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The effectiveness of a strategic reserve in the presence of a high portfolio share of renewable energy sources

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ABSTRACT

To ensure sufficient investment in electricity generation capacity, mechanisms such as strategic reserves are being considered or already implemented. We analyze the effectiveness of a strategic reserve in the presence of a growing portfolio share of renewable energy sources (RES) with EMLab-Generation, an agent-based electricity market model. A strategic reserve can stabilize investment, but within limits. Uncertainty regarding future demand may cause the market to become instable, potentially leading to periods with very high electricity prices. In the presence of a large share of variable renewable energy sources, the reserve design should be adjusted or replaced by an alternative capacity mechanism.

1. Introduction

We investigate the effectiveness of a strategic reserve with respect to incentivizing adequate generation investment in an electricity system with strong growth in the portfolio share of intermittent or variable renewable energy sources (RES). The increasing reliance on variable renewable electricity generation makes cost recovery more uncertain for thermal power plants in Europe. Their capacity is needed when the variable resources are not sufficiently available, but the number of hours per year that they operate declines when the share of renewable energy increases. In theory, this should not affect their business case as long as scarcity prices are allowed to rise high enough, but investment becomes riskier as their revenues come to depend increasingly on infrequent but high scarcity prices. When other causes of risk and uncertainty are taken into account, such as carbon-policy uncertainty, fuel-price uncertainty, and uncertain demand growth, there arises a legitimate concern that there will not be enough investment in thermal power generation capacity and that unprofitable thermal power plants might be decommissioned. In their paper on the decommissioning of power stations between 2001 and 2005, Wissen and Nicolosi (2007) contend that although much of the observed decommissioning was most likely due to other reasons, there is a possibility that some of these units would have remained operational in absence of growth of renewable energy (Sensfuß et al., 2008). Similarly, Nicolosi and Fürsch (2009) and Bushnell (2010) expect a lower share of base-load power plants in the supply mix over the long run. More recently, plants in the Netherlands are being mothballed due to a combination of excess capacity and shorter running hours due to the import of variable renewable energy from Germany (Straver, 2014).

In response to the rising share of renewables and the vulnerabilities of the electricity markets discussed in literature (Borenstein et al., 1995; Brown, 2001; De Vries and Hakvoort, 2003; De Vries, 2007; Joskow and Tirole, 2007; Joskow, 2008; Keppler, 2014; Pérez-Arriaga, 2001; Stoft, 2002; Woo et al., 2003), capacity mechanisms are being considered or already implemented in many countries (ACER, 2013; BMWi, 2015; Creti et al., 2012; DECC, 2014; Mastropietro et al., 2015; RTE, 2014; Spees et al., 2013). For our purposes, capacity mechanisms refer to policy instruments for ensuring adequate investment in generation capacity; in the European debate, they are also called capacity remuneration mechanisms. The impacts and the concerns regarding implementation of different capacity mechanisms have been discussed in depth in literature (Cramton et al., 2013; Finon, 2015, 2013; Meyer and Gore, 2015; Newbery and Grubb, 2014; Regulatory Assistance Project, 2013; Rodilla and Batlle, 2013, 2012). One such option is a strategic reserve (Cramton et al., 2013; Rodilla and Batlle, 2013), typically consisting of generators with high operating costs and/or demand-side resources that are contracted by the transmission system operator (TSO) and are dispatched when the market does not provide sufficient generation capacity. Conceptually, a strategic

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reserve may resemble operating reserves pricing (Stoft, 2002), depending on whether the decision to dispatch the reserve units on short notice as a function of the electricity price or some other variable. In Sweden, a strategic reserve was implemented to prevent old units from being decommissioned, despite their limited economic prospects. In southern Germany, a strategic reserve is currently used to allow the transmission system operator to purchase electricity from units that are more expensive than the market price, but that are locally needed due to network constraints. In this case, the reserve is used for congestion management.

The creation of a strategic reserve itself might not change the volume of available generation capacity, as it simply transfers the control of some power stations to the transmission system operator (TSO). The exception is if, by doing so, it prevents plant from being decommissioned. In case there is not enough available generation capacity, the TSO dispatches the strategic reserve at a price above the variable costs of the generation units. This will cause the average electricity price to increase and thus stimulate investment in generation capacity. The market design challenge, therefore, is to ensure that the dispatch price of the reserve provides an adequate investment incentive.

We analyze the effectiveness of a strategic reserve in providing reliability in the presence of a growing share of renewable energy supply in the supply mix. We also consider short-term and long-term effects on economic efficiency. We expand an existing agent-based model of electricity markets called EMLab-Generation (De Vries et al., 2013; Richstein et al., 2015a, 2015b, 2014). In the next section, we describe the fundamentals of designing and operating a strategic reserve. In Section 3, the EMLab-Generation agent-based model, the implementation of a strategic reserve in this model and calculation of the strategic reserve parameters are explained. Section 4 describes the scenarios used for our model runs. In Section 5, we present the results of our analysis of the effectiveness of a strategic reserve without and with a large share of renewable energy sources. We test it in a Monte Carlo-style analysis with uncertain demand growth rate and fuel-price developments. The indicators that we use in this analysis are described in detail in Section 5.1. The conclusions are summarized in Section 6.

2. Designing and operating a strategic reserve

2.1. Overview

We define a strategic reserve as a set of power plants and/or interruptible demand contracts that are controlled by the transmission system operator, to be deployed during shortages (De Vries, 2004; De Vries and Heijnen, 2006; Rodilla and Batlle, 2013). We analyze a strategic reserve that is dispatched when the market price exceeds a certain level. We do not consider alternative dispatch criteria, such as those based on the reserve margin (defined as the available generation capacity over the peak demand). In the basic strategic-reserve design, the system operator contracts electricity generation units with high operating costs (ideally, the last units in the merit order) and offers their electricity to the market at a price (P_{SR}), which is well above their variable cost (see Fig. 1). The pays the owners of these power plants their annual operations and maintenance costs. If the reserve capacity is dispatched, the operator pays the owners of these power plants their marginal cost of generation. Thus the operator pays all the reserve costs and keeps (most of) the profit when the reserve is dispatched. From the perspective of the operator, these profits should cover the fixed costs, but the operator takes the financial risk of keeping the reserve units available. In case the operator is unable to recover all its cost of contracting the reserve, the remaining costs are socialized (or spread across usage) as part of the network or system tariffs.

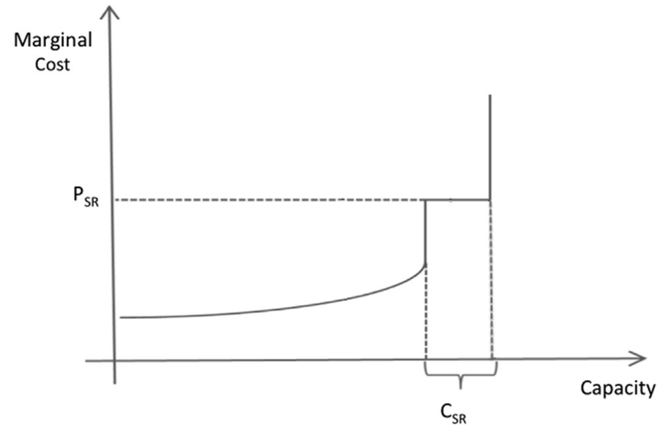

Fig. 1. Example of impact of strategic reserve on the supply curve (De Vries, 2004).

2.2. Reserve design

A strategic reserve with a price-based dispatch criterion, as analyzed here, withdraws a certain volume of generation capacity from the market and makes it available at a price that is (substantially) higher than its variable cost. This should stimulate investment in generation capacity as explained by Stoft (2002). The level of the reserve dispatch price (P_{SR}) is a key factor, as it effectively caps the market price (Stoft, 2002; De Vries and Heijnen, 2008). It therefore determines the strength of investment incentive, and, as a consequence, the total equilibrium volume of generation capacity and hence the level of generation adequacy. In principle, the reserve price P_{SR} should be determined such that the revenues earned by the power producers in the presence of the strategic reserve are equivalent to the revenues that they would have earned in an energy only market. In a perfect market, if the supply ratio[1] was optimal without the reserve, the reserve should lead to the same supply ratio. In case of market imperfections that cause insufficient investment, the reserve could provide compensation by raising generation companies' average revenues. The determination of an optimal supply ratio is beyond our paper's scope. In theory, it should follow from the minimization of social costs, but in practice it is often determined by the regulator. In our research, we focus on the effectiveness of a strategic reserve in providing reliability without and with a large share of renewable energy sources. A second criterion is the impact of the strategic reserve on economic efficiency.

The only time when the reserve price does not function as a maximum price is the rare occasion when the reserve is exhausted. Then the price may increase to the value of lost load if there are no more demand-side resources available. If the reserve functions well, it has attracted sufficient investment in generation capacity and is exhausted only under rare circumstances. As a result, generators lose some peak revenues. With a well-designed reserve, this loss is offset by the fact that the reserve increases the market price up to P_{SR} during other hours, namely when there is no absolute shortage but the reserve is needed to meet demand. The challenge is to design the reserve so it balances these two effects. Consequently, in a market with a strategic reserve, price spikes up to P_{SR}

[1] Supply ratio is defined as the ratio of available supply at peak over peak demand.

occur more frequently than scarcity prices would occur in a system without a reserve, but these price spikes are lower. The lower but more frequent price spikes should make electricity prices more predictable and investment consequently less risky, according to Stoft (2002). We describe this change in the shape of the price–duration curve in the Section 3.2.

