Cross-border effects of capacity mechanisms in interconnected power systems

Pradyumna C. Bhagwat*, Jörn C. Richstein, Emile J. L. Chappin and Laurens J. De Vries

Faculty of Technology, Policy and Management, Delft University of Technology, Jaffalaan 5, 2628 BX, Delft, The Netherlands

*Corresponding author, mail: p.c.bhagwat@tudelft.nl; Telephone: +31 152 783 963.

ABSTRACT

The cross-border effects of a capacity market and a strategic reserve in interconnected electricity markets are modeled. Both capacity mechanisms improve security of supply and reduce consumer costs. Our results indicate that interconnections do not affect effectiveness of a capacity market, while a strategic reserve is affected negatively. The neighboring zone may free ride on the security of supply provided by the zone implementing a capacity mechanism. However, a capacity market causes crowding out of generators in the energy-only zone. A strategic reserve implemented by this region could aid in mitigating this risk.

KEYWORDS: capacity mechanisms, capacity market, cross-border effect, strategic reserve.
1 Overview

The growing penetration of intermittent renewable resources is leading to concerns regarding security of supply and generation adequacy in the European Union. These concerns revive and add to the existing debate about the security of supply of electricity markets (Borenstein and Bushnell, 2000; Brown, 2001; De Vries and Hakvoort, 2003; De Vries, 2007; Hesmondhalgh et al., 2010; Hreinsson, 2006; Joskow and Tirole, 2007; Pérez-Arriaga, 2001; Stoft, 2002; Woo et al., 2003). As a consequence, the debate is reopened in the remaining energy-only markets in Europe whether to implement a capacity mechanism. Capacity mechanisms are policy instruments for ensuring adequate investment in generation capacity; in the European debate, they are also called capacity remuneration mechanisms. The arguments for and against implementing capacity mechanisms have been described extensively in the literature (Chao and Lawrence, 2009; Cramton et al., 2013; De Vries, 2004; Hobbs et al., 2001; Joskow, 2008a; Stoft, 2002), but variable renewable energy sources add a new dimension to it.

In the EU the decision whether to implement a capacity mechanism and its design and implementation are left to the discretion of the member states. The UK has recently implemented a capacity market (DECC, 2014) while France will do so in the near future (RTE, 2014). Belgium, Sweden and Finland make use of strategic reserves. Germany may implement a capacity reserve but decided against a full scale capacity market for the near future (BMWi, 2015). In a highly interconnected system such as the continental European electricity system, there appears to be a risk that the uncoordinated implementation of capacity mechanisms reduces economic efficiency and may even negatively affect the security of supply in neighboring systems (Pérez-Arriaga, 2001; Elberg, 2014; Tennbakk, 2014; Finon, 2015; Gore, 2015; Mastroianni et al., 2015; Meyer and Gore, 2015; Bhagwat et al., 2016a). We utilize an agent-based model to analyse the effectiveness of capacity mechanisms in interconnected systems. We also study the cross-border effects on prices, investment and security of supply that they may cause. We expand EMLAb-Generation, an existing agent-based model of electricity markets, by modeling a strategic reserve and a capacity market.

2 Model description

2.1 EMLab-Generation

EMLAB-Generation is an open source agent-based model (ABM) of interconnected electricity markets (De Vries et al., 2013; Richstein et al., 2015a, 2015b, 2014) that makes use of the AgentSpring framework (Chmieliauskas et al., 2012). Agent-based modeling (ABM) is a
bottom-up approach to modeling in which agents make decisions independent from each other based on their interaction with other agents and the system (Chappin, 2011; Dam et al., 2013; Farmer and Foley, 2009). The advantage of using this approach is that there is no need for system-level assumptions regarding the effects of policy instruments, as the model results are an aggregation of the actions of all the agents (Chappin, 2011; Dam et al., 2013).

EMLab-Generation was developed with the goal of addressing questions that arise from the implementation of various policy combinations (such as CO₂ and system adequacy policies) in interconnected electricity markets. As the model is created to assess the long-term impact of policy instruments, the simulation is run over 40 years. The time step is one year. Fuel price and demand growth uncertainty are represented by using a Monte-Carlo approach in which these variables are varied randomly in 120 different runs, all starting from the same conditions.

Power generation companies are the main agents in EMLab-Generation. They make decisions regarding investment in new generation capacity, dismantling of existing power plants and how to bid their capacity in the electricity market. Their decisions are based on past and current prices of fuels and capital costs and on expectations regarding demand growth etc. The main external factors that cause change in the model are (changes to) policy instruments, fuel prices and electricity demand. The decisions of the agents are based on these exogenous factors and on endogenous outcomes from the model such as electricity prices. Therefore, power companies interact with each other only via the electricity market.

