Hobbs en S. Oren, *Opinion on Flexible Capacity Procurement: Risk of Retirement,* Folsom, CA, USA, 2012.

[6] C. Elberg, C. Growitsch, F. Höffler, J. Richter en A. Wambach, „Untersuchungen zu einem zukunftsfähigen Strommarktdesign," EWI, Cologne, 2012.

[7] L. Meulman en N. Meray, „Capacity Mechanisms in Northwest Europe: Between a Rock and a Hard Place," CIEP, Den Haag, 2012.

[8] R. O'Neil, U. Helman, B. Hobbs en R. Baldic, „Independent system operators in the United States: History, lessons learned, and prospects," in *Electricity Market Reform: An International Perspective*, Amsterdam, Elsevier, 2006, pp. 479-528.

[9] L. Vries de, Securing the public interest in electricity generation markets, Delft: TU Delft, 2004.

[10] G. Doorman, A. Botterud en O. Wolfgang, „A Comparative Analysis of Capacity Adequacy Policies," Stockholm, Sweden, 2007.

[11] P. Cramton en A. Ockenfels, „Economics and design of capacity markets for the power sector," *Zeitschrift für Energiewirtschaft,* vol. 36, nr. 1, pp. 113-134, 2012.

[12] L. Beurskens, M. Hekkenberg en P. Vethman, „Renewable Energy Projections as Published in the National Renewable Energy Action Plans of the European Member States,” ECN, Petten, The Netherlands, 2011.

[13] ENTSO-E, „Ten-Year Network Development Plan 2010-2020'.,” European Network of Transmission System Operators for Electricity, 2010. [Online]. Available: https://www.entsoe.eu/fileadmin/user_upload/_library/SDC/TYNDP/TYNDP-final_document.pdf. [Geopend 6 May 2011].

[14] B. Hobbs and F. Rijkers, "Strategic generation with conjectured transmission price responses in a mixed transmission system I: Formulation," *IEEE Transactions on Power Systems,* vol. 19, no. 2, pp. 707-717, 2004.

[15] A. Ehrenmann en Y. Smeers, „Stochastic equilibrium models for generation capacity expansion,” University of Cambridge, Cambridge, 2010.

[16] A. Ehrenmann en Y. Smeers, „Generation capacity expansion in a risky environment: A stochastic equilibrium analysis,” *Operations Research,* vol. 59, nr. 6, pp. 1332-1346, 2011.

[17] O. Ozdemir, Simulation Modeling and Optimization of of Competitive Electricity Markets and Stochastic Fluid Systems, Tilburg: Tilburg University, 2013.

[18] G. Infanger, „Monte Carlo (importance) sampling within a benders decomposition algorithm for stochastic linear programs,” *Annals of Operations Research,* vol. 39, nr. 1, pp. 69-95, 1992.

[19] B. F. Hobbs en Y. D. Ji, „Stochastic programming-based bounding of expected production costs for multiarea electric power systems,” *Operations Research,* vol. 44, nr. 6, pp. 836-848, 1999.

[20] F. D. Munoz, J. Ho, S. Kasina en B. F. Hobbs, *An Engineering-Economic Approach for Transmission Planning Under Market and Regulatory Uncertainty: WECC,* Baltimore, USA: John Hopkins University, 2013.

[21] WEPPS, „World Electric Power Plants Database,” PLAATS, 2010.

[22] E. Gaxiola, F. Nieuwenhout, G. Orfanos, O. Ozdemir en A. van der Welle, „European scenario synthesis to be used for electricity transmission network planning,” in *9th International Conference on the European Energy Market (EEM*, Florence, 2012.

[23] IRENE-40, „Infrastructure Roadmap for Energy Networks in Europe: Analysis and Scenarios of Energy Infrastructure Evolution,” 2012. [Online]. Available: http://www.irene-40.eu/. [Geopend 12 2012].

[24] TRADEWIND, „Integrating Wind: Developing Europe's power market for the large-scale integration of wind power,” EWEA, 2009.

[25] „SODA,” 2011. [Online].

[26] C. De Jonghe, B. Hobbs and R. Belmans, "Optimal generation mix with short-term demand response and wind penetration," *IEEE Transactions on Power Systems,* vol. 27, no. 2, pp. 830-839, 2012.

[27] O. Ozdemir, M. Scheepers en A. Seebregts, „Future electricity prices. Wholesale market prices in and exchanges between Northwest European electricity markets," ECN, Petten, 2008.

[28] O. Ozdemir, J. Hers, E. Fisher, G. Brunekreeft en B. Hobbs, „A nodal pricing analysis of the future German electricity market," in *6th International Conference on European Electricity Markets (EEM 2009)*, Leuven, Belgium, 2009.

[29] W. Lise, J. Sijm en B. Hobbs, „The impact of the EU ETS on prices, profits and emissions in the power sector: Simulation results with the COMPETES EU20 model," *Environmental and Resource Economics,* vol. 47, nr. 1, pp. 23-44, 2010.

[30] W. Lise en B. Hobbs, „A model of the European electricity market - What can we learn from a geographical expansion to EU20?," ECN, Belgium, 2005.

[31] B. Hobbs, G. Drayton, E. Fisher en W. Lise, „Improved Transmission Representations in Oligopolistic Market Models: Quadratic Losses, Phase Shifters, and DC Lines. IEEE Transactions on Power Systems," IEEE Transactions on Power Systems, vol. 23, nr. 3, pp. 1018-1029, 2008.

[32] DENA, "Energiewirtschaftliche Planung für die Netzintegration von Windenergie in Deutschland an Land und Offshore bis zum Jahr 2020," Deutsche Energie-Agentur, Berlin, 2005.

Appendix A. Electricity generation technologies

Table 3: Electricity generation technologies included in the COMPETES model

FUEL	TECHNOLOGY	DESCRIPTION
CONVENTIONAL TECHNOLOGIES		
Gas	GT	Gas Turbine
Gas	CCGT	Combined cycle
Gas	CHP	
Gas	CCS CCGT	
Gas	CCS CHP	
Coal	PC	
Coal	IGCC	
Coal	CCS	
Lignite	PC	
Oil	-	
Nuclear	-	
RENEWABLES		
Biomass	Cofiring	
Biomass	Standalone	
Waste	Standalone	
Geo	-	
Sun	PV	Photovoltaic
Sun	CSP	
Wind	Onshore	
Wind	Offshore	
Hydro	Conv	Conventional
Hydro	PS	Pump Storage
RES	Other	

The input data for the generation technologies consist of:

- Installed[14] capacities for EU27 (+ Norway and Switzerland/ Balkan).
- Availability (seasonal) and efficiency per technology per country.
- Emission factors per technology.
- Fuel and CO2 prices per country.
- Hourly time series of intermittent RES (wind, solar etc.).
- RoR (run of river) shares of hydro in each country.

[14] For static model, installed capacities are exogenous and should represent a scenario in future years. For investment model, existing capacities are the input and future conventional capacities are endogenously determined by the model.

ECN
Westerduinweg 3
1755 LE Petten
The Netherlands

P.O. Box 1
1755 LG Petten
The Netherlands

T +31 88 515 4949
F +31 88 515 8338
info@ ecn.nl
www.ecn.nl