2.3. The dismantling paradox

During the development of this model, we came upon an interesting long-term effect of a strategic reserve, which we label "the dismantling paradox". In the long run, a strategic reserve may distort the merit order by supporting power generation units that should be dismantled and which may also be the most polluting. A strategic reserve may be intended to prolong the service life of old power plants, but over time this may cause a dilemma when the oldest plant in the system is no longer necessary or should be replaced for economic reasons. Investment in new plants, new interruptible demand contracts or declining demand, in combination with the aging of the plants in the reserve, may create a situation in which the marginal plant no longer is economic, even as part of the reserve. However, if the system operator ceases to contract it, its owner could offer it to the market at its marginal cost, which is below the reserve price. This plant would then be the last to be dispatched before the reserve, running at least as many hours as the reserve, while being less efficient than the plants in the reserve. As this would artificially increase its operating hours, relative to its position at the end of the merit order, it could make the plant profitable again, causing it to continue to be profitable despite its position at the end of the merit order. The extent to which this occurs depends on the shapes of the supply and demand functions. We encountered this behavior in our model runs.

A similar risk exists for demand resources with relatively high activation costs (resources that require a relatively high remuneration per MWh of load reduction). If cheaper demand resources become available, the system operator would prefer them. However, if the operator does not contract the more expensive demand resources, the latter may be offered to the market and dispatched before the strategic reserve, out of merit. A key difference with generators with high variable costs is that demand resources do not age and do not need to be dismantled. The advent of cheaper demand resources may simply mean that size of the strategic reserve can be reduced.

3. Model description

3.1. EMLab-generation

EMLab-Generation[2] is an agent-based model (ABM) (De Vries et al., 2013; Richstein et al., 2014). The model has been developed for the purpose of analyzing long-term impacts of different renewable energy, carbon emissions, and resource adequacy policies and their interactions, that is, "what-if" scenarios rather than forecasts or optimizations. It is a bottom-up model in which actors, the main ones of which are power companies, are modeled as agents who make decisions, e.g. bidding on electricity market and investment, independently from each other (Chappin, 2011; Dam et al., 2013). The model functions within the AgentSpring framework (Chmieliauskas et al., 2012). The main external drivers for change in this model are the fuel prices, electricity demand scenarios, and policy instruments such as capacity mechanisms. The main outputs are investment behavior and its impact on electricity prices, generator cost recovery, CO_2 emissions, fuel consumption, and system reliability. The agents base their investment and dispatch decisions on scenario variables, such as electricity demand and fuel prices, and on endogenous variables such as the electricity price. A key advantage of this approach is that it is not necessary to make assumptions about the reaction of the system as a whole to policy changes, as the system-level performance is a resultant of all agents' actions (Chappin, 2011). Therefore, assumptions must be made only at the level of the agents.

EMLab-Generation was developed in order to model questions that arise from the heterogeneity of the electricity sector between EU member states (De Vries et al., 2013; Richstein et al., 2015a, 2015b, 2014). In connected electricity markets, multiple policy instruments (such as renewable energy and generation adequacy policies) may influence investment in generation capacity. To assess these, the model simulates several decades, with a time step of one year. We represent the uncertainty regarding fuel prices and demand growth, varying these two scenario parameters in multiple runs, Monte-Carlo style.

In the model, generation companies interact with each other in the electricity market. They make decisions regarding capital investments, bids into the electricity markets, and purchases of carbon credits. Choices about dispatch are affected by demand, fuel prices, electricity and CO_2 prices, and the fuel efficiency of generators. Investment decisions by agents are based on the expected net present value of new plant. Power producers make investment decisions sequentially in an iterative process. The investment decision of each power producer affects the investment decision of the next producer by changing its forecast of available capacity. In reality, as construction permits are typically made public, we assume that power producers have full information about investment decisions that have already been made by competitors. The iterative process stops when no participant is willing to invest further. In order to prevent a bias towards any particular agent, the sequence of power producers is determined randomly in every time step. The investment algorithm is presented in a flowchart in the Appendix (see Fig. 19) and a detailed description is available in Richstein et al. (2014). There are 14 power-plant technology options available to a generator. Future development of these technologies is modeled as a gradual decrease in costs and improvement in operational parameters, such as efficiency. The attributes of the power plants, such as fuel efficiencies, investment costs, operation and maintenance costs, and technological learning, are based on data from the IEA World Energy Outlook 2011, New Policies Scenario (IEA, 2011). The development of renewable energy generation is implemented as investment by a renewable 'target investor'. If investment in renewable energy source (RES) capacity by the competitive power producers is lower than the government target, the target investor will invest in additional RES capacity in order to meet the target even to the extent that they do not recover their costs in the market. This simulates the current subsidy-driven development of renewable energy sources.

Electricity demand is represented in the form of a load-duration curve. The curve changes each year as demand changes. Empirical load data is approximated by a step function with 20 segments of variable length (see Fig. 2). Within a one-year time step, the electricity market is cleared for each step of the load-duration curve. The intermittency of renewables is a short-term effect, which is difficult to implement in a long-term model such as EMLab-Generation. In this model, intermittency is approximated by varying the contribution of these technologies (availability as percentage of installed capacity) in different segments of the load-duration function. The segment-dependent availability is varied linearly from a high contribution to the base segments, to very low contribution to the highest peak segment. A detailed description of

[2] http://emlab.tudelft.nl/.

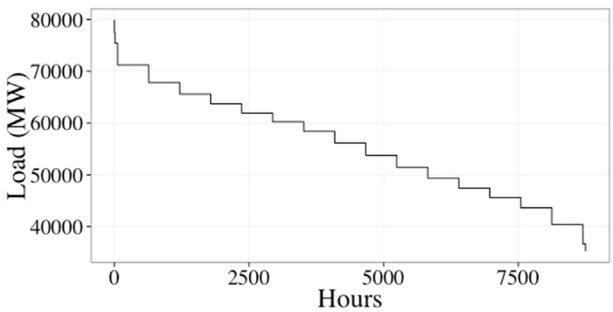

Fig. 2. Load-duration curve in EMLab-Generation for one country.

how intermittency is modeled is available in De Vries et al. (2013); Richstein et al. (2015a, 2015b, 2014). Table 2 in the Appendix summarizes all the assumptions regarding the power generation technologies. The most important advantage of working with a load-duration curve is that it allows for a shorter run time, enabling a larger number of Monte-Carlo simulations within a practical time frame (Richstein et al., 2014).

In this paper we review the impact of a strategic reserve on a single, closed market. The electricity market is modeled as an abstraction of a hourly power system (Richstein et al., 2014). During the electricity market clearing process, each generation company submits a price-volume bid pair for each power plant that it owns and for each of the segments of the load-duration curve. The highest accepted bid sets the electricity market-clearing price for that segment and that market. If demand is higher than supply, the clearing price is set to the value of lost load. The overview of the model activities during a time step is presented in a flowchart in the Appendix (see Fig. 18). A detailed description of this model is available online in the EMLab-Generation technical report and previously published work (De Vries et al., 2013; Richstein et al., 2015a, 2015b, 2014).

3.2. The strategic-reserve algorithm

The strategic reserve is modeled as an extension of EMLab-Generation. Here we describe the algorithms that determine the behavior of the strategic-reserve operator in our model. The operator contracts the most expensive power plants, based on their variable costs, until the reserve has the required volume. The operator selects these plants because they are the least likely to run, so the opportunity cost of withdrawing them from the market is the smallest. This means that, if a tendering process were organized, they would have made the lowest bids. The strategic reserve only contracts complete power plants, thus the full capacity of the last required power plant is contracted.

The owners of the contracted power plants are paid the annual fixed operating costs of the plants and the plants are offered to the electricity spot market at the strategic reserve dispatch price (P_{SR}). In the event that this capacity is sold in the market and dispatched, the strategic reserve operator keeps the revenue earned by the generating units in the reserve (R_{GR}) above their variable costs of generation (VC). This can be defined as the revenue of the strategic reserve operator (R_{SR}) (see Equation (1)).

$$R_{SR} = R_{GR} - VC \tag{1}$$

If all non-contracted generators are running and the reserve is also not large enough to meet demand, there is a physical shortage of electricity. In this case, the market price is set equal to the value of lost load (VOLL) in our model. It is assumed that the system operator passes on the reserve costs to the consumers via the network tariffs. The process of contracting power plants for the strategic reserve is presented in a flowchart in Appendix (Fig. 20).