The power companies base their investment decisions on the expected net present value of new generation technologies. The power producers can choose from 14 different power generation technologies. The investment process is iterative; the power producers make investment decisions sequentially and they know each other’s decisions. Thus the investment decision of a power producer reduces the attractiveness of an investment by the next producer. The iterative process stops when no producer is willing to invest anymore. In order to prevent a bias towards a particular agent, the sequence of power producers is determined randomly in every year of the simulation.

There are annual targets for investment in several renewable energy technologies that are set exogenously for the duration of the simulation. If private investment in renewable energy sources (RES) fails to achieve these targets, a dedicated renewable energy investor will make up the difference, regardless of the cost. In this way, the current subsidy-driven development of RES is simulated. The intermittency of renewable resources is modeled by varying the availability of these resources in the different segments of the load-duration curve (least in the highest peak segment and
most in the base segment). This availability factor is set deterministically for each segment of the load-duration curve for each technology.

Electricity demand is modeled by approximating a load-duration curve with 20 segments of variable length. During every time step in the model, the electricity market is cleared for each segment of the load-duration curve. The two zones in the model have different load-duration curves. The advantages of using this approach are described in Richstein et al. (2014).

We consider a system of two interconnected electricity markets. The power generation companies make price-volume bids for each power plant in their portfolio and for every segment of the load-duration curve. The bids are equal to the variable costs of the power plants. The highest clearing bid sets the price for each segment of the load-duration curve. If demand cannot satisfy supply, the clearing price is set to the value of lost load. The two electricity markets are cleared together through market coupling. A detailed description of this model is available online in the EMLab-Generation technical report and in previously published work (De Vries et al., 2013; Richstein et al., 2015a, 2015b, 2014). An analysis of a strategic reserve in an isolated market was presented in (Bhagwat et al., 2016c) and one of a capacity market was presented in Bhagwat et al., (2016b). This paper builds on these two papers. The following description of the model implementation of a strategic reserve and a capacity market are brief summaries.

2.2 Strategic reserve

2.2.1 Overview

When a system operator implements a strategic reserve, he contracts and dispatches a certain volume of generation capacity, usually the generation units with the highest variable costs. This contracted capacity is then deployed when the electricity price exceeds an administratively set ‘reserve price’ that is higher than the power plant’s marginal cost of generation but below VOLL. In theory, the artificial tightening of the supply due to the presence of a strategic reserve would attract investment in generation capacity before a physical shortage occurs. Consequently, the high price spikes that occur in periods of scarcity would be replaced by more frequent but also lower price spikes (capped at the reserve dispatch price ($P_{SR}$)) (De Vries and Heijnen, 2008). This is similar to operating reserve pricing as described by Stoft (2002). The reserve dispatch price should be calculated such that the revenues earned by the competitive generators remain same in the presence of a strategic reserve as in an energy-only market. The theory behind a strategic reserve is described in Stoft, (2002); De Vries, (2004); De Vries and Heijnen, (2008); Rodilla and Batlle,
There are different ways of implementing a strategic reserve, but we chose this design because the rules are simple and founded in theory.

2.2.2 The strategic reserve algorithm

The main agent in the strategic reserve extension of EMLab-Generation is the strategic reserve operator. He contracts a set of power plants with a total capacity that is equivalent to the administratively established reserve size. The reserve volume is user-defined as a percentage of the expected annual peak demand. The power plants with the highest variable costs are selected because they have the lowest opportunity cost of withdrawing from the electricity market and therefore should bid the lowest in the strategic reserve capacity tender.

The companies that own contracted power plants are compensated for their annual fixed operations and maintenance costs of these power plants. The operator contracts only entire power plants, thus the complete capacity of the last required power plant is contracted. There are different decision rules for how this capacity is offered to the market. In this model, contracted power plants are offered to the electricity spot market at the strategic reserve dispatch price ($P_{SR}$), which is calculated as explained in (Bhagwat et al., 2016c). This ‘reserve price’ is considerably higher than its marginal cost of generation but lower than the value of lost load. This is in accordance with Stoft’s (2002) theory of operating reserves pricing.

When the reserve capacity is dispatched, the strategic reserve operator pays the power plant owner(s) the variable cost of generation while keeping the additional revenue earned over and above the variable cost of generation (which is equal to the reserve dispatch price minus the variable costs of generation). The fixed payments ensure that the owners of these generating units do not make disproportionate profits but at the same time cover all their costs.

