D5.2 Report on the quantitative evaluation of policies for post 2020 RES-E targets

Bettina Burgholzer, Aurèle Fontaine, Frédéric Galmiche, Steve Völler, Stefan Jaehnert, Fernando Bañez-Chicharro, Luis Olmos Camacho, Peter Ahcin

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MAIN AUTHORS

Name	Organisation	E-mail
Bettina Burgholzer	EEG	burgholzer@eeg.tuwien.ac.at
Sophie Dourlens-Quaranta	TECHNOFI	sdourlens@technofi.eu
Aurèle Fontaine	RTE	aurele.fontaine@rte-france.com
Frédéric Galmiche	RTE	frederic.galmiche@rte-france.com
Luis Olmos Camacho	IIT-Comillas	luis.olmos@iit.comillas.edu
Fernando Banez-Chicharro	IIT-Comillas	Fernando.Banez@iit.comillas.edu
Stefan Jaehnert	SINTEF	Stefan.Jaehnert@sintef.no
Steve Völler	SINTEF	steve.voller@sintef.no
Peter Ahcin	SINTEF	peter.ahcin@sintef.no

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Executive summary

This is a report on seven analyses of future electricity market policies carried out by EEG, IIT-Comillas, RTE and SINTEF. The analyses are based on the ENTSO-E 2020 and 2030 scenarios [5,6]; detailed specifications of the studies and a description of the models used can be found in Market4RES report D5.1 [3].

The studies focus on policy instruments related to short and long-term markets that the Market4RES consortium has positively assessed according to the criteria of market efficiency and use of public funds, effectiveness in terms of deployment of renewables, robustness and implementability.[1] The report also includes a study of the effects of risk on the evolution of the energy mix and the relationship between the support for renewables and the profitability of demand response. The topics addressed by the studies are summarized in the table below:

Areas of market design assessed in the project

Market design options related to short-term markets	Market design options related to long-term markets
Validation of possible future balancing market mechanisms	Impacts of RES support on incentives for the deployment of Demand Side Response in the long-term
Effect of moving the timing of day-ahead markets towards real time	Comparison of explicit support mechanisms and carbon pricing in terms of deployment of high shares of RES in the power system
Effects of RES support mechanisms on short-term markets	Impact of investor risk on the evolution of the power system in presence of capacity remuneration mechanisms and in an energy only market
	Interdependence of the costs of capacity remuneration mechanisms and RES support mechanisms

Validation of possible future balancing market mechanisms

The study *"Validation of possible future balancing market mechanisms"* has compared different balancing market arrangements under the ENTSO-E 2030 reference scenario. The geographical scope of the analysis includes Austria, Germany, Belgium and the Netherlands. Specifically, it compares the effectiveness and efficiency of joint and separate procurement of balancing capacity and balancing energy products; the joint and separate procurement of upward and downward balancing capacity products; the length of products; the use of pay-as-bid vs. marginal pricing; and the size of the area where balancing capacity can be exchanged between TSOs.

The reference case considers the auctioning of asymmetric positive & negative balancing capacity with the following characteristics:

[1] See Market4RES reports D3.1 and D3.2 [2,9].

- for all balancing regions/areas the same market design is applied
- **separated** procurement of balancing capacity and balancing energy products
- **separated** procurement of upward and downward balancing capacity products
- **week-ahead** procurement of Peak, Off-Peak and Weekend aFRR products in Austria, and Haupttarif (Mo-Fr 8:00-20:00) and Nebentarif (Mo-Fr 0:00-8:00 and 20:00-24:00, Sa-So) aFRR products in Germany, Belgium and the Netherlands
- daily procurement of 4h products for mFRR
- imbalance settlement period of 15 minutes
- balancing capacity can be **only exchanged** between German TSOs/balancing areas.

The reference case is compared to five alternative balancing market settings:

Case A – Asymmetric positive & negative balancing capacity (daily).
Difference with respect to reference:

- **day-ahead** procurement of Peak, Off-Peak and Weekend aFRR products in Austria, and Haupttarif and Nebentarif aFRR products in Germany, Belgium and the Netherlands

Case B – Symmetric positive & negative balancing capacity (weekly).
Difference with respect to reference:

- **joint** procurement of upward and downward balancing capacity products

Case C – Symmetric positive & negative balancing capacity (daily).
Difference with respect to reference:

- **joint** procurement of upward and downward balancing capacity products
- **day-ahead** procurement of Peak, Off-Peak and Weekend aFRR products in Austria, and Haupttarif and Nebentarif aFRR products in Germany, Belgium and the Netherlands

Case D – Asymmetric positive & negative balancing capacity (daily) & exchanges are possible.
Difference with respect to reference:

- **day-ahead** procurement of Peak, Off-Peak and Weekend aFRR products in Austria, and Haupttarif and Nebentarif aFRR products in Germany, Belgium and the Netherlands
- balancing capacity can be **exchanged** between all TSOs/balancing areas

Case E – Asymmetric positive & negative balancing capacity (12 hours) & exchanges are possible.
Difference with respect to reference:

- **12 hours-ahead** procurement of Peak, Off-Peak and Weekend aFRR products in Austria, and Haupttarif and Nebentarif aFRR products in Germany, Belgium and the Netherlands
- balancing capacity can be **exchanged** between all TSOs/balancing areas

Case F – Asymmetric positive & negative balancing capacity (1 hour) & exchanges are possible

Difference with respect to reference:

- **1 hour** products in Austria, Germany, Belgium and the Netherlands
- balancing capacity can be **exchanged** between all TSOs/balancing areas

The results of the study show that:

- Separate procurement of upward and downward balancing capacity reduces total generation and procurement costs, as well as exchanges between TSOs.
- Common procurement of balancing capacity by all balancing areas reduces total generation costs and costs of procurement.
- Shorter time frames of block products reduce the implicit allocation of transmission capacity among balancing areas, as well as generation and procurement costs.

Effects of RES support mechanisms on short-term markets

A previous study (L. Olmos et al. 2015, D3.2 of the project) has identified the most promising RES support mechanisms for a post 2020 power market. This study compares the effects of four of those options on short-term markets, namely the revenues earned by different technologies on the spot market and energy produced, as well as the energy market efficiency, measured in trms of the corresponding system operating costs. The studied options are:

- Long term clean capacity auction
- Long-term clean energy auction
- FIP fixed premium from an auction
- FIP floating premium from an auction.

The study is performed under Vision 3, the reference scenario, from the TYNDP 2014 for the year 2030 for the area of Portugal, Spain and France. It is assumed that all three countries have the same support mechanism in place. The transfer capacity between the countries is modelled as net transfer capacities, and the transmission bottlenecks within each country are neglected.

Under all four support mechanisms, as well as without a support mechanism, the occurrence of negative and very high prices is most frequent in France.

Under Vision 3, the price of CO_2 permits is 93 EUR per tonne, which keeps prices high enough for wind and solar in Spain and wind in Portugal to recover their cost in the market. Only other renewable technologies apart from solar and wind require some support. This is not the case in France, where average prices are lowest, and all renewable technologies require significant support, as it can be seen in the table below. The left column shows total market revenues; the middle column the revenues minus variable costs; and the right hand column the total required level of support for the different technologies, as difference between net revenues in the dispatch and investment costs.

Energy revenues from the market and net benefits from the generation dispatch by technology and country in the target year when no RES support is applied

Units	Location	Market revenues [M€]	Net benefits in the dispatch [M€/yr]	Net benefits – Inv. Costs [M€/yr]
Wind	Spain	3,378	3,378	1,400
Solar	Spain	2,700	2,700	534
OtherRES	Spain	57	2	-3,271
Wind	France	2,003	2,003	-985
Solar	France	882	882	-1,433
OtherRES	France	215	91	-2,463
Wind	Portugal	176	176	75
OtherRES	Portugal	3	0	-94

A clean capacity auction would not affect the short-term decisions and market prices with respect to the optimal dispatch without support. The required level of support per MW of installed capacity is, therefore, given by the total level of support, as given in the above table, divided by the installed capacity –. Results are provided in the table below.

Support to be provided to RES generation for each technology and country when capacity auctions are implemented

Units	Location	Total support required [M€]	Capacity payment [M€/MW]
Wind	Spain	0	0
Solar	Spain	0	0
OtherRES	Spain	3,271	0.32
Wind	France	985	0.05
Solar	France	1,433	0.07
OtherRES	France	2,463	0.31
Wind	Portugal	0	0
OtherRES	Portugal	94	0.32
Total		8,246	

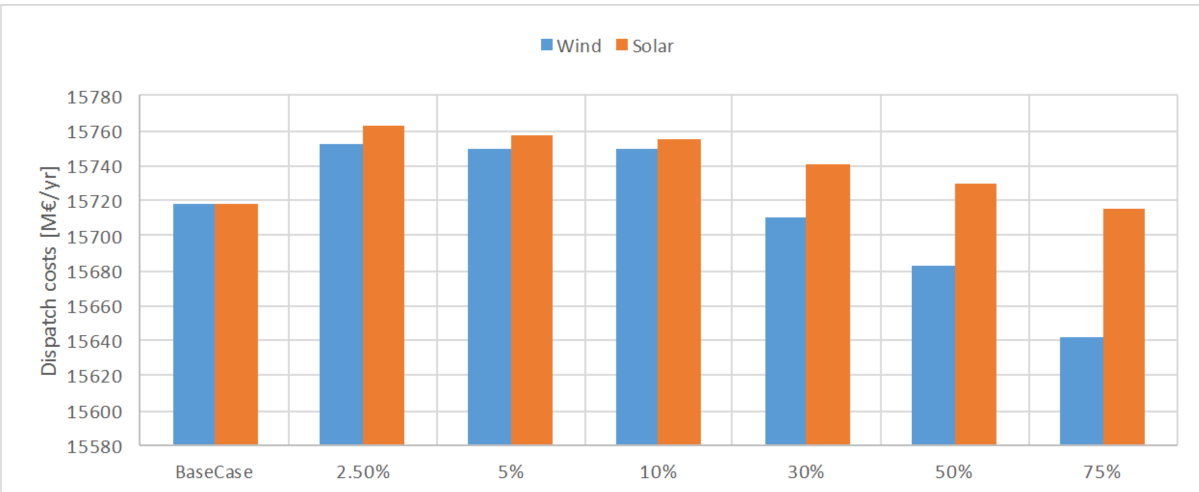
Similarly to a capacity auction, the floating premium would not affect the short term-market operation with respect to the optimal one to the extent that support provided is fixed before system operation and cannot be modified based on the results of the dispatch. This may be the case, since the support provided should be largely independent of the market price, thus short term revenues are coincident with market ones. Premiums per MWh in total would need to cover the same amount as given in the table above.

The fixed premium affects the market operation. These premiums allows RES generators to obtain positive revenues from energy sales even when market prices drop below zero, as long as the market losses they make are lower than the premium they receive. With fixed premiums the production from other renewable generation technologies would be significantly higher than in the refrence case - 9% of total generation, up from 0% without support - replacing nuclear generation and CCGT units. The number of hours with negative prices would increase from 82 to 190 in France, and from 0 to 6 hours in Spain and 5 in Portugal.

Finally, the long-term clean energy auction obliges RES generators to produce a specified amount of energy in a specified timeframe at an agreed upon price. In that sense, it is conceptually analogous to a floating premium applied over only at specified times. In the study, it was considered that about 50% of the energy is sold under an auction and the remaining energy produced is sold at market prices. This mechanism would reduce the number of hours with negative prices. However, clean energy auctions seem to be more efficient than a pure FIP. Clean energy auctions push down the market price less than FIP and, thus, a larger share of S generation revenues come from the market. Moreover, since it affects prices to a lower extent, it also results in a more efficient dispatch than FIP.

Effect of moving the timing of day-ahead markets towards real time

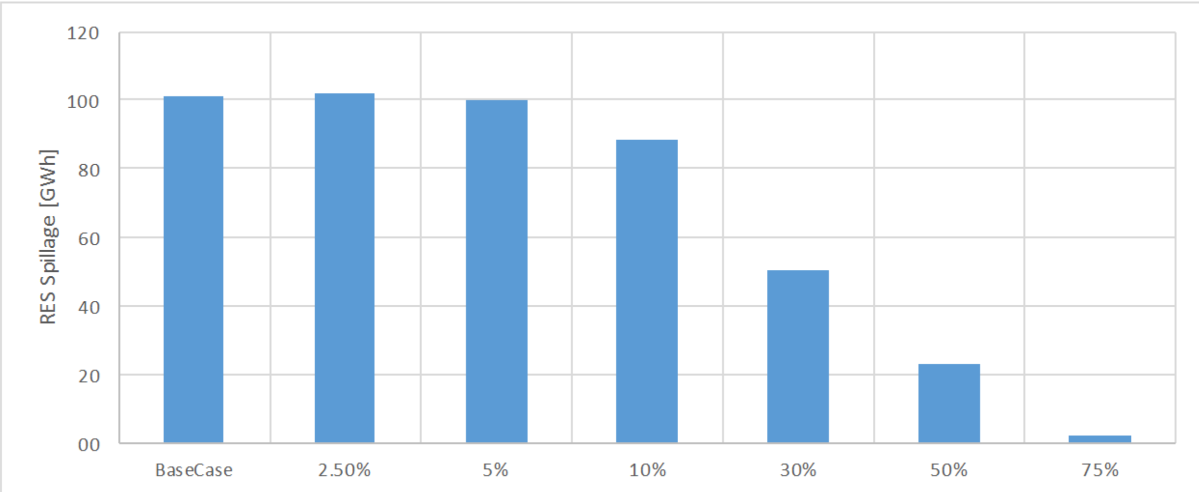
A shorter time interval between the day-ahead market and the real time should reduce the forecast error of wind and solar production, which would in turn lead to less operating reserves being needed by the system operator. This analysis was performed by IIT-Comillas' ROM model on the Spanish system, again neglecting the internal transmission capacities, under the TYNDP-2014 Vision 3 scenario for 2030.



Evolution of the generation dispatch costs with the reduction in the wind (blue) and solar (orange) forecast error

It can be observed that for low levels of forecast error reduction the dispatch cost actually increases (figure above). Lower forecast errors result in an increase of the amount of renewable energy being integrated. In the presence of larger amounts of renewable energy, it is mainly hydro power plants that are no longer committed to provide operating reserves and energy in some hours. On the other hand, thermal generation, being less flexible, must remain committed in order to provide energy and reserves in other hours when it is actually needed. Thus, a larger share of upward reserve is supplied by the more expensive thermal generators, and a larger amount o expensive thermal generation is committed. The reduction in wind forecast errors has a larger effect than the same reduction in solar forecasts.

For larger reductions in the combined wind and solar forecast error, 30% and upwards, we can observe the expected reduction in dispatch costs. At these RES penetration levels, the energy spillage for wind and solar in the base case scenario becomes significant, which is another reason why dispatch costs begin to fall (figure below).



Evolution of the RES energy spillage with the simultaneous reduction in the wind and solar forecast error

Interestingly, an error reduction of 75% leads to almost no RES energy being spilled. In sum, high forecast error reductions are needed in order to achieve reductions in the required reserves and total dispatch costs. This requires the day-ahead, or rather, the spot market, being moved to just a few hours before dispatch. This is, however, only an option for systems with a large enough amount of flexibility, such as the Nordic hydro power based system, rather than the Spanish system where thermal units with longer start-up and shout-down times make a large part of the energy mix.

Impacts of RES support on incentives for the deployment of Demand Side Response in the long-term

The scope of the study is limited to France. There are no internal transmission constraints considered. Six scenarios are considered:

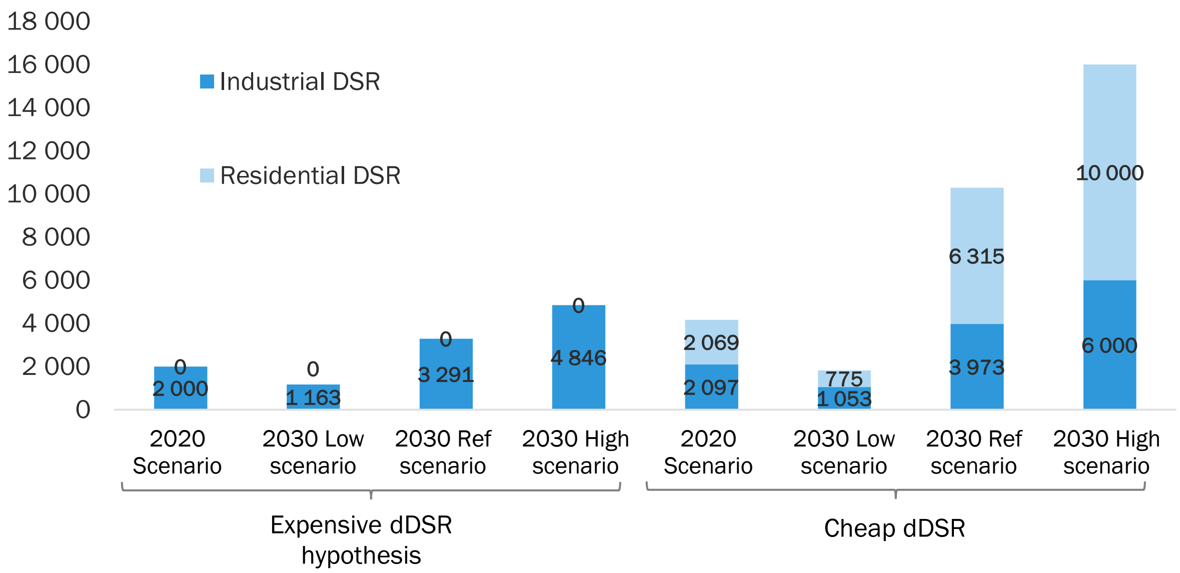
- **The 2020 scenario** regarded as the medium term scenario.
- **The 2020 scenario N1**: Installed capacities are those obtained in the 2020 scenario with, additionally, 10 GW of RES. This scenario with excess capacity represents the medium term effect of RES support policies if other generation and DSR are not able to adapt its installed capacities. The medium-term impact of this on the profitability of DSR's profitability can be analysed.

- **The 2020 scenario N2**: Installed capacities except DSR are those obtained in the 2020 scenario with 10 GW of RES additionally. Unlike the previous scenario, DSR's installed capacities are optimally adapted.
- **Three long-term scenarios** (2030), among which there are significant differences in the deployment of variable RES beyond 2020

Two types of demand response are included:

- 8 GW of industrial DSR at a fixed cost of between 10 and 55 k€/MW and variable cost of 300 €/MWh
- 10 GW of residential or distributed DSR at a fixed cost of 11 k€/MW, or, alternatively, 29 k€/MW. Its variable cost in both cases is 50 €/MWh and it is modelled with a 50% rebound effect distributed over 6 hours after a trigger event.

Industrial demand response seems to be profitable under all scenarios at the specified cost, whereas the residential one is only deployed at 11 k€/MW (see figure below). The total capacity is higher for scenarios with higher shares of renewables. However, when adding renewables to an otherwise adequate electricity mix the profitability of demand response drops.



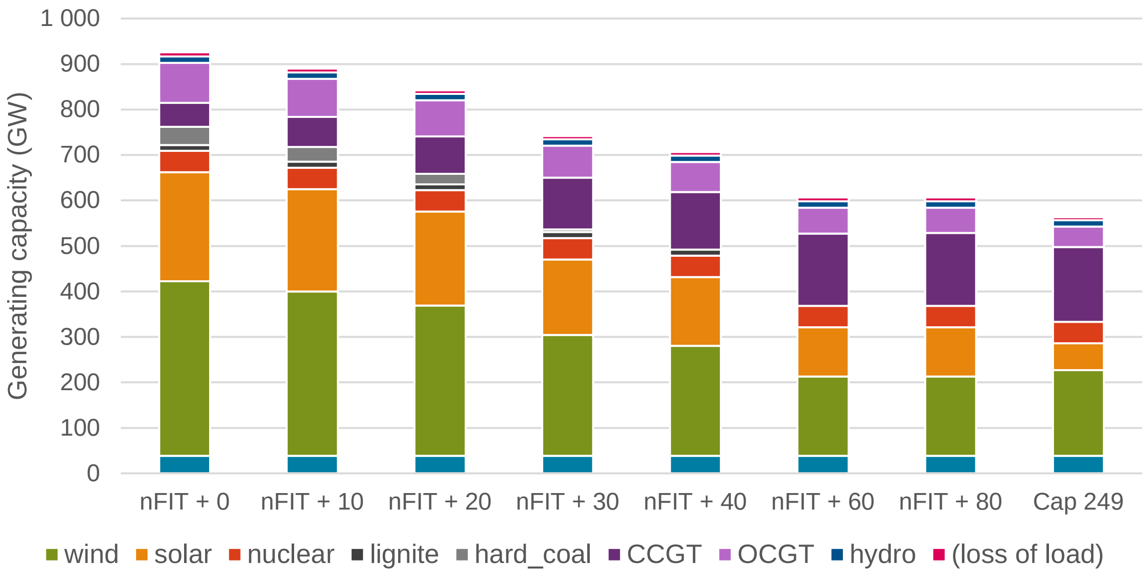
DSR's installed capacities (MW) in each scenario, for both distributed DSR costs hypotheses

Interestingly, the industrial and residential demand response show some complementarity. It can be observed that, for the lower value of fixed costs of residential demand response of 11 k€/MW, not only the residential demand response is deployed, but there is also an increase in industrial demand response.

Comparison of explicit support mechanisms and carbon pricing in terms of deployment of high shares of RES in the power system

Renewables projects in France usually have high debt to equity ratios. Feed in tariffs represent a secure revenue stream that reduces investors risk and required returns. They also provide a guarantee to banks that would otherwise be reluctant to finance renewables projects at high ratios. Exposing renewables to market prices increases investors' risk and required returns as well as swings the financing ratio from the cheaper bank capital to more expensive private capital.

This study spanning over Germany, France and Spain, compares the costs of achieving an emissions targets, with only an ETS in place to the costs of system with a feed in tariff only policy and a policy of both ETS and a feed in tariff. Capital costs are assumed to be lower when a FIT is in place.



Generation mix (total installed capacity) in the Reference scenario in the cases corresponding to the nFIT+x and the Cap (249 $MtCO_2$)

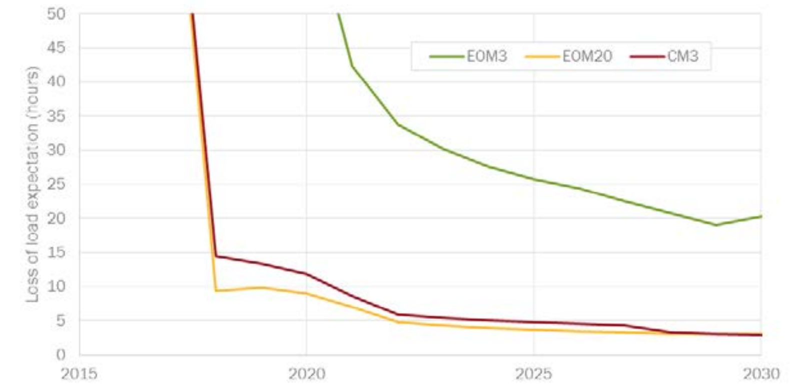
The figure above shows the generation mixes that meet the emission reduction targets in several scenarios. With only an emissions cap at 249 MtCO2 in place (right column) the share of renewables is lowest. The target is met rather by the decommissioning of coal and lignite generation and a switch to natural gas. With a carbon tax of 80 €/tCO2 and a technology specific national FIT (nFIT + 80), the results are similar with some more renewables. Without a carbon tax and the technology specific FIT (nFIT + 0) the lignite and coal remain in the mix and there are a lot more renewables to compensate for them, yet the cost is relatively high.

Over the different capital cost scenarios the more efficient instrument to reach emissions targets seems to be the CO2 cap and tradable permits. Feed-in tariffs alone require very large resources, yet a combination of a high CO2 price and a FIT seem to perform best.

Impact of investor risk on the evolution of the power system in presence of capacity remuneration mechanisms and in an energy only market

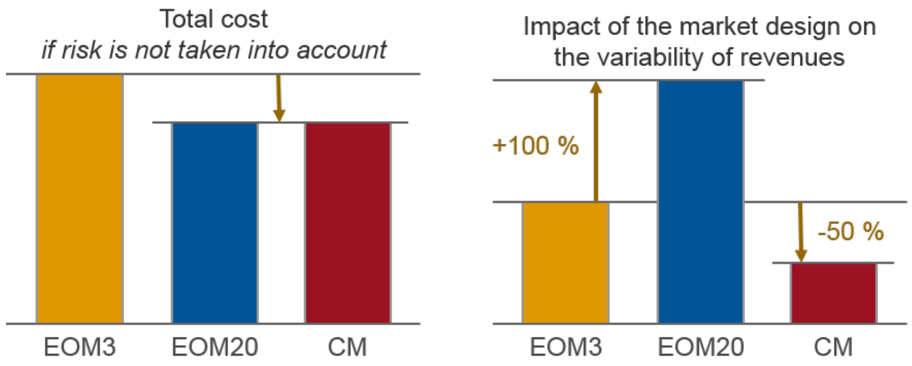
Peak load units have a relatively capital intensive cost structure. They produce a low number of MWh per year and most of their cost is fixed and capital related. Their profits depend largely on a small number of hours of high prices, that can vary considerably from year to year. Removing or raising the price cap can increase these generators' income and provide the investment incentives to keep security of supply at an acceptable level. Capacity remuneration mechanisms can do the same, while in addition stabilizing the income and consequently reducing investor risk and with the capital cost.

This study compares the societal or system cost of the energy only market with a low 3000 EUR/MWh, a high, 20.000 EUR/MWh price cap, and of having in place a capacity remuneration mechanism. In addition to the societal cost, the three settings are compared in terms of loss of load expectation. The simulation is run for the French system without the interconnections to neighboring countries for the time span from 2015 to 2030.



Loss of load expectation year by year in the Reference scenario, for the energy only market with a 3.000 EUR/MWh price cap (green), a 20.000 EUR/MWh price cap (yellow), and capacity mechanism (red).

As is shown in the figure above, the system suffers from lack of capacity at the beginning. This is in part due to the exclusion of hydro capacity in the simulation and in part to the exclusion of interconnection lines. The figure clearly shows that both the energy only market with a high price cap (yellow line) and the capacity mechanism (red curve) provide sufficient investment incentive to build out new capacity in the system and reduce loss of load. A low price cap (green curve) on the other hand does not guarantee sufficient security of supply.



Respective impacts of scarcity pricing and a capacity mechanism on economic efficiency (in the absence of risk aversion) and on the risk taken when investing in peaking units.

In terms of total system costs the energy only market with a low price cap performed worst due to less new capacity installed higher variable costs of the existing technologies (left in the figure above).

Interestingly, the energy only market with a high capacity price (in figure above EOM20) performs similarly to the energy market with a capacity remuneration mechanism (CM). However, simulations showed that profits of peak load generators can vary very significantly from between years, which would imply a high investor risk. If this factor is taken into account, the energy only market with a high price cap generates much larger societal costs than the capacity mechanisms (above figure right).

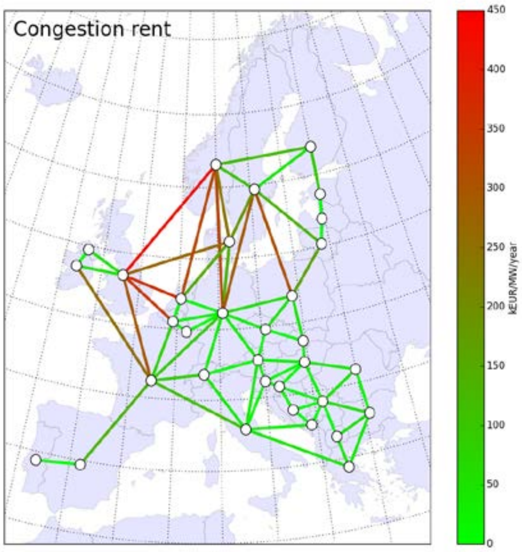
Interdependence of the costs of capacity remuneration mechanisms and RES support mechanisms

Finally, the last study has been performed over the entire ENTSO-E area under the Vision 3, reference ENTSO-E, scenario for 2030 and Vision 4, considering an increased 55% share of renewables. The optimal operation of the ENTSO-E system considering the net transfer capacities and installed capacities is computed for these two scenarios. From each of the two scenarios, a scenario with 5% more peak capacity in the form of gas turbines is built to simulate the effect a CRM would have on the generation mix.

The study concludes that both CRM and renewables support in themselves drive down market prices and have, thus, an indirect cost in the form of lost revenues. This loss has to be compensated for by an increase in renewables support in case of CRM and vice versa.