3.3. Determining the strategic-reserve parameters

We now describe how the key parameters of the reserve are chosen. The regulator needs to choose either the reserve size or the dispatch price P_{SR} and calculate the other variable so that the average revenues of the generators are just sufficient to remunerate their investments. The regulator could also implement a step-wise dispatch price function by making capacity from the reserve available at different price levels, but for simplicity we consider a single dispatch price for the entire reserve. In our model, fixing the reserve volume was most practical. The system operator in the model chooses the size of the strategic reserve as a fraction F_{SR} of expected peak demand to be contracted. In every time step, the total capacity contracted into the strategic reserve (C_{SR}) is calculated from the fraction of the reserve volume (F_{SR}) over peak load, multiplied by the peak load (V_{PL}) (see Equation (2)).

$$C_{SR} = F_{SR} * V_{PL} \tag{2}$$

In calculating the reserve price from the reserve volume, we apply the principle that (in a perfect market) the reserve should not change the average electricity price. Thus, the total revenues earned by the generators during the hours when the reserve sets the price in a market with a strategic reserve should be equal to the revenues earned by the power producers during the same hours in an energy-only market. In other words, the revenue loss that generators experience due to fewer hours of scarcity prices should be perfectly compensated by an increase in revenues during hours when the reserve has the effect of raising the electricity price from the marginal cost of generation to the reserve price. This is illustrated in Fig. 3 with a simplified price–duration curve where the area under the curve represents the revenues earned by the power producers. The reserve price (indicated by line FG) must be adjusted such that the area under polygon ABCDE must be made equal to area under polygon FGDE for a fixed reserve volume.

In order to determine the dimensions of the strategic reserve, a baseline scenario with fixed fuel prices and no demand growth is run 120 times over a time horizon of 40 year. A price–duration curve is created from the electricity prices in these runs. Next, the reserve volume is set as 6% of the peak demand, as at this volume of capacity the reserve must be active for 10 h annually on average. Since we consider electricity prices from all the runs as separate data points, this reserve volume would lead to 48,000 h with reserve prices (P_{SR}) over the entire simulation (of 10 h * 40 years * 120 runs). As we assume that the presence of a strategic reserve does not affect electricity prices during the hours that the reserve is not activated, we restrict our analysis to the segments of the load-duration curve during which the reserve would be activated, if present.

In the next step, the total revenue generated during the 48,000 peak hours of the combined load-duration curve is calculated. The model has a segmented load-duration curve, so the total revenue earned by the competitive generators is calculated as the summation of the revenue per segment of the load-duration curve for all the segments that together make up the 48,000 peak hours. The revenues per segment are equal to the product of the price, the number of hours in the segment and the volume of generation in the segment. Total generator revenues in an energy-only market R_{eom} are given by:

$$R_{eom} = \sum_{i=1}^{n} P_i * h_i * g_i \tag{3}$$

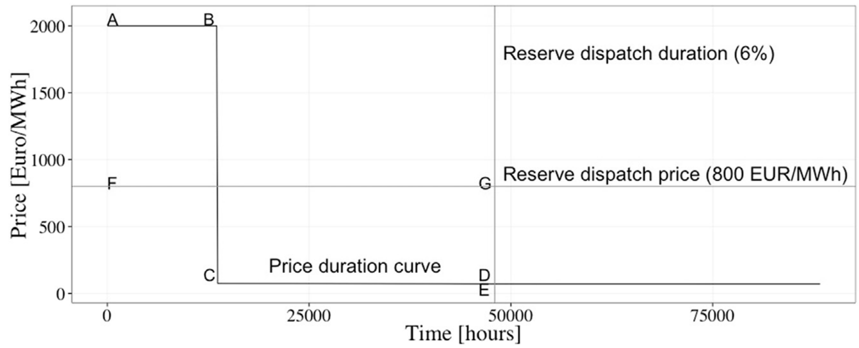

Fig. 3. Modification to the peak of the price–duration curve due to a strategic reserve.

Here, n is the number of segments in the load-duration curve during which the reserve would be activated, P_i is the price in segment i, h_i is the number of hours in segment i and g_i is the total generation in segment i.

If a strategic reserve is implemented, the price during these segments is equal to the reserve dispatch price P_{SR}. Then, the generation companies' revenues R_{SR} are determined by the reserve dispatch price instead of the market price:

$$R_{SR} = \sum_{i=1}^{n} P_{SR} * h_i * g_i \quad (4)$$

If the strategic reserve is not to change average revenues, Equation (3) must equal (4). This way, the strategic reserve price P_{SR} is calculated.

3.4. Strategic reserve in a static thermal-only scenario

We use the process described in Section 3.3 to determine the strategic-reserve parameters in a scenario with static fuel prices, zero demand growth, and thermal-only generation capacity: the *Deterministic Baseline Scenario*. The purpose is to determine an optimal strategic reserve for the starting situation of the model. The main source of uncertainty in this scenario arises from the power producer's investment decisions, as described in Section 3.1. The reserve volume is set at 6% (V_{SR}); the corresponding dispatch price (P_{SR}) was calculated to be 800 €/MWh in the previous section. When we run the model again, under the same Deterministic Baseline Scenario, with the strategic reserve, we find that the reserve is dispatched 6.9 h annually on average. The supply ratio increases by 5.3% (see Fig. 4) and the number of shortage hours is reduced by 95%–0.13 h per year (see Fig. 5). The strategic reserve operator does not recuperate all the cost of contracting the reserve, but this cost amounting to 0.23 €/MWh is just 0.6% of the total cost to consumer which is 39.33 €/MWh. As average prices are comparable to the situation without a strategic reserve, the average cost to consumers remains comparable to the baseline scenario. These results validate our method used for sizing the reserve.

Another observation is that in the presence of a strategic reserve there is a more gradual rise and fall in the supply ratio in this static scenario, as seen in Fig. 4. Comparing this result with the electricity prices shown in Fig. 6 reveals that when the supply ratio starts to decrease, the average electricity price rises as the reserve is activated more frequently. Although in some scenarios there are strong swings in the electricity price, the median (see Fig. 4) and mean (see Table 7 in the Appendix) of the price are lower with a strategic reserve in the baseline scenario throughout the time horizon under consideration.

At the beginning of the run with a strategic reserve, high electricity prices are observed. The reason is that at the start of the run, the supply ratio is lower than the equilibrium level for the market with a strategic reserve, so until new capacity gets built, the reserve is activated more frequently than the long-term average. The sharp decline in average price during the succeeding period also indicates that the strategic reserve provides a strong incentive for investment in new generation capacity (Fig. 6). In fact, the model indicates an investment overshoot and subsequent dip in capacity; this points to the need to phase in a reserve of this size in a system with a tight supply ratio. The price–duration curve in which the price data is presented in a descending order of magnitude is illustrated in Fig. 7. The average number of hours for every price level each year is calculated based on the electricity price data obtained from the 120

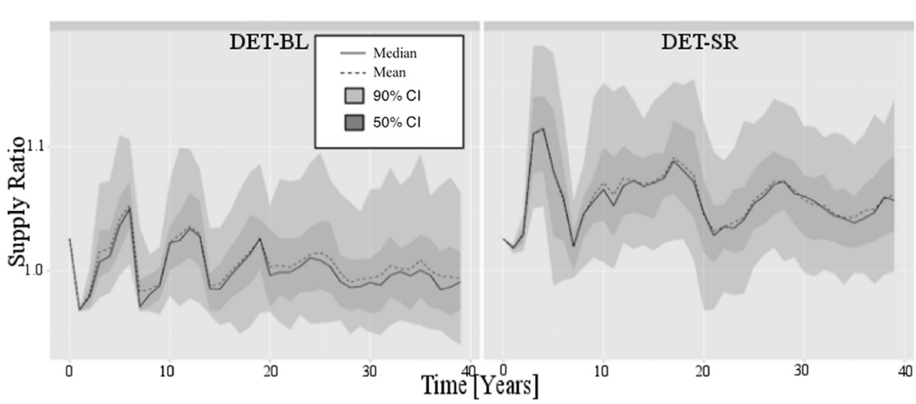

Fig. 4. The supply ratio without (left) and with (right) a strategic reserve in a scenario without demand growth.

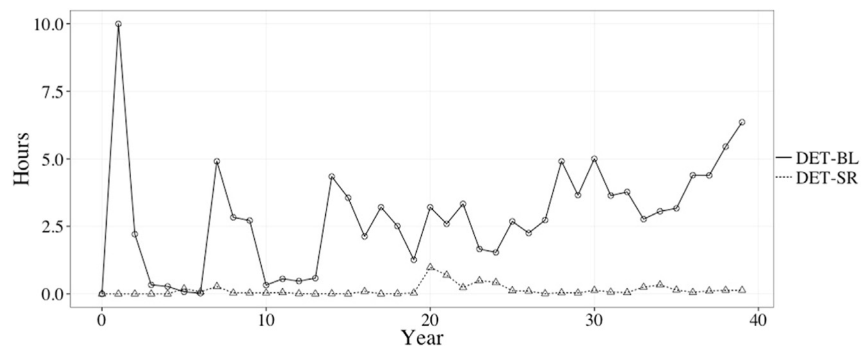

Fig. 5. Comparison of change in average shortage hours in scenario without demand growth (DET-BL) and with (DET-SR) a strategic reserve.

Monte-Carlo runs for the given scenario. We observe a reduction in the occurrence of sharp price peaks caused by scarcity, as expected from theory.

4. Scenarios

We first test the effectiveness of a strategic reserve in an environment with uncertain demand growth and fuel prices. These scenarios only include thermal power plants. Subsequently, we add a growing share of variable renewable energy in order to answer the main research question, namely how this relates to the effectiveness of the reserve (See Table 1 for scenario parameters).

In all scenarios, a market with four identical power producers is considered. The initial supply mix consists of four power-generating technologies (Coal, CCGT, OCGT, and Nuclear). The

Table 1
Scenario parameters.