In a perfectly designed reserve, this revenue of the strategic reserve operator should exactly cover the cost of contracting the strategic reserve. In case the strategic reserve operator is unable to recover the costs of contracting the reserve, it is assumed that the system operator passes on the additional costs to the consumers via the network tariffs. While making investment and dismantling decisions, the power generators consider the possibility of gaining additional revenues from the strategic reserve. A detailed description of the strategic reserve algorithm is available in Bhagwat et al., (2016b).
2.3 Capacity market

2.3.1 Overview

In a capacity market, consumers, or an agent on their behalf, are obligated to purchase capacity credits equivalent to the sum of their expected peak consumption plus a reserve margin (that is determined by the system operator or the regulator) through a process of auctions (ACER, 2013; Cramton and Ockenfels, 2012; Cramton et al., 2013; Creti and Fabra, 2003; Iychettira, 2013; Stoft, 2002; Wen et al., 2004). The additional revenues from the capacity market are intended to help (peaking) power plants to recover their fixed costs and thus mitigate the missing money problem (Joskow, 2008a, 2008b, 2006; Shanker, 2003). A capacity requirement is expected to provide a stronger and earlier investment signal than wholesale electricity prices and improve adequacy. A variety of capacity market designs have been implemented around the world (ACER, 2013; Cramton and Stoft, 2008, 2005; Cramton et al., 2013; DECC, 2014; RTE, 2014; Spees et al., 2013). For this research, we base the design of the capacity market in our model on the installed capacity market (ICAP) organized by the New York Independent System Operator (NYISO) in the United States (NYISO, 2013a, 2013b).

In the NYISO-ICAP, power generators offer unforced capacity (UCAP) in a series of auctions. These mandatory spot auctions are conducted each year for the coming year. Market parties may correct their positions during the year by participating in monthly spot auctions and capability period auctions that are carried out once every six months. The market is cleared against a sloping demand curve. The ISO contracts capacity on the behalf of the load-serving entities (LSEs). The LSEs purchase capacity credits equivalent to the minimum UCAP assigned to them (Harvey, 2005; NYISO, 2013a, 2013b). This value of unforced capacity is calculated as the product of the Installed Reserve Margin (IRM) and the forecasted peak demand (NYISO, 2013b). The IRM is a value that is set by the regulator based on loss of load expectation of once in 10 years. NYISO allows bilateral capacity contracts and imports to participate in the capacity market as long as they adhere to all rules and regulations. A detailed description of the market rules is available (NYISO, 2013b; Spees et al., 2013).

2.3.2 The capacity market algorithm

In our model, capacity is traded for the coming year in a single annual auction. The installed reserve margin (IRM), capacity market price cap and slope of the demand curve are set as user defined values. The demand requirement (MW) is calculated from the IRM and a forecast of the expected demand for the coming year, which is generated using a geometric regression trend. The capacity market supply curve is generated from the price (€/MW) and volume (MW) bid pairs of the
power generators. The volume component of each bid is calculated as the generation capacity of the underlying power plant that is available in the peak segment of the load-duration curve. A marginal cost-based approach is utilized for calculating the bid prices in the capacity market. Generation companies set their bids equal to the additional revenue that they need from the capacity market to cover their short-term fixed costs. If a power plant is expected to earn sufficient revenues from the electricity market to cover its fixed costs of remaining online in the coming year, then its capacity bid price is set to zero. For units that are not expected to make adequate revenues from the energy market to cover their fixed costs of remaining online, the capacity bid price is set as the difference between their fixed costs and their expected electricity market revenue.

A uniform price auction is used for clearing the capacity market. Capacity bids submitted by the power producers are sorted in ascending order by price and cleared against a sloping demand curve (as is used in the NYISO-ICAP and PJM – RPM capacity markets). The demand curve is generated from the exogenously set market cap, the slope values and the endogenously calculated value of the demand requirement. The units that clear the capacity market are paid the market-clearing price for the capacity made available by them. While making investment and dismantling decisions, the power generators consider the expected revenues from the capacity market. Imports are not allowed to participate in the capacity market. There are no restrictions on exports during scarcity periods. A detailed description of the capacity market is available in (Bhagwat et al., 2016b).

3 Scenarios

Both markets have four power producers with identical initial power plant portfolios. The shares of generation technologies in the initial supply mix are based on the portfolio of thermal generation technologies in Germany (based on Eurelectric (2012) data; see also Table 4 in the Appendix). Power plant attributes such as capital costs, O&M costs and fuel efficiencies are based on the IEA World Energy Outlook 2011, New Policies Scenario (IEA, 2011). Technology development is simulated as a gradual improvement of these attributes, such as decreasing costs and improving efficiency rates. The assumptions regarding the power generation technologies are presented in Table 2 of the Appendix.

The load-duration function is derived from 2010 ENTSO-E data for Germany (ENTSO-E, 2010). The peak demand at the start of the model run in both zones of all scenarios is 79884 MW. We utilized triangular trend probability distribution functions to generate stochastically varying fuel price and demand growth time series (see Table 3 in the Appendix). The coal and gas prices are
based on scenarios of the UK Department of Energy & Climate Change (2012). The biomass prices are based on Faaij (2006) and those of lignite on Konstantin (2009). The development of renewable energy resources is based on the national renewable energy action plan for Germany (NREAP, 2010) up to 2020 and interpolated further.