In the Vision 4 scenario with increased generation from RES-E, significant RES generation curtailment occurs, indicating an inefficient integration of RES in the system. Norway, Sweden and the UK produce together over 37% of all hydro power and over 27% of wind power in the ENTSO-E system in 2030. Congestion on the lines connecting Norway, Sweden and the UK to continental Europe get more relevant, as renewables shares rise further after 2030 (figure below).

Additional transmission capacity could reduce the amount of spilled energy, allow renewables to replace thermal generation on the continent, reward existing renewables capacity, and trigger further development of these cheaper and clean energy sources in Northern Europe.



Congestion rents under the high renewables 2030 scenario

When computing the operation of the system in a large number of climatic years, it is observed that higher RES support or CRM lead to lower power prices, resulting in lower and more variable profits for producers, which, in turn, raises the WACC of the corresponding investments.

Finally, a carbon tax seems to be necessary to keep prices high enough for RES to be cost competitive against conventional sources in 2030 and beyond.

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aFRR	Frequency restoration reserve with automatic activation
AS	Ancillary Services
ATC	Available transmission capacity
BRP	Balance Responsible Party
BSP	Balancing Service Provider
CRM	Capacity Remuneration Mechanism
DSR	Demand Side Response
dDSR	Distributed Demand Side Response
ENTSO-E	European Network of Transmission System Operators for Electricity
ETS	Emissions trading scheme
FIP	Feed-in Premium
FIT	Feed-in Tariff
GHG	Greenhouse gas
IGCC	International Grid Control Cooperation
KPI	Key Performance Indicator
LCOE	Levelized cost of Electricity
mFRR	Frequency restoration reserve with manual activation
NREAP	National Renewable Energy Action Plan
PHS	Pumped Hydro Storage
SoS	Security of supply
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan
WACC	Weighted Average Cost of Capital
WP	Work Package

1 Introduction

1.1 Purpose of this report and role within Market4RES

This is a report on the results of the investigations of alternative electricity market designs for the time period 2020-2030. Its purpose is to provide a quantitative basis for recommendations and guidelines on further market development. It is the second of the two reports prepared as part of Work Package 5 of the Market4RES project. The following investigations represent the continuation of the analyses of the target model in the time frame 2013-2020 (Work Package 4 in the project).

Prior to these analyses, an assessment of the current status of the so called target model of the electricity market had been made as part of Work Package 2. The assessment has focused on the opportunities, challenges and risks related to the integration of renewable energy sources (RES) into the EU electricity market. Work Package 3 provided the assessment of novel market designs identifying the most promising options for RES integration.

Together with the Work Package 4 studies of the impact of demand response and the transition from feed in tariffs to feed in premiums, these studies constitute the basis for recommendations and guidelines for policy makers that are developed in Work Package 6. The studies mainly focus on policy instruments related to short and long-term markets that had been positively assessed in WP3, in particular in Deliverables D3.1 [2] and D3.2 [9] of the project on criteria of market efficiency and use of public funds, effectiveness in terms of renewables deployment, robustness and implementability.

In addition to the investigation of these market instruments, the report also includes a study of the effects of risk on the evolution of the energy mix and the relationship between the support for renewables and the profitability of demand response.

The analyses were undertaken by four institutions, IIT-Comillas, EEG, RTE and SINTEF Energy Research, with significant contributions from Technofi.

1.2 Structure of this report

The rest of the report is structured in the following way:

Section 2 is dedicated to the results of the investigation of different balancing market mechanisms. It has been performed by EEG.

Section 3 describes the results of IIT-Comillas' comparative study of the effects of four promising renewables support mechanisms on the short term markets. These are long-term clean energy auctions, long-term clean capacity auction, fixed feed in premiums and finally floating feed in premiums.

Section 4 discusses the results of the investigation by, again, IIT-Comillas' of the effect of moving the day-ahead market closer to real time.

Section 5 discusses RTE's investigation of the effects of renewables support mechanisms on the profitability of demand response.

Section 6 is a comparative analysis by RTE of the effectiveness in renewables deployment of explicit renewables support mechanisms and the carbon tax.

Section 7 by RTE compares the energy only market with two different price caps with capacity remunerations mechanisms.

Section 8 summarizes SINTEF's study of the effect of capacity remuneration mechanisms' costs on the cost of renewables support and vice versa.

2 Validation of possible future balancing market mechanisms

2.1 Background and assumptions of the study

The results of the qualitative assessment of possible future balancing market mechanisms are summarized in Chapter 5 of Market4RES deliverable D3.2 (L. Olmos et al.). In the present report the quantitative impacts of several possible future balancing market mechanisms are analysed. A short description of the used simulation tool for validating different future balancing market mechanisms and designs is already included in Chapter 3 of Market4RES deliverable D5.1. More details about the EDisOn model and the add-on balancing markets can be found in (Burgholzer, Auer, 2015) and in (Burgholzer, 2016).

Nonetheless, some relevant equations of the model are stated below. By default, the procurement of balancing capacity and energy products is organised separately by default. To allow considering also the joint procurement of both, additional constraints have to be added in the second step of the model, where the imbalances and bids for balancing energy are simulated. Therefore, step 2 simulates the real-time market. The following inequalities describe the boundaries for the positive and negative balancing energy ($thFRR_{h,th}^{j+}$, $thFRR_{h,th}^{j-}$). They are limited to the procured up- and downward capacity ($\overline{thFRR}_{h,th}^{j}$, $\underline{thFRR}_{h,th}^{j}$).

$$thFRR_{h,th}^{j+} \leq \overline{thFRR}_{h,th}^{j} \quad (1)$$

$$thFRR_{h,th}^{j-} \leq \underline{thFRR}_{h,th}^{j} \quad (2)$$

For evaluating the joint or separated procurement of up- and downward balancing capacity the following constraint has to be added in the first step of the model, where the procurement of balancing capacity is simulated simultaneously with the power plant dispatch. It describes the joint procurement, meaning that positive balancing capacity has to be reserved in the same way as negative.

$$\overline{thFRR}^{j}_{h,th} = \underline{thFRR}^{j}_{h,th} \tag{3}$$

Implementing the minimum bid size in step 1 of the model is not really reasonable, due to the fact that individual generators are not included in the model. Rather, they are aggregated per balancing group/area. For the thermal power plants, every fuel type can be split into a certain number of clusters of units corresponding to different efficiency levels. In addition, the minimum bid sizes can be implemented with binary variables only, i.e., in this case, the model would become a mixed-integer problem. Due to these reasons the impact of having different minimum bid sizes is not analysed.

To evaluate the impact of changes in the behaviour of market parties due to the application of different pricing schemes for balancing products, an agent-based model approach would be needed. The development of this additional model is not possible within the project duration. Nevertheless, the total procurement costs can be derived either based on pay-as-bid or marginal pricing. The incorporation of pay-as-bid or marginal pricing is done by respecting the opportunity costs or the dual variable of the corresponding equation.

The preference of the imbalance pricing system can be analysed after the real time simulation of the model (step 2), when all imbalances are balanced and the needed balancing energy is called, based on the calculation of revenues and payments for every Balancing Responsible Party (BRP). The used model is developed within the Market4RES project, due to the reason that step 2 is not that advanced as expected, the effects of different imbalance pricing systems will not be analysed in this chapter.

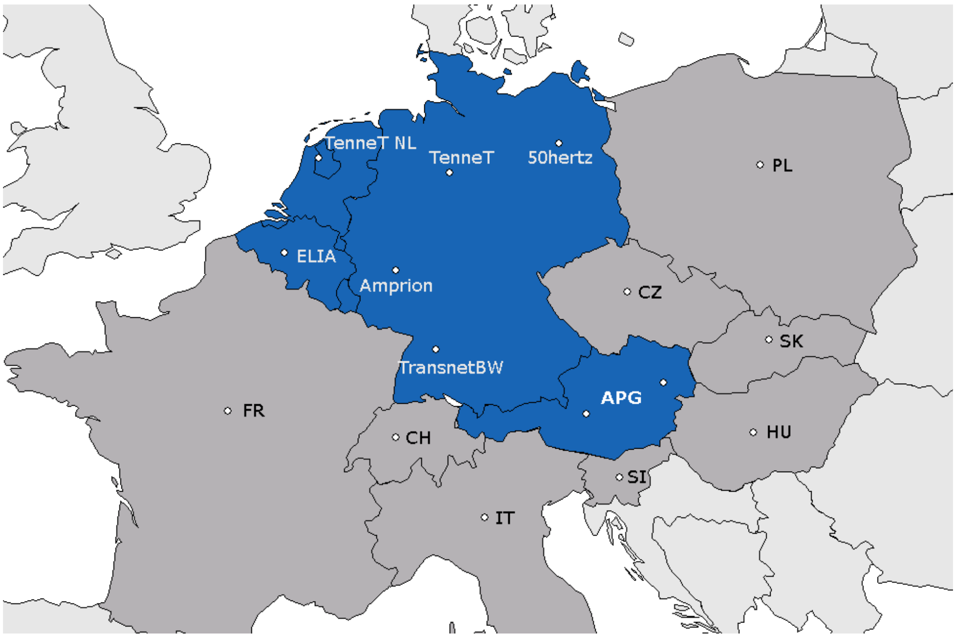
The settlement period will not be varied, it is considered as 15 minutes.

In the next section, the geographic scope of the analysis and the different cases for the time horizon 2030 are defined and described in detail. The resulting quantitative impacts, like the procured capacity in each balancing area, total annual costs of procurement, total generation costs, etc., of different balancing market designs are shown in section 2.3. Finally, the conclusions based on the simulation results are summarized.

2.2 Defined cases for the time horizon 2030

For all case studies the assumed installed capacities and prices are based on the reference 2030 scenario; for a detailed scenario description see D5.1. The geographical scope of the study is central Europe, whereas balancing market mechanisms are considered for the Netherlands, Belgium, Germany (divided into the four German TSOs: TenneT, 50Hertz, Amprion and TransnetBW) and Austria, see Figure 1.

Figure 1: Geographical scope of the analysis, blue: balancing market designs, dark grey: only day-ahead market simulations.



The features of the reference case of the study are as follows:

Reference case – Asymmetric positive & negative balancing capacity (weekly)

- for all balancing regions/areas the same market designs
- **separated** procurement of balancing capacity and balancing energy products
- **separated** procurement of upward and downward balancing capacity products
- **week-ahead** procurement of Peak, Off-Peak and Weekend aFRR products in Austria, and Haupttarif (Mo-Fr 8:00-20:00) and Nebentarif (Mo-Fr 0:00-8:00 and 20:00-24:00, Sa-So) aFRR products in Germany, Belgium and the Netherlands
- daily procurement of 4h products for mFRR (like in Austria)
- imbalance settlement period of 15 minutes
- balancing capacity can be **only exchanged** between German TSOs/balancing areas

For the following cases, only the differences compared to the reference case are mentioned.

Case A – Asymmetric positive & negative balancing capacity (daily)

- **day-ahead** procurement of Peak, Off-Peak and Weekend aFRR products in Austria, and Haupttarif and Nebentarif aFRR products in Germany, Belgium and the Netherlands

Case B – Symmetric positive & negative balancing capacity (weekly)

- **joint** procurement of upward and downward balancing capacity products

Case C – Symmetric positive & negative balancing capacity (daily)

- **joint** procurement of upward and downward balancing capacity products
- **day-ahead** procurement of Peak, Off-Peak and Weekend aFRR products in Austria, and Haupttarif and Nebentarif aFRR products in Germany, Belgium and the Netherlands

Case D – Asymmetric positive & negative balancing capacity (daily) & exchanges are possible

- **day-ahead** procurement of Peak, Off-Peak and Weekend aFRR products in Austria, and Haupttarif and Nebentarif aFRR products in Germany, Belgium and the Netherlands
- balancing capacity can be **exchanged** between all TSOs/balancing areas

Case E – Asymmetric positive & negative balancing capacity (12 hours) & exchanges are possible

- **12 hours-ahead** procurement of Peak, Off-Peak and Weekend aFRR products in Austria, and Haupttarif and Nebentarif aFRR products in Germany, Belgium and the Netherlands
- balancing capacity can be **exchanged** between all TSOs/balancing areas

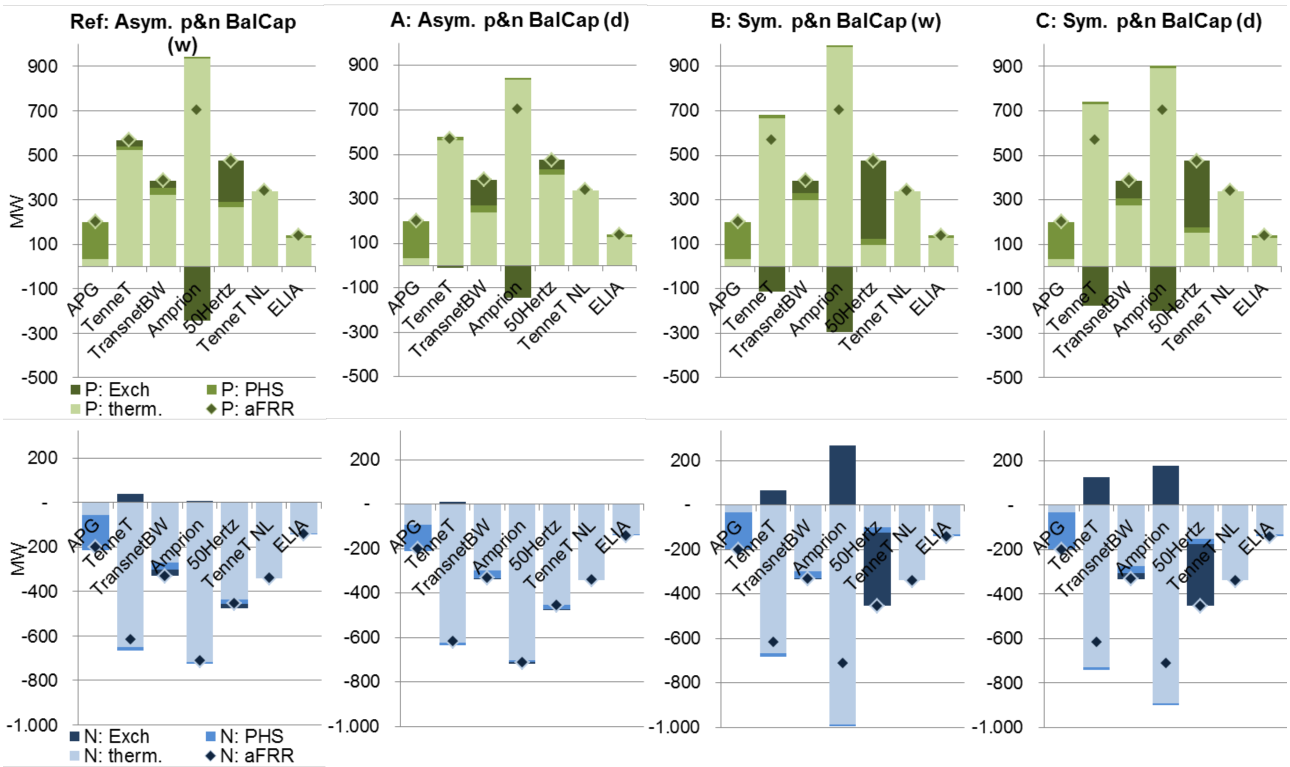
Case F – Asymmetric positive & negative balancing capacity (1 hour) & exchanges are possible

- **1 hour** products in Austria, in Germany, Belgium and the Netherlands
- balancing capacity can be **exchanged** between all TSOs/balancing areas

2.3 Results

Figure 2 and Figure 3 show the average procured balancing capacity for upward (positive) and downward (negative) aFRR for each balancing area. The balancing capacity can be provided by thermal power plants (therm.) and pumped hydro storages (PHS). The German TSOs can exchange balancing capacity (Exch) in all cases. ,For the remaining control areas, this is possible in case D to F only. Most of the aFRR capacity is procured by thermal units. Except in the Austrian balancing area APG the majority is supplied by pumped hydro storages, negative as well as positive capacity.

Figure 2: Average procured positive and negative balancing capacity aFRR of the different balancing areas for the reference case and case A to C (P: positive, N: negative, aFRR: required capacity/h, in MW).

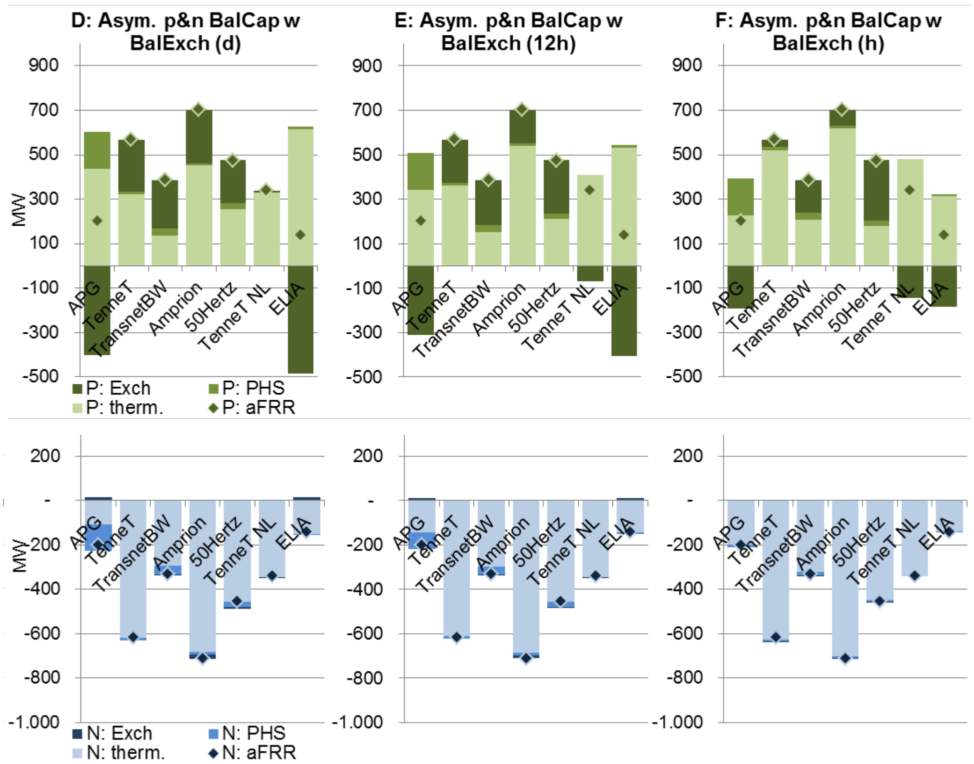


Comparing the cases where weekly auctions (reference case and case B) are applied with the daily ones (case A and C), it can be observed that the average exchanges of balancing capacity between the German balancing areas are reduced significantly. For example, the procurement of positive capacity in 50Hertz area from the remaining German balancing areas decreases around 78 % in case A compared to the reference case, and Amprion provides around 40 % less balancing capacity to the others. The same is observed when upward and downward balancing capacity has to be procured jointly (case B and C), not only regarding positive balancing capacity but also negative capacity. These reductions result from the flexibility gained in time. This means that the TSOs can manage the installed capacities and the prequalified capacities for aFRR and mFRR of their own balancing area more efficiently. Therefore, the need of obtaining additional balancing capacity from other TSOs is reduced. Furthermore, having in mind demand side management and renewable energy sources, like wind farms, the shorter the product length and the shorter the timing of the auction ahead, the better for these sources to bid into balancing markets. For example, for wind farms, a week-ahead forecast and then a potential bid of procured capacity for a whole week is not economic for this kind of technology.

The comparison of asymmetric cases with symmetric cases (reference case and case A with case B and C) shows that more capacity is exchanged between German TSOs, if symmetric procurement of up- and downward balancing capacity is applied. Especially, the negative balancing capacity is increased by 10 to 100-fold, due to the reason that both upward and downward balancing capacity has to be procured to the same extent. Again, for renewable energy sources like wind farms, it is not beneficial to bid upward and downward capacity/energy simultaneously, because providing positive balancing capacity means that they cannot use their full generation capacity. They always have to be able to provide the bidden upward balancing energy, when called.

When allowing exchanges of balancing capacity between all balancing areas, the common procurement increases as expected. Particularly in Belgium and Austria the procurement of positive balancing capacity rises significantly, see case D to F in Figure 3. However, when reducing the timing of products these exchanges are declining, see also the duration curves in Figure 5.

Figure 3: Average procured positive and negative balancing capacity aFRR of the different balancing areas for case D to F (P: positive, N: negative, aFRR: required capacity/h, in MW).



The average common procurement for positive balancing capacity per hour is shown for case A and D in Figure 4. Specifically, the figure of case D shows significant average procurements of positive balancing capacity from Belgium (300 MW) and Austria (403 MW) to Germany. The average exchanges within Germany are approximately the same in D as in case A, except for the fact that the exchanges between TenneT and 50Hertz are nearly 5 times higher, due to high supplies from ELIA via TenneT NL to TenneT, and from APG to TenneT.

Figure 4: Average common procurement of positive balancing capacity for case A and D (in MW).

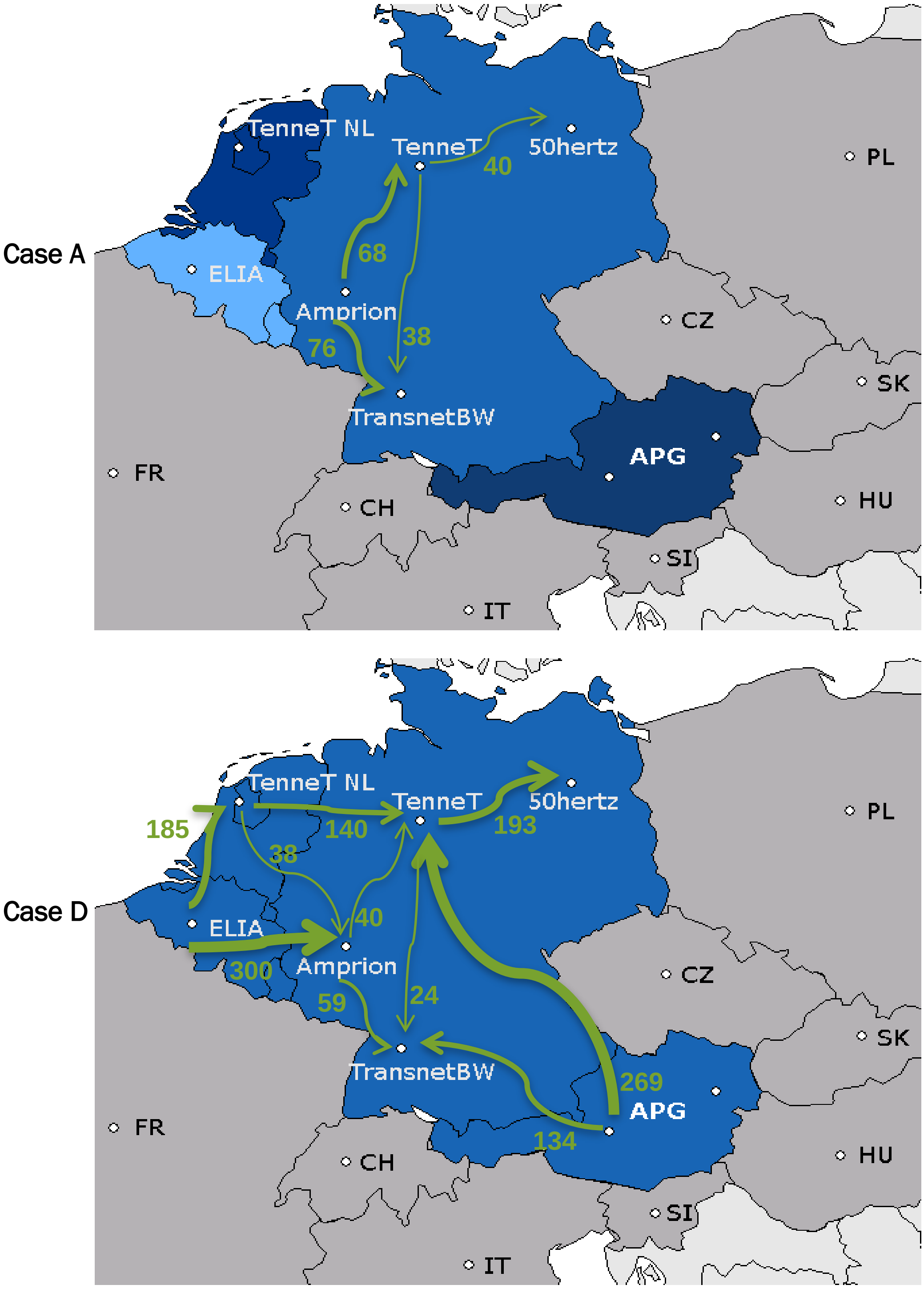
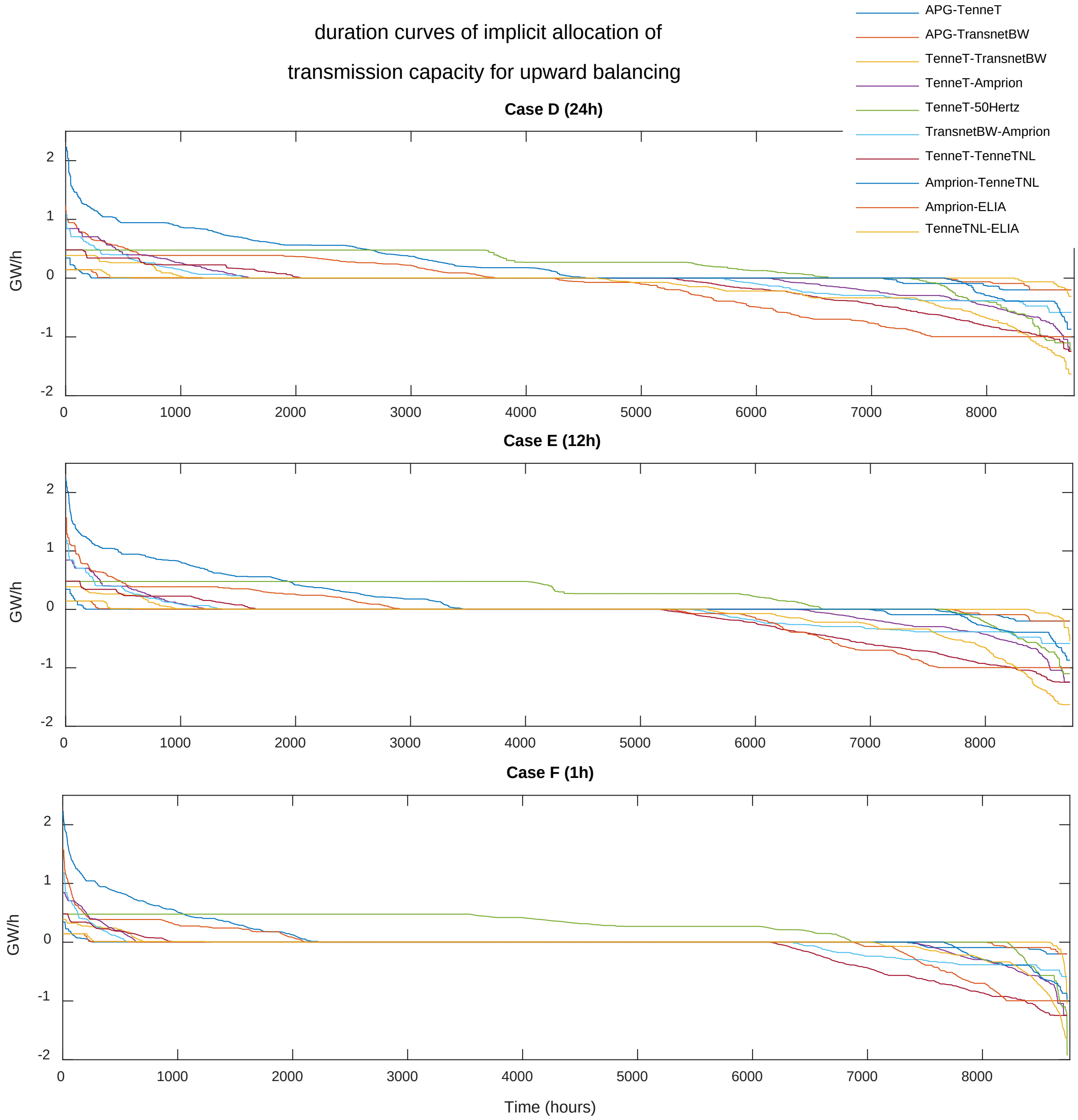


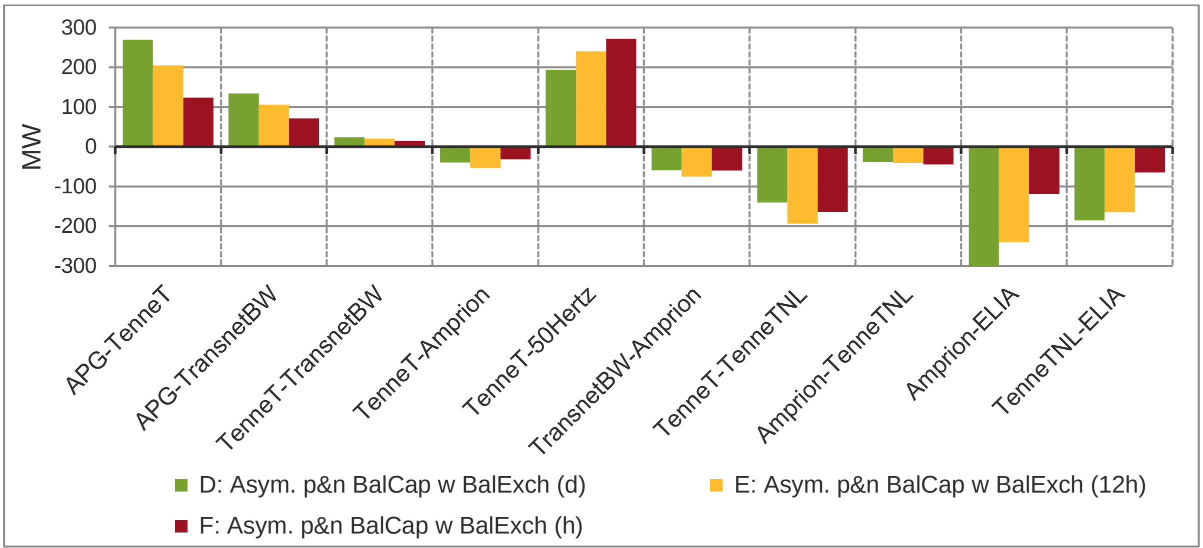
Figure 5 shows that, when there is more flexibility in terms of shorter time frames for balancing capacity bids, the implicit allocation of transmission capacity between the balancing areas declines.