Scenario	RES	Strategic reserve
TM-BL	–	–
TM-SR	–	×
RES-BL	×	–
RES-SR	×	×

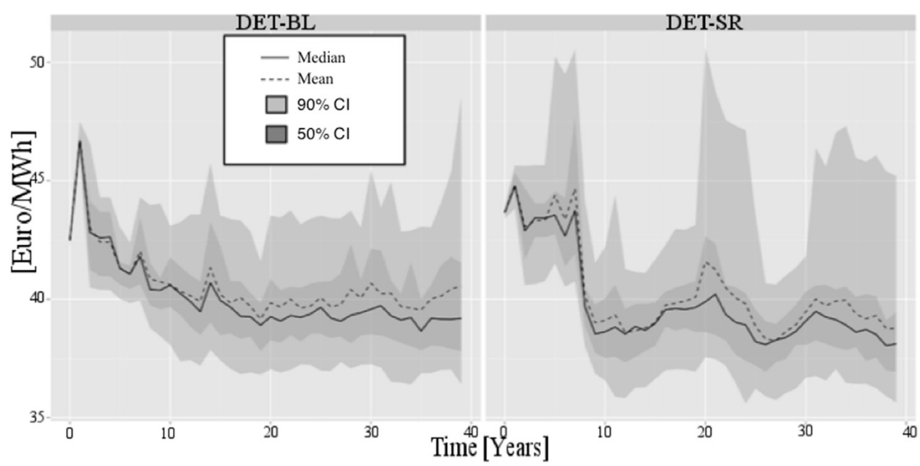

Fig. 6. Electricity prices in a scenario without demand growth, without (left) and with (right) a strategic reserve.

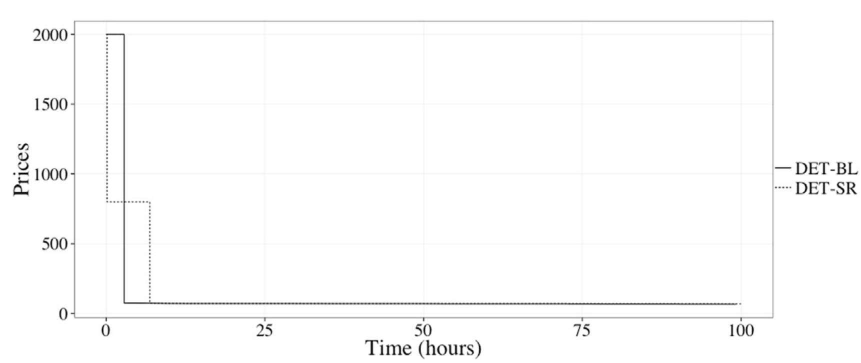

Fig. 7. Peak section of the price–duration curve in a scenario without demand growth, without (DET-BL) and with a strategic reserve (DET-SR).

shares of the different technologies in the supply mix are based on the power-generation capacity portfolio of Germany in 2010 (based on Eurelectric (2012) data; see also Table 5 in the Appendix). The load-duration function in this paper is based on the 2010 ENTSO-E data for Germany. The coal and gas prices trends are based on fossil-fuel scenarios published by Department of Energy and Climate Change (2012). The biomass cost trends are based on Faaij (2006) and those for lignite are based on Konstantin (2009).

Each scenario was run 120 times according to the Monte Carlo method with the same starting conditions but with different fuel-price and demand-growth assumptions. All scenarios consist of 40 time steps each of which represents one year. A triangular probability distribution was used to create variations in electricity demand growth and fuel prices around an average growth rate (Table 4 in the Appendix). The TM scenario serves as a reference case for understanding the effects of a strategic reserve under dynamic conditions. We run this scenario for a baseline case without a strategic reserve (indicated as TM-BL) and for a case with a strategic reserve (indicated as TM-SR).

In our second scenario ('RES'), the share of (variable) renewable energy in the supply mix grows substantially (see Table 6 in the Appendix). This is the key scenario for our analysis, which we use for analyzing the effectiveness of a strategic reserve in the presence of a growing share of renewable energy in the total generation portfolio of the system. The renewable energy trends are based on the German renewable energy action plan (NREAP, 2010) until 2020 and interpolated further. Aside from the share of renewable energy, we use the same scenario as in the thermal-only case (TM). Again, we make a baseline run for an energy-only market (RES-BL) and a run with the same strategic reserve as before (RES-SR).

Estimating the value of lost load is difficult (Cramton et al., 2013; Stoft, 2002). The estimates of the value of lost load in literature (Anderson and Taylor, 1986; Baarsma and Hop, 2009; Leahy and Tol, 2011; Linares and Rey, 2013; Pachauri et al., 2011; Wilks and Bloemhof, 2005) vary widely depending on the location and nature of the load. In this modeling study, the value of lost load (VOLL) was chosen at the relatively low level of 2000 €/MWh. We also chose this level in order to take into account demand flexibility that might occur during periods of high prices.

5. Results and analysis

5.1. Introduction

In this section, we present the results of running the above-mentioned scenarios in our model. We applied the following indicators to evaluate the effectiveness of the strategic reserve:

- Average electricity price (€/MWh): the average electricity price over the entire run.
- Strategic-reserve dispatch duration (hour/year): the average number of hours that the reserve is dispatched per year.
- Shortage hours (hour/year): the average number of hours per year with scarcity prices, averaged over the entire run.
- Cost to consumers (€/MWh): the sum of the electricity price, the net cost of the reserve, and cost of renewable policy (if applicable) per unit of electricity consumed.[3]
- The cost of the strategic reserve (€/MWh): the net cost of maintaining the strategic reserve to the system operator, which is equal to the fixed and operating costs of the reserve minus the revenues from operating it. (A negative value would indicate a profit to the operator.)
- Supply ratio: the ratio of available supply at peak over peak demand.
- Outage cost per year (€/y): the product of the value of lost load (2000 €/MWh) and the annual load not served (MWh). This value indicates the cost to consumers due to shortages of supply.

[3] Note that this includes the cost of outages, because in our model the electricity price rises to the VOLL during shortages.

An overview of the results of the simulation is presented graphically in Fig. 8. Table 7 in the Appendix contains the average values for the same variables over all runs. In the remainder of this section, we discuss the results per scenario and graphically present supply ratios, average electricity prices, and shortage hours over time. For the supply ratios and electricity prices over time, the median trend and the 50% and 90% confidence intervals (CI) are shown. 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.

5.2. Thermal-only generation portfolio with demand growth

We test here whether the strategic reserve that we designed in Section 3.2, is effective in a scenario with stochastically varying fuel prices and growing demand (TM-SR). We compare the results for the same scenario without a strategic reserve (TM-BL).

The presence of a strategic reserve leads to an increase of 5% in the supply ratio, reducing the average number of shortage hours per year by 84%, from 12.9 h/y to 2.1 h/y (see Fig. 8 and Table 7 in the Appendix). In Fig. 9, it can be observed that a strategic reserve indeed improves the supply ratio. An overshoot in the supply ratio is observed at the beginning of the simulation run in both the TM-BL and TM-SR scenarios (see Fig. 9). This is because the agents in the model cannot develop forecasts due to insufficient information for previous years. This initial cycle should be considered a model artifact.

The strategic reserve is dispatched 34.3 h per year on average, leading to a 1.7% rise in the electricity prices and a 2% increase in the cost to consumers. The difference is caused by the cost of the reserve (see also Table 7 in Appendix). It can be observed from Fig. 10 that the presence of a strategic reserve leads to a consistent reduction of shortages.

Even if the *average* supply ratio does not change, price cycles increase the net income of the strategic reserve operator because the reserve is used more frequently. This reduces the cost of maintaining the strategic reserve as compared to the design case (DET-SR) from 0.23 €/MWh to 0.14 €/MWh. In some scenarios, there is a possibility of reserve imbalance and development of investment cycles. As illustrated by the price–duration curve in Fig. 11, the presence of the reserve leads to a reduction in occurrence of sharp price peaks caused by scarcity as expected from theory. This can be further confirmed from the mean and median values shown in Fig. 12.