For cases in which supply does not meet demand there is an electricity market price cap at 2000 €/MWh, which we assume is the value of lost load (VOLL). In this modeling study, the value of lost load (VOLL) was chosen at the relatively low level. This is done in order to take into consideration demand flexibility that might occur during periods of high prices and also the segmented nature of the load duration curve that makes the model sensitive to VOLL.

As a reference scenario, the model is run in an “energy-only” mode, with no capacity mechanisms. Three scenarios with capacity mechanism are implemented; see Table 1. In the first scenario (SR-EO), a strategic reserve is implemented in one zone while the other zone maintains an energy-only market. In the second case (CM-EO), a capacity market is implemented in one zone while the interconnected zone maintains an energy-only market. In the third case (CM-SR), a capacity market is implemented in one zone, while a strategic reserve is implemented in the interconnected zone.

The reserve volume of the strategic reserve is set at 10% of peak demand and the reserve price is 800 €/MW. The dimensions of the capacity market are roughly based on the requirements of the NYISO-ICAP, the capacity market price cap is set at a 60000 €/MW. The IRM value is set at 9.5% of peak demand, this value is calculated to by de-rating the 17% IRM requirement by the Equivalent Forced outage Rate – Demand (EFoRD). This size of the interconnector in all the scenarios is set at 7536 MW.

### Table 1: List of scenarios

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Zone A</th>
<th>Zone B</th>
</tr>
</thead>
<tbody>
<tr>
<td>BL</td>
<td>Energy-only</td>
<td>Energy-only</td>
</tr>
<tr>
<td>SR-EO</td>
<td>Strategic Reserve</td>
<td>Energy-only</td>
</tr>
<tr>
<td>CM-EO</td>
<td>Capacity Market</td>
<td>Energy-only</td>
</tr>
<tr>
<td>CM-SR</td>
<td>Capacity Market</td>
<td>Strategic Reserve</td>
</tr>
</tbody>
</table>

4 Results and analysis

4.1 Indicators

The following indicators are used in the analysis of the model results:

- The average electricity price (€/MWh): the average electricity price over an entire run.
• Shortage hours (hours/year): the number of hours per year with scarcity prices, averaged over the entire run.

• The supply margin (MW/MW): the ratio of available supply over peak demand.

• The cost of the capacity mechanism (€/MWh): the cost incurred by the consumers for contracting the mandated capacity credits from the capacity market or for contracting generating units into the strategic reserve.

• The cost to consumers (€/MWh): the sum of the electricity price, the cost of the capacity market and the cost of renewable policy (if applicable) per unit of electricity consumed, averaged over the entire run.

The percentage change in the values of indicators in both zones for the SR-EO, CM-EO and CM-SR scenarios, as compared to the baseline scenario (BL), are presented in Figure 1. The results are also presented numerically in Table 6 of the Appendix. The average values presented in the results are calculated as annual values based on values from the 120 simulation runs over the 40-year time horizon. For the supply ratios and electricity prices over time, the median and mean trend along with the 50% and 90% confidence intervals (CI) are shown.

Figure 1: The percentage change in values of various indicators in Zone A (top) and Zone B (bottom) on implementation of capacity mechanisms as compared to the baseline scenario

Note that this includes the cost of outages, because in our model the electricity price rises to the VOLL during shortages.
4.2 Cross-border effects of a strategic reserve

In this scenario, a strategic reserve is implemented in Zone A, while the interconnected zone (B) has an energy-only market. We compare the outcomes from this scenario with the baseline case (BL) in which both zones have energy-only markets.

The zone that implements a strategic reserve sees its supply ratio rise to 1.02, as observed in Figure 2, an increase of 9% compared to the baseline scenario. The shortage hours decline from 58.4 hours per year to 11 hours per year in this zone. As expected, the extreme price spikes in baseline scenario are replaced by more frequent, but lower price spikes in the electricity market (see Figure 3). The average electricity price drops by 8%, from 58.1 €/MWh in the baseline to 53.7 €/MWh, which is due to the reduction in shortage hours. The strategic reserve operator is almost able to recover the cost of contracting the strategic reserve, which is indicated by the capacity mechanism cost to the consumers of -0.3 €/MWh. The operator earns revenues when the strategic reserve is dispatched in the zone where it is implemented and also from exports of the reserve capacity during hours that are consequent to the peak load hours. An overall decrease of 6% in the cost to consumers is observed.

Figure 2: Comparison of supply ratio in Zone A without (left) and with a strategic reserve implemented.

Figure 3: Comparison of electricity price in Zone A without (left) and with a strategic reserve implemented.
The supply ratio in the interconnected zone (Zone B) that has an energy-only market is 0.93, which is marginally lower than in the baseline scenario (Figure 4). However, the number of shortage hours in this zone is reduced by 74% from 58.4 h/yr to 15 h/yr, due to import of power from the neighboring zone during shortage situations. This leads to fewer price spikes in this zone and a reduction of the electricity price from 58.1 €/MWh to 54.1 €/MWh. An overall improvement in consumer benefit is observed, with the cost to consumers reduced by 5%.