Figure 5: Duration curves of implicit allocation of transmission capacity for asymmetric cases, for A-B positive values mean A to B (e.g. APG to TenneT), and negative vice versa (e.g. TenneT to APG).



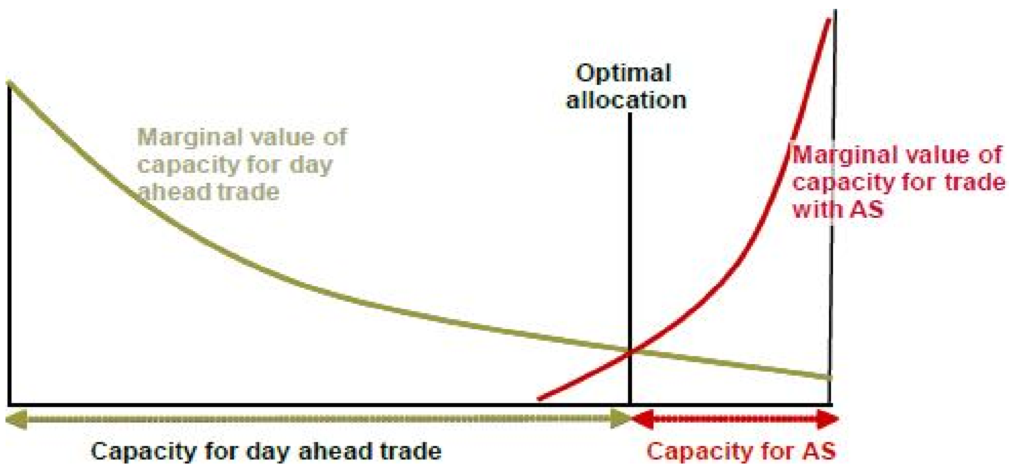
In case D, for most of the hours and transmission power lines, a certain capacity is reserved for balancing purposes. In case E, there are already more than 2000 hours for almost all power lines where no capacity is used for balancing. This number of hours increases to more than 4000 hours in case F. Just the common procurement of TenneT and 50Hertz remains on a certain level. The average allocated transmission capacities for positive balancing capacity for case D to F are shown in Figure 6.

Figure 6: Average allocated transmission capacity for positive balancing capacity for case D to F. Positive value means A to B (A-B) and negative vice-versa (in MW).



The implication of this observation is that between two markets more transmission capacity can be used for day-ahead and intraday trades, if the gate closure of the balancing market is before day-ahead gate closure. In (ENTSO-E, 2011) the theoretical issues in terms of optimal determination of allocation of capacity between energy trading and reserve (balancing capacity) trading are briefly outlined. It is assumed that transfer capacity has a positive and declining marginal value in all markets. Assuming only two products (in this example day-ahead energy and reserves) and a given level of transfer capacity, the optimal allocation of capacity can be illustrated as indicated in Figure 7.

Figure 7: Optimal allocation of transfer capacity between two markets (AS=Ancillary Services).

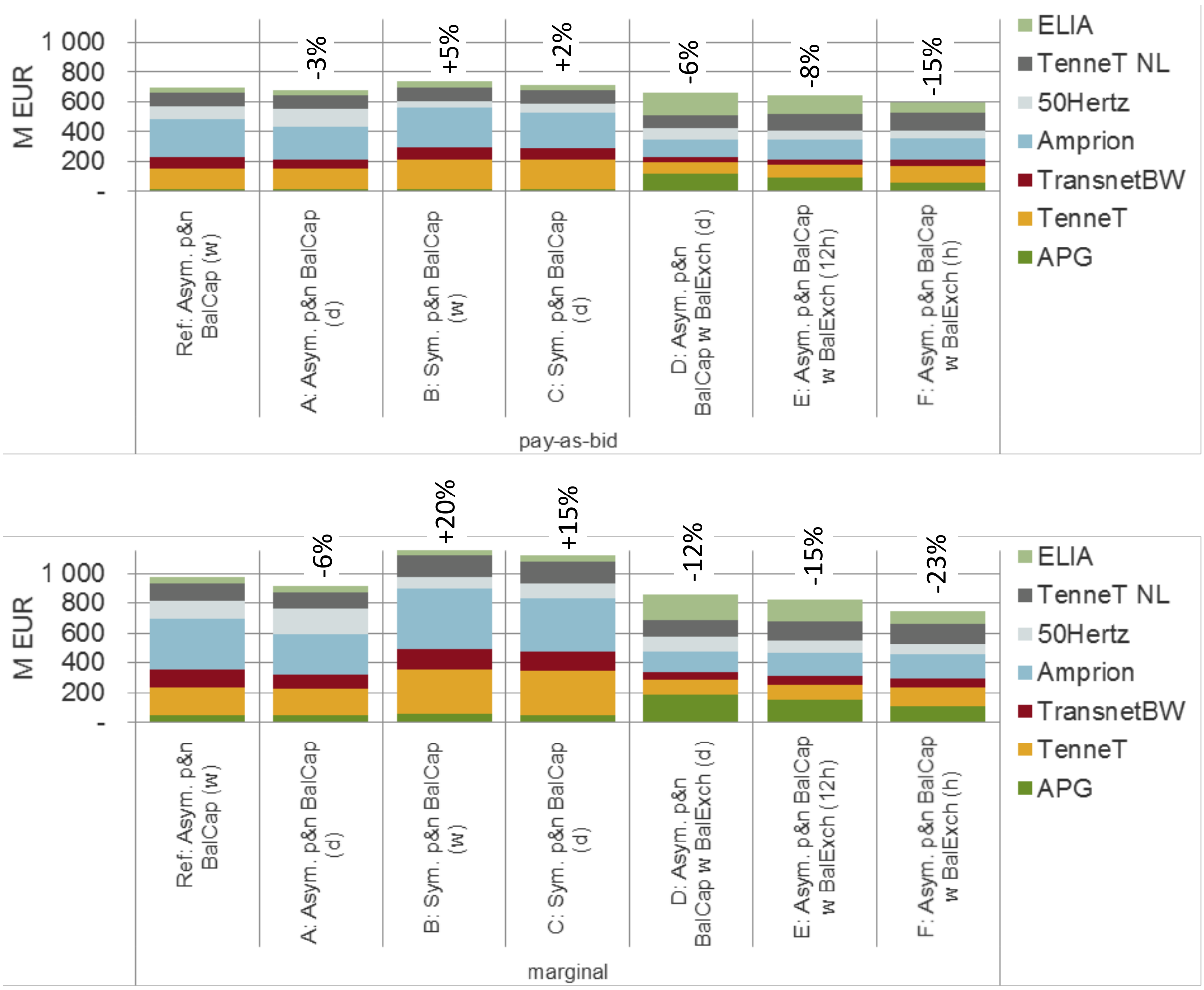


Source: (ENTSO-E, 2011)

Therefore, the optimal allocation of capacity is illustrated by the intersection of the two curves. Allocation at these levels in both markets will optimise social welfare since an extra MW allocated to either market will reduce social welfare.

As mentioned before, the impacts on market parties' behaviour of different approaches for the pricing of balancing products, like pay-as-bid versus marginal, cannot be analysed with this type of model. Another model approach, where different bidding strategies can be analysed, for example with an agent-based model, would be needed. Nevertheless, the resulting costs of balancing capacity procurement can be calculated both based on pay-as-bid as well as on marginal pricing. The annual procurement costs and the percentage of total changes compared to the reference case of all cases are shown in Figure 8.

Figure 8: Comparison of the annual costs (pay-as-bid & marginal) for positive and negative balancing capacity aFRR for different cases (in M EUR and in percentage the total changes).

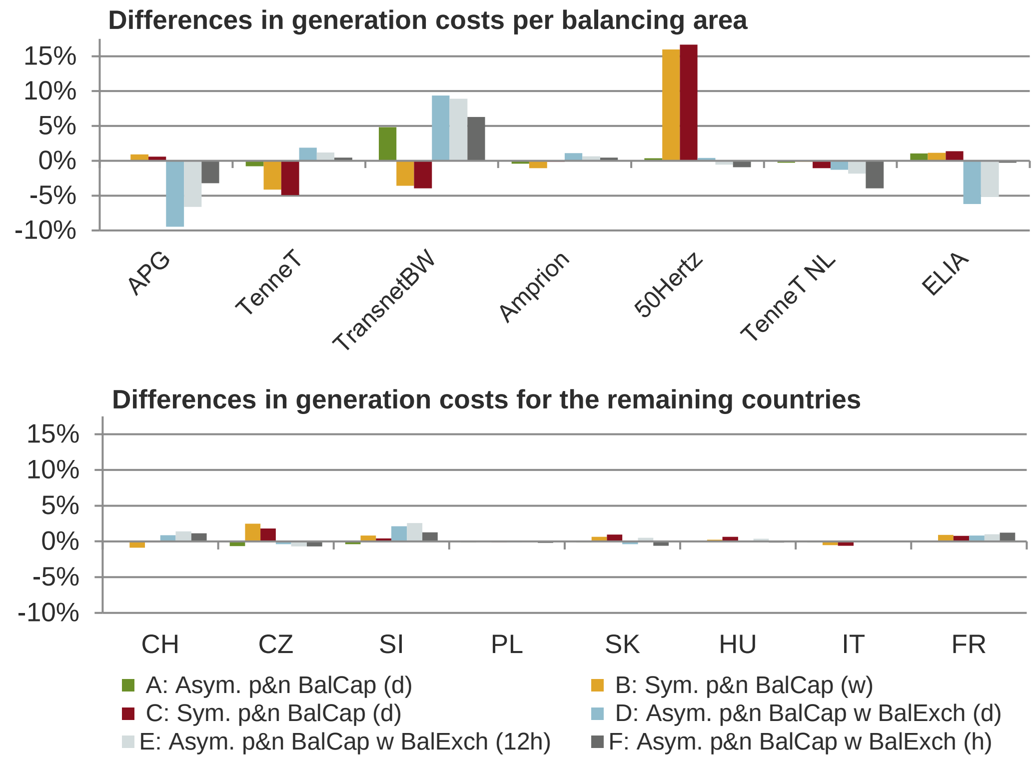


Applying symmetric procurement results in the highest costs. In the case of pay-as-bid (marginal) pricing, the annual costs are 5 % and 2 % (20 % and 15 %) higher than in the reference case for weekly and daily procurement (case B and C in Figure 8). The shorter the product length gets, the lower the costs are. In addition, common procurement of all balancing areas can reduce these costs significantly. For the procurement of hourly products, reductions of 15 % for pay-as-bid calculation (23 % for marginal) are possible. It has to be mentioned that the costs are allocated to the balancing areas where they emerge, but due to exchanges they have to be borne by other balancing areas. Therefore, the procurement costs of the balancing areas ELIA and APG are lower. than indicated in Figure 8 in case D to F.

In case F, the balancing products are harmonised to one hour products in all balancing areas and this design yields the lowest costs. Hence, harmonising the definition of balancing products, meaning product length and frequency of auction, can reduce procurement costs of balancing capacity significantly.

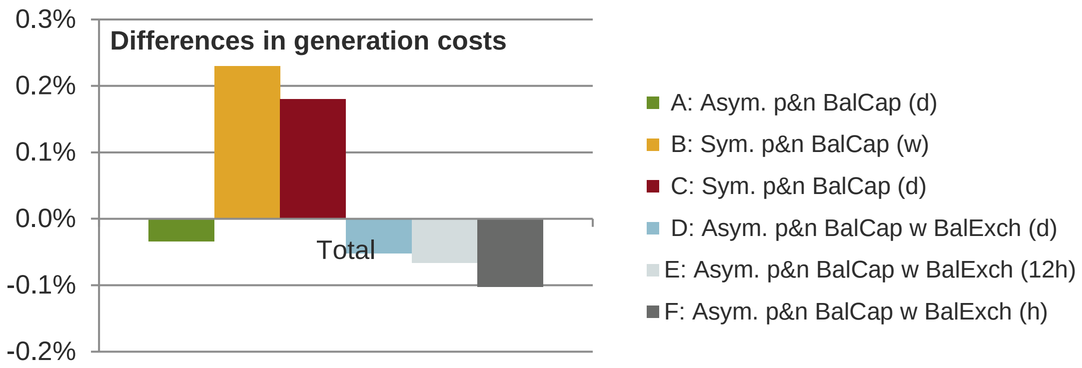
Different designs of balancing products do not only affect procurement costs, they also influence the total electricity generation costs of the spot markets. The differences in generation costs compared to the reference case are shown in Figure 9. In the upper plot, impacts on the balancing areas are shown, and, in the plot below, the impacts on the remaining countries, where only day-ahead modelling is applied, are presented.

Figure 9: Differences in generation costs compared to reference case Asym. p&n BalCap (w)



Most of the changes happen in the balancing areas where balancing markets are simulated, but there are also some changes in the neighbouring countries. The highest impacts occur in case B and C, due to the application of joint procurement of up- and downward balancing capacity. Therefore, the flexibility in terms of bidding capacity/energy into the markets is limited in the balancing areas, which results in a not optimal allocation of the assumed generation portfolio and to compensate this effect neighbouring countries have to adjust their power plant dispatch. The influences on generation costs of applying common procurement in all balancing areas are significant. The costs are reduced in some areas, e.g. in Austria, Belgium and the Netherlands, whereas in some other countries the costs are increased. In total, the generation costs can be diminished by applying common procurement. Furthermore, shorter product lengths promote this development, see Figure 10 (cases E and F).

Figure 10: Total differences in generation costs compared to reference case.



2.4 Conclusions and further developments

From the results of the preceding analysis the following conclusions can be withdrawn:

- The symmetric (joint) procurement of positive and negative balancing capacity
    - increases total generation costs (see Figure 10),
    - increases total procurement costs (see Figure 8),
    - increases procurement exchanges between German TSOs (see Figure 2),
    - is a poor design for RES integration, due to the fact that e.g. wind farms cannot use their full electricity generation capacity in order to be able to provide also upward balancing capacity.
- Common procurement of balancing capacity by all balancing areas
    - reduces total generation costs (see Figure 10),
    - and reduces total costs of procurement (see Figure 8).
- Shorter time frame of block products
    - reduces implicit allocation of transmission capacity between balancing areas (see Figure 3),

- reduces total generation costs (see Figure 10),
- reduces total procurement costs (see Figure 8),
- is a good option to integrate RES in balancing markets, because the shorter the product length is, the more efficient RES can bid into the market.

In order to improve the analysis, further developments of the model are planned. The most important ones are listed below:

- allow wind farms to provide balancing products (especially mFRR),
- more detailed integration of hydropower plants,
- integration of Demand Side Management (DSM),
- analyse additional scenarios of future market designs,
- further development of the real-time application of the model (step 2):
    - implementation of composite stochastic processes,
    - implementation of Imbalance Netting,
- and consideration of balancing markets in other EU countries.

3 Effects of RES support mechanisms on short-term markets

3.1 Background and assumptions of the study

This section discusses the impact of the application of the several support schemes considered for the deployment of RES generation on the performance of short-term energy markets. The idea is to compare how the implementation of different RES support schemes would affect the operation of the power system in the short-term. The different support schemes evaluated in this section are:

1. Long-term clean capacity auction,
2. Long-term clean energy auction,
3. FIP (auction): fixed premium,
4. FIP (auction) floating premium.

The analyses described in this section have been carried out using the ROM model developed by IIT-Comillas. The geographical scope of the analyses comprises the power systems of Portugal, Spain and France, while not considering the internal network of these countries. The time scope of the analysis is one year (8,760 hours), and the target year considered is 2030. The generation capacity and demand considered are based on the Vision 3 of the TYNDP-2014. RES generation profiles are scaled-up based on the RES profiles obtained in 2013 and on the forecasted installed capacity for 2030.

The analysis carried out in this section takes into account only the day-ahead market (unit-commitment) in Portugal, Spain and France, without considering the balancing and/or any intra-day market. However, the required reserves have still to be provided. These reserves – up and down – are obtained, for each country, based on these formulas (Gil et al, 2010):

$$UpReserve(h) = \alpha \cdot Demand(h) + MaxUnit(h) + \beta \cdot RES(h)$$

$$DwReserve(h) = \alpha \cdot Demand(h)$$

The up reserve protects the system from the uncertainty in the level of demand, the availability of RES generation (wind and solar), and the failure of the biggest unit generating electricity. The down reserve protects the system only from the uncertainty in the demand. Thus, parameters α and β are calculated in order to protect the system from a pre-determined uncertainty of these sources. In the analysis carried out in this section, parameter α is selected to shield the system for 2% error in the demand and parameter β is calculated to protect the system for 90% of the errors in the prediction.

A detailed description of the methodology employed for the analysis can be found in Market4RES deliverable D5.1 (B. Burgholzer et al. 2016).

The investment costs of the units installed in the period 2020-2030 are presented in Table 1[2]. The design of the RES support schemes should guarantee that the investments costs incurred by new RES generation being supported are recovered from the revenues obtained by this generation (considering together the revenues obtained from the market and the revenues provided by the support scheme).

Table 1: total RES capacity installed and investment costs incurred per technology in the period 2020-2030 (ENTSO-E, 2014)

Units	Location	Capacity 2020-2030 [MW]	Annualized investment costs [M€/MWyr]	Total Annualized investment cost [M€/yr]
Wind	Spain	13,250	0.15	1,980
Solar	Spain	17,950	0.12	2,166
OtherRES[3]	Spain	10,250	0.32	3,273
Wind	France	20,000	0.15	2,988
Solar	France	19,187	0.12	2,315
OtherRES	France	8,000	0.32	2,554
Wind	Portugal[4]	675	0.15	101
OtherRES	Portugal	295.5	0.32	94

The different support schemes are analyzed based on the changes they cause in the system operation with respect to the optimal system operation. The optimal system operation is the one occurring when no support scheme is being applied. As a consequence of changing the operation of the power system, the costs and the short-term price signals of the system also change.

3.2 Base case: Optimal short-term operation (without any RES support scheme)

This case does not consider any support scheme being in place. Thus, generation units (agents) offer their energy in the market at their marginal cost.

3.2.1 System operation

Table 2 provides the amount of power produced by each generation technology when no support scheme is applied. Figures are total ones for all the region and for the different countries of the region.

Table 2: electric energy produced by each technology in the target year (2030) when no support scheme is in place

Technology	GWh		Spain	France	Portugal
Nuclear	369,840	38%	50,836	319,004	0
Coal	20,188	2%	16,441	3,747	0
GT	1,700	0%	565	163	973

[2] The installed capacities are obtained from Vision 3 of the TYNDP 2014-2030 (ENTSO-E, 2014).
[3] OtherRES units comprise technologies like biomass, biogas, CHPs…
[4] Notice that solar units in Portugal do not appear in this table. Based on the data obtained for periods 2020 and 2030, it is assumed that all the solar capacity to be deployed in Portugal will be done previously to 2020.

CCGT	145,923	15%	109,735	19,796	16,392
Oil	10,180	1%	0	10,180	0
OtherNonRES	181	0%	0	181	0
Hydro	131,666	14%	71,857	52,030	7,779
Wind	214,706	22%	122,381	76,406	15,919
Solar	73,442	8%	43,218	28,333	1,891
OtherRES	1,101	0%	325	760	17

It is noticeable that the generation by the OtherRES technologies is very low. This can be confirmed in Table 3. This table shows the spillages incurred by each RES generation technology (with respect to the energy that can be produced by this technology). This is because OtherRES technologies are not cost competitive at the time when they are available.

Table 3: energy spillages incurred by each RES generation technology

RES	Spillage
Wind	0%
Solar	0%
OtherRES	99%

The resulting CO_2 emissions amount to 80 $MtCO_2$.

3.2.2 System costs and prices

The difference in market prices (or marginal power production prices) of the three national power systems in the region are displayed in Figure 11. The energy prices of the Spanish and Portuguese systems are most of the time aligned. Moreover, the energy price in the French system is, often, lower than the prices in Portugal and Spain. In the French system, there are many hours when the price is close to –or even– zero. However, the price in the French system during other hours is as high as 1,000€/MWh. These are hours when there is a scarcity of energy only in the French system.

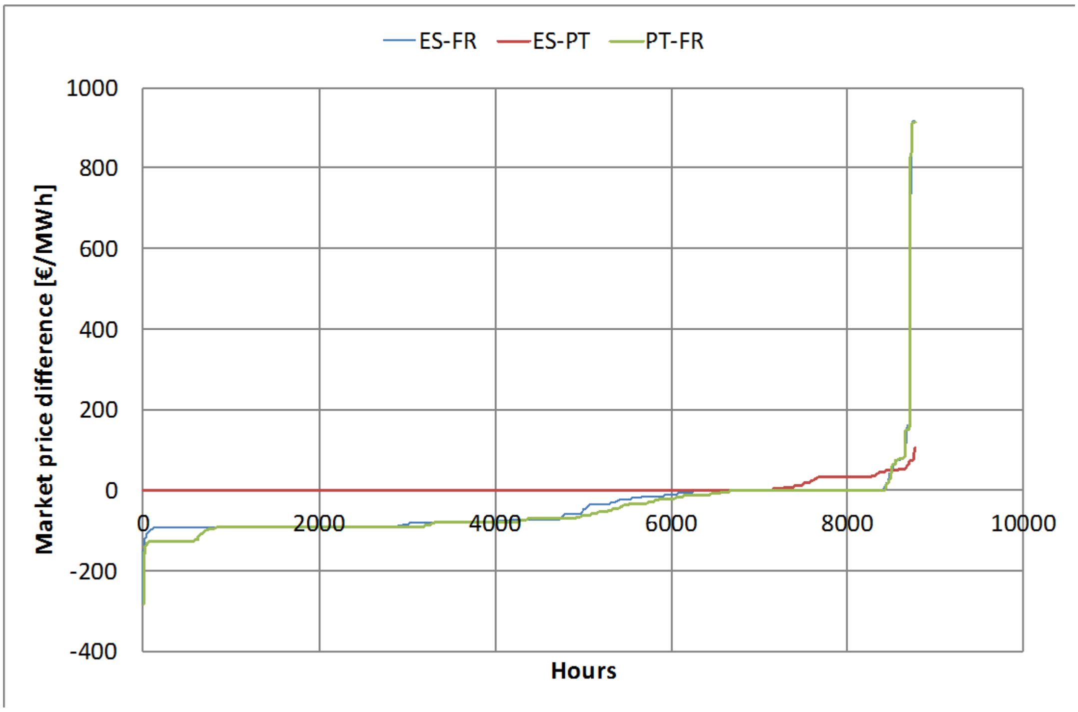


Figure 11: difference in electricity prices in the target year in the Spanish, French, and Portuguese systems in the absence of any RES support scheme

Table 4 shows the average market (marginal) price in each of the three national systems in the target year, and Table 5 shows the number of hours in the three power systems when the market prize is zero. Figures in these tables show that market prices in the French power system are frequently lower than the Spanish and Portuguese ones. Besides, low prices are much more common in the French system. The difference in the average price between France and Spain and Portugal mainly comes from the different generation mix obtained for these countries (see Table 2). The variable production cost of nuclear power is lower than the cost of gas units. While France produces much more energy with nuclear power plants, Spain and Portugal generate more energy with CCGT and GT units. Thus, the prices in Spain and Portugal are higher.

Table 4: average market price in the Spanish, French, and Portuguese systems in the absence of any RES support scheme

System	Average price [€/MWh]
Spain	104
France	60
Portugal	110

Table 5: number of hours with market price equal to zero

System	Hours
Spain	2
France	82
Portugal	1

The total annual market revenues and net benefits in the dispatch obtained by the RES units installed between 2020 and 2030 is showed in Table 6. These net benefits should be enough to recover the annualized investment costs incurred by these units. The last column of Table 6 shows the difference between net benefits and annualized investment costs. A negative value of this difference means that the corresponding generation technology would require additional support in order to recover the investment costs.

Table 6: energy revenues from the market and net benefits from the generation dispatch by technology and country in the target year when no RES support is applied

Units	Location	Market revenues [M€]	Net benefits in the dispatch [M€/yr]	Net benefits – Inv. Costs [M€/yr]
Wind	Spain	3,378	3,378	1,400
Solar	Spain	2,700	2,700	534
OtherRES	Spain	57	2	-3,271
Wind	France	2,003	2,003	-985
Solar	France	882	882	-1,433
OtherRES	France	215	91	-2,463
Wind	Portugal	176	176	75
OtherRES	Portugal	3	0	-94

As it can be seen, there is a huge difference among energy market revenues obtained by the several RES generation technologies. It is especially remarkable that the OtherRES generation obtains very low incomes. Very low incomes result in even lower net benefits –almost zero– from the dispatch (due to the high variable costs of these units). The last column of Table 6 shows the gap between the net benefits obtained in the dispatch and the annualized investment costs for RES generation from each technology built in the period 2020-2030. Wind and solar generation installed in France would require additional support in order to be able to recover their investments costs. OtherRES generation in all countries would also require large support, since their income in the energy market is almost non-existent.

The total annual generation dispatch costs of the system are displayed in Table 7. These are the costs incurred by the power systems in the short-term in order to produce the electricity required. They are classified into those incurred by thermal and RES technologies, and according to the power systems considered (Spain, France and Portugal). Notice that, although RES units include wind, solar and Other RES technologies, the costs associated with this group come only from the Other RES technologies, because the variable cost of wind and solar is zero.

Table 7: total annual generation dispatch costs in the 2030 horizon for the case where no RES support is applied

	Thermal technologies	RES technologies	Total
Spain	14,332	56	14,388
France	8,051	134	8,185

Portugal	1,941	3	1,944
Total	24,324	192	24,516

3.3 Long-term clean capacity auction

This section considers the application of a long-term capacity auction in order to guarantee the recovery of the investment costs incurred by RES generators. Therefore, it implies providing some subsidies out of the market so that generation from each RES technology installed in the period 2020-2030 can recover its investment costs. The subsidy provided by the scheme complements the revenue obtained in the market by the sale of energy. But this amount is decided ex-ante. Hence, the application of this support scheme would not affect the operation of the power system. Therefore, the operational results of the system are the same as those already displayed (and considered the optimal short-term operation).

3.3.1 RES support

As shown in Table 8, wind and solar generation installed in France in the 2020-2030 period would require some support in order to recover its investment costs. The OtherRES generation installed in the three countries would require relevant support. The value of support required in order to ensure the recovery of investments for each technology and country is provided in Table 8.

Table 8: investment gap for RES generation installed in each country in the 2020-2030 period

Units	Location	Net benefits – Inv. Costs [M€]	Support required [M€/MW]
Wind	Spain	1,400	Not required
Solar	Spain	534	Not required
OtherRES	Spain	-3,271	0.32
Wind	France	-985	0.05
Solar	France	-1,433	0.07
OtherRES	France	-2,463	0.31
Wind	Portugal	75	Not required
OtherRES	Portugal	-94	0.32

OtherRES generation requires an amount of support that is almost the same as the investment costs of this generation. This is because it produces almost nothing due to its high variable costs.

3.3.2 System operation

The system operation under this support scheme is the same as that in the situation without any support scheme being applied. The power production of generation from the several technologies is provided in Table 2.