In a dynamic setting (TM), the strategic reserve is less effective in improving the supply ratio and reducing shortage hours than in the static design case (DET). The reason is that uncertainty about future demand always causes some investment overshooting and undershooting. However, the strategic reserve still reduces shortage hours to 2.07 h per year, which corresponds to a decrease in outage costs from €48 million to €8.5 million per year. However, now the net cost to consumers is 48.34 €/MWh, which is 2% higher than in the baseline scenario (TM-BL). This rise in the cost to consumers is equivalent to €564 million annually. Therefore, in this case, the presence of a strategic reserve reduces net consumer benefit. The consumer benefit from a reduction in shortages depends on the value of loss load for individual consumers. We use a

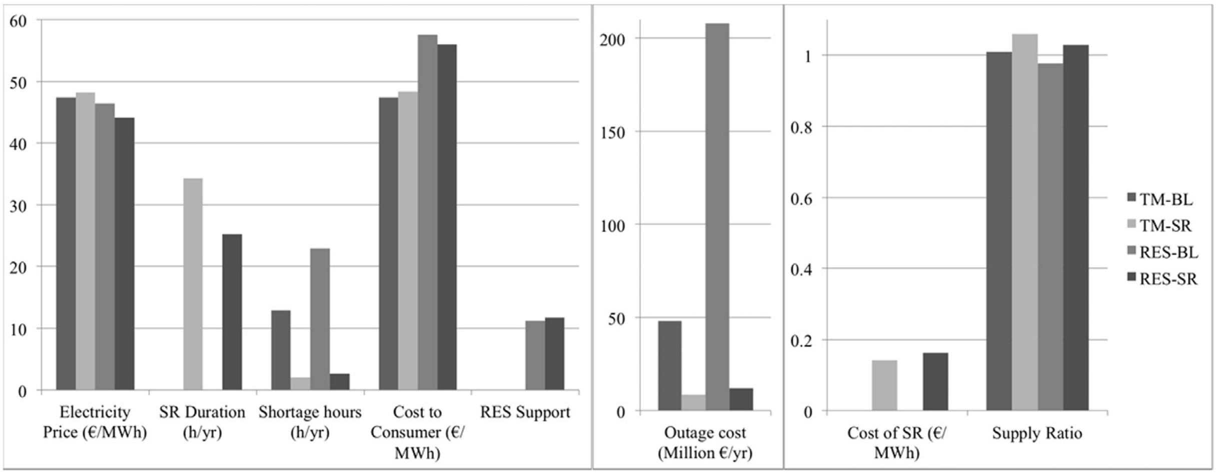

Fig. 8. Comparison of indicators for the TM and RES scenarios (SR Duration stands for Strategic reserve dispatch duration).

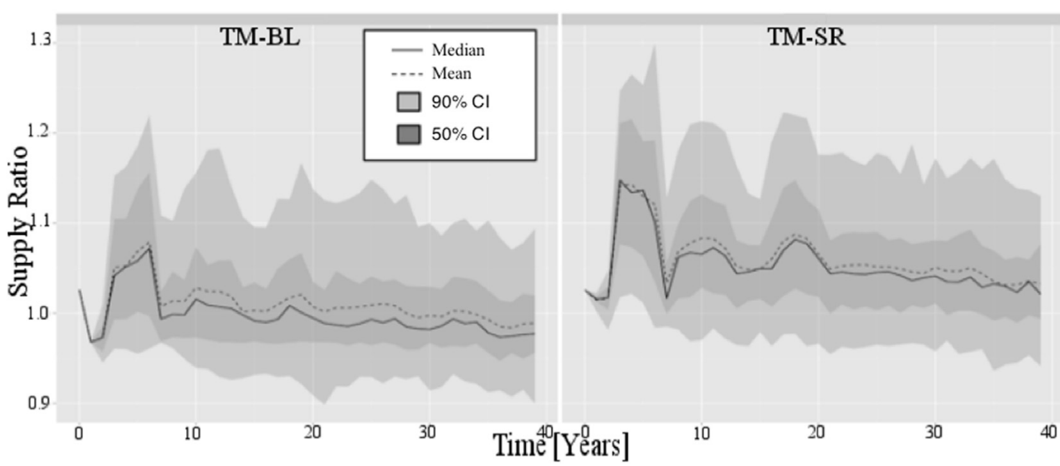

Fig. 9. Supply ratio in a scenario with stochastically varying fuel prices and rising demand, without (left) and with a strategic reserve (right).

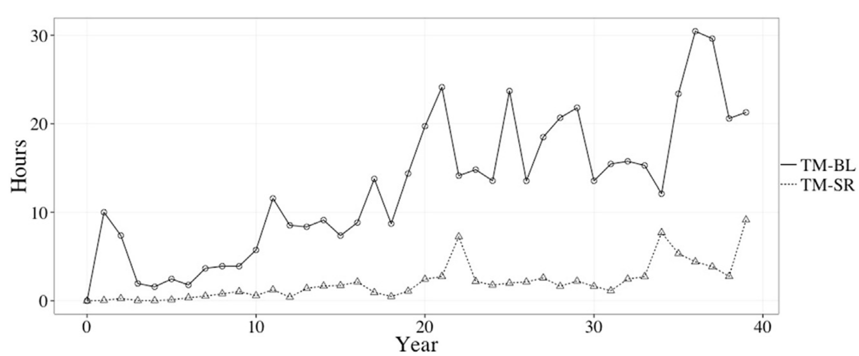

Fig. 10. The average number of shortage hours in a scenario with stochastic fuel prices and a rising demand, without (BL) and with a strategic reserve (SR).

relatively low value of lost load (2000 €/MWh); the consumer benefit from reduced outage costs would be significantly higher with the use of a higher VOLL for this calculation.

5.3. Generation portfolio with RES

The expansion of renewable energy increases the availability of inexpensive but intermittent electricity, which reduces the window of opportunity for thermal power generators to recover their investment; scenarios RES-BL and RES-SR represent this case. In the latter scenario, the size of the strategic reserve is the same as in the thermal-only scenario of the previous section. This simulates a shift from a completely thermal energy mix to a renewable energy mix without a change in the design of the strategic reserve.

The presence of a high share of variable renewable energy depresses the investment incentive, as a result of which the number

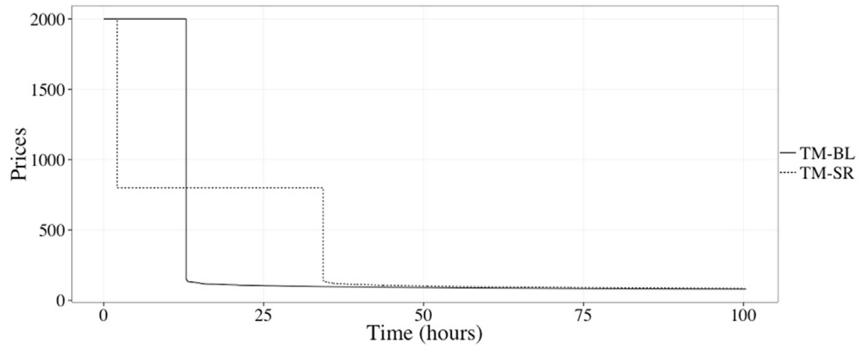

Fig. 11. Peak section of the price–duration curve in scenarios with stochastically varying fuel prices and rising demand, without (BL) and with a strategic reserve (SR).

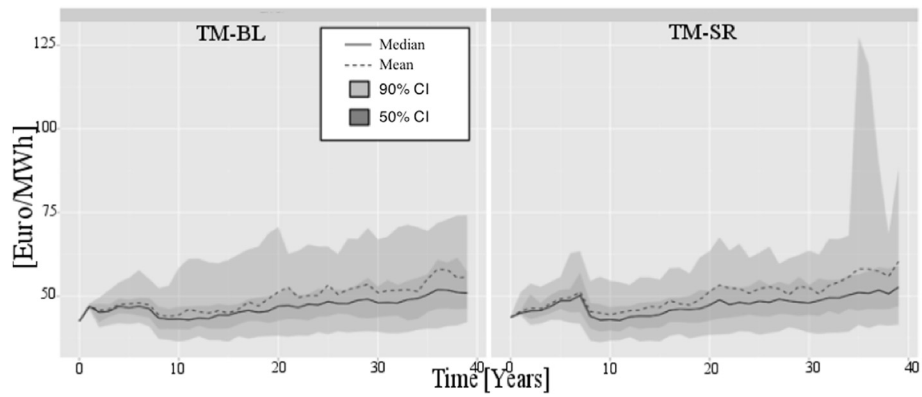

Fig. 12. Electricity prices in a scenario with stochastic fuel prices and rising demand, without (left) and with a strategic reserve (right).

of shortage hours nearly double (from an average 12.8 h/y in *TM-BL* to 23.0 h/y in *RES-BL*). Introducing a strategic reserve reduces the number of shortage hours to 2.7 h/y on average, which corresponds to a reduction in outage costs from €208 million to €12 million annually (see Fig. 13).

On average, the strategic reserve was dispatched for 25.3 h per year. Again, it improved the supply ratio by about 5% (see Fig. 9). However, as can be observed in Fig. 14, although the strategic reserve's effectiveness over the first 20 years is satisfactory, there is a gradual decline in the supply ratio over the time horizon of the simulation. The effectiveness of a strategic reserve in providing an adequate investment incentive declines with the increasingly steep residual load-duration curve that is the consequence of a growing share of renewable energy in the portfolio. Therefore, in the longer, it may be necessary to establish a more robust reserve by sizing the reserve with a higher price or volume in the first place or by adjusting the reserve periodically. In the next section, the possible resizing options available to the system operator are discussed.

Contrary to the thermal-only case, the presence of the reserve led to an average reduction of electricity prices of 5%. Two main factors contribute to this price reduction. First is the steep reduction in the period with scarcity prices (that is, shortage hours), as explained above. Second is the higher availability of RES capacity in off-peak segments combined with the larger generation capacity available at the peak. Thus, for the same supply ratio, more capacity would be available (at a cheaper price) in the off-peak segments of the load-duration curve in a RES scenario as compared to the thermal-only scenario. This not only reduces the number of hours for which the reserve is active but it also pushes out the more expensive thermal power plants from the merit order.