Figure 4: Comparison of the supply ratio in Zone B without (left) and with a strategic reserve (right) implemented in the neighboring interconnected Zone A

Figure 5: Comparison of electricity price in Zone B without (left) and with a strategic reserve (right) implemented in the neighboring interconnected Zone A

We compare these results to an isolated system with a similarly sized strategic reserve. The supply ratio is the same with and without a interconnector because the agents do not consider the interconnector explicitly in their investment decision. However, in the presence of an interconnector, part of the capacity from the zone with a strategic reserve is exported to the neighboring market, as there is no restriction on exports. Consequently, there are more shortage hours in the zone with the strategic reserve than in the isolated case, while the shortage hours in the neighboring energy-only region are reduced. This spillover leads to 2% increase in the net cost to consumers in Zone A, which increases from 64.4 €/MWh in an isolated system to 65.7 €/MWh in the scenario with an interconnector (SR-EO Zone A).
To summarize, implementation of a strategic reserve in one zone of an interconnected system improves the security of supply and net consumer benefit in that zone. The benefits spill over to the neighboring interconnected zone, both in terms of reduction in shortage hours and reduction in cost to consumers. In the other zone (with an energy-only market), no significant effect on investment is observed; however, this result may be caused by the fact that the investment decisions in the model did not consider imports.

4.3 Cross-border effects of a capacity market

In this scenario, a capacity market was implemented in Zone A, while the interconnected zone (B) has an energy-only market. We compare the results from this scenario with the baseline (BL) scenario in which both zones have energy-only markets.

![Figure 6: Comparison of supply ratio in Zone A without (left) and with a capacity market (right)](image)

![Figure 7: Comparison of electricity price in Zone A without (left) and with a capacity market (right)](image)

In the zone with a capacity market (A), the average supply ratio is 1.12, which is 2.5-percentage point higher than the adequacy target. (See Figure 6.) The capacity market more than meets the adequacy goals in the presence of an interconnection. The apparent overshoot in capacity can be attributed to the configuration of the capacity market demand curve (slope and price cap) and
also the segmented nature of the load duration curve. The high reserve capacity causes a steep reduction in shortage hours, from 58.4 hours per year to almost zero. The average electricity price drops by 20.7%, from 58.1 €/MWh in the baseline to 46.1 €/MWh. There is also a sharp decline in electricity price volatility in this zone, as can be seen in Figure 7. The capacity payments cost the consumer an additional 4.8 €/MWh. However, the gains from reduction in shortage hours offset the cost of the capacity market: the total cost to consumers decreases by 8.2%, from 69.6 €/MWh to 63.9 €/MWh.

Figure 8: Comparison of the supply ratio in Zone B without (left) and with a capacity market (right) in the neighboring interconnected Zone A

Figure 9: Comparison of average electricity prices in Zone B without (left) and with a capacity market (right) in the neighboring interconnected Zone A

On the other hand, a clear negative spillover effect in terms of adequacy is observed in the interconnected zone with an energy-only market (Zone B), where the supply ratio declines by 5.6%, from 0.93 in the baseline scenario to 0.87 (Figure 8). Nevertheless, the import of electricity from the neighboring zone damps electricity prices (Figure 9) and reduces the number of shortage hours by 46.8% from 58.4 h/yr to 31 h/yr. The average electricity price declines from 58.1 €/MWh to 52.8 €/MWh. The net cost to consumers declines by 6.8% from 69.6 €/MWh to 64.9 €/MWh.
Figure 9 shows that there is some risk of an investment cycle in Zone B (the energy-only market), also in the presence of a capacity market in Zone A. The generators in Zone B are crowded out to the extent that even the additional capacity due to the capacity market in A may not be able to cover all the demand in the neighboring zone. In such situations, periods with substantial shortage hours in the energy-only market are observed (See Figure 10). Thus, despite the higher supply ratio in Zone A of the CM-EO scenario, the average reduction of shortage hours in Zone B is lower in this scenario than in scenario SR-EO.

![Figure 10: Average shortage hours in the energy-only market zone (Zone B).](image)

Figure 10: Average shortage hours in the energy-only market zone (Zone B).

We compare the results for Zone A with the case of a capacity market in a similar but isolated system. The average electricity price in the presence of an interconnector is 5.2% higher than in an isolated system, but the cost of the capacity market is 16.4% lower in the presence of an interconnector. This can be attributed to lower bids in the capacity market due to the additional income for generators from exports. On average, the capacity market clearing price observed in an isolated scenario is 31,558 €/MW as compared to 27,017 €/MW in the CM-EO scenario. On the whole, the net cost to consumers in Zone A increases by 1.2% in the presence of an interconnector. This is the cost of free riding by consumers in the neighboring region. Note that this cost is a function of the relative sizes of the two interconnected systems and of the size of the interconnector.