This operation of the system results in CO_2 emissions that amount to 80 $MtCO_2$ (the same as the base case).

3.3.3 System prices and costs

Because the system operation in this case is the same as that when no support scheme is applied, market prices are also the same. Thus, the revenues obtained in the energy market by RES generation are also the same. These are provided in Table 6.

Table 9: support to be provided to RES generation for each technology and country when capacity auctions are implemented

Units	Location	Total support required [M€]	Capacity payment [M€/MW]
Wind	Spain	0	0
Solar	Spain	0	0
OtherRES	Spain	3,271	0.32
Wind	France	985	0.05
Solar	France	1,433	0.07
OtherRES	France	2,463	0.31
Wind	Portugal	0	0
OtherRES	Portugal	94	0.32
Total		8,246	

Finally, the support to be provided to RES generation installed in the period 2020-2030 is shown in Table 9. This support is provided both in absolute terms and in terms of the capacity payments to be made to each unit located in Spain, France and Portugal. The total support required by these units amounts to 8,236M€/yr.

Note that the unit short-term revenues from the production of electricity of RES generation being supported through long-term capacity auctions fully coincide with the electricity market price, which is deemed to coincide with the short term value of electricity produced for well-functioning energy markets. Then, assuming that the development of new technologies is driven by the learning effects of the production of the components of power plants and their installation, short-term price signals applied to RES generation being supported are efficient and drive this generation to make efficient short-term operation decisions.

3.4 Feed-In-Premium auction: fixed premium

This section considers the application of a Feed-In-Premium (FiP) scheme to RES generation units in order to guarantee the recovery of their investment costs. A FiP scheme applies a fixed premium over the market price. Thus, the revenues obtained in each hour by generation agents being subject to this FiP are:

$$Revenue(g,h) = Production(g,h) \cdot [market\_price(h) + premium(g)]$$

The premium is only applied if the corresponding unit is producing electricity. Thus, the application of this scheme affects the energy offers these agents make in the system:

$$Offer(g) = marginal\_cost(g) - premium(g)$$

Generation agents being affected by the FiP are willing to offer their energy in the market at a cost that is lower than the marginal cost of producing this energy because, in the case they are dispatched, they will receive a premium over the market price. When the premium is zero, the offer coincides with the marginal cost of the generation unit. Therefore, it is exactly as the base case and the long-term clean capacity auctions. But if the premium is higher than zero, the offers are lower than the marginal cost of these units. Thus, the operation of the power system is affected.

3.4.1 RES support

This section shows the premiums to be applied to the various generation technologies in each national power system when this is the mechanism chosen to support RES generation. A different premium is applied to each generation technology in each country, see Table 10.

Table 10: premiums to be applied to the several generation technologies in each national power system when this is the mechanism chosen to support RES generation installed in the 2020-2030 period

Units	Location	Premium [€/MWh]
Wind	Spain	0
Solar	Spain	0
OtherRES	Spain	147
Wind	France	39
Solar	France	92
OtherRES	France	189.5
Wind	Portugal	0
OtherRES	Portugal	124

3.4.2 System operation

In this case, the application of different premiums to different technologies has different impacts on offers made by RES generation of different technologies in the day-ahead market. Therefore, the operation of the power system differs in this case from that in the base case. The amount of energy produced by each technology in each country is provided in Table 11.

Table 11: electricity produced annually in 2030 by each technology when FiP are applied to support RES generation

Technology	GWh		Spain	France	Portugal
Nuclear	34,2247	35%	50,836	291,411	0
Coal	16,331	2%	13,955	2,376	0
GT	965	0%	203	122	640
CCGT	95,527	10%	68,456	12,269	14,802
Oil	6,897	1%	0	6,897	0
OtherNonRES	220	0%	0	220	0
Hydro	131,502	14%	71,699	52,024	7,779
Wind	214,523	22%	122,381	76,224	15,918
Solar	73,419	8%	43,218	28,311	1,891
OtherRES	90,071	9%	44,780	43,704	1,587

Notice that the amount of power produced by each technology is similar to that in the base case in general terms. As an exception, the production by OtherRES generation would increase from almost nothing in the base case to about 9% of the electricity produced in the system under a FiP scheme. This replaces, mainly, part of the energy produced in the base case by nuclear power plants (whose production changes from 38% to 35%) and CCGT units (whose production changes from 15% to 10%). Table 12 shows the spillages incurred by each RES generation technology (with respect to the energy that can be produced by this technology) when the FiP scheme is implemented. Notice that the spillages of wind and solar generation are almost non-existent.

Table 12: energy spillages incurred by each RES generation technology

RES	Spillage
Wind	0%
Solar	0%
OtherRES	19%

3.4.3 System prices and costs

Changes occurring in the operation of the power system, and those in bids by RES generation under a FiP scheme, affect prices in the system. Differences in market prices among the systems of Spain, France and Portugal are displayed in Figure 12. In addition, Table 13 shows the average prices applied in these systems.

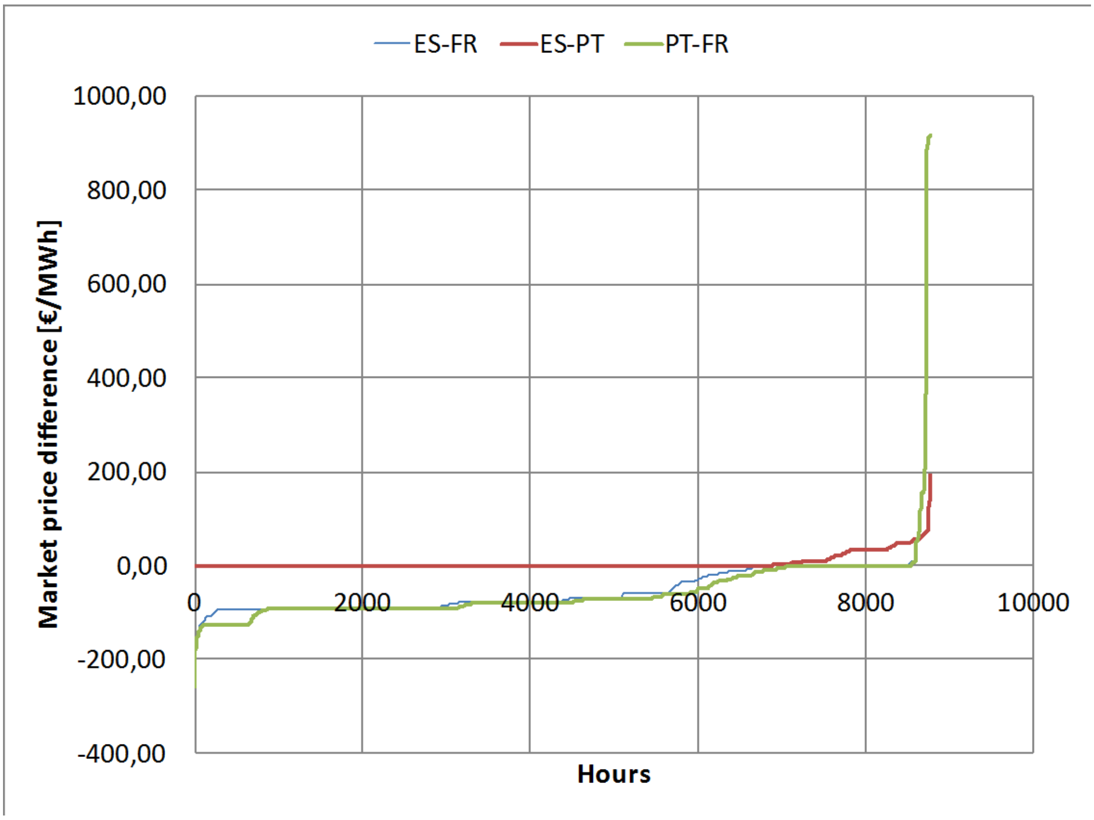


Figure 12: difference in electricity prices in the target year in the Spanish, French, and Portuguese systems when a FiP support scheme is applied

Figure 12 shows that, again, the prices of Spain and Portugal are most of the time equal. Prices in France are also lower in this case than those in Spain and Portugal. However, there are still some hours when prices in France are very high.

Table 13: Average electricity prices in France, Spain and Portugal under a FiP scheme

System	Average price [€/MWh]
Spain	97
France	47
Portugal	103

Table 13 confirms that the application of a FiP reduces prices in the system. The reduction of prices is especially remarkable for the French system. Despite this system already has the lower prices in the base case, the implementation of a FiP scheme reduces these prices by about a 22%. The reduction in prices in Spain and Portugal is almost the same for the two systems (6%-7%).

Table 14 shows the number of hours in the three power systems when electricity prices are zero. Note that the number of hours in France when the price is zero grows from 82 to 190 hours w.r.t. the base case.

Table 14: number of hours with zero prices under a FiP scheme

System	Hours
Spain	6
France	190
Portugal	5

The total annual generation dispatch costs (operation short-term costs) of the system are displayed in Table 15. These costs do not include the investment costs of the units installed between 2020 and 2030. They are provided separately for thermal and RES technologies within Spain, France and Portugal. Notice that, although RES units include wind, solar and Other RES technologies, the costs associated with this group come only from the Other RES technologies, since the variable costs of wind and solar are zero.

Table 15: total annual generation dispatch costs in the 2030 horizon for the case where a FiP scheme is applied

	Thermal technologies	RES technologies	Total
Spain	9,469	7,706	17,175
France	6,478	7,525	14,003
Portugal	1,718	273	1,991
Total	17,665	15,504	33,169

Total generation dispatch costs increase significantly with respect to the base case (by about 35%). This increase is a result of the increase taking place in the production from Other RES technologies, whose variable costs are high. Thus, the total dispatch costs of RES technologies (only Other RES technologies have a variable production cost in this group) rise from only 192M€/yr to 15,504M€/yr. As previously mentioned, due to this increase in the energy produced by RES generation, thermal units reduce their production (mainly nuclear and CCGTs). Therefore, the dispatch costs incurred by thermal technologies also decrease.

France is the system where the increase in the dispatch costs is largest (about 42%). Dispatch costs also increase in Spain and Portugal due to the increase in the production by Other RES technologies. But this increase is partly compensated by a decrease in the dispatch costs incurred by thermal generation. Thus, for example, the dispatch costs of the OtherRES technologies in Spain increase in about 7,700M€/yr while the dispatch costs of thermal generation decrease in about 5,000M€/yr. The dispatch costs of OtherRES generation increase in the French system in the same amount as in Spain, while the thermal dispatch costs in this system decrease only in about 1,500M€/yr.

Table 16 shows the revenues and net benefits from the production of energy of each RES generation technology in each country. Revenues and benefits are divided into several types:

- Market revenues only. These amount to the revenues earned by RES generation from the sale of energy at the market price, e.g. revenues from premiums are not considered.
- Revenues from premiums. These amount to the extra revenues obtained thanks to the application of premiums. Thus, these are the extra funds provided by the system to RES generation.
- Net benefits in the dispatch. These amount to the total revenues obtained in the dispatch by each RES technology less the variable costs of producing electricity. They include revenues from premiums.

Net benefits are able to recover the investments costs of all RES generation technologies, as it can be seen by comparing these to investment costs.

Table 16: energy revenues from the market, those from the application of FiP, and net benefits obtained in the generation dispatch by each technology within each country

Units	Location	Market revenues only [M€/yr]	Revenues from premiums [M€/yr]	Net benefits in the dispatch [M€/yr]
Wind	Spain	3,089	0	3,089
Solar	Spain	2,470	0	2,470
OtherRES	Spain	4,397	6,583	3,274
Wind	France	1,528	1,492	3,020
Solar	France	664	1,668	2,332
OtherRES	France	1,844	8,269	2,604
Wind	Portugal	164	0	164
OtherRES	Portugal	170	197	94

Due to the reduction taking place in market prices, market revenues of those technologies whose production is not largely affected by premiums are lower. This is not a problem for wind generation in Spain and Portugal, but it is for wind generation located in France.

Unit revenues from the production of energy by each RES generation technology built in the period 2020-2030 in each country are provided in Table 17. These revenues are only computed for the hours when these units produce electricity, and include both the revenues coming from the market and from the application of FiP. Moreover, the ratio of the total revenues earned by this generation to the average market price of the system over these same hours is also provided.

Table 17: average unit energy revenues (including those from the market and the application of FiP) obtained by each RES generation technology within each country and average marginal price in the generation dispatch. Only those hours when the corresponding generators are producing are considered to compute the average price

Units	Location	Unit revenue [€/MWh]	Marginal price [€/MWh]	Coefficient
Wind	Spain	97.2	97.2	1.0
Solar	Spain	97.6	97.6	1.0
OtherRES	Spain	245.4	98.4	2.5
Wind	France	85.7	46.7	1.8
Solar	France	135.0	43.0	3.1
OtherRES	France	236.2	46.7	5.1
Wind	Portugal	103.2	103.2	1.0
OtherRES	Portugal	230.3	106.3	2.2

Wind and solar generation in Spain and wind generation in Portugal are earning revenues from the production of energy that coincide with the ones from the sale of energy in the market, since they are not receiving any support. Then, assuming that the market price coincides with the short-term value of energy, the short-term price signals being applied to these generation technologies in these countries are efficient, i.e. these price signals drive this generation to produce electricity only when the cost of producing this electricity is lower than its short-term value for the system.

On the other hand, short-term revenues from the production of electricity by OtherRES generation in Spain; wind, solar, and OtherRES generation in France; and OtherRES generation in Portugal are significantly larger than revenues from the sales of electricity in the short-term market by this generation, as a consequence of the application of high premiums on the production of electricity by this generation. Specifically, the former are between 1.8 and 5.1 times larger than the latter. This involves that the total price earned by this generation per unit of energy produced is significantly larger than the market price, representing the short-term value of this energy. Here we are assuming that the development of new technologies is driven by the learning effects of the production of the components of power plants and their installation, not by the production of electricity by these power plants. Under the previous assumptions, one shall conclude that there are probably many hours, the ones when the market price is lowest among the ones when RES generation being supported is producing electricity, when this generation decides to produce electricity whose cost is higher than its short-term value, thus replacing other generation in the dispatch whose energy production cost is lower. As a result of this, the application of premiums on these technologies is interfering with efficient short-term signals and resulting in an unnecessary increase in the system operation costs.

3.5 Feed-In-Premium auction: floating premium

This section considers the application of a Feed-In-Premium (FiP) scheme. However, contrary to the previous section, the premium applied over the market prices is floating. This premium is computed as the difference between the reference value and the reference market price:

- Reference value: This is the value that the generation units would need to earn in order to receive an income that guarantees the recovery of the investment costs.
- Reference market price: It is the average market price over a predefined market price (hourly, monthly…), and it can be computed ex-ante or ex-post.

The support provided by this scheme, together with the estimated revenue obtained in the short-term market, must guarantee the recovery of the investment costs. Hence, the revenue obtained by the generation agents comes from two different sources:

$$Revenue\_support(g) = Gross\_Production(g) \cdot [ref\_value(g) - ref\_market\_price(g)]$$

$$Revenue\_market(g,h) = Production(g,h) \cdot market\_price(g,h)$$

If the reference market price is computed for a long time period and the amount of energy to be remunerated by the support scheme does not depend on the energy finally dispatched, but, instead, coincides with the gross energy production, agents do not have any incentive to change their offers in the short-term market (they will make optimal offers). Therefore, the short-term operation is the same as the optimal one.

Under these conditions, this option is very similar to **long-term clean capacity auctions**, because the revenue obtained by the subsidy is fixed and it does not depend on the energy sold in the short-term market by RES generation.

3.6 Long-term clean energy auction

A long-term clean energy auction would sell a pre-determined amount of energy of the different RES generation units in the long-term. In addition, this energy sold in the long-term would be subject to a premium over the market price. The remaining energy, which is not sold in the long-term, is sold in the short-term market and is remunerated at the market price. Hence, the revenue obtained by the generation agents comes from two different sources:

$$Revenue\_market(g,h) = Production(g,h) \cdot market\_price(h)$$

$$Revenue\_longterm(g,h) = Production\_longterm(g,h) \cdot premium(g)$$

The premium only applies to the energy sold in the long term. Notice that agents of the system must dispatch the energy sold in the long-term. Thus, they have to ensure the production of this amount of energy. Some units – like wind and solar – will not have any problem to sell this energy (they will dispatch almost all the production they have). But other type of units – like OtherRES technologies – will have to adapt their offers to guarantee the dispatch of the amount of energy sold in the long-term. They will change their offers at specific times using the following formula:

$$Offer(g,h) = marginal\_cost(g) - premium(g)$$

The modified offers will occur in the hours in which they have more probability to be dispatched: the most expensive ones. This is due to the fact that they would obtain a higher revenue in the market for selling this energy in these hours (the market price is higher). Notice that RES generation changes only its offers in the minimum amount of hours required to comply with the energy production that was sold in the long-term. As a consequence of changing the offers in some hours, the operation of the power system is affected, and then it will be different than the optimal one.

3.6.1 RES Support

This section shows the premiums to be applied in order to guarantee the recovery of the investment costs by RES generation being supported as well as to guarantee that the amount of energy sold in the long term auction by subsidized RES generation, in this case set to 50% of its overall potential production (gross production), is actually produced by this generation and dispatched in the market. Then, a different premium is applied to each generation technology in each country, see Table 18. The premium is deemed to be only applied to the energy sold in the long-term auction. The remaining energy sold is remunerated at the market price.

Table 18: premiums to be applied to the energy sold in the long-term for the several generation technologies in each national power system

Units	Location	Premium [€/MWh]
Wind	Spain	0
Solar	Spain	0
OtherRES	Spain	197
Wind	France	77
Solar	France	187
OtherRES	France	233
Wind	Portugal	0
OtherRES	Portugal	182

3.6.2 System Operation

The fact that part of the energy produced by new RES generation has been sold in a long-term auction affects the offers made by these generators in the energy market. Wind and solar generators do not need to change their offers in order to guarantee that they shall be dispatched in the energy market at least the amount of energy sold in the long term auction (50% of their potential production). However, OtherRES generators need to change their energy market offers, taking into account in them, together with their variable production costs, the premium they are earning for energy sold in the long-term auction, in order to be dispatched at least the amount of energy they have sold in the long term. They do so in those hours when prices are highest. As a result, the operation of the power system changes. The amount of energy produced by each technology in each country under this support scheme is provided in Table 18.

Table 19: electricity produced annually in 2030 by each technology when a long-term energy auction is applied to support RES generation (applied to 50% of gross energy production)

Technology	GWh		Spain	France	Portugal
Nuclear	368,065	38%	50,836	317,229	0
Coal	19,505	2%	16,873	2,632	0
GT	903	0%	178	127	598
CCGT	111,404	11%	82,466	13,078	15,861
Oil	7,210	1%	0	7,210	0
OtherNonRES	220	0%	8	201	11
Hydro	130,032	13%	70,223	52,030	7,779
Wind	214,747	22%	122,381	76,446	15,919
Solar	73,448	8%	43,218	28,340	1,891
OtherRES	43,406	4%	24,996	17,698	712

The application of premiums resulting from a long-term clean energy auction results in a slight change in the operation of the power system, mainly affecting the operation of CCGT and OtherRES units. CCGT units decrease their production to 11% of the total one, while OtherRES generation increases its production from 0% to 4%. This increase in the production by OtherRES generation is also reflected in the amount of energy spillage incurred by these units. Under this support scheme, the spillage of energy by this kind of generation is reduced from a 99% to 61% of the overall amount of energy it has available.

Table 20: energy spillages incurred by each RES generation technology

RES	Spillage
Wind	0%
Solar	0%
OtherRES	61%

Finally, the operation of the power system results in 64 $MtCO_2$ emissions.

3.6.3 System prices and costs

The market price and operation costs of the power system under study are affected by the changes in the operation of the power system resulting from the organization of long-term clean energy auctions. Figure 13 displays the three monotonic price-difference curves for the three pairs of countries in the region. As displayed in this figure, market price differences between Spain and Portugal are zero in most of the hours. In contrast, prices in these countries differ from those in France in almost every hour of the year. This figure also shows that the market price in France is lower than that in Spain and Portugal in all hours but those when there are energy scarcity problems (hours with a difference in price close to 1,000€/MWh).

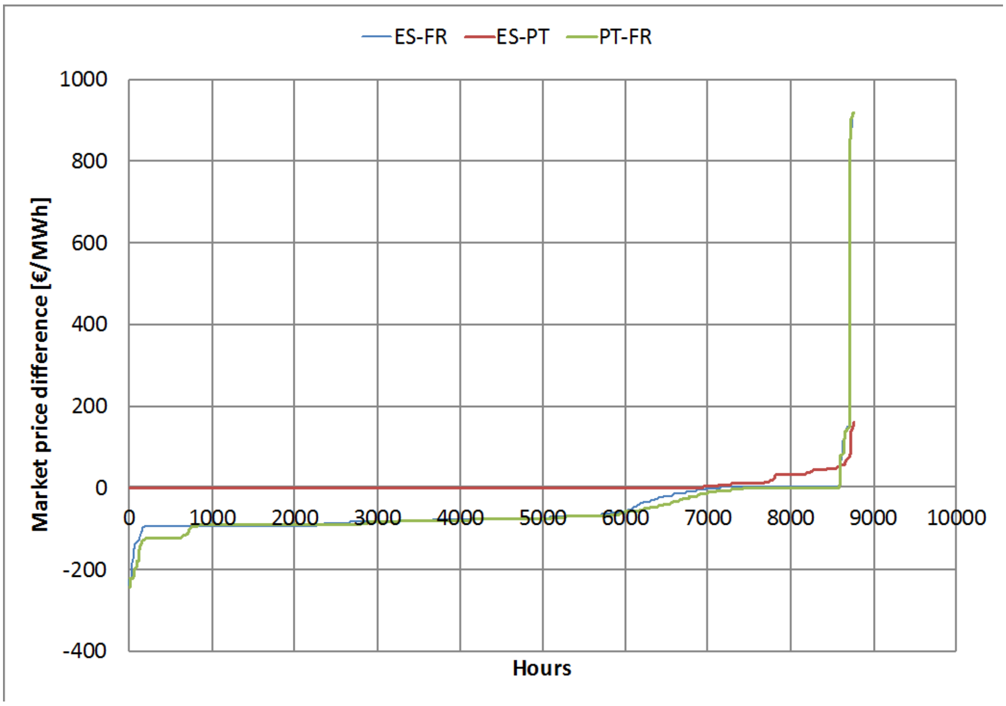


Figure 13: difference in market prices among the different power systems under a long-term energy auction scheme

The application of this support scheme involves, in general, a reduction in the market prices of the three national systems. However, this reduction is greater in the French power system. The average market price in each power system is provided in Table 20. This table confirms that the reduction in the price in the French power system is higher than that in Spain and Portugal. The market price in France decreases from 60€/MWh to 48€/MWh, while in Spain and Portugal prices only decrease by 2€/MWh on average terms.

Table 21: Average electricity prices in France, Spain and Portugal under a long-term energy auction

System	Average price [€/MWh]
Spain	102
France	48
Portugal	108

However, it is remarkable that this reduction in market prices does not imply an increase in the number of hours when the market price is zero. On the contrary, the number of hours when the price is zero decreases, especially in France (see Table 21).

Table 22: number of hours with zero prices under a long-term energy auction scheme

System	Hours
Spain	1
France	71
Portugal	0

The total annual system operation costs, also called generation dispatch costs, of the region are indicated in Table 23. Notice that these costs do not take into account the investment costs of the units installed in the period 2020-2030, but only their short term production costs. Table 23 shows these costs for each type of generation (thermal and RES technologies) and each national power system in the region: Spain, France and Portugal. Notice that, although RES units include wind, solar and OtherRES technologies, the costs associated to this group coincide with those of OtherRES generation, since the short-term production costs of wind and solar are zero.

Table 23: total annual generation dispatch costs in the 2030 horizon under a long-term energy auction scheme

	Thermal technologies	RES technologies	Total
Spain	11,250	4,304	15,555
France	6,991	3,049	10,040
Portugal	1,824	123	1,946
Total	20,065	7,476	27,541

The total generation dispatch costs incurred in the region, when a long-term energy auction for about 50% of gross RES energy production by new generation of this type is implemented, are higher than operation costs in the base case. As previously mentioned, the energy that RES technologies are dispatched increases, mainly for OtherRES units, which are the most expensive ones in terms of short-term production costs. Thus, the operation cost associated with these units rises from almost zero to about 7,500M€/yr in the region. This increase is partially compensated by the decrease taking place in the costs incurred by conventional thermal units (it has been previously explained that CCGT units reduce their production significantly).

The analysis by country shows that the dispatch costs of units located in France and Spain increase by more than 1,000M€/yr in each of these power systems. On the other hand, the dispatch costs in the Portuguese system remains, approximately, the same.

Table 24 provides the revenues and net benefits from the production of energy of each RES generation technology built in the period 2020-2030 in each country. Revenues and benefits are divided into the same types as in the previous section. This table shows that most of the revenues obtained by OtherRES technologies come from the premiums they earn. For example, in the case of the OtherRES generation located in France, the revenues obtained from premiums amount to 73% of the total revenue obtained by these units. Wind and solar generation located in France also earns large revenues from the application of premiums. The net benefits obtained by this generation in the dispatch (revenues from the market sales and premiums less the variable production costs of the corresponding technology) should be able to cover, at least, the annualized investment costs of these technologies (Table 1). As it can be seen, wind and solar generation located in Spain and wind generation located in France do not only recover their investment costs from net revenues in the dispatch, but also make a profit.

Table 24: revenues in the energy market, those from the application of the premiums resulting from the long-term energy auction, and net benefits obtained in the dispatch by each technology in each country

Unit	Location	Market revenues only [M€/yr]	Revenues from premiums [M€/yr]	Net benefits in the dispatch [M€/yr]
Wind	Spain	3,317	0	3,317
Solar	Spain	2,642	0	2,642
OtherRES	Spain	2,672	4,915	3,294
Wind	France	1,599	1,401	3,001
Solar	France	703	1,614	2,316
OtherRES	France	1,494	4,111	2,569
Wind	Portugal	175	0	175
OtherRES	Portugal	88	130	95

Table 25 indicates the unit revenues from the production of energy of each RES generation technology built in the period 2020-2030 in each country. These revenues include both those from the market and the ones resulting from the application of premiums set in the corresponding long-term clean energy auctions, and are computed only for the hours when these units produce electricity. In addition, this table also provides the average marginal price of the system where these units are located over these same hours. The last column of the table provides the ratio of the two previous values, i.e. the one of total short term revenues to market ones.

Table 25: unit short term energy revenues (including those from the market and the ones from the application of the premiums set in the long-term clean energy auctions), and average marginal price in the generation dispatch earned by each new RES generation technology within each country. Only the hours when the corresponding generators are producing electricity are considered

Units	Location	Unitary revenue [€/MWh]	Marginal price [€/MWh]	Coefficient
Wind	Spain	102.4	102.4	1.0
Solar	Spain	102.9	102.9	1.0
OtherRES	Spain	304.4	107.4	2.8
Wind	France	86.5	48.2	1.8
Solar	France	144.2	45.1	3.2
OtherRES	France	326.7	93.7	3.5
Wind	Portugal	108.3	108.3	1.0
OtherRES	Portugal	304.6	122.6	2.5

As in the case of FiP being applied to all electricity production from the supported technologies, only wind and solar generation in Spain and wind generation in Portugal are being applied efficient short-term price signals, which coincide with the short-term market price for those hours when these generation is producing electricity. The rest of new RES generation, which is being supported, earns total revenues from the production of electricity that exceed the ones corresponding to the sale of this electricity at short-term market prices. This may potentially lead to inefficiencies in the dispatch, as discussed for the case of pure FiP being applied to all electricity production by this generation.

However, there are two reasons why inefficiencies in this case should be smaller than those for pure FiP being applied to all the production by technologies being supported. The first reason is the fact that the ratio of total energy revenues to revenues from sales in the market for RES technologies being supported is lower than this ratio when pure FiP are applied. The second reason is the fact that, in the case of clean energy auctions, support provided to RES generation is only being considered by this generation when building their bids in the energy market, thus resulting in a reduction of these bids w.r.t. competitive ones, in those hours when the market price is highest, which are the ones when a decrease in the bids submitted by this generation is less likely to result in this generation replacing in the dispatch other more cost-competitive generation (since in high price hours all types of generation need to be dispatched to achieve the supply of all load in the system).