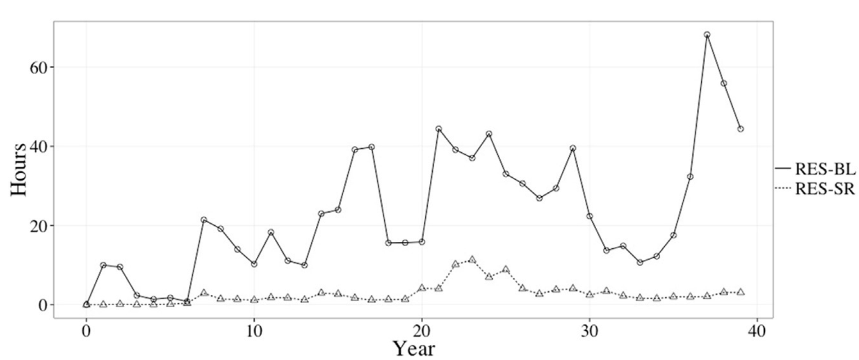

Fig. 13. The average number of shortage hours per year in a dynamic scenario with increasing RES, without (BL) and with a strategic reserve (SR).

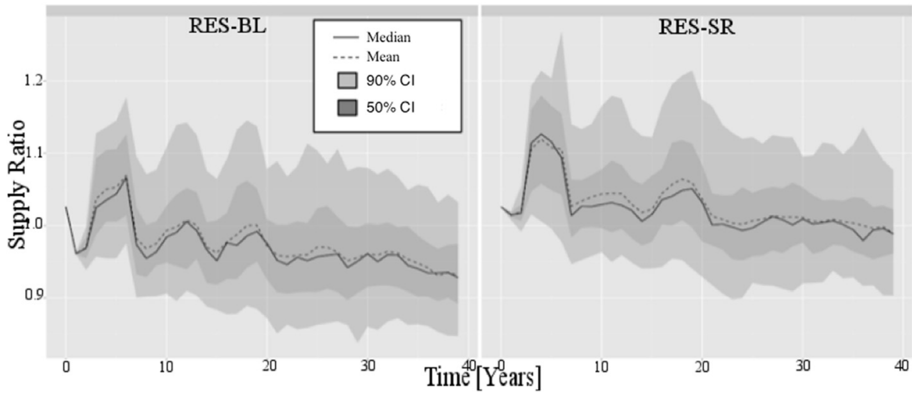

Fig. 14. Supply ratio in a dynamic scenario having increasing RES without (left) and with a strategic reserve (right).

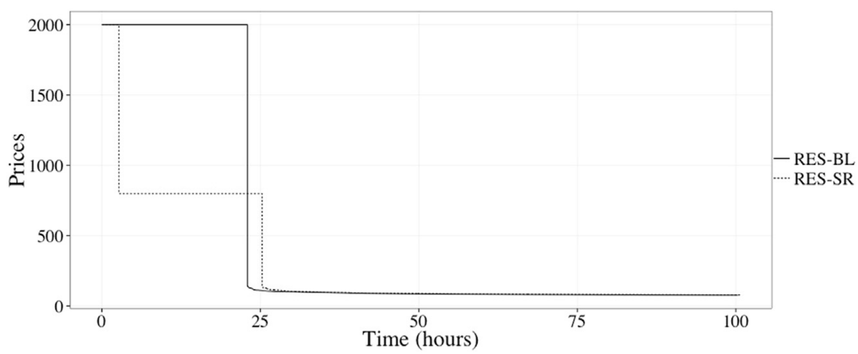

Fig. 15. Peak section of the price–duration curve in the RES scenario, without (BL) and with a strategic reserve (SR).

As observed in Fig. 15, the presence of a strategic reserve is associated with a strong decline in the occurrence of extreme price spikes, leading to more stable electricity prices, as was also observed in the thermal-only scenario (see Fig. 16). The lower prices increase the need for renewable energy subsidies, but a net reduction in the cost to electricity consumers remains. This 2.7% net reduction in consumer costs is equivalent to €980 million per year. The reserve is used fewer hours than in the thermal-only scenario (25 instead of 34 h per year on average) because some of the demand peaks are met by variable renewable energy.

Comparing the overall effectiveness of a strategic reserve in a thermal-only scenario with a scenario with increasing RES, it is clear that the reserve performs better in a thermal-only scenario, with a higher supply ratio and fewer shortage hours. However, the relative improvement is greater in the case with high share of renewable energy in the generation portfolio. While the reserve becomes less effective in scenarios with renewable energy, the simulation results show that a strategic reserve can provide a viable alternative for maintaining security of supply during the early stages of this transition to low-carbon technologies at a relatively low cost to consumers. These results pertain to a closed market, however; the effects of a reserve will 'leak' away across borders in strongly interconnected markets. We intend to investigate these cross-border effects in future research.

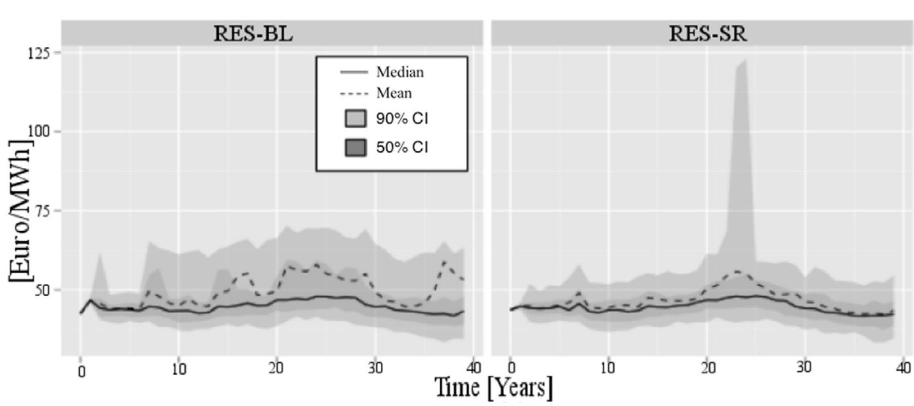

Fig. 16. Electricity prices in a dynamic scenario with an increasing share of RES, without (left) and with (right) a strategic reserve.

5.4. Impact of the dimensions of the strategic reserve on its effectiveness

In order to explore the impact of the size and the dispatch price of the strategic reserve on reliability, we ran our model with different price and volume combinations. This analysis also provides insight into possible options for improving the effectiveness of the strategic reserve as the share of renewable energy grows.

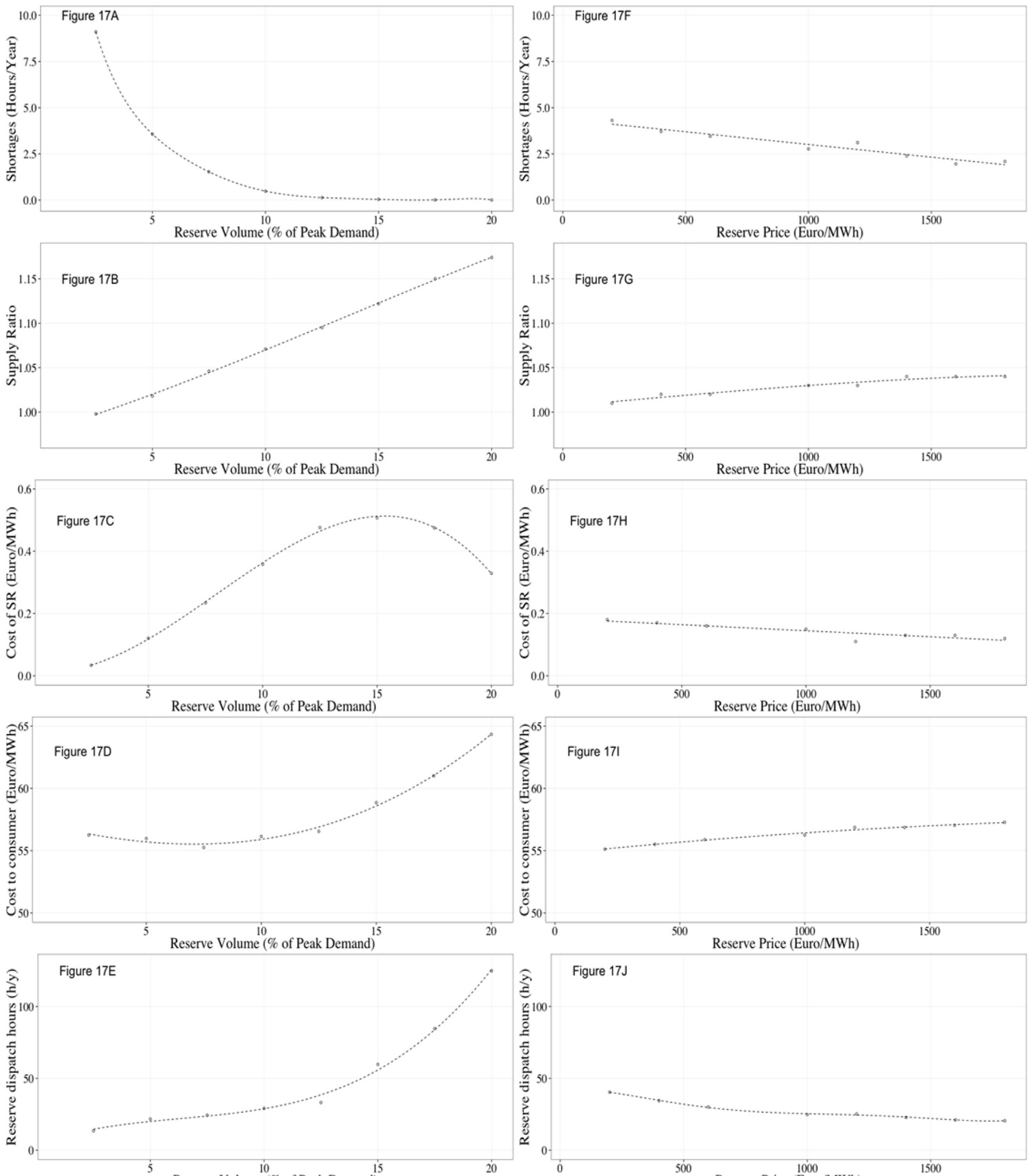

Fig. 17. The effects of different reserve volumes (left side) and dispatch prices (right side) on the average number of shortage hours, the supply ratio, the cost of the reserve, the cost to consumer and reserve dispatch hours.