To summarize, the capacity market achieves the adequacy goals in the zone that implements it, even in the presence of interconnections. The supply margin remains adequate and due to the low number of shortage hours, the total cost to consumers is reduced. The connected energy-only zone free rides on the security of supply provided by the capacity market. The free riding leads to a marginal increase in the cost to consumers of the region implementing a capacity market, but the overall consumer benefit improves. However, a capacity market suppresses investment in the
interconnected zone, which may make the neighboring zone import dependent and can lead to an investment cycle there.

4.4 Cross-policy effects due to implementation of dissimilar capacity mechanisms

In this scenario (CM-SR), a capacity market is implemented in one zone (Zone A) while the interconnected zone (Zone B) implements a strategic reserve. We analyze the cross-border effects that may arise from the implementation of dissimilar capacity mechanisms in interconnected zones. The results from scenario CM-SR are compared with those from scenario CM-EO and SR-EO. This allows us to analyze the impact that capacity mechanisms have on each other’s effectiveness when implemented in interconnected markets.

Based on the values of the various performance indicators presented in Figure 1, the implementation of dissimilar capacity mechanisms in the two zones leads to a reduction of shortages and of the cost to consumers in both zones. The performance of the capacity market is hardly affected by the presence of a strategic reserve in the neighboring zone. There is no significant change in the indicators of the zone that implements a capacity market (Zone A), without (CM-EO) or with (CM-SR) a strategic reserve in the neighboring interconnected zone (Zone B), as is observed in Figure 11 and Figure 12. These results not only indicate that the capacity market is a robust policy mechanism, but also that the strategic reserve in the neighboring zone does not impact the capacity market negatively. This is not surprising, as the strategic reserve was shown to have a positive spillover effect in the SR-EO case.

![Figure 11: Supply ratio in the baseline (left) and in CM-SR scenario (right) in Zone A](image-url)
In Zone B, with a strategic reserve, the import of electricity from A (with a capacity market), along with the additional capacity available due to the strategic reserve, leads to a strong reduction in shortages hours (by 98% as compared to SR-EO), a reduction of the price volatility and a 9% reduction in the average electricity prices (Figure 14). However, the exports from A to B reduce the need for the strategic reserve, as a result of which the strategic reserve no longer is able to recover it costs, which now are 0.2 €/MWh. Apparently, in this case a smaller strategic reserve would have sufficed.

The supply ratio in Zone B in scenario CM-SR (0.96) is lower than in the SR-EO scenario (1.02), a difference of 6 percentage points, as can be seen in Figure 13. This indicates that in the presence of the capacity market, the strategic reserve is less effective in maintaining a certain supply ratio. However, the strategic reserve reduces the risk of investment cycles, as is shown in Figure 10, and contributes to a low number of shortage hours.

With respect to the capacity market in Zone A, the difference in the capacity market clearing price is less than 1% in CM-SR (27,231 €/MW) as compared to CM-EO (27,017 €/MW), which indicates that the presence of a strategic reserve in the interconnected zone does not impact capacity prices significantly. See Figure 15.
4.5 Model limitations

In this model, the power generating companies do not exercise market power or any other kind of strategic behavior in the electricity market or the capacity market. Demand response and storage are also outside the scope of this research. The capacity mechanism design was not adjusted to cross-border trade; neither cross-border trade of capacity rights or any kind of export restriction was included. Finally, as EMILab-Generation was developed to study the long-term development of electricity markets under different policy conditions, short-term operational constraints and unplanned shutdowns of power plants were not modeled. These limitations, along with the segmented nature of the load-duration curve, cause the short-term dynamics to be less precise.

5 Conclusions

We present an analysis of the cross-border effects that may arise due to the implementation of capacity mechanisms in interconnected electricity markets with the use of an agent-based model. We analyze a capacity market and a strategic reserve. In our model, both capacity mechanisms improve the security of supply and contribute positively to consumer benefit in both Zones.
In our model, interconnection with a neighboring zone does not affect the ability of a capacity market to reach its policy goals. The neighboring zone may experience a positive spillover and therefore free ride on the capacity market, but may also become import dependent. The free riding may cause an increase in cost to the consumers in the capacity market that are paying for the additional adequacy. The generators in the neighboring energy-only zone may be crowded out, in some cases to the extent that an investment cycle develops.

A strategic reserve also has a positive spillover effect on a neighboring energy-only market, both in terms of reduction in shortage hours and cost to consumers. However, the presence of an energy-only market in a neighboring zone has a negative effect on the performance of the strategic reserve with respect to the net cost to consumers and the number of shortage hours, when compared to an isolated system with a strategic reserve.

A capacity market reduces the need for, but may also reduce the effectiveness of a strategic reserve implemented in an interconnected zone. However, a strategic reserve can reduce the crowding-out effect that is caused by the capacity market on its electricity market and thus lower the risk of investment cycles.