3.7 Conclusions

Based on the analysis performed in the previous sections, some conclusions can be drawn:

- **Long-term clean capacity auctions** do not provide any incentive to generators to sell more energy in the market than what is optimal for the system, because the subsidy they receive does not depend on the amount of energy sold in the short-term. As a consequence, these auctions do not affect the short-term operation of the power system. Therefore, the operation of the system is the same as the optimal one and thus, short-term signals are efficient.
- The application of a **Feed-In-Premium** scheme with a **fixed premium** provides generators with incentives to sell more energy in the short-term market, because the amount of money received from the mechanism depends on the energy sold. Therefore, generation units change their offers in the market in order to be dispatched and produce more energy. As a consequence, the short-term operation of the power system changes, moving towards a non-optimal one and, therefore, sending non-efficient signals in the short-term. Hence, the generation dispatch costs of the system increase with respect to the optimal operation.
- The application of a **Feed-In-Premium** scheme with a **floating premium** when the reference price considered in the scheme is computed over a long enough period of time and the premium is applied to gross energy production buy RES generation guarantees the required amount of long-term revenues of generators while not providing any incentive to generators to sell more energy in the short-term market. Therefore, the short-term operation of the power system is the same as the optimal one.
- In a **long-term clean energy auction,** generators sell a pre-defined amount of energy in the long-term, which they commit themselves to produce in the short-term, subject to a premium determined by the auction. Therefore, they have strong incentives to produce this amount of energy in the short-term. Some generation units – wind and solar – are probably able to produce this amount of energy without changing their offers in the market. However, other types of units may need to change their offers in order to be dispatched and comply with the amount of energy promised in the long-term. As a consequence, the optimal short-term operation of the power system is no longer achieved and therefore, the generation dispatch costs of the system increase with respect to the optimal operation.

- Conceptually speaking, **Feed-In-Premiums** and **long-term clean energy auctions** produce similar results (they both change the optimal short-term operation of the power system). However, notice that the long-term clean energy auction introduces a cap in the amount of energy whose production is being supported in the short-term (the amount that is sold in the long-term). Therefore, the changes produced in the short-term operation by the application of a long-term clean energy auction are smaller than the ones caused by the application of a Feed-In-Premium. As a consequence, the increase in the generation dispatch costs with respect to the optimal operation is also smaller.

4 Effect of moving the timing of day-ahead markets towards real time

4.1 Background and assumptions of the study

This section discusses the impact on system operation of changing the timing of the day-ahead market getting it closer to the real-time operation of the power system. We assume that reducing the time lag between the day-ahead market and real time results in a reduction in the forecast error of wind production and solar production. As a result of this reduction in the forecast error, the amount of operating reserves required by the system operator would also decrease.

The analyses described in this section have been carried out using the ROM model developed by IIT-Comillas. The analyses carried out comprise only the power system of Spain, while not considering its internal network. The time scope of the analysis is one year (8,760 hours), and the target year considered is 2030. The generation capacity and demand considered are based on the Vision 3 of the TYNDP-2014; RES generation profiles are scaled-up based on the RES profiles obtained in 2013 and on the forecasted installed capacity for 2030.

The analysis carried out in this section takes into account both the day-ahead market (unit-commitment) and the real-time simulation of the power system. The up and down reserves required are obtained based on these formulas (Gil et al, 2010):

$$UpReserve(h) = \alpha \cdot Demand(h) + MaxUnit(h) + \beta \cdot RES(h)$$

$$DwReserve(h) = \alpha \cdot Demand(h)$$

The up reserve shields the system from the uncertainty in the demand and RES generation and the failure of the biggest unit generating electricity. In this analysis, only the uncertainty coming from wind and solar generation is being considered. The down reserve protects the system only from the uncertainty in the demand. Thus, parameters α and β are calculated in order to protect the system from a pre-determined uncertainty degree of these sources. In the analysis carried out in this section, parameter α is selected to shield the system for 2% error in the demand and parameter β is calculated to protect the system for 90% of the errors in the prediction.

The methodology employed in the analyses is described with more detail in Market4RES deliverable D5.1.

4.2 Reduction of wind forecast error

Figure 14 displays the short-term electricity production costs for the base case and the cases where the wind forecast error is reduced by 2.5%, 5%, 10%, 30%, 50% and 75% w.r.t. the base case. As it can be seen, the reduction in the forecast error does not necessarily imply a reduction in the dispatch costs when changes in this error are small (2.5% to 10%). However, reducing this error almost always helps authorities to integrate more RES energy into the power system, thus reducing RES energy spillages (see Figure 16).

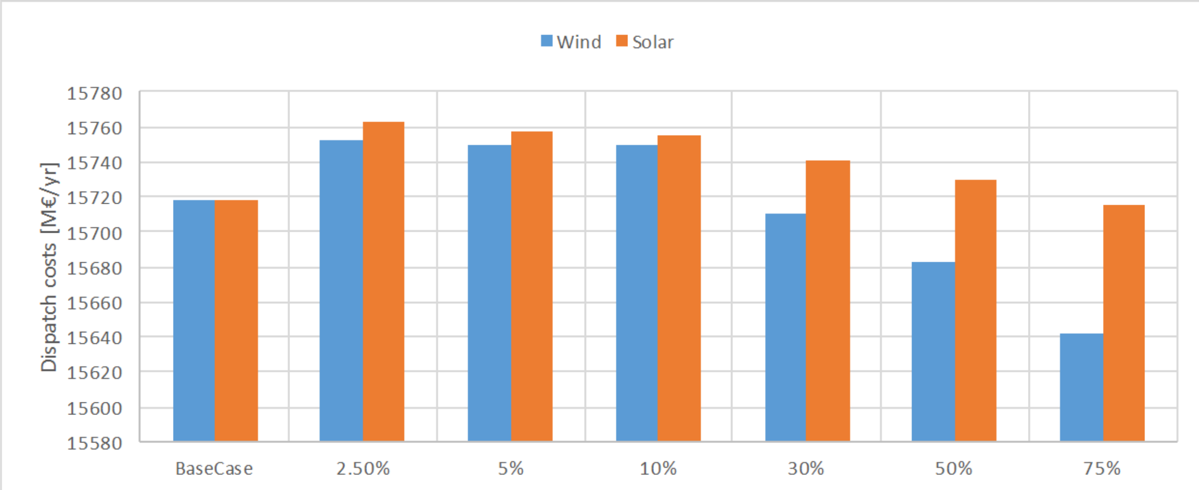


Figure 14: evolution of the generation dispatch costs along the reduction in the wind (blue) and solar (orange) forecast error

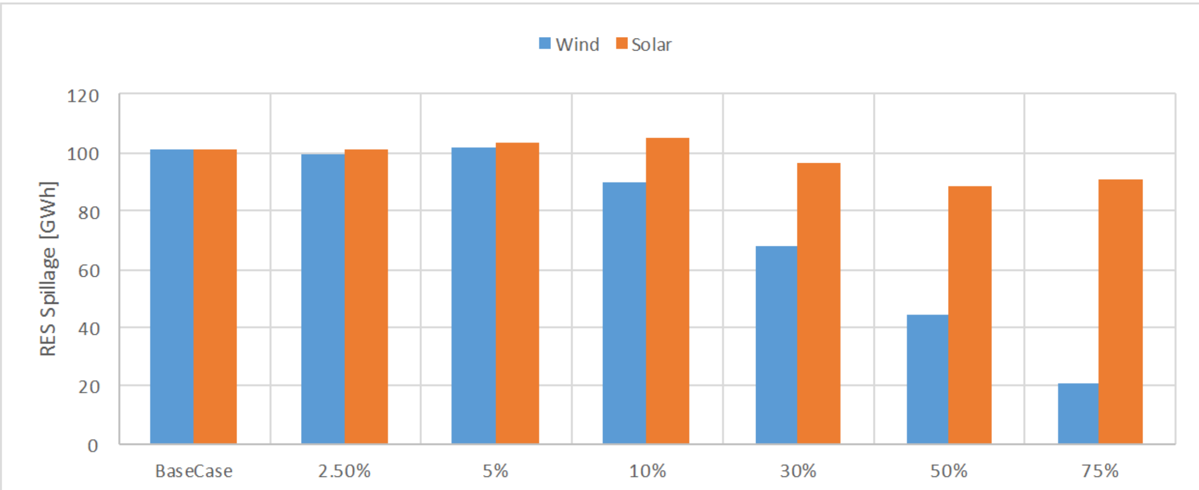


Figure 15: evolution of the RES energy spillage along the reduction in the wind (blue) and solar (orange) forecast error

Figure 16 displays the evolution of the total reserve required by the System Operator and the reserve provided by thermal units along the reduction in the wind forecast error. Figure 17 provides the evolution of the energy production by thermal generation along the reduction in the wind (and solar) forecast error. The reduction of the wind forecast error should imply that the System Operator requires a lower amount of up reserves. Besides, given that the reduction of the forecast error allows an increase in the amount of RES energy being integrated into the system, the amount of energy produced by thermal generation should also decrease with the error. However, the reduction in the amount of reserves required is only significant for high reduction levels of the forecast error (from 30% on). For low levels of reduction of the total amount of reserves required, the amount of reserves provided by thermal units does not decrease. It, instead, increases, as Figure 16 shows. Besides, the amount of energy produced by thermal generation increases for low levels of reduction of the wind or solar forecast error. Electricity production by thermal generation only decreases for high levels of reduction of the wind or solar forecast error.

This is so because new RES energy being integrated into the system results in some flexible generation plants, largely hydro ones, being no longer committed. Hydro plants can be left out of the dispatch in those hours when they are not needed while being committed in others where their power production is needed. However, thermal units are less flexible due to, among other things, the technical minimum production levels they have and the long periods of time over which they need to remain non-committed when being constrained off. Hence, thermal generation cannot be committed selectively in specific hours while not being committed in others. Due to this, part of the electricity being produced and up reserves being provided by hydro units in the base case are being produced, or provided, by thermal units for low levels of reduction of the wind (or solar) forecast error. This means that thermal production costs increase for low levels of reduction of the wind forecast error, since, in this case, more electricity is produced by thermal generation and this electricity is largely being produced by units that are not operating at their nominal rate, but at a lower rate in order to be able to provide upward regulation reserves.

Of course, this only occurs for low levels of reduction of the wind, or solar, forecast error. For high levels of reduction of the forecast error, the extra amount of RES energy integrated into the system and the decrease in the amount of reserves required by the System Operator are large enough to keep some extra thermal units non-committed for long enough periods of time. As a result of this, the amount of electricity produced and reserves provided by thermal generation decreases with respect to the base case and, therefore, the system operation costs decrease as well.

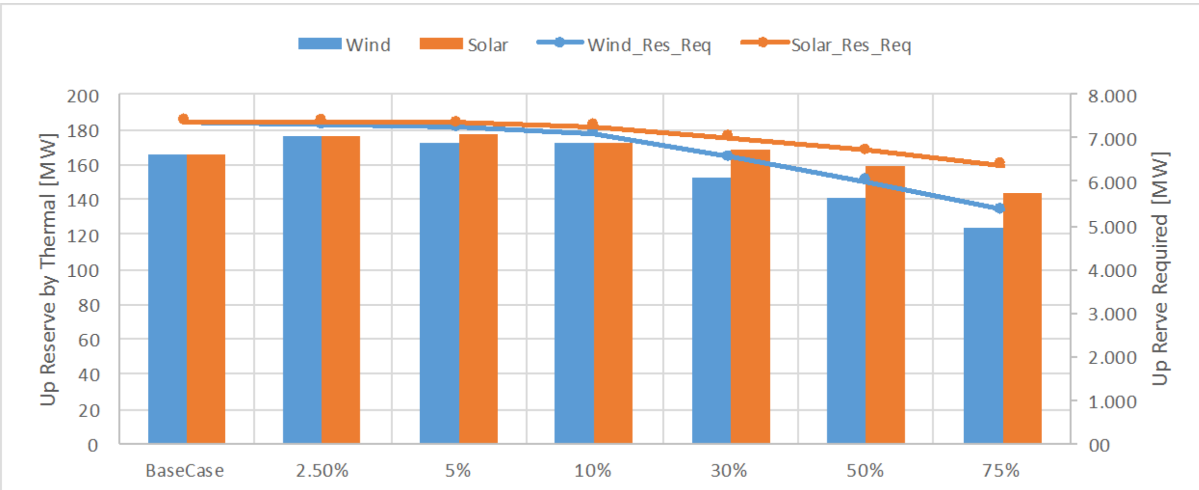


Figure 16: evolution of the amount of up reserves provided by thermal units (bars) and total up reserve required in the system (lines) along the reduction in the wind (blue) and solar (orange) forecast error

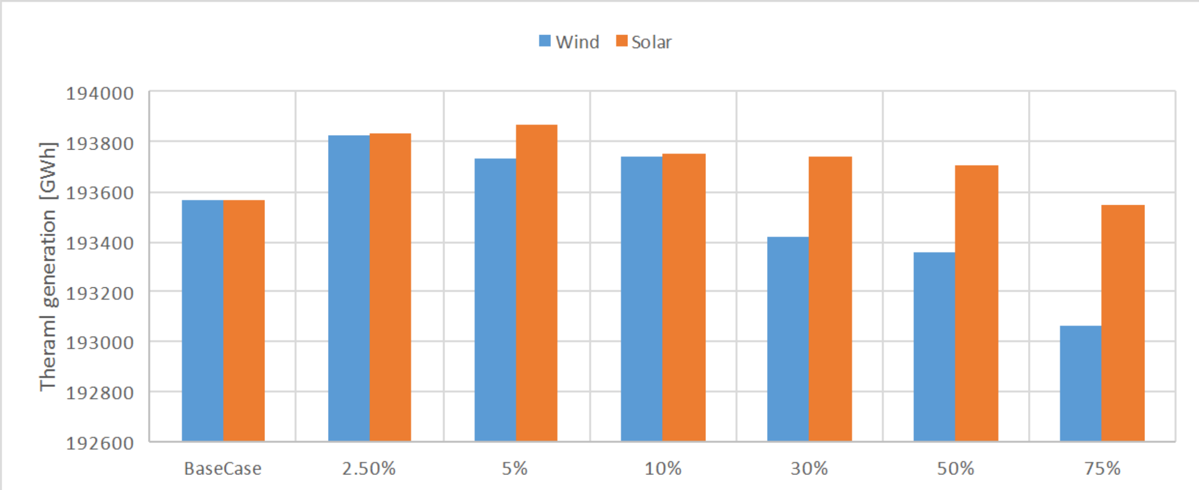


Figure 17: evolution of the electricity production by thermal generation along the reduction in the wind (blue) and solar (orange) forecast error

4.3 Reduction of the solar forecast error

The evolution of the short-term electricity production costs along the reduction in the solar forecast error is displayed in Figure 14. Figure 15 displays the effect of this reduction on RES energy spillages. As shown by these figures, reducing the solar forecast error may not help authorities to reduce the system dispatch costs. In fact, these costs increase slightly until the solar forecast error is reduced by 75%. On the other hand, reducing the solar forecast error to a large enough extent (from 30% on in our analyses) helps authorities to integrate more RES energy into the system.

The evolution of system operation costs with the level of reduction of the solar forecast error is analogous to that of operation costs with the level of reduction of the wind forecast error. Operation costs evolution along the solar forecast error can be explained using the same arguments provided when discussing the impact of the wind forecast error on system operation costs, see the discussion in section 4.2 and Figure 16 and Figure 17. However, due to the fact that the solar forecast error is –usually– smaller than the wind one, only very large reductions in the solar forecast error (from 75% on) result in large enough reductions in the level of regulation reserves needed in the system and the amount of RES energy spillages (or large enough increases in the amount of RES energy integrated into the system) to achieve a decrease in the amount of electricity produced by thermal generation. Therefore, only for levels of reduction of the solar forecast error of 75% or higher, a reduction in system operation costs is achieved. It is interesting to see that the total amount of regulation reserves required by the System Operator for a 75% reduction in the solar forecast error is very similar to the amount of reserves required for a 30% reduction in the wind forecast error, which is the minimum level of reduction of the latter forecast error for which a reduction in the operation costs is achieved.

4.4 Reduction of wind and solar forecast error

The evolution of the short-term electricity production costs and RES energy spillages with the combined reduction in the wind and solar forecast errors by 2.5%, 5%, 10%, 30%, 50% and 75%

w.r.t. the base case are displayed in Figure 18 and Figure 19, respectively. The results displayed in these figures provide similar conclusions to those drawn from the cases where wind and solar forecast errors are reduced separately. Instead of reducing the system dispatch costs, a small combined reduction of the wind and solar forecast error increases the system dispatch costs. These costs only decrease when the combined forecast error is reduced by 30% or more. Notice that this is the same trigger value identified when only the reduction in wind forecast error is analyzed, while it is lower than the minimum reduction in the solar forecast error, considered alone, that is needed for the dispatch costs to decrease w.r.t. the base case. This is so because the wind forecast error has more weight than the solar forecast error in the total system power imbalance occurring. Besides, reducing the wind forecast error allows the system to increase to a significantly larger extent the amount of RES energy integrated than reducing by the same percentage the solar forecast error. Reducing the forecast error of both types of generation by 5% or more helps authorities to integrate more RES generation into the system. Remarkably, reducing the combined wind and solar forecast error by 75% or more results in almost none RES energy spillage.

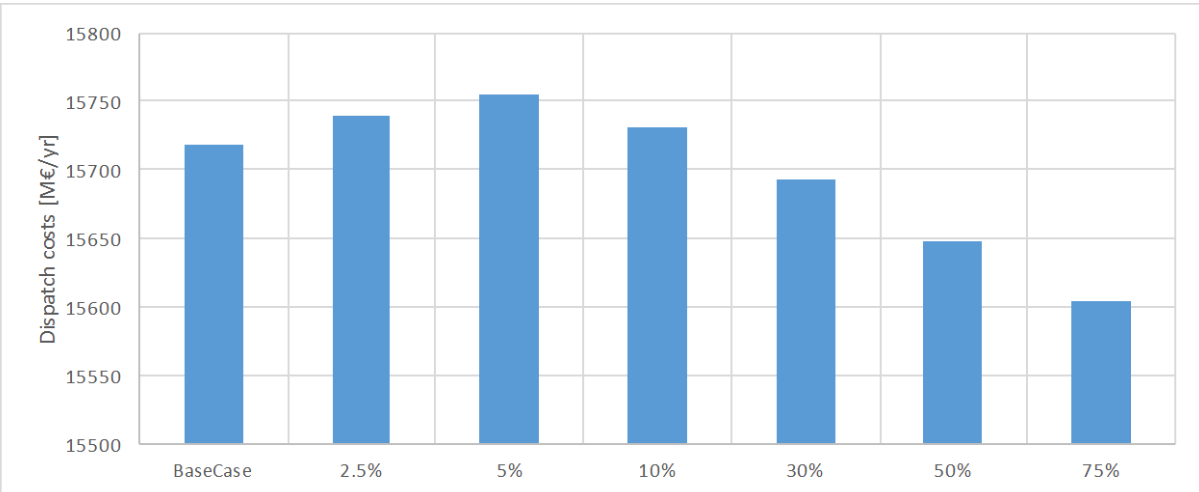


Figure 18: evolution of the generation dispatch costs along the simultaneous reduction in the wind and solar forecast error

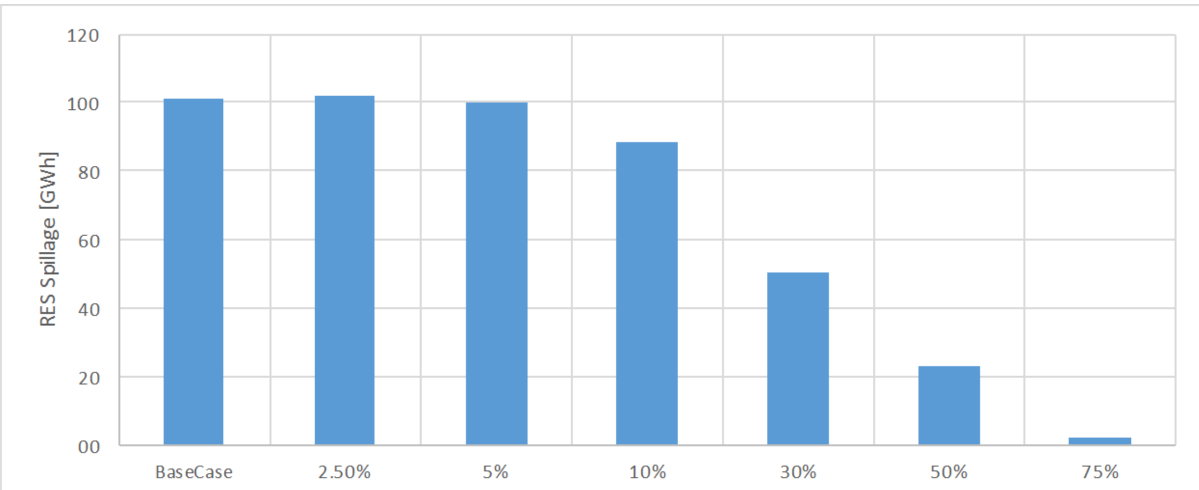


Figure 19: evolution of the RES energy spillage along the simultaneous reduction in the wind and solar forecast error

Figure 20 displays the evolution of the total reserve required by the System Operator and the reserve provided by thermal units along the reduction in the level of the combined wind and solar forecast error. The evolution of the energy production by thermal generation along the reduction in the aggregated forecast error is shown in Figure 21. The same reasoning as for the assessment of the impact of the reduction of the wind and solar forecast errors considered separately can be applied here (see section 4.2, Figure 16 and Figure 17). In this case, both errors are reduced jointly, and thus, the effects of the reduction of the two are combined. Given that the reduction of the wind forecast error is most significant, the combined impact of the reduction of both is more similar to the impact of the reduction of the wind forecast error than to the impact of reducing the solar forecast error.

In this case, a 10% reduction in the combined forecast error already results in an increase in the amount of RES energy dispatched in the power system. Moreover, the level of reserves provided by thermal units for a 10% reduction in the combined forecast error is almost the same as that of reserves provided by thermal generation in the base case. However, the amount of energy produced by thermal generation is still slightly larger than in the base case (due to the reasons explained before). As a result, the generation dispatch costs in the system for a 10% forecast error reduction are still slightly higher than those for the base case. Notice that, when only the wind or solar forecast error is reduced by 10%, the system dispatch costs are still significantly larger than in the base case. For higher levels of reduction of the combined forecast error, the resulting increase in RES energy being integrated into the system and the reduction in the reserves provided by thermal units results in a lower number of these units being committed and a decrease in the amount of energy produced by thermal generation. This, in turn, results in a decrease in the system dispatch costs.

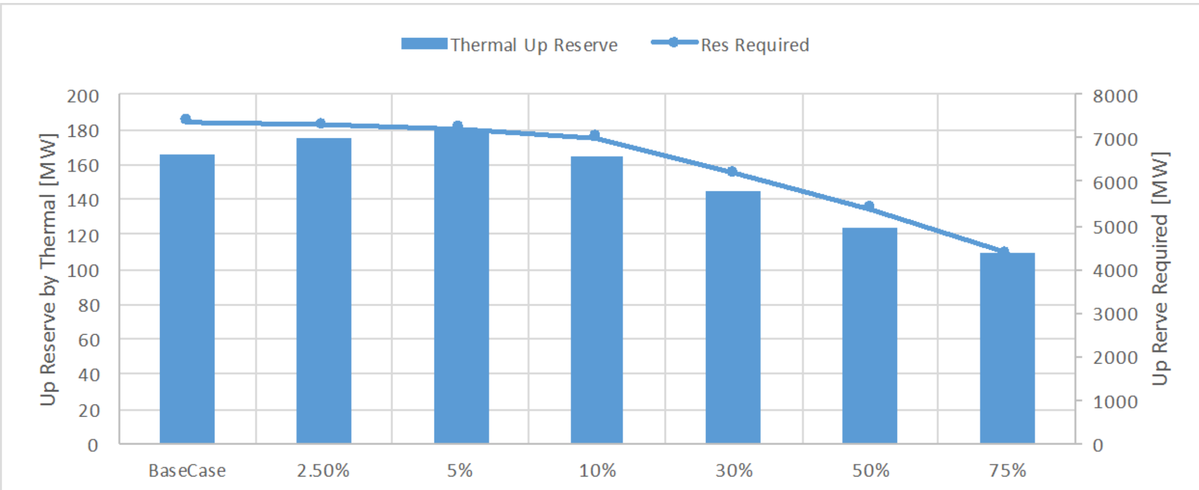


Figure 20: evolution of the amount of up reserves provided by thermal units (bars) and total up reserve required in the system (lines) along the simultaneous reduction of the wind and solar forecast error

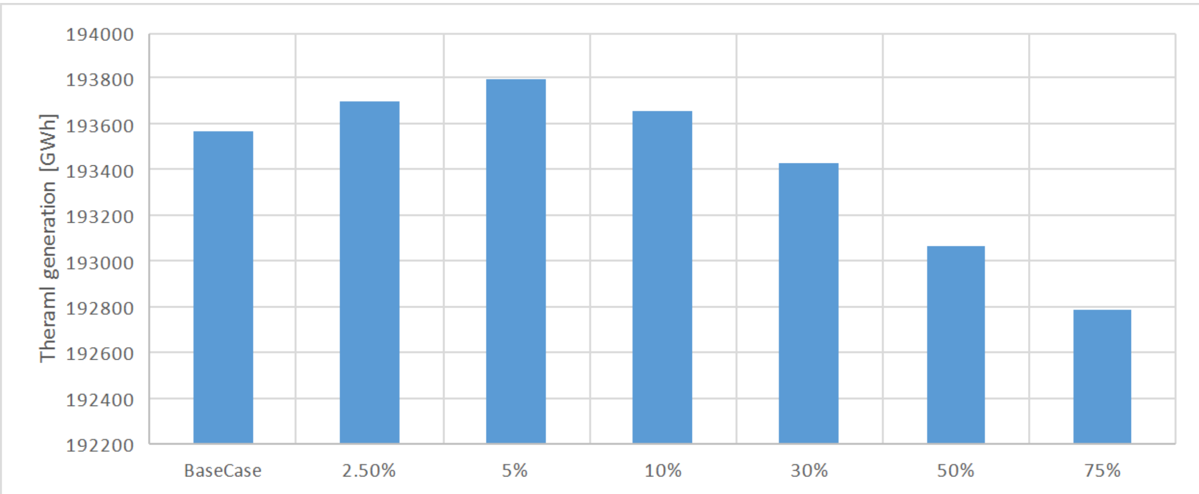


Figure 21: evolution of the electricity production by thermal generation along the simultaneous reduction of the wind and solar forecast error

4.5 Relationship between moving the timing of day-ahead markets closer to real time and the reduction in forecast errors

The previous sections have analyzed how the reduction in the forecast errors of wind and/or solar generation would affect the operation of the power system. This section relates the reduction in the forecast errors of both technologies to the shift closer to real time of the celebration of the day-ahead market. In other words, we will provide data that links the error in forecasting wind and solar production to the number of hours ahead of real time this forecast is made. Figure 22 shows the evolution of the wind forecast error with the lead time of the forecast. As can be seen, 24 hours ahead, the mean of the forecast error is about 15% of the average production (for the 2009 case).

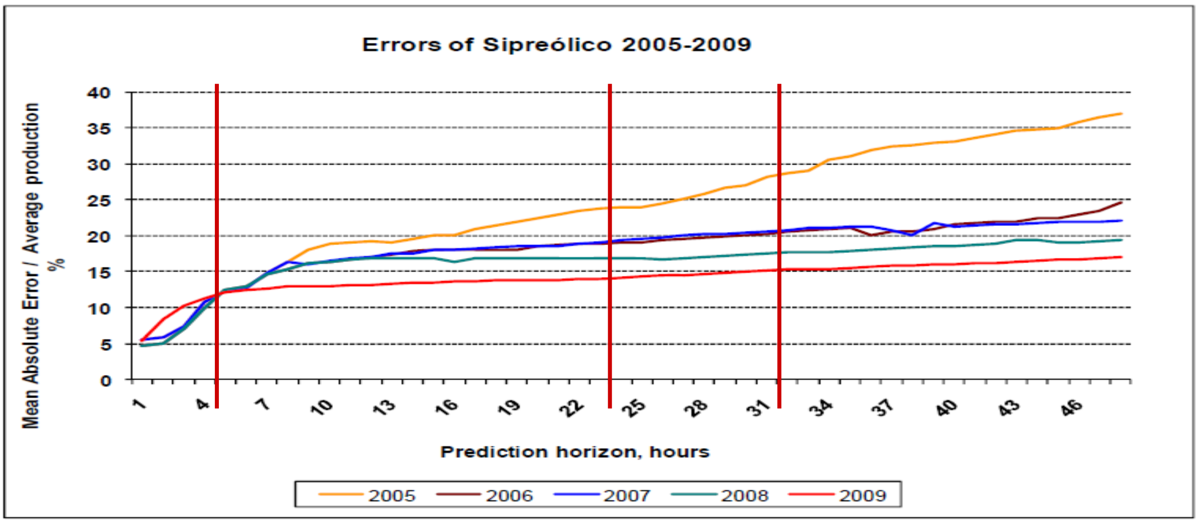


Figure 22: evolution of the wind forecast error along the forecasting horizon

Notice that from hour 4 to hour 24 ahead of real time, the forecast error is almost flat. Thus, moving the day-ahead market closer to real time within this block of hours does not achieve a relevant reduction in the wind forecast error. For example, moving the market closer to real time by 20 hours, i.e. if it is located only 4 hours ahead to real time, the wind forecast error would only be reduced from about 15% to 12.5% of average production (about 17% reduction in the forecast error). Bringing closer the day-ahead market will reduce the forecast error greatly (to a minimum of 5% of average production).