Scenario runs were carried out for the RES-SR scenario by changing either the price or the volume of the strategic reserve and Fig. 17 shows the results. Within runs, the reserve parameters were kept constant. In the first case, illustrated by the left-side graphs in Fig. 17, the reserve price was kept at 800 €/MWh and the reserve volume was varied between 2.5% and 20% of peak demand in increments of 2.5%. In the second case, illustrated by the right-side graphs in Fig. 17, the reserve volume was fixed at 6% and the reserve price was varied from 200 €/MWh to 1800 €/MWh with increments of 200 €/MWh.

The impact of changes in the reserve dimensions on the net cost of the strategic reserve, on the average number of shortage hours and on the supply ratio, are illustrated in Fig. 17. Increasing either the volume or the price of the reserve, while keeping the other variable constant, causes the supply ratio to increase and shortages to decline. The impact on the cost of the strategic reserve is less clear. The effectiveness of the strategic reserve is more sensitive to changes in volume than to changes in dispatch prices. The number of shortage hours comes close to zero with a reserve size of 10%. The trends shown Fig. 17E indicate that an increase in the volume of capacity contracted into the reserve leads to higher utilization of the strategic reserve, causing prolonged periods of high prices and thus increasing the final cost to consumer by more than when the reserve price is increased (see Fig. 17D and I).

When the reserve volume is increased, the number of hours that the reserve is dispatched per year increases at more than a linear rate, as it crowds out other generators (Fig. 17E.). The cost of contracting the reserve to the system operator increases at first, but begins to decline when the contracted reserve volume is beyond a certain level (Fig. 17C). At this point, the revenue earned by the operator is higher than the cost of contracting additional capacity, leading to a reduction in the overall cost of contracting the reserve to the operator. A reserve volume that exceeds the optimal level leads to a reduction in the cost incurred by the operator for contracting the reserve. However, the increased reserve dispatch duration due to the higher reserve volume causes a considerable rise in the cost to consumers, which means that a very large reserve volume would not be an efficient solution from the consumer-cost perspective. An excessive reserve volume, given the reserve dispatch price (P_{SR}), constitutes an abuse of market power to raise wholesale electricity prices beyond what is needed to attract investment; it recovers more cost but negatively affects consumer welfare. The cost of the reserve is lowest at a reserve volume of 15% of peak demand. Even then, the net cost of the strategic reserve is only about 1% of the average wholesale electricity price. Increasing the reserve price is not as effective in reducing shortages or increasing the supply ratio, as is indicated by Fig. 17 (Fig. 17A, F, B and G).

It is observed from Fig. 17 (Subfigure D1) that in the presence of growing RES, the cost to consumers is lowest when the reserve volume is around 7.5%. This is higher than the 6% volume that was calculated for a thermal-only scenario with the same reserve price. This indicates that a larger reserve volume would be required in order to minimize the cost to consumer in the presence of growing RES as compared to a thermal-only scenario.

A comparison of the results from the design parameter analyses indicates that increasing the reserve volume would be the most effective way of improving the effectiveness of a strategic reserve in a scenario with a growing share of RES. However, a large strategic reserve could conflict with the intended neutrality of the system operator vis-à-vis market parties.

5.5. Model limitations

The model does not consider any exercise of market power and generators are assumed to bid at marginal costs at all times. The risk that generation companies might withhold capacity when the supply ratio is tight, in order to activate the reserve and thereby increase the price, has not been taken into account. Generation companies might be able to withhold just enough capacity to activate the reserve, leading to an increase in the number of hours with high prices. This is a real risk that could cause significant income transfers from consumers to producers. This risk also exists in energy-only markets, but there the number of shortage hours is relatively small compared to the number of hours that a strategic reserve is activated, so the number of hours during which capacity withholding might occur is much larger in the presence of a strategic reserve.

In this paper we studied a closed system with no interconnections. In practice, interconnections with neighboring markets could reduce the effectiveness of the strategic reserve due to the leakage of the reserve's benefits to the interconnected region. In future research, we plan to study these cross-border effects. As here we modeled the long-term development of the market, short-term operational constraints and unforeseen shutdowns are ignored. Grid constraints and congestion management are also outside the scope of this analysis. Moreover, the robustness of a strategic reserve in the context of black-swan events should be studied in greater detail.

6. Conclusions

We present a model of a strategic reserve with which we analyze its dynamic effectiveness without and with a large share of renewable energy in the portfolio. We present a method for determining the parameters of a strategic reserve based on Stoft (2002). A strategic reserve can have a stabilizing effect on an electricity market in a reasonably cost-effective manner, depending on the scenario. Early investment incentives improve the supply ratio and therefore reduce shortages.

In our model, a strategic reserve increases the net cost of electricity supply to consumers in a scenario without variable renewable energy, but in the presence of a high volume of variable renewable energy, it reduces the cost to consumers because it has a stabilizing effect on investment cycles in thermal power generation capacity.

We find two problems with a strategic reserve. First, there is a risk of extended periods of high average electricity prices if the reserve fails to attract sufficient investment. For instance, imperfect investment decisions, for example due to uncertainty regarding future demand growth, may still cause an investment cycle, resulting in high average electricity prices in some years. Second, the effectiveness of the reserve with respect to maintaining generation adequacy appears to decrease as the share of variable renewable energy grows. In the latter case, the reserve may need to be redesigned or replaced by an alternative capacity mechanism.

The effectiveness of the reserve may be improved by increasing its volume. Increasing the dispatch price is less effective. A larger volume also may improve the reserve's cost recovery rate, given a certain reserve dispatch price, but this would reflect an abuse of the reserve's market power and reduce consumer welfare. Our long-term model of a strategic reserve also reveals what we describe as the dismantling paradox. When a reserve contains old units that should be dismantled, the presence of the reserve may cause undue life extension, whether these units are contracted in the reserve or not.

We plan to extend this research by analyzing the impact of strategic reserves on carbon emissions reduction as well as cross-border effects, including the interaction between a strategic reserve and a capacity market implemented in two interconnected countries.

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Appendix

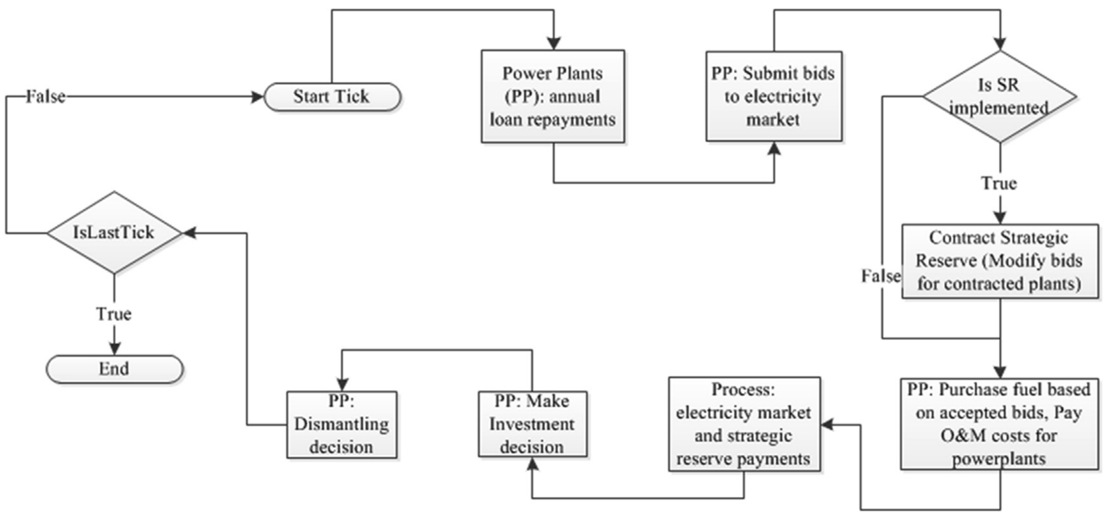

Fig. 18. Stylized flowchart of the model activities during a time step.