Acknowledgments

Pradyumna Bhagwat and Jörn C. Richstein have been awarded the Erasmus Mundus Joint Doctorate Fellowship in Sustainable Energy Technologies and Strategies (SETS) hosted by the Universidad Pontificia Comillas, Spain; the Royal Institute of Technology, Sweden; and Delft University of Technology, The Netherlands. The authors would like to express their gratitude towards all partner institutions within the program as well as the European Commission for their support.

Reference

ACER, 2013. Capacity remuneration mechanisms and the internal market for electricity.
BMWi, 2015. An electricity market for Germany’s energy transition: White Paper by the Federal


Gore, O., 2015. IMPACTS OF CAPACITY REMUNERATIVE MECHANISMS ON CROSS-BORDER TRADE. Lappeenranta University of Technology.


APPENDIX

Table 2: Assumptions for power generation technologies

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>758</td>
<td>4</td>
<td>1</td>
<td>50</td>
<td>20</td>
<td>5000</td>
<td>1</td>
<td>1</td>
<td>Coal, Biomass (10%)</td>
</tr>
<tr>
<td>CCGT</td>
<td>776</td>
<td>2</td>
<td>1</td>
<td>40</td>
<td>15</td>
<td>0</td>
<td>1</td>
<td>1</td>
<td>Gas</td>
</tr>
<tr>
<td>OCGT</td>
<td>150</td>
<td>0.5</td>
<td>0.5</td>
<td>30</td>
<td>15</td>
<td>0</td>
<td>1</td>
<td>1</td>
<td>Gas</td>
</tr>
<tr>
<td>Nuclear</td>
<td>1000</td>
<td>7</td>
<td>2</td>
<td>40</td>
<td>25</td>
<td>5000</td>
<td>1</td>
<td>1</td>
<td>Uranium</td>
</tr>
<tr>
<td>IGCC</td>
<td>758</td>
<td>4</td>
<td>1</td>
<td>50</td>
<td>20</td>
<td>0</td>
<td>1</td>
<td>1</td>
<td>Coal, Biomass (10%)</td>
</tr>
<tr>
<td>Wind Offshore PV</td>
<td>600</td>
<td>2</td>
<td>1</td>
<td>25</td>
<td>15</td>
<td>0</td>
<td>0.6</td>
<td>0.07</td>
<td>-</td>
</tr>
<tr>
<td>Wind Onshore Biomass</td>
<td>500</td>
<td>3</td>
<td>1</td>
<td>40</td>
<td>15</td>
<td>5000</td>
<td>1</td>
<td>1</td>
<td>Biomass</td>
</tr>
<tr>
<td>CCGTCCS</td>
<td>600</td>
<td>3</td>
<td>1</td>
<td>40</td>
<td>15</td>
<td>0</td>
<td>1</td>
<td>1</td>
<td>Gas</td>
</tr>
<tr>
<td>CoalCCS</td>
<td>600</td>
<td>4</td>
<td>1</td>
<td>50</td>
<td>20</td>
<td>5000</td>
<td>1</td>
<td>1</td>
<td>Coal, Biomass (10%)</td>
</tr>
<tr>
<td>Lignite</td>
<td>1000</td>
<td>5</td>
<td>1</td>
<td>50</td>
<td>20</td>
<td>5000</td>
<td>1</td>
<td>1</td>
<td>Lignite</td>
</tr>
<tr>
<td>Biogas</td>
<td>500</td>
<td>3</td>
<td>1</td>
<td>40</td>
<td>15</td>
<td>0</td>
<td>1</td>
<td>1</td>
<td>Biomass</td>
</tr>
<tr>
<td>IGCCCCS</td>
<td>600</td>
<td>4</td>
<td>1</td>
<td>50</td>
<td>20</td>
<td>0</td>
<td>1</td>
<td>1</td>
<td>Coal, Biomass (10%)</td>
</tr>
</tbody>
</table>

Table 3: Fuel price and demand price growth rate assumptions

<table>
<thead>
<tr>
<th>Type</th>
<th>Unit</th>
<th>Coal</th>
<th>Gas</th>
<th>Lignite</th>
<th>Uranium</th>
<th>Biomass</th>
<th>Demand</th>
</tr>
</thead>
<tbody>
<tr>
<td>Start</td>
<td>€/GJ</td>
<td>3.6</td>
<td>9.02</td>
<td>1.428</td>
<td>1.29</td>
<td>4.5</td>
<td>-</td>
</tr>
<tr>
<td>Lower</td>
<td>[%]</td>
<td>-3</td>
<td>-6</td>
<td>-1</td>
<td>0</td>
<td>-3</td>
<td>2</td>
</tr>
<tr>
<td>Upper</td>
<td>[%]</td>
<td>5</td>
<td>8</td>
<td>1</td>
<td>2</td>
<td>5</td>
<td>2</td>
</tr>
<tr>
<td>Average</td>
<td>[%]</td>
<td>1</td>
<td>1.5</td>
<td>0</td>
<td>1</td>
<td>1</td>
<td>1.5</td>
</tr>
</tbody>
</table>
### Table 4: Initial supply mix for all scenarios