However, moving the day-ahead market closer to real time 20 hours or more is not possible in some power systems, like the Spanish one, because some generation units will not be able to commit in such a short-time period (4 hours for example). Therefore, if the market is run only 4 hours ahead of real time, these units would be left out of the market automatically. However, this is very dependent on the types of units existing the power system. Power systems with a more flexible generation mix may be able to move the day-ahead market as close as necessary to the real-time so as to achieve large reduction in the wind and solar forecast error.

Including intraday markets beyond the day-ahead one could allow the commitment of non-flexible plants in the first one while still leaving some of them out of the final dispatch eventually if this is needed. However, changes in the commitment state of non-flexible units in the intraday markets would still be limited by the maximum lag of time ahead of real time they can be constrained-off.

4.6 Conclusions

Based on these analyses, several conclusions can be depicted:

- Bringing closer the day-ahead market to real time only a few hours is not worthy sensible option, because the small reduction in the wind and solar forecast error does not result in a reduction in generation dispatch costs.
- The day-ahead market needs to be very close to real-time to achieve a reduction in the forecast errors that is enough to produce benefits in the operation of the power system.
- Bringing closer day-ahead markets this amount of hours would not be possible for some power systems due to the lack of flexibility of their generation mix. If the day-ahead market is very close to the real-time, some generation units will not be able to start-up or shut-down in the required time and therefore, they will be automatically out of the market. Intraday markets could be useful in this regard, though to a limited extent.
- Other power systems with more flexibility of their generation mix, like the Nordic ones, may consider moving their energy market closer to real time to the extent it is useful.

5 Impacts of RES support on incentives for the deployment of Demand Side Response in the long-term

5.1 Scope of the study

5.1.1 Aim of the study

An electrical mix characterized by a high share of RES brings about a need in peak load installed capacities. Demand response represents a significant flexibility potential in the electrical system and could therefore limit the system costs by enabling the load to better follow the volatility of the variable production. However, policies aiming at developing RES technologies beyond the levels at which their profitability is ensured by the sole market price affect adversely the profitability of the other capacities in the electricity mix and, in particular of demand response.

Thus, the aim of this study is to identify the impact of RES support policies on demand response's deployment and profitability on a mid-term and long-term basis.

5.1.2 Methodology

The study is conducted (for France considered as isolated, see below) for the four Market4RES scenarios (see deliverable D5.1 for a detailed description of each scenario):

- **The 2020 scenario** regarded as the mid-term scenario
  Besides, two additional scenarios are set up to complete mid-term analyses. They model a transitional state before removal of some installed capacities:
    - **The 2020 scenario N1:** Installed capacities are those obtained in the 2020 scenario with additional 10 GW of RES. This scenario with excess capacity represents the mid-term effect of RES support policies if industry has not been able to adapt their installed capacities. Mid-term impact on the profitability of DSR's profitability can be analysed.
    - **The 2020 scenario N2:** Installed capacities except DSR are those obtained in the 2020 scenario with additional 10 GW of RES. Unlike previous scenario, DSR's installed capacities are optimally adapted.

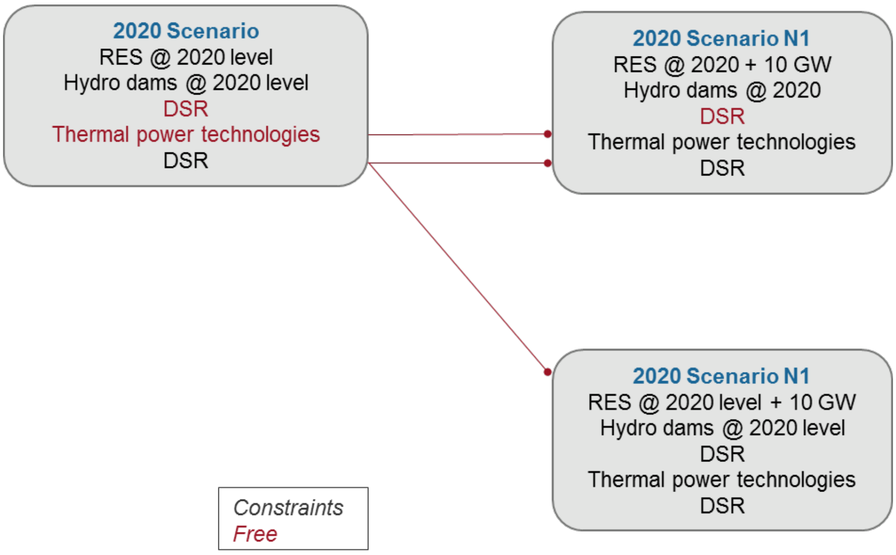


Figure 23: Description of the 2020 scenarios

- **Three long-term scenarios** (2030) which present significant discrepancies in the deployment of variable RES beyond 2020, as presented in Table 26.

	Installed capacities of RES in France (MW)				
Technologies	2020 Scenario	2020 Scenarios + 10 GW of RES	2030 Low scenario	2030 Ref scenario	2030 High scenario
Solar	10 813	13 623	12 000	30 000	49 600
Wind	20 000	25 200	20 000	40 000	52 400
Hydro run-of-river	7 634	9 624	7 400	10 400	10 400

Table 26: RES installed capacities within the different scenarios considered in the study

The data set includes twelve hour-by-hour consumption scenarios and twelve load factor time series for both solar and wind, based on historic weather conditions between 2000 and 2011 so as to be representative of the full distribution of consumption and whether conditions in 2020 or 2030. Additional hourly time series represent the load and the availability of the each technology (thermal power technologies and DSR).

This study relies on the **"MICadO" tool** which is designed **to calculate an optimal electricity mix (in terms of installed capacities) and the optimal production within a year.** The objective function is the total yearly cost of the system and installed capacities can be constrained to represent political decisions or technical potential. The dual value of the supply/demand equilibrium constraint is used as a proxy for the hourly market price, which makes it possible to determine DSR's income.

However, the "MICadO" tool is not able to calculate the optimal electricity mix and dispatching for all the time series at a time. Thus, for computability purposes, we use a virtual year, reconstituted after the Monte-Carlo series thanks to a **pre-selection of relevant "weeks"**. The aim of the week selection is to create a set of 52 weeks (made of hourly values of load) that has a net load duration curve as close as possible to the net load duration curve of the entire data set. The week selection is carried out once for each scenario.

5.1.3 Hypotheses

Geographical scope

In order to limit results to a size that allows to interpret them, and also in reason of the lack of hypotheses on the DSR potential and costs in a wider area, the geographical scope of this analysis is limited to only one country: **France**. No internal grid constraint is considered.

Hypothesis on costs and installed capacities

- First of all, the load shedding cost is set to 20,000 €/MWh to follow a less-than-3-hour-criterion of yearly loss of load duration (LOLD). This criterion is fulfilled by considering the load shedding as a power plant with no installation cost but with a high variable cost for production. This load shedding power plant has the highest variable cost among all power plants. Thus it represents the last power plant that can be dispatched in the merit order.
- The costs of conventional technologies used in the study are detailed in the appendix. Only some of them are constrained in capacity; such constraints are also described in the appendix.
- The study is conducted for two different **fixed costs for residential DSR**: 11,000 €/MW (cheap distributed DSR hypothesis) and 29,000 €/MW (expensive distributed DSR hypothesis).

Modelling DSR

DSR can be modeled as a power plant and the energy that this power plant produces corresponds to load voluntarily shed. The production can also be negative if the shed energy is adjourned on the following hours. It would probably be too far from reality to model DSR as only one homogeneous technology, because the first MWs of installed capacity are easier (and thus cheaper) to put in place than the following ones and industrial DSR and distributed DSR have very different features. Two types of DSR objects are therefore regarded in this study:

- **Industrial DSR**: The maximum capacity in France is set to 8 GW with fixed costs (FC) increasing as a function of the installed capacity from 10 to 55 k€/MW/year by 1 GW steps[5]; their variable cost is 300 €/MWh. Industrial DSR, through load shedding or self-production, is considered without rebound effect and available during working hours (see Figure 24, Figure 25 and Figure 26). Later in this report, these industrial DSR "technologies" will be referred to as Ind_DSR_1 (the cheapest, with fixed costs of 10 k€/MW/year) to Ind_DSR_8 (the most expensive).

[5] Corresponding to an expert estimate of the industrial demand response potential in France. The costs are chosen arbitrarily from 10 k€/MW/year to slightly less than 60 k€/MW/year, i.e. the annualized fixed cost of an open-cycle combustion turbine, by steps so as to model the fact that some resources are more expensive than others (for example smaller industrial sites are generally more expensive to equip and manage).

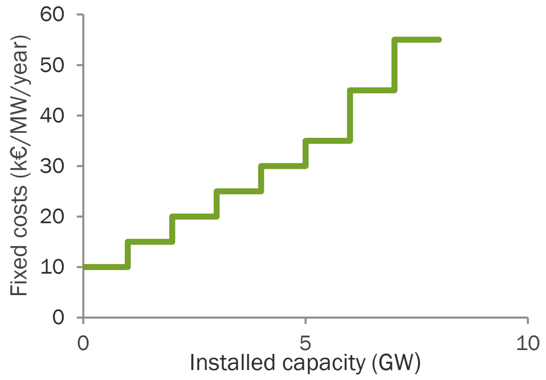


Figure 24: Fixed costs of industrial DSR (GW)

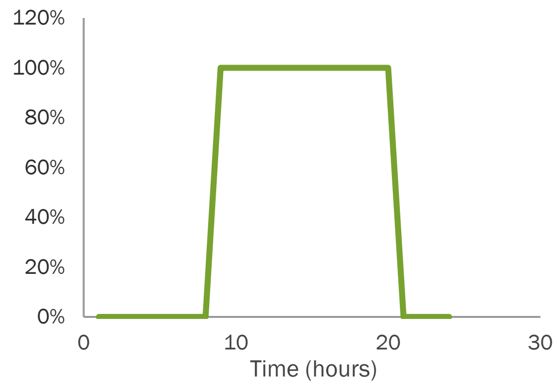


Figure 25: Availability daily profile of industrial DSR

- **Distributed (residential) DSR:** A maximum capacity of 10 GW is considered, with investment costs set at 11 k€/MW (cheap dDSR) or 29 k€/MW (expensive dDSR) [RTE 2014]. Their variable cost is 50 €/MWh and a 50 % rebound spread over the 6 hours subsequent to the shedding is implemented (see Figure 26). The availability of distributed DSR (dDSR) is computed based on the per household-average consumption of electric heating in France in each scenario. Tertiary DSR is not considered in this study.

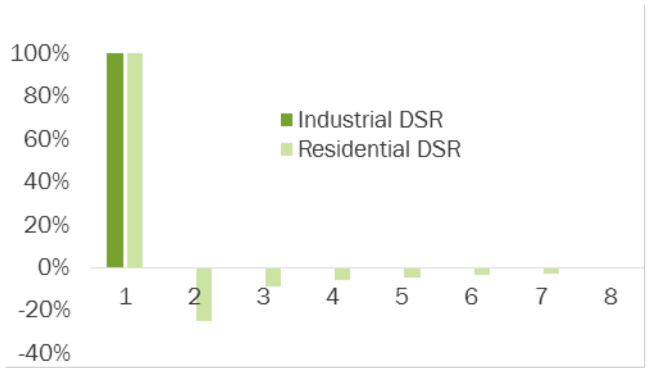


Figure 26: Activation profile of DSR

5.2 Results

5.2.1 Adequacy (all scenarios)

Scenarios	Loss of load duration: Case 1: cheap dDSR hypothesis (FC=11,000 €/MW)	Loss of load duration: Case 2: expensive dDSR hypothesis (FC=29,000 €/MW)
2020 Scenario	2 hours	3 hours
2020 Scenario N1	1 hour	1 hour
2020 Scenario N2	1 hour	1 hour
2030 Low scenario	2 hours	2 hours
2030 Ref scenario	0 hour	3 hours
2030 High scenario	1 hour	3 hours

Table 27: loss of load duration for each scenario and for cheap and expensive dDSR cases

5.2.2 Equilibrium analysis

The results presented in this section correspond to the Market4RES scenarios presented above (2020 and 2030 Reference, Low and High). The generation and DSR mix has been optimized so as to reach a loss of load duration of 3 hours, in the case where distributed DSR is expensive and is therefore not developed. They correspond to a long-term equilibrium of the mix.

Installed capacities

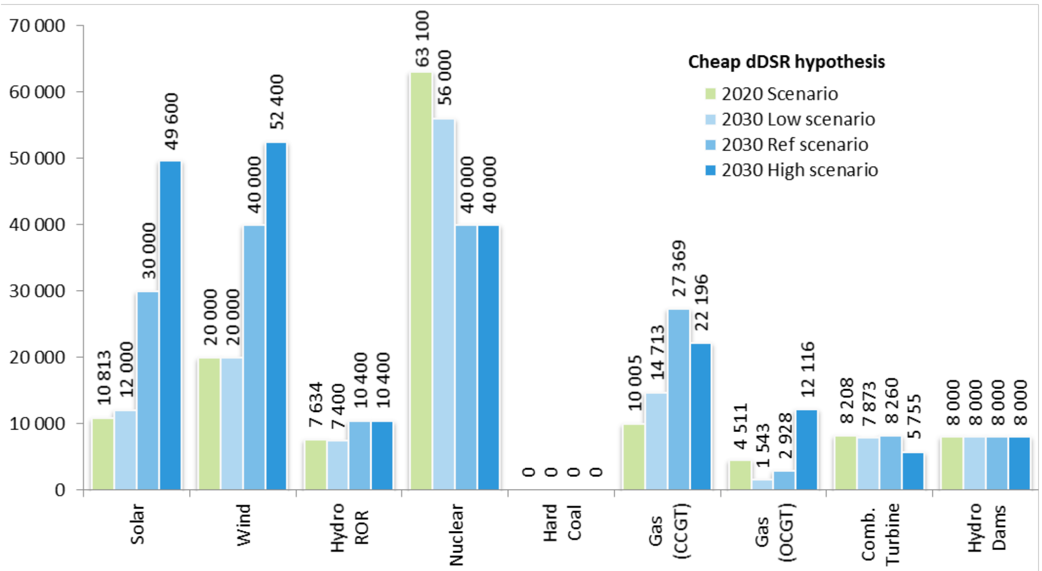


Figure 27: DSR's installed capacities (MW) in each scenario, for both distributed DSR costs hypotheses

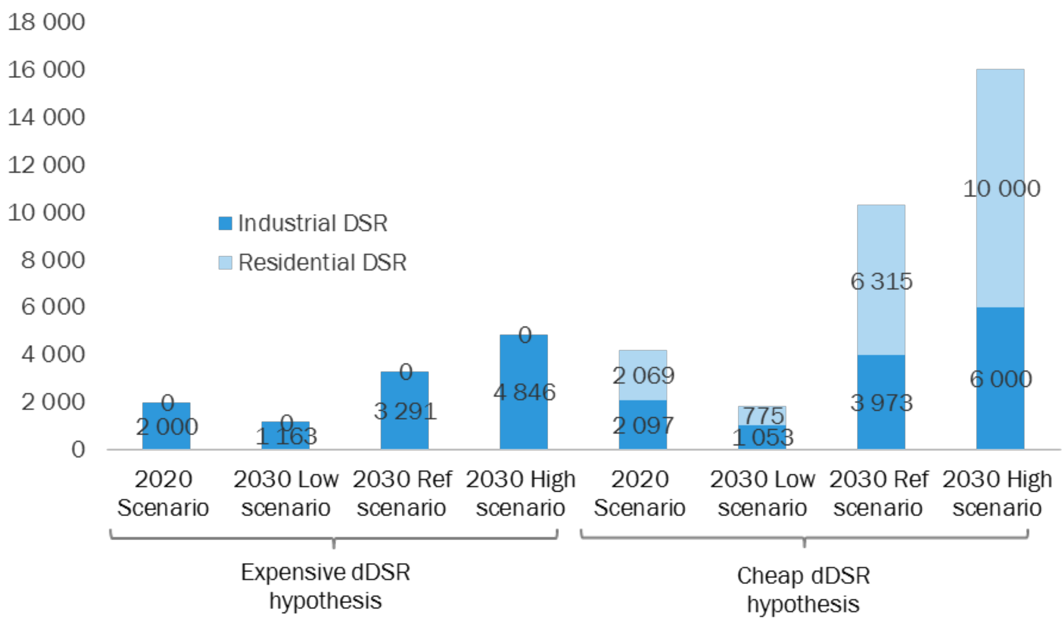


Figure 28: Installed generation capacities (MW) in the cheap dDSR hypothesis

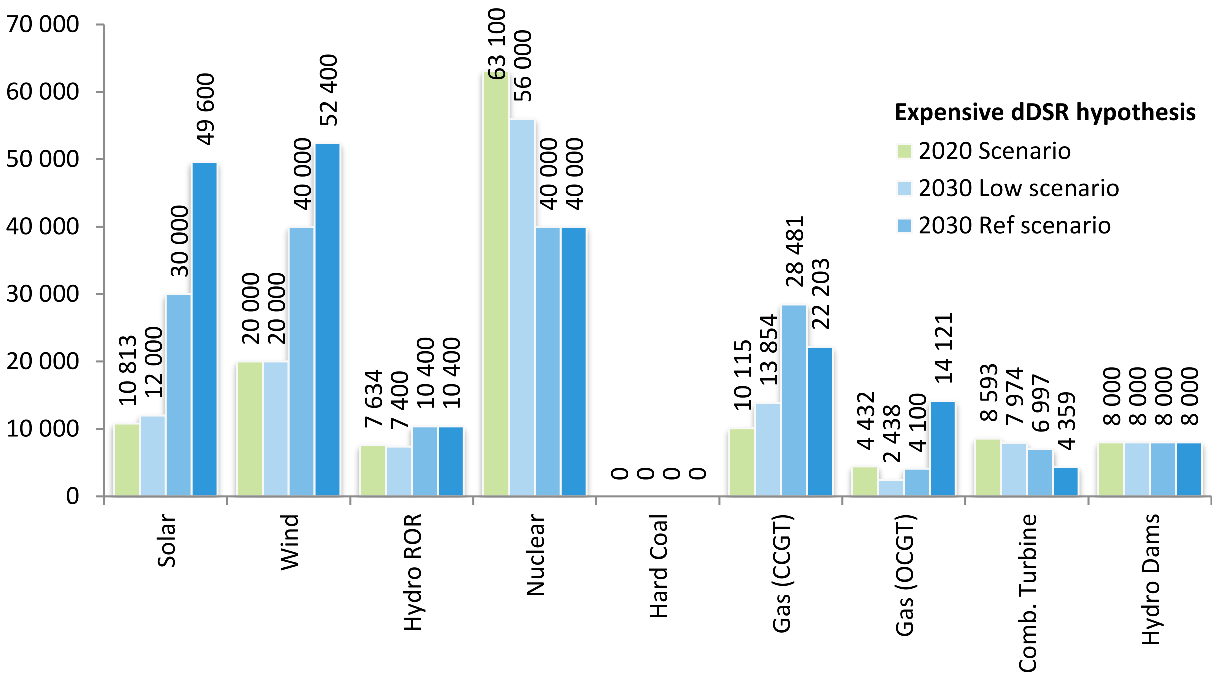


*Figure 29: Installed generation capacities (MW) in the expensive dDSR hypothesis*DSR's rent

The rent of a DSR technology as computed here designates the market revenues of one technology minus its variable and fixed costs. If a technology has a positive rent, it means that it should be developed further (but there may be a potential limit), if it has a negative rent, its installed capacity should be reduced.

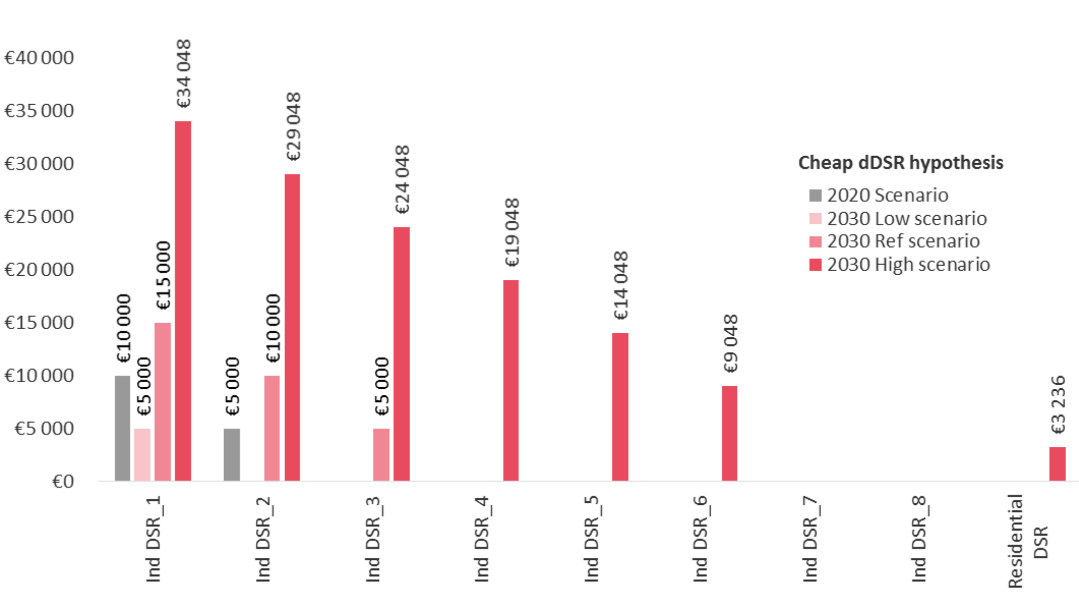


Figure 30: DSR's net annual rent in the cheap dDSR hypothesis

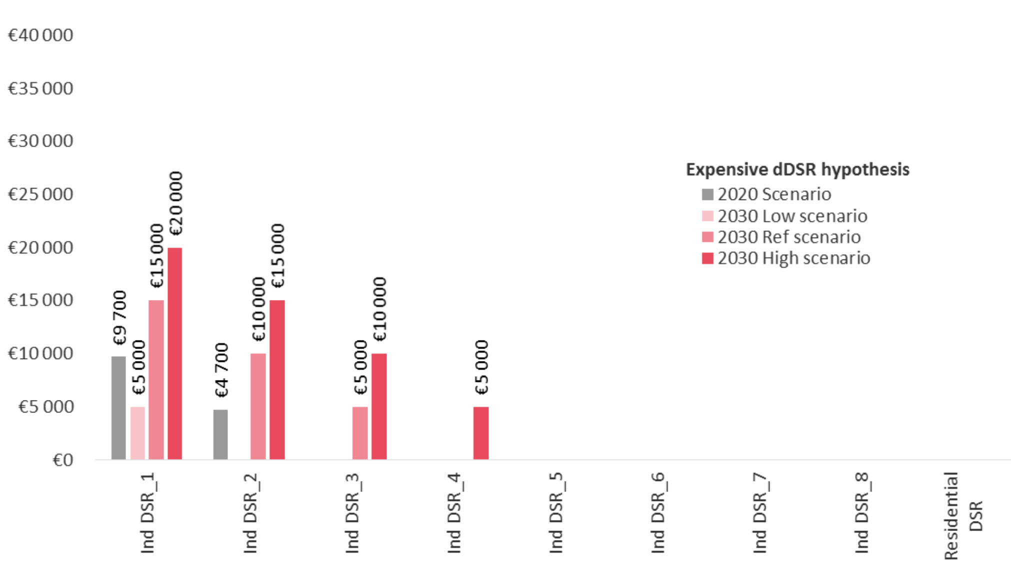


Figure 31: DSR's net annual rent in the expensive dDsr hypothesis

5.2.3 Mid-term scenarios N1 and N2

Scenarios N1 and N2 correspond to Market4RES' 2020 scenario to which 10 GW of variable RES were added to simulate a situation where the investors would have underestimated the effect of the RES development policy. The mix is therefore no longer at the equilibrium.

More precisely, N1 considers the capacities determined in the 2020 scenario for all technologies whereas in N2 we make the hypothesis that DSR is more "flexible in the long-term", i.e. that it can be invested in or disinvested faster than conventional technologies. As a consequence, in N2, DSR capacities were recomputed so as to take the new market conditions into account, given a higher share of renewables.

Installed capacities

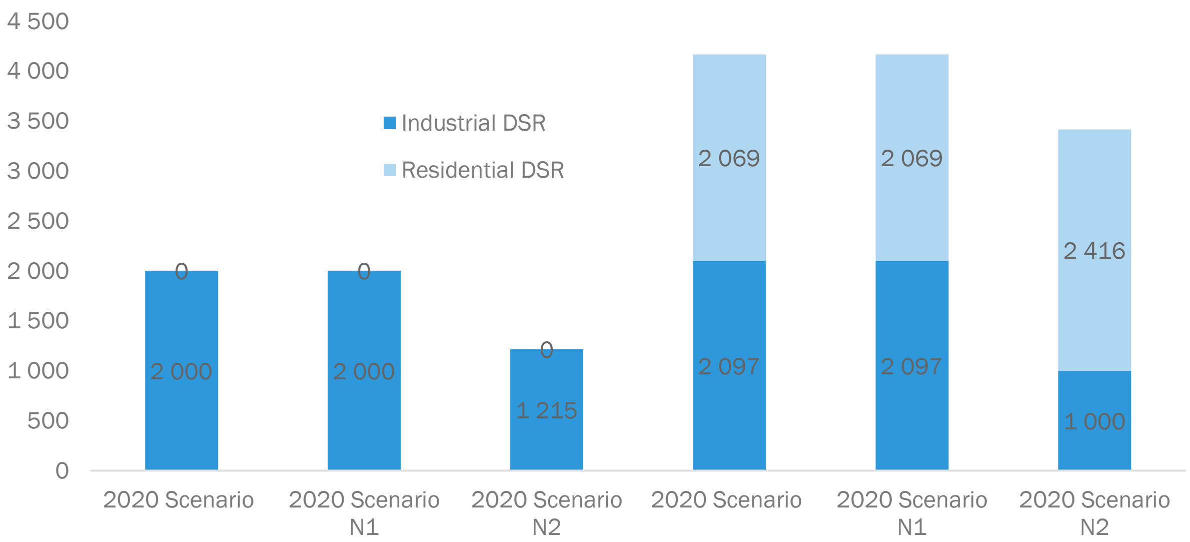


Figure 32: DSR's installed capacities (MW) in mid-term scenarios, for both distributed DSR costs hypotheses

The thermal capacities are, by definition of scenarios N1 and N2, the same than in the 2020 scenario.

DSR's rent

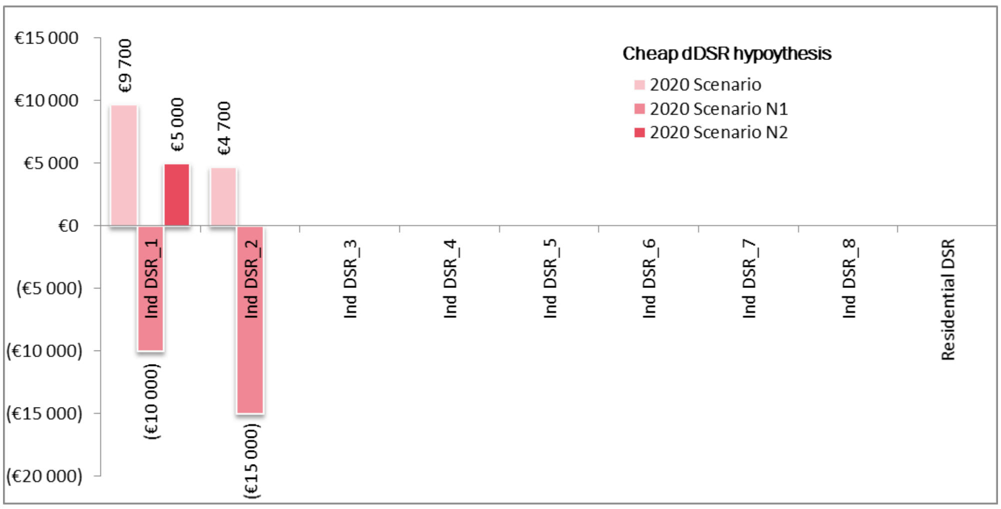


Figure 33: DSR's net annual rent in the cheap dDSR hypothesis for mid-term scenarios

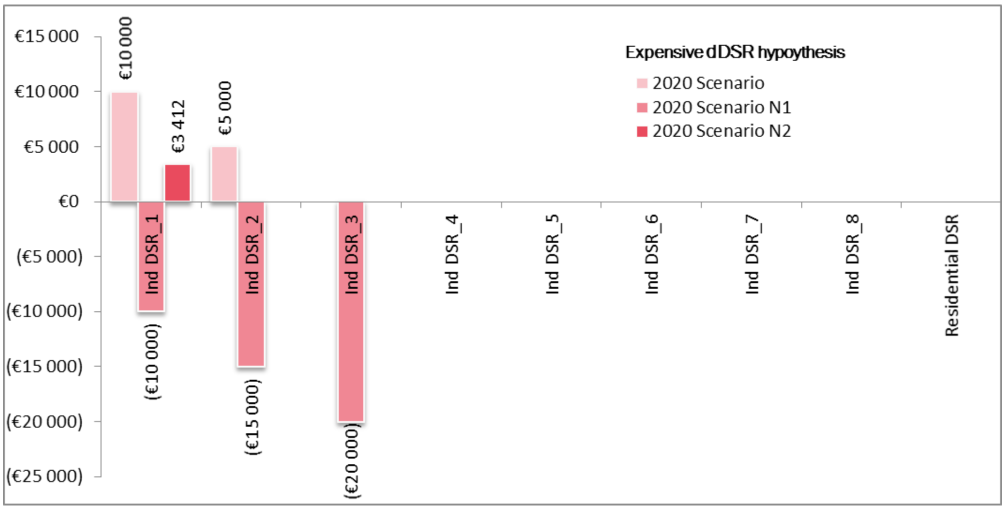


Figure 34: DSR's net annual rent in the expensive dDSR hypothesis for mid-term scenarios

5.3 Analysis of the results

First it is important to note that the classic normative hypothesis of a cost of loss of load set at 20,000 €/MWh (see 5.1.3) leads to a loss of load duration expectation below three hours per year (Table 27: loss of load duration for each scenario and for cheap and expensive dDSR cases). This criterion canonically corresponds to having three hours of load shedding per year on average when optimizing a purely thermal generation mix with a non-responsive demand. In this study we have added demand flexibility with a fixed cost below 60 k€/MW/year, which implies that consumers who have a utility of power from the grid lower than 20 k€/MWh will be able to express their preference for not consuming; the mere fact of enabling industrial DSR to compete in the market improves SoS and increases the total social welfare.

5.3.1 Impact of the level of RES' installed capacities

By focusing on the different long-term scenarios, we notice that **the higher the level of RES, the higher is the installed capacities of both industrial and residential DSR** (residential DSR for 11 k€/MW only). Besides, DSR's income (see Figure 30 and Figure 31) is more profitable when the share of RES is high. It is consistent with the idea that RES brings about a need in peak load installed capacities that DSR could ensure in an economical way.

5.3.2 Impact of dDRS's fixed costs

By analyzing Figure 28 and Figure 29, we can see that there is a transfer of peak load installed capacities (combustion turbine) to CCGT when we move from 29 k€/MW (expensive dDSR hypothesis) to 11 k€/MW (cheap dDSR hypothesis) for residential DSR's fixed costs. This transfer benefits the system, which is an incentive to low residential DSR's fixed costs.

Above all, the difference between cheap and expensive dDSR hypothesis is made on **DSR's installed capacities which are higher when cheap dDSR hypothesis is considered.** For example, in the case of the 2030 reference scenario DSR's installed capacities move from 3,291 MW to 10,288 MW when considering respectively expensive or cheap dDSR hypothesis (see Figure 27).

Besides, when set to 29 k€/MW, the fixed cost of residential DSR is too high to get residential DSR when compared to the value of this flexibility.

There tends to be a complementarity in the development of distributed and industrial DSR in scenarios with high shares of RES; indeed the development of industrial DSR does not change significantly according to the value of residential DSR's fixed costs.

5.3.3 Mid-term scenarios

Results for the 2020 scenario highlight the fact that even in a mid-term scope DSR is profitable and should be seen as a complementary way to RES to deal with volatility of the load, as long as DSR's installed capacities are adapted. As previously mentioned, **the cheap dDSR hypothesis enables more DSR's installed capacities than the expensive one**: respectively 4,166 MW and 2,000 MW (see Figure 32).

Two additional studies are conducted to complete mid-term analyses and the 2020 scenario is regarded as a reference for mid-term scenarios. Thus, 2020 scenarios N1 and N2 (see 5.1.2 and for description) modelled a transitional state when the mix is not optimally adapted to an increase in RES' installed capacities (+10 GW).

	Installed capacities of RES in France (MW)				
Technologies	2020 Scenario	2020 Scenarios + 10 GW of RES	2030 Low scenario	2030 Ref scenario	2030 High scenario
Solar	10 813	13 623	12 000	30 000	49 600
Wind	20 000	25 200	20 000	40 000	52 400
Hydro run-of-river	7 634	9 624	7 400	10 400	10 400

5.3.4 Impact of RES' incentive policies on the profitability of DSR

The 2020 scenario N1 shows mid-term impact on the profitability of DSR in a mix with excess capacity of RES, all other capacities being identical to the 2020 scenario. In such a situation (see Figure 33 and Figure 34), **the profitability of industrial DSR then becomes negative** (from -10 k€ to -20 k€ depending on DSR's installed capacities and cheap or expensive hypothesis). This drop of DSR's profitability is due to a decrease in loss of load duration (from 2 or 3 hours to 1 hour, see 2.1)

5.3.5 Impact of RES' incentive policies on DSR's capacities

Now, if we consider the 2020 scenario N2 where DSR's installed capacities are adapted to RES' marginal increase of 10 GW, we notice that DSR's installed capacities fall by 750 MW for cheap dDSR hypothesis and by 785 MW for expensive dDSR hypothesis compared to the 2020 scenario and the 2020 scenario N1 (see Table 32). **DSR's installment capacities do not disappear but they significantly decrease. The drop of DSR's installment capacities bring back the profitability of remaining ones** (see Figure 33 and Figure 34).

As a result, when RES' incentive policies are set and producers do not anticipate an increase in RES' installment capacities, there is a deterioration of DSR's profitability which becomes negative.

However, if DSR's installment capacities are adapted to the new mix, they decrease and are once again profitable.

5.4 Conclusion

If, thanks to a generous support, RES installed capacities grow faster than what market players – and in particular investors – anticipate, then it produces low market prices on the medium term that depreciate generation assets but prevent DSR to develop. It can even lead existing DSR capacities disappear.

By contrast, if the development of RES is well anticipated – or in the long-term after an adjustment phase consecutive to a period of non-anticipated over-capacity – the room for both residential and industrial DSR is enlarged and their profitability is increased.

6 Comparison of explicit support mechanisms and carbon pricing in terms of deployment of high shares of RES in the power system

6.1 Scope of the study

6.1.1 Aim of the study

To decarbonize its CO_2 intensive industrial sectors, and in particular electricity, the EU has made the choice of a global quota associated with a tradable permits system, the quota being reduced each year along a path towards long-term targets. However, there used to be few low-carbon renewable electricity generation technologies available at a price that could compete with traditional power plants and, to foster the required energy transition and make such technologies affordable, national RES penetration targets were appended to GHG targets and put to music by massive support schemes. They have resulted in RES installed capacity and generated electricity to grow rapidly: whereas it almost only consisted in hydro generation one decade ago, the amount of electricity produced from RES has since then doubled thanks to the development of wind, solar and biomass and now account for around 30 % of EU's electricity consumption.

The idea behind these support schemes was obviously to fill the gap between the cost of renewable projects and the revenues they could expect if they had to market their production. However, most subsidies have consisted in feed-in tariffs, i.e. an amount of money paid to the producer in proportion to the electricity produced and injected into the public network. Such provisions have also made easier to forecast the future earnings of new projects, reducing the uncertainty on these revenues. This higher predictability of revenues has facilitated the access to bank loans for project developers. Recent analyses show that RES projects usually have high debt to capital ratios: for instance in France, the regulator found out that on average, onshore wind projects were financed with 80 % of debt and 20 % of equity [13].

Equity should be more expensive than debt, even not considering the fact that taxes apply on equity (profit taxation) and not to debt, because it is riskier since debt has to be repaid before the project is able to pay dividends to the shareholders. Therefore, by allowing high debt over capital ratios, support schemes have led to relatively low weighted average cost of capital (WACC) for RES projects.

In addition, the level of support is sometimes indexed on macroeconomic parameters to compensate for variations of the cost of inputs to the projects[6]. This is of such a nature to reduce the interdependence between the revenues from the project and the revenue from the market portfolio (in the sense of the capital assets pricing model), and could possibly lead to lower the systematic risk taken by investors, therefore the profitability that they would expect from the projects and the WACC.

Since the uncertainty on a project's future yearly revenue has a major influence on how much money the project carriers will be able to borrow and the correlation of these revenues with those from the financial markets, it is a key parameter in the cost of the capital needed for these projects. The total cost of a capital-intensive power plants project benefiting from a support scheme with a long-term visibility on the unit revenue level may therefore be very different from the costs of the same project if its revenues came from the market (possibly supplemented by a volatile premium, for instance, obtained from selling green certificates).

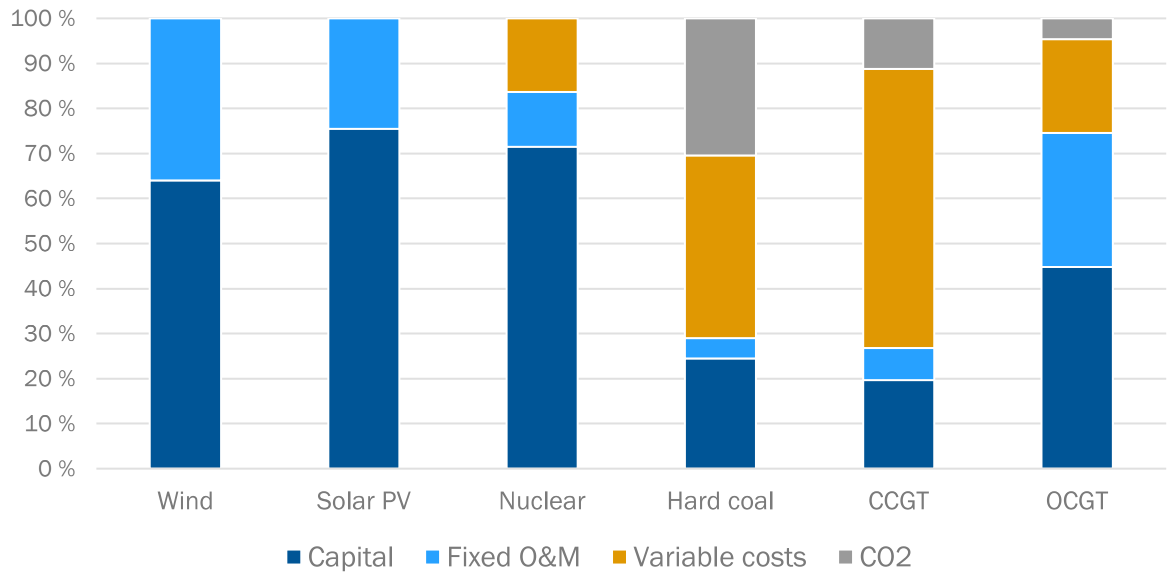


Figure 35 - Split cost of the energy generated according to the technology
Estimated cost structure per MWh generated in a long-term equilibrium mix with a CO_2 cost of 30 €/t.

As shown in Figure 35, low-carbon technologies are very capital intensive, whereas mid-merit order plants (OCGT, hard coal-fired plants) rely much more on variable costs. It should be noted that peaking units are relatively capital intensive when compared with other fossil fuel-based assets

[6] This has been the case in France, for instance the 2014 order on the FIT applicable to onshore wind defines the level of support in reference in reference to macroeconomic indexes in its article 6.

(and to a greater-extent fixed costs-intensive): their fuel costs are limited in proportion because they only generate a few MWh per year.

Thus, by securing the future revenues of RES projects, support schemes have helped limiting their total cost. Whereas this seems relevant to the capital-intensive low-carbon technologies, these energy policy tools are also widely seen as hindering the short-term optimization of the power system through the wholesale markets – which Europe tries, in the meanwhile, to improve in particular through coupling them – and the long-term investment signal because penetration targets and pace are political decisions that can change to the detriment of long-term visibility of the market conditions for the other players.

A well-functioning energy only market associated with the pan-European emission trading system (ETS) and no support scheme is, from a theoretical point of view, the most efficient way to reach a predetermined level of CO2 emissions in the power sector (at least if this sector is regarded as isolated from the rest of the economy and we consider that the ETS applies to this sector alone). However, under such provisions, low-carbon technologies being fully exposed to the market price, the risk taken by investors is higher than if they had benefitted from a long-term visibility on their revenues provided by a support scheme and so is the cost of these technologies. The aim of this study is therefore to explore whether a decarbonization policy based on explicit RES targets implemented through support schemes could cost less than the decentralized optimization through the ETS alone and all technologies competing on an equal footing in the electricity market.

6.1.2 Methodology

6.1.2.1.1.1 Analytical framework

This study focuses on the long-term situation and is based on the computation of the least-cost generation mix (and yearly dispatch) considering each technology's fixed and variable costs and in response to a given set of investment constraints (in particular in RES) and other policy factors such as the price of CO_2 or a global cap on CO_2 emissions.

The grounds for the postulate that this optimal mix is the outcome of the distributed investment decisions of market players is its long-term equilibrium property: every technology is exactly profitable, any positive deviation leads the next asset to be unprofitable and any negative deviation lets room for new generation capacity. The transition from the present situation is not envisaged.

6.1.2.1.1.2 Taking risk into account

Risk-adverse investors are willing to build a new power plant if they are *reasonably* confident that its discounted future revenues (minus operating costs) will be higher than the present investment cost. In practice, one invested euro will be compared with:

- more than one euro of certain but future benefits (cost of time),
- more than one euro of present but uncertain expected benefits (cost of uncertainty). Intuitively, one is not willing to invest 1 € to win either 0 or 2 € with a 50 % probability but will demand an expected gain higher than 1 €).

The cost of time is relatively easy to handle through discounting future revenues at a reference yearly rate (however it could be argued that the discount rate could change over time): at a τ_f discount rate, one euro today has the same value as $1+\tau_f$ euros next year, as $\left(1+\tau_f\right)^2$ euros in two years, etc.

A more theoretical approach to the cost of risk was introduced by Von Neumann and Morgenstern in 1944: economic agents maximize the expected utility of their wealth. Yet this utility is generally seen as concave, *i.e.* growing (we are happier when we have more money) but at a decreasing rate (the first euros earned are more useful than the 1M^th^) and the consequence of this concavity is that agents prefer a level of wealth W instead of an uncertain wealth drawn out of a distribution with W as expectation. However there exists a level of wealth W' at which a given agent (given its own utility function) would indifferently choose the certain wealth W' or the uncertain wealth distribution: W' is called the *certainty equivalent* of the uncertain wealth distribution. Due to the concavity of the utility function, $W' < W$.

Under some few extra assumptions, it is possible to take the uncertainty characterizing the future revenues from a decision we make today into account along with the cost of time in a single factor used to discount these revenues. In this case, the net present value (discounted for risk) of uncertain future revenues happening in N years take the form $\frac{R}{(1+\tau_t+\tau_r)^N}$ which is very convenient to the modelling used in this study and that also enable the identification of the weighted average cost of capital with the discounting factor (including the cost of both risk and time).

Micado indeed implements a static representation of the electricity mix in which each generating technology is characterized by:

- a fixed cost including an annualized investment cost and an annual O&M cost;
- a variable cost, proportional to the generated energy.

To be able to compute the yearly fixed cost, the initial investment I is supposed to be repaid in the form of fixed amount $A_t = A$, including both debt annuities and averaged dividends:

$$I = \sum_{t=1}^{T} \frac{A}{(1+\tau)^t} \; therefore \; A = \frac{\tau * I}{1-(1+\tau)^{-T}}$$

τ being the weighted average cost of capital (WACC) and T the economic lifespan of the asset.

The WACC depends on:

- the cost of equity which is linked to the risk-free rate of return and the systematic risk of the project;
- the cost of debt, which is highly dependent on the monetary policy of the Central Bank;
- the rate of profit taxation;
- and the relative proportion of equity and debt in the project.

The cost of equity and the relative proportion of equity and debt in the project are influenced by the variability of its future revenues and their correlation with the overall macroeconomic situation and, therefore, by the design of the power market and the specific provisions applying to the project. In the next part some market designs will be chosen and linked to WACC.

6.1.2.1.1.3 Policy options

The study consists in comparing different policy options to reach a predetermined regional level of CO_2 emissions from electricity generation. The following policy options are considered:

- "cap": a cap and trade system, energy market players facing a carbon price corresponding to the marginal cost of CO_2 emissions abatement in the power system in their investment and dispatch decisions;
- "FIT+0": no carbon pricing, decarbonisation being the result of the development of RES thanks to a support scheme such as a feed-in tariff. In this option, the RES development target can be:
    - either national, technology specific ("nFIT"),
    - or regional, technology neutral ("rFIT");
- "FIT+x": hybrid policies, mixing both a price of CO_2 emissions and a RES development policy. In this case the price of CO2 can be established through a carbon tax or a price-floor in the ETS since it does not correspond to the marginal cost associated with an explicit constraint on the level of emissions. Several levels of CO2 price are tested, from 10 to 80 €/tonne.

Feed-in tariffs are the only support scheme considered in this simulation where we use WACC computed in this specific case for a prior project (see below). In fact, according to their design, variable feed-in premiums can result in a similar level of predictability of their future revenues for projects' developers while enabling RES to be part of the global optimization organized through the market (they are subjected to balancing responsibilities, they can be price-responsive if the premium is not granted for the energy produced at negative prices, etc.). Therefore, our WACC hypotheses under FIT should also be representative of the financing conditions under a variable FIP.

If all costs were kept constant, the decarbonisation based on the development of RES should be less efficient than the ETS-only policy option because the former cannot resort to ways of avoiding CO2 emissions that can potentially be cheaper than to replace conventional generation with RES. Moreover, developing RES in proportion of the installed capacities defined in the scenarios (which come from ENTSO-E's *Scenario outlook and adequacy forecast*) for each technology (wind, photovoltaic) and each country may be less efficient than letting the model decide whether to invest in wind or photovoltaic and where to build these capacities. For this reason, this study includes both options in the RES support-only case and in each hybrid policy cases:

- RES developed according to an overall installed capacity objective, corresponding to a regional, technology-neutral call for tenders,
- RES developed in proportion to the installed capacities defined in the scenarios, corresponding to national, technology-specific calls for tenders.

The first option (ETS only) is easier to compute since it is achieved through (i) freeing all investment variables associated with variable RES (investment in RES are solely driven by the wholesale market) and (ii) adding a constraint on the total CO_2 emissions in the linear programme. The dual variable associated with this constraint represents the marginal (long-term) cost of CO_2 abatement in the system and therefore the price of CO_2 that should emerge from the cap and trade system. The solution of the problem is exactly the same if the constraint on total CO_2 emissions is removed and an explicit price of CO_2 equal to this dual variable is taken into account.

In the FIT+x policy options, it is not possible to directly compute the level of RES penetration that would result in the meeting the CO_2 target. Instead, a multiplier is defined to drive the level of investment in RES:

- for national, technology specific (nFIT) call for tenders, the multiplier corresponds to the ratio between the wind and photovoltaic capacities installed in each country to the capacities defined in the scenario. For instance, in the "High" scenario, Germany has 113 100 MW of wind turbines; this capacity would be 147 030 in a nFIT simulation at a multiplier of 1.3;
- for regional, technology neutral (rFIT) calls for tenders, the multiplier corresponds to the ratio between the minimum cumulative wind and photovoltaic capacity installed in the whole region and the sum of wind and photovoltaic generating capacities in the scenario. For instance, the sum of the wind and photovoltaic capacities in Spain, France and Germany in the "High" scenario is 342 700 MW, therefore there must be at least 445 510 MW of variable RES in the whole region in an rFIT simulation at a multiplier of 1.3.

Then a dichotomous strategy is used to find the correct multiplier in each case, with a precision set at 500 000 tonnes of CO_2 (equivalent to around 0.2 % of the emissions target in the "Reference" scenario being around 250 Mt). For each policy option, finding the multiplier requires between 10 and 15 rounds of simulation (i.e. computation of the optimal mix for a given multiplier).

The list of all cases considered in the study including the value of the multipliers can be found in an appendix to this chapter.

Finally, for each of the different options the total cost of the mix is computed as a proxy to the (long-term) social welfare. The cost of unserved load is included and therefore the total cost difference between two simulations is exactly the opposite of the social welfare variation. Moreover, the cost of CO_2 is not included in the computation of the total cost: the level of emissions being exactly the same in all the cases we compare (they only differ from one scenario to the other), it would only add the same amount to the total cost found in each of them. Thus the cost difference (and the social welfare difference) is not affected.

6.1.3 Hypotheses

6.1.3.1.1.1 Cost of capital

The central hypotheses in this study are the discount rates chosen as representative of the financing conditions of the different technologies according to the market arrangements.

The three Market4RES 2030 scenarios define a default WACC:

- "Reference" scenario: 8 %,
- "Low" scenario: 12 %,
- "High" scenario: 8 %.

Beyond 2020 [G. Resch et al.], a prior European project, explored the influence of different RES-policy instruments on the WACC and estimated that it should be 30 % higher for a project earning its revenues from the energy market alone (including the impact of the carbon pricing under the ETS), or the energy market complemented with a green certificate system, than for a project earning its revenues from a feed-in tariff. We have therefore applied this hypotheses to the default WACC defined in each scenario to obtain the WACC applying to supported technologies.

In addition, the sensitivity to these hypotheses was explored considering the following alternative rates:

- Beyond 2020 original hypotheses, i.e. 7.5 % WACC for wind and PV when they benefit from a support scheme (here we have not taken account of the "technology-specific risk factor"; according to the authors of this report, this rate should in fact be reduced by 10 % for onshore wind and by 0 to 25 % for solar PV; this is due to the relative maturity of these two technologies in comparison with many others but also for PV to the fact that some investors seem to be willing to invest under the market profitability of an asset exhibiting this level of risk);
- Some arbitrary hypotheses which could be regarded as more optimistic regarding the extent of the capital cost reduction that can be achieved through securing the unit revenues of wind and solar PV projects. This reflects some discussions with specialists from both WindEurope and SolarPower Europe who think that this advantage may be of an even greater extent than the Beyond 2020 assumptions of a WACC ratio of 1.3 between projects marketing their production and projects supported through a FIT. Therefore, we chose a WACC equal to 5 % for the former and 10 % for the latter.

Regarding these WACCs, it should be noted that we have not considered any difference between technologies and neither between countries; this is however not necessarily realistic since in theory, it depends on how stable investors think the investment framework is and their assessment of this stability may change from one country to the other.

Scenario	WACC of wind and PV projects when they benefit from a FIT	WACC for all other technologies and for wind and PV w/o support scheme
Reference	6.2 %	8 %
Low	9.2 %	12 %
High	6.2 %	8 %
Original Beyond 2020	*7.5 %*	*9.8 %*
"optimistic"	*10 %*	*5 %*

Table 28: WACC hypotheses in the differnet scenarios and for the sensitivity analysis

6.1.3.1.1.2 Geographic perimeter

Initially, it was foreseen that the study would encompass six countries (Belgium, Spain, France, Germany, Portugal and the Netherlands) but given the very numerous computation rounds that had to be performed (for there are three scenarios and the same level of CO_2 emissions had to be reached in each of 15 subcases of each scenario), it was finally decided to limit the geographic extent to Spain, France and Germany, which accelerates the computation of the solution of the optimization problem.

6.1.3.1.1.3 Scenarios' dataset

Demand time series are those used in the ENTSO-E's Ten years development plan (2014), i.e. the historic demand of 12 years from 2000 to 2011 modified to fit the usage changes and total consumption in 2030.

The average consumption and peak load over the region are described in the following table. The peak load is measured as the load reached, on average, in 3 hours per year, *i.e.* the 36th highest load in the data set since it contains 12 years.

Scenario	Average consumption	Peak load (3rd hour)
Reference	1 549 TWh	261 GW
Low	1 362 TWh	230 GW
High	1 591 TWh	273 GW

Table 29: average and peak load in the three scenarios

The problem is solved on an hourly basis for a subset of 52 weeks selected for their representativeness of the full dataset: they are chosen so that the net load duration curve fits that of the full dataset for each country. This is done for each scenario at the nominal wind and photovoltaic installed capacity. The performance of the selection method is relatively good as shown on Figure 36, at least as far as the study is not focused on adequacy since the error is bigger in the distribution's tails.

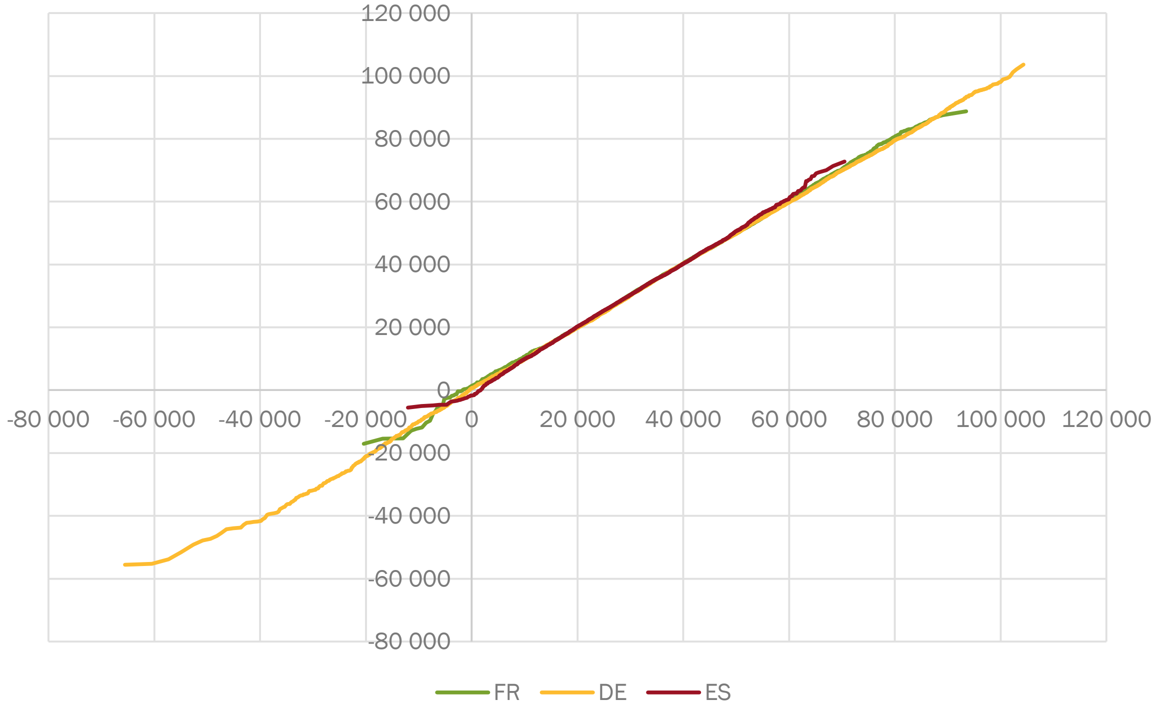


Figure 36 - Net load-duration curve of the snapshot selection plotted against that of the full dataset, High scenario (y = x would mean that the fit is perfect)

6.1.3.1.1.4 Mix constraints

To account for domestic energy policies, a few mix constraints have been included. In particular Germany is supposed to have got rid of nuclear power while the French nuclear capacity is reduced to 40 GW.

Lignite is only available in Germany and the capacity of hydroelectric dams is also considered constant because allowing the model to invest in hydropower would require data on the available potential and different projects may have a very different cost. Since dams and run of river are constant along all simulations, this lack of precision on the fixed cost hypotheses does not affect the cost comparisons.

These mix constraints are represented in Figure 37.

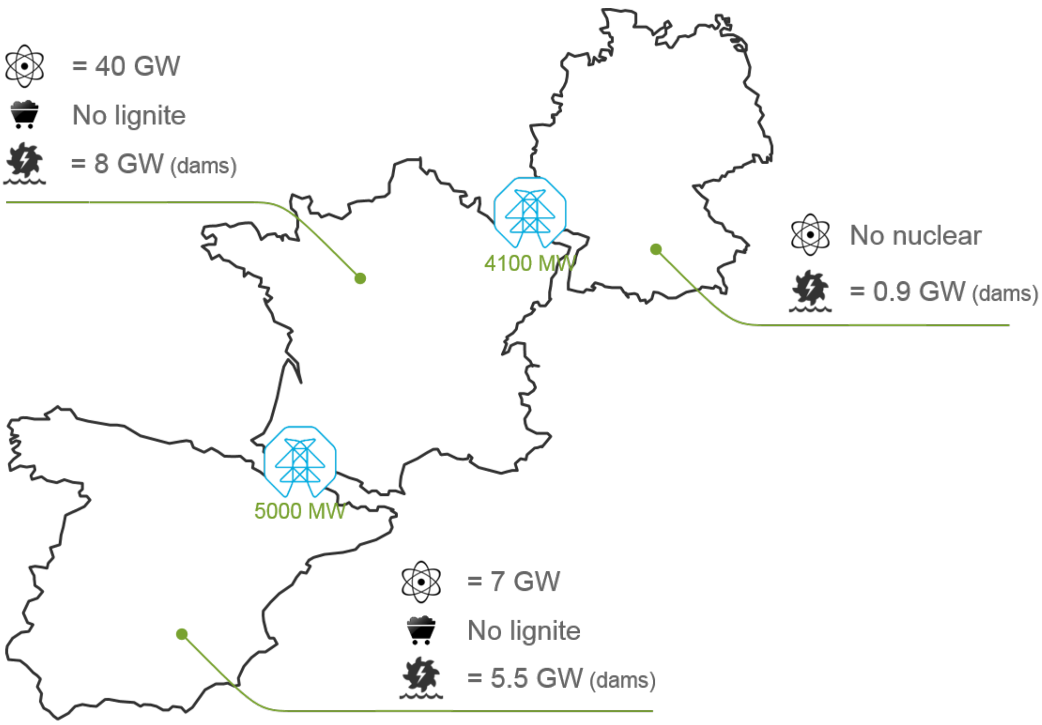


Figure 37 - Mix constraints in all scenarios

6.1.3.1.1.5 CO_2 emissions targets

In each scenario, the CO_2 emissions target corresponds to the emissions level in the conditions defined by the scenario. To compute these reference emissions, the nominal wind and photovoltaic generating capacities are used as well as the mix constraints defined above. Then, the optimal mix and dispatch are computed.

Scenario	CO2 emissions target	Corresponding CO_2 intensity
Reference	249 Mt	161 kg/MWh
Low	309 Mt	227 kg/MWh
High	234 Mt	147 kg/MWh

Table 30: CO_2 emissions target for the geographic area of the study, in each scenario

6.2 Results

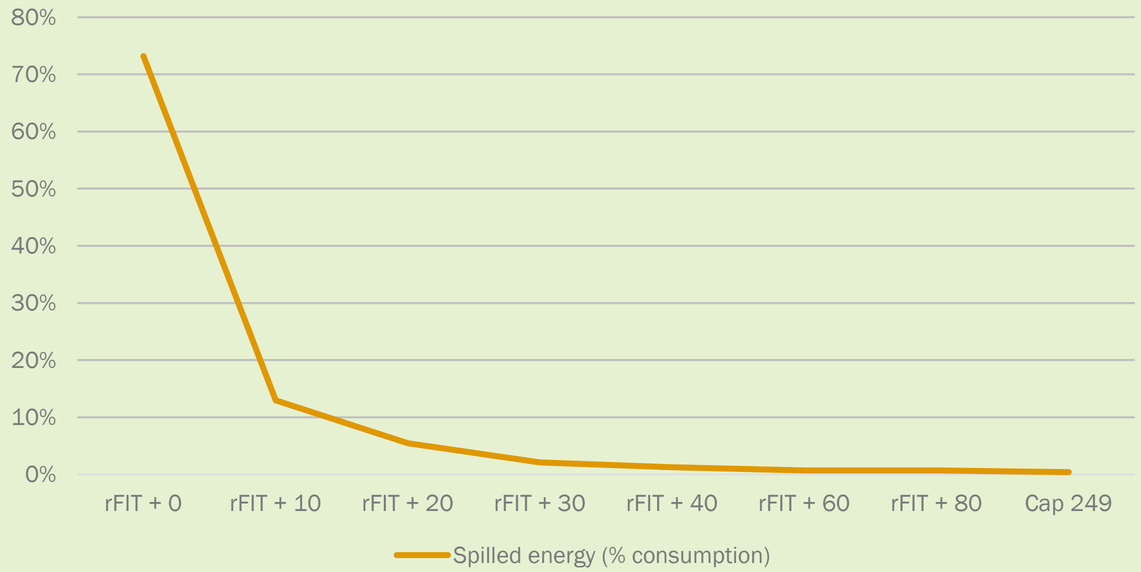
6.2.1 Results with the default discount rates defined in the scenarios

6.2.1.1.1.1 "Reference" scenario

In the "Reference" scenario, the marginal cost of CO2 in the "Cap 249 $MtCO_2$" policy option is 174 €/MWh. In this case, the total installed capacity amounts to 563 GW, wind representing a third (189 GW) and solar PV a tenth (59 GW). A limited proportion of the energy is spilled (1.2 % of the RES production, or 0.4 % of the consumption).

Important preliminary remark

The first observation that can be made when looking at the results is that the cases with a low CO_2 level result in a generation mix that does not seem realistic. Indeed, in the FIT cases, the investment model has to abide by a minimum RES installed capacity and, only interested in complying with this constraint, it chooses to invest in huge solar capacities. This is so because, as far as the amount of installed capacity is concerned, solar PV is cheaper than wind. This occurs until most of coal generation is pushed out of the merit order. This strategy leads to huge total installed capacities (up to 1 800 GW in the rFIT+0, instead of 563 in the Cap case), most of which are variable renewables and, in particular solar (1 240 GW in the same scenario, *i.e.* 69 % of all installed capacity). This leads to extreme levels of spillage: 1 132 TWh or 73 % of the consumption are spilled in the rFIT+0 case.



The total cost is largely above that of the scenarios in which carbon is priced beyond 20-30 €/tonne, in particular the unit cost is as high as 76 €/MWh above the unit cost in the Cap case. **This makes it impossible not to consider storage and other flexibility options in the optimization** since some of them would undoubtedly be very useful to avoid the waste of energy and provide a much better optimization of the system. Therefore, **the results for regional, technology neutral feed-in tariffs associated with a low CO2 price** (0 to 10 and maybe 20 €/tCO_2) **are by far too wrong to draw numeric conclusions.** They are simply given in the report as “raw” results of the study but are out of the validity range of the relatively simple modelling used here.

This remark holds for the two other scenarios.

The generation mix obtained in each case is represented in Figure 38 and Figure 39. The total generating capacity is the smallest in the case of the Cap option, which comprises more CCGTs and less renewables than other options. The proportion of coal-fired power plants tend to shrink when the CO2 price increases: hard coal-fired plants are not chosen any longer beyond around 35 €/tCO_2, whereas lignite-fired plants, which have a lower fuel cost, disappear for a CO2 price between 40 and 60 €/tCO_2.

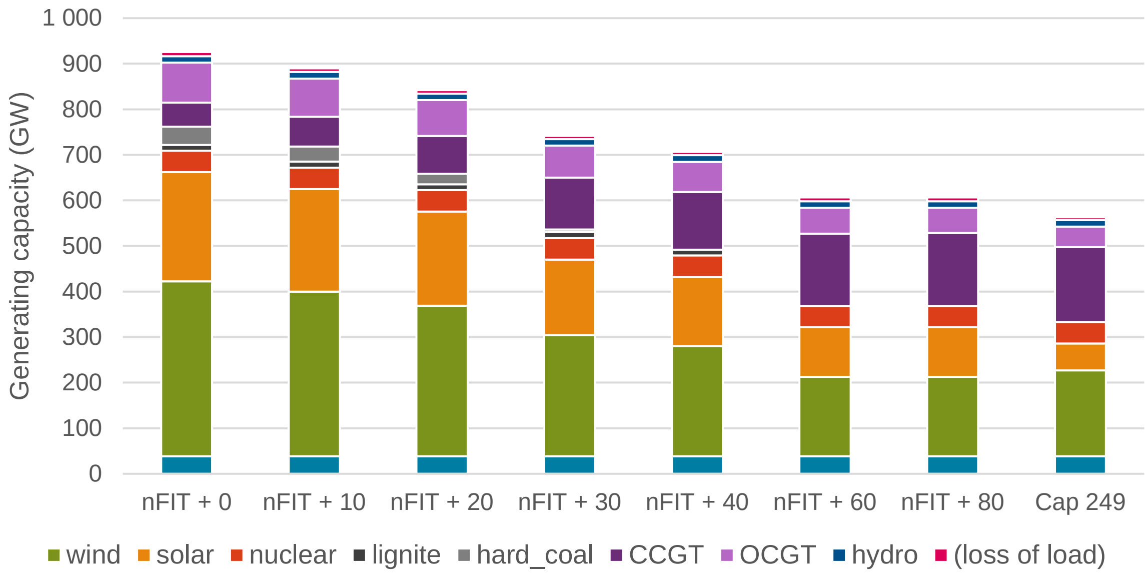


Figure 38 - Generation mix (total installed capacity) in the Reference scenario, in the cases corresponding to the nFIT+x and the Cap (249 $MtCO_2$)

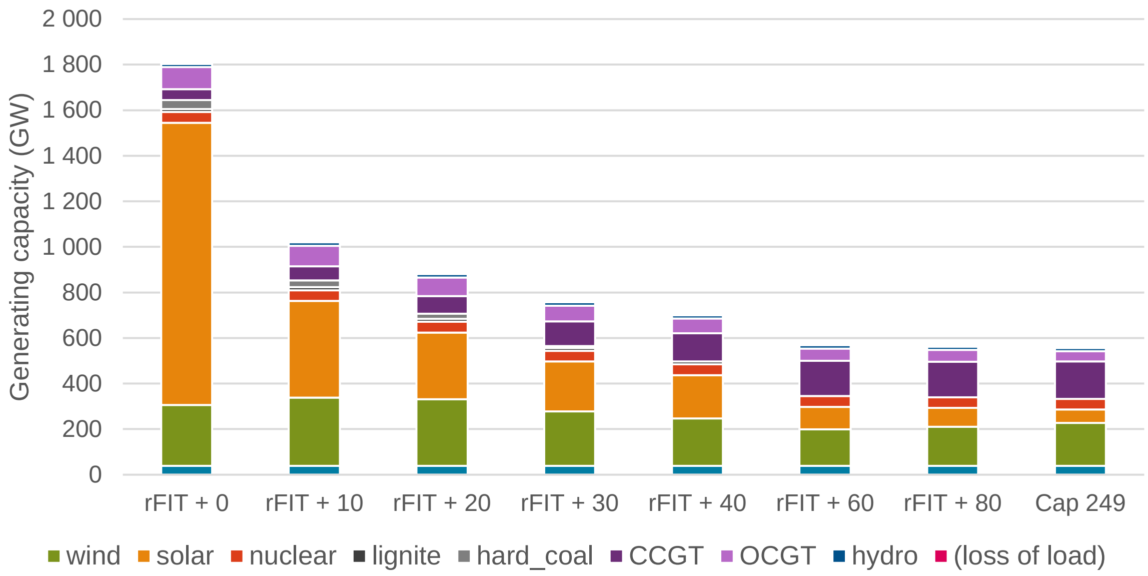


Figure 39 - Generation mix (total installed capacity) in the Reference scenario, in the cases corresponding to the rFIT+x and the Cap (249 $MtCO_2$)

The relative proportion of wind and photovoltaic changes a lot from one case to another. The Cap case exhibits a relatively small solar capacity whereas the regional, technology neutral call for tender result in a much bigger share of photovoltaic and even to a completely disproportionate development of this technology when there is no CO_2 price at all. In the rFIT+0€/tCO_2 case indeed, as much as 1 240 GW of solar capacity is invested in. As explained in the preliminary remark, the energy spillage is massive (1 132 TWh, *i.e.* 73 % of the consumption in this scenario) but the model preferred photovoltaic over wind turbines because it had to abide by a minimum of total RES installed capacity and, as far as the installed amount of capacity installed is concerned, solar PV is cheaper than wind turbines. This should not be regarded as a realistic long-term outcome since, as previously said, such high shares of variable renewables would make flexibility and storage solutions very appealing and there is no doubt that they would develop and enable the same level of decarbonization with much less renewables. Such solutions are however not modelled in the tool that was used.

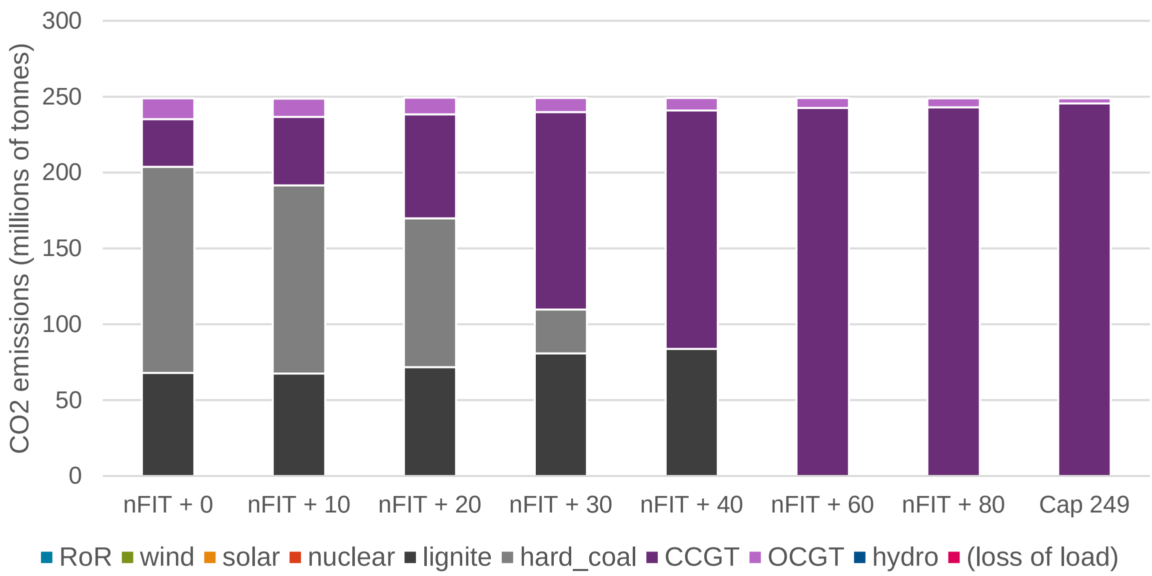


Figure 40 – Yearly CO_2 emissions by technology (Reference scenario)

Figure 40 clearly shows that, whereas coal is responsible for most of the emissions when CO_2 is cheap, it is not present in cases with a CO2 price is above 60 €/tCO_2, where the totality of CO_2 emissions are due to gas which is mostly burnt in CCGTs but also marginally in OCGTs, the main peaking technology in these scenarios (the fixed cost of OCGT is equivalent to that of oil turbines, but they have a lower variable cost and the model therefore never invested in oil turbines). The result in the cases representing regional, technology neutral calls for tender is very similar.

The total cost of the mix is represented in Figure 41 and Figure 42. In these graph, the total cost has been split between variable RES and the other technologies. In the result of the Cap simulation, an emphasis was put on the part of the cost of renewables that is due to the fact that the WACC is higher (8 %) in this case than when a FIT is set up (6,2 %). This additional cost amounts to 4.6 Bn€ per year. The total costs of the rFIT+60 and rFIT+80 cases are roughly the same as those in the Cap case if the WACC had corresponded to an investment in a FIT context, therefore, these two FIT cases are 4.6 Bn€ cheaper than the Cap policy option. In spite of a less efficient (since it is defined *a priori*) proportion of wind and photovoltaic. This also holds when the renewable penetration targets are set nationally and for each technology (nFIT), though to a lesser extent. Thus, nFIT+60 and nFIT+80 are around 500 M€ cheaper than the Cap option.

Interestingly, the total cost of the regional, technology neutral policy option is higher than that of the national, technology specific option when the price of CO_2 is low. This is due to the fact that massive capacities have to be invested in to let as little space as possible for coal. In such conditions, the value of RES generation is very small and have little influence in the arbitrage between photovoltaic and wind. The former being cheaper to the MW installed, the model choses it to reach the RES capacity target at the least cost, even if it is not efficient in meeting the CO_2 target (that is never given directly as an optimization constraint to the model in the FIT+x cases). The weights of each technology in the national, technology specific calls for tenders includes a higher share of wind, which is more efficient in reducing the need to resort to coal-fired power plants. Therefore, the renewable generating capacity needed to meet the CO_2 target in the nFIT cases with a low carbon price is smaller than in the rFIT cases and so is the total cost (although again, as explained above, the generating mixes in the latter are not realistic).

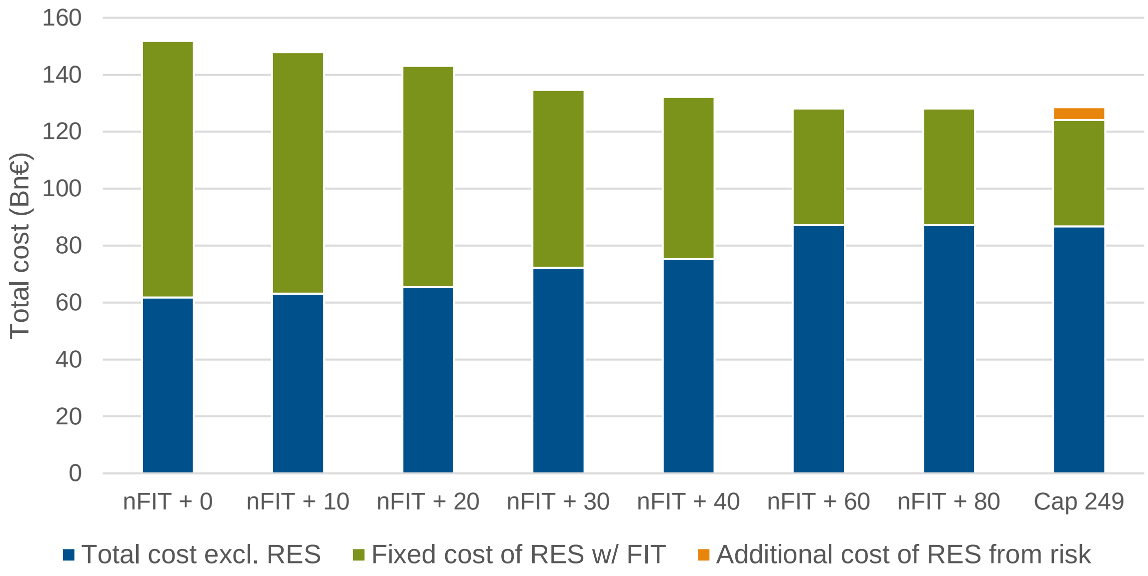


Figure 41 – Yearly total cost of the mix (excluding CO2) in the Reference scenario, in the cases corresponding to the nFIT+x and the Cap (249 $MtCO_2$)

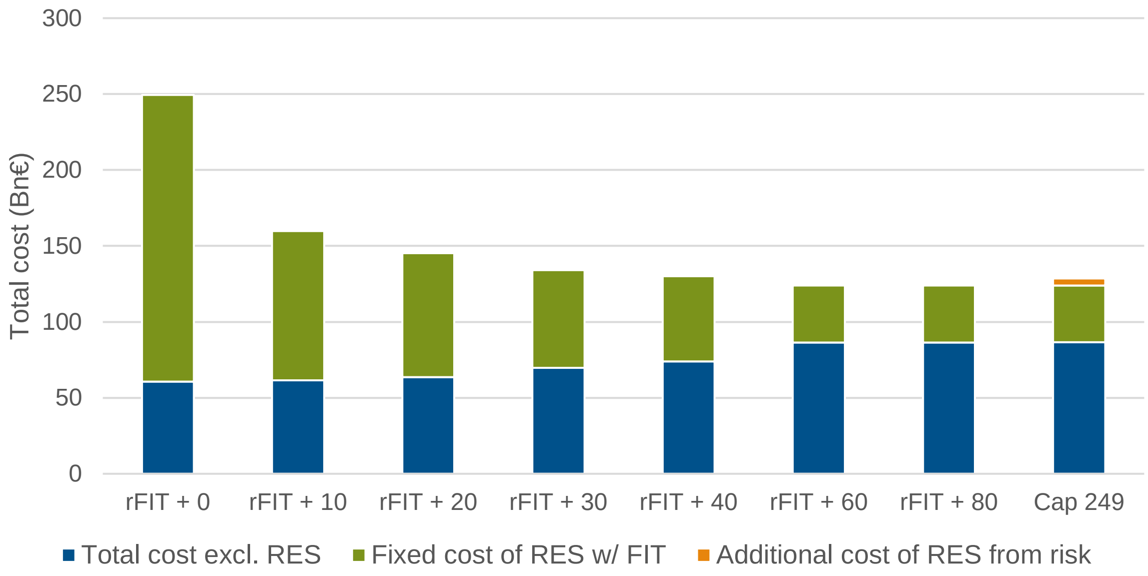


Figure 42 – Yearly total cost of the mix (excluding CO2) in the Reference scenario, in the cases corresponding to the rFIT+x and the Cap (249 $MtCO_2$)

The total cost per MWh of consumption is represented in Figure 43 whereas Figure 44 compares the different options with the ETS-only option. The rFIT+60 and rFIT+80 policy options allow to save around 3 €/MWh whereas the nFIT+60 and nFIT+80 options save 0.3 €/MWh in comparison to the ETS-only option.

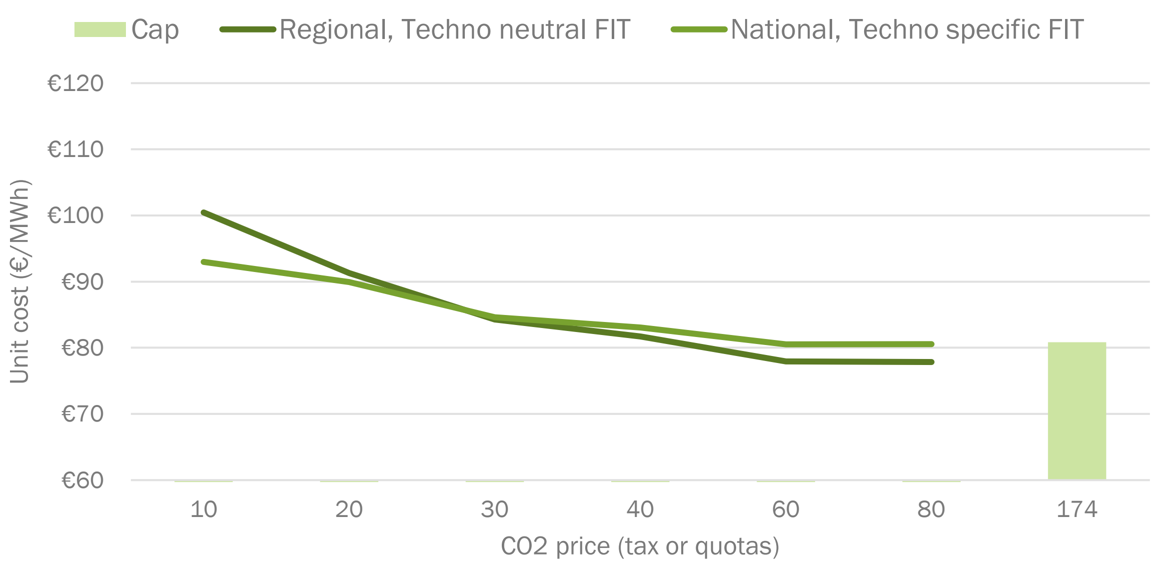


Figure 43 - Unit cost of electricity (excluding the cost of CO2) in the Reference scenario The FIT+0 cases were not plotted, the unit cost of the rFIT+0 being very high compared to the others.

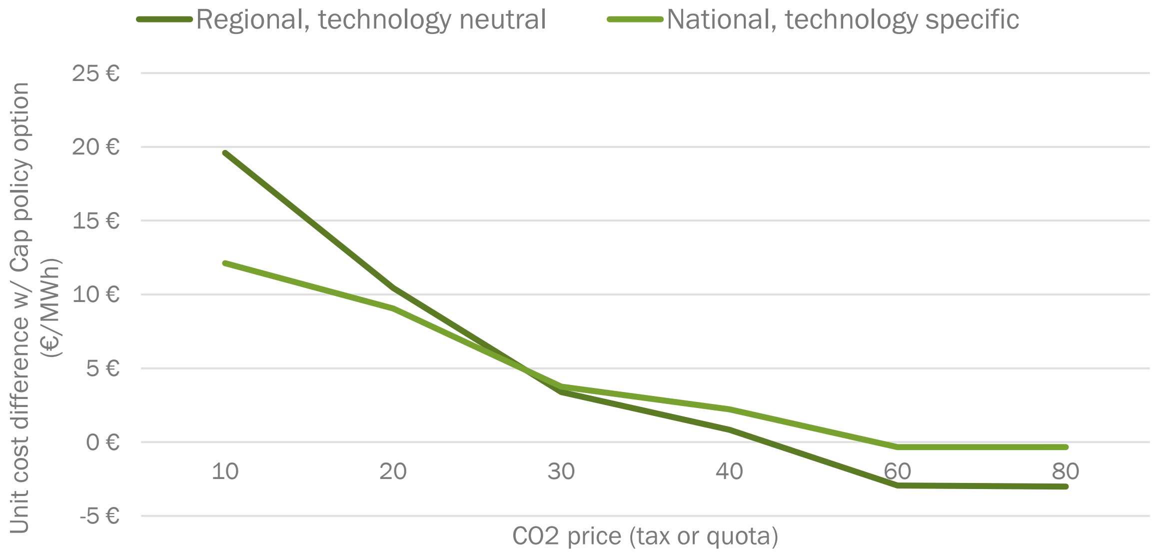


Figure 44 - Unit cost of electricity (excluding the cost of CO2) in each case compared to the Cap policy option (not plotted since = 0 by definition) in the Reference scenario The FIT+0 cases were not plotted, the unit cost of the rFIT+0 being very high compared to the others.

6.2.1.1.1.2 "Low" scenario

In the "Low" scenario, the marginal cost of CO2 in the "Cap 309 $MtCO_2$" policy option is 105 €/MWh. In this case the total installed capacity amounts to 358 GW, wind representing only 6 % (21 GW) and solar 7 % (25 GW). The spilled RES production energy is reduced to virtually nothing.

The total cost per MWh of consumption is represented in Figure 45, whereas Figure 46 compares the different options with the ETS-only option. The rFIT+60 and rFIT+80 policy options allow to save slightly less than 1 €/MWh whereas the nFIT+60 and nFIT+80 options are around 0.5 €/MWh more expensive than the ETS-only option.

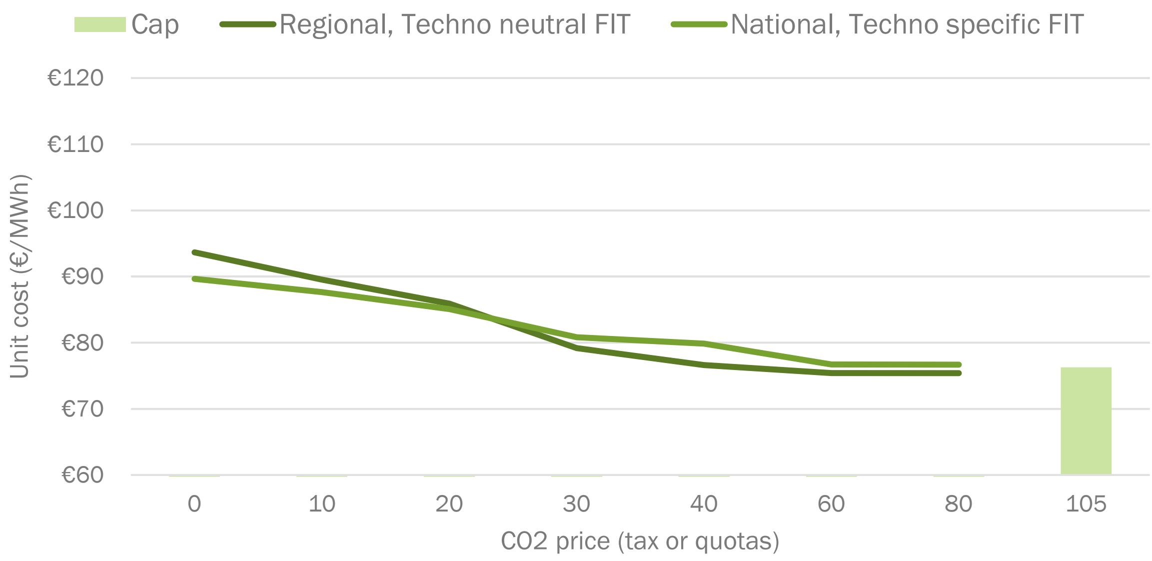


Figure 45 - Unit cost of electricity (excluding the cost of CO2) in the Low scenario