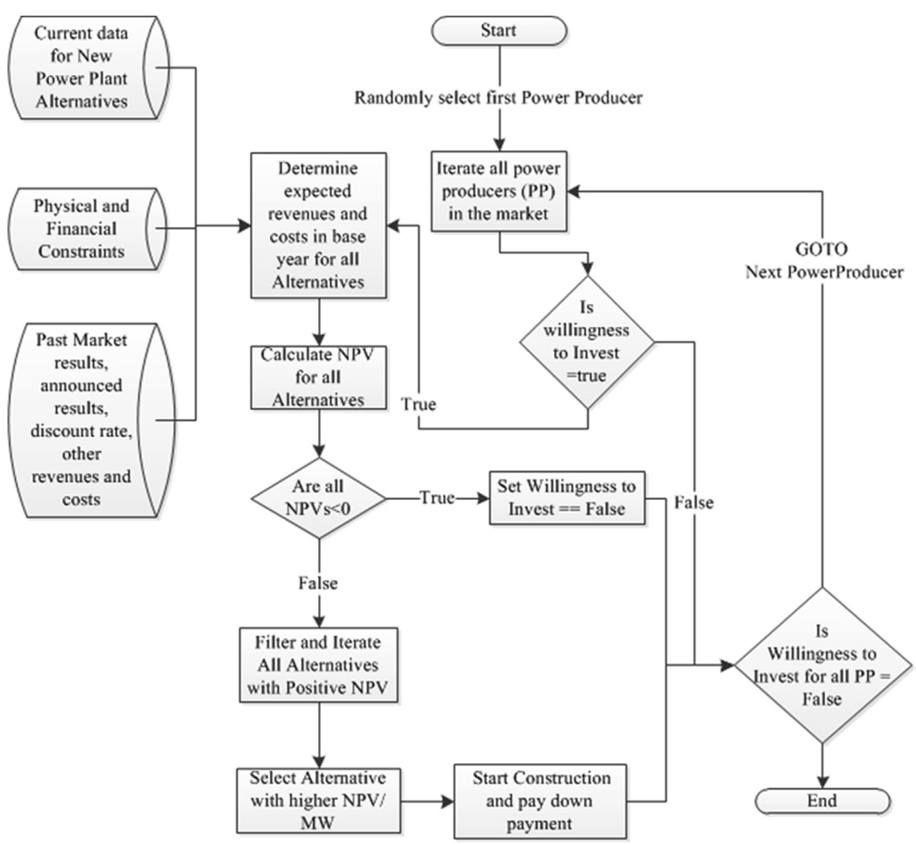

Fig. 19. Stylized flowchart of the investment algorithm.

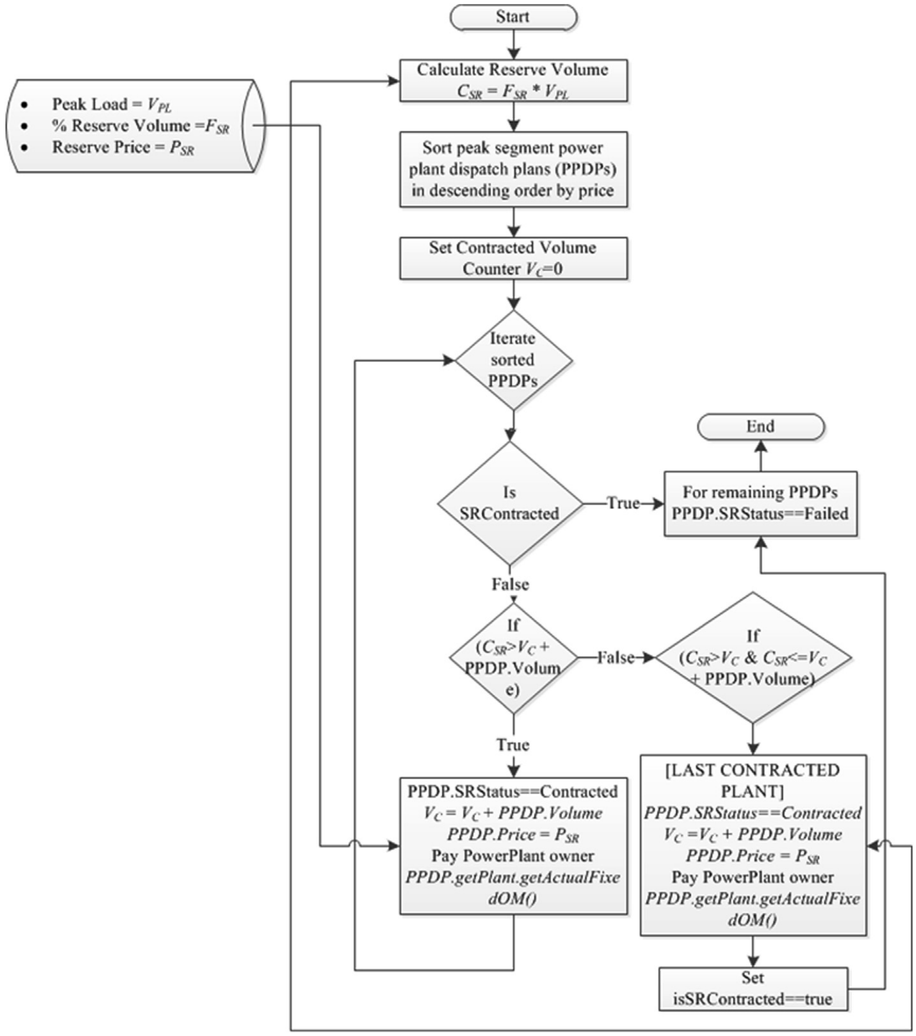

Fig. 20. Stylized flowchart of the algorithm for contracting power plants for the strategic reserve.

Table 2
Assumptions for power generation technologies

Technology	Capacity [MW]	Construction time [years]	Permit time [years]	Technical lifetime [years]	Depreciation time [years]	Minimum running hours	Base availability [%]	Peak availability [%]	Fuels
Coal	758	4	1	50	20	5000	1	1	Coal, Biomass (10%)
CCGT	776	2	1	40	15	0	1	1	Gas
OCGT	150	0.5	0.5	30	15	0	1	1	Gas
Nuclear	1000	7	2	40	25	5000	1	1	Uranium
IGCC	758	4	1	50	20	0	1	1	Coal, Biomass (10%)
Wind Offshore	600	2	1	25	15	0	0.6	0.07	–
PV	100	2	1	25	15	0	0.2	0.04	–
Wind Onshore	600	1	1	25	15	0	0.4	0.05	–
Biomass	500	3	1	40	15	5000	1	1	Biomass
CCGTCCS	600	3	1	40	15	0	1	1	Gas
CoalCCS	600	4	1	50	20	5000	1	1	Coal, Biomass (10%)
Lignite	1000	5	1	50	20	5000	1	1	Lignite
Biogas	500	3	1	40	15	0	1	1	Biomass
IGCCCCS	600	4	1	50	20	0	1	1	Coal, Biomass (10%)

Table 3
Description of scenario abbreviations

SR NO	Code	Description
1	TM	Thermal Mix only
2	RES	Renewable energy policy enabled
3	BL	Baseline energy-only market
4	SR	Strategic reserve implemented
5	DET	Determination of reserve scenario

Table 4
Fuel price and demand price growth rate assumptions

Type	Unit	Coal	Gas	Lignite	Uranium	Biomass	Demand
Start	€/GJ	3.6	9.02	1.428	1.29	4.5	–
Lower	[%]	−3	−6	−1	0	−3	1
Upper	[%]	5	8	1	2	5	5
Average	[%]	1	1.5	0	1	1	2

Table 5
Initial supply mix for all scenarios

Technology	Coal	CCGT	OCGT	Nuclear
% Share	50.0%	19.0%	13.0%	18.0%

Table 6
Development of the supply-mix in scenario with growing RES

		Scenario V	Scenario VI	Scenario V	Scenario VI
Technology	Initial mix	Final mix	Final mix	Final capacity (MW)	Final capacity (MW)
Coal	50.0%	11.0%	10.7%	40136.1	39,548.7
CCGT	19.0%	8.2%	8.0%	29,772.5	29,533.3
OCGT	13.0%	1.5%	3.4%	5413.8	12,758.8
Nuclear	18.0%	3.0%	3.0%	11,083.3	11,141.7
IGCC	–	1.5%	1.6%	5577.6	5760.8
Wind Offshore	–	10.7%	10.5%	39,043.4	38,810.4
PV	–	51.1%	50.2%	186,349.4	185,929.8
Wind	–	11.3%	11.1%	41,133.7	40,935.0
Biomass	–	1.6%	1.6%	5941.2	5846.9
CCGTCCS	–	–	–	0.0	0.0
CoalCCS	–	–	–	0.0	0.0
Lignite	–	–	–	0.0	0.0
Biogas	–	–	–	0.0	0.0
IGCCCCS	–	–	–	0.0	0.0
Total	100.0%	100.0%	100.0%	364,451.0	370,265.2

Table 7
Annual average values of key indicators for the deterministic scenarios

Scenario name	Cost to consumer (€/MWh)	Electricity price (€/MWh)	Cost of SR (€/MWh)	RES support (€/MWh)	Shortage hours (h/yr)	SR duration (h/yr)	Outage cost (million €/yr)	Supply ratio
DET-BL	39.36	39.36	N.A.	N.A.	2.82	N.A.	4	1.01
DET-SR	39.33	39.09	0.23	N.A.	0.13	6.9	0.17	1.06
TM-BL	47.39	47.39	N.A.	N.A.	12.87	N.A.	48	1.01
TM-SR	48.34	48.20	0.14	N.A.	2.07	34.3	8.5	1.06
RES-BL	57.54	46.38	N.A.	11.168	22.96	N.A.	208	0.98
RES-SR	55.97	44.10	0.16	11.711	2.67	25.3	12.8	1.03

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