<table>
<thead>
<tr>
<th>Technology</th>
<th>Coal</th>
<th>CCGT</th>
<th>OCGT</th>
<th>Nuclear</th>
</tr>
</thead>
<tbody>
<tr>
<td>% Share</td>
<td>50.0%</td>
<td>19.0%</td>
<td>13.0%</td>
<td>18.0%</td>
</tr>
</tbody>
</table>

### Table 5: Development of installed capacity the supply-mix in a scenario with growing RES

<table>
<thead>
<tr>
<th>Technology</th>
<th>Initial Mix</th>
<th>Final Mix</th>
<th>Final capacity (GW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>50.0%</td>
<td>11.8%</td>
<td>44.8</td>
</tr>
<tr>
<td>CCGT</td>
<td>19.0%</td>
<td>10.2%</td>
<td>38.7</td>
</tr>
<tr>
<td>OCGT</td>
<td>13.0%</td>
<td>1.9%</td>
<td>7.2</td>
</tr>
<tr>
<td>Nuclear</td>
<td>18.0%</td>
<td>2.3%</td>
<td>8.8</td>
</tr>
<tr>
<td>IGCC</td>
<td>-</td>
<td>1.8%</td>
<td>6.7</td>
</tr>
<tr>
<td>Wind Offshore</td>
<td>-</td>
<td>8.8%</td>
<td>33.4</td>
</tr>
<tr>
<td>PV</td>
<td>-</td>
<td>43.4%</td>
<td>164.7</td>
</tr>
<tr>
<td>Wind</td>
<td>-</td>
<td>16.4%</td>
<td>62.4</td>
</tr>
<tr>
<td>Biomass</td>
<td>-</td>
<td>3.4%</td>
<td>12.9</td>
</tr>
<tr>
<td>CCGTCCS</td>
<td>-</td>
<td>-</td>
<td>0</td>
</tr>
<tr>
<td>CoalCCS</td>
<td>-</td>
<td>-</td>
<td>0</td>
</tr>
<tr>
<td>Lignite</td>
<td>-</td>
<td>-</td>
<td>0</td>
</tr>
<tr>
<td>Biogas</td>
<td>-</td>
<td>-</td>
<td>0</td>
</tr>
<tr>
<td>IGCCCCS</td>
<td>-</td>
<td>-</td>
<td>0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>100.0%</strong></td>
<td><strong>100.0%</strong></td>
<td><strong>379.7</strong></td>
</tr>
</tbody>
</table>

### Table 6: Annual average values of key indicators all scenarios

<table>
<thead>
<tr>
<th>Scenario Name</th>
<th>Shortage hours (h/y)</th>
<th>Supply ratio</th>
<th>Electricity price (€/MWh)</th>
<th>Cost of RES (€/MWh)</th>
<th>CCCM (€/MWh)</th>
<th>Cost to consumers (€/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>BL-A</td>
<td>58.4</td>
<td>0.93</td>
<td>58.1</td>
<td>11.5</td>
<td>0.0</td>
<td>69.6</td>
</tr>
<tr>
<td>BL-B</td>
<td>58.4</td>
<td>0.93</td>
<td>58.1</td>
<td>11.5</td>
<td>0.0</td>
<td>69.6</td>
</tr>
<tr>
<td>CM-E0-A</td>
<td>0.0</td>
<td>1.12</td>
<td>46.1</td>
<td>13.0</td>
<td>4.8</td>
<td>63.9</td>
</tr>
<tr>
<td>CM-E0-B</td>
<td>31.0</td>
<td>0.87</td>
<td>52.8</td>
<td>12.1</td>
<td>0.0</td>
<td>64.9</td>
</tr>
<tr>
<td>SR-E0-A</td>
<td>11.0</td>
<td>1.02</td>
<td>53.7</td>
<td>12.3</td>
<td>-0.3</td>
<td>65.7</td>
</tr>
<tr>
<td>SR-E0-B</td>
<td>15.0</td>
<td>0.91</td>
<td>54.1</td>
<td>12.2</td>
<td>0.0</td>
<td>66.3</td>
</tr>
<tr>
<td>CM-SR-A</td>
<td>0.0</td>
<td>1.12</td>
<td>46.0</td>
<td>13.0</td>
<td>4.9</td>
<td>63.9</td>
</tr>
<tr>
<td>CM-SR-B</td>
<td>1.2</td>
<td>0.96</td>
<td>50.8</td>
<td>12.5</td>
<td>0.2</td>
<td>63.6</td>
</tr>
</tbody>
</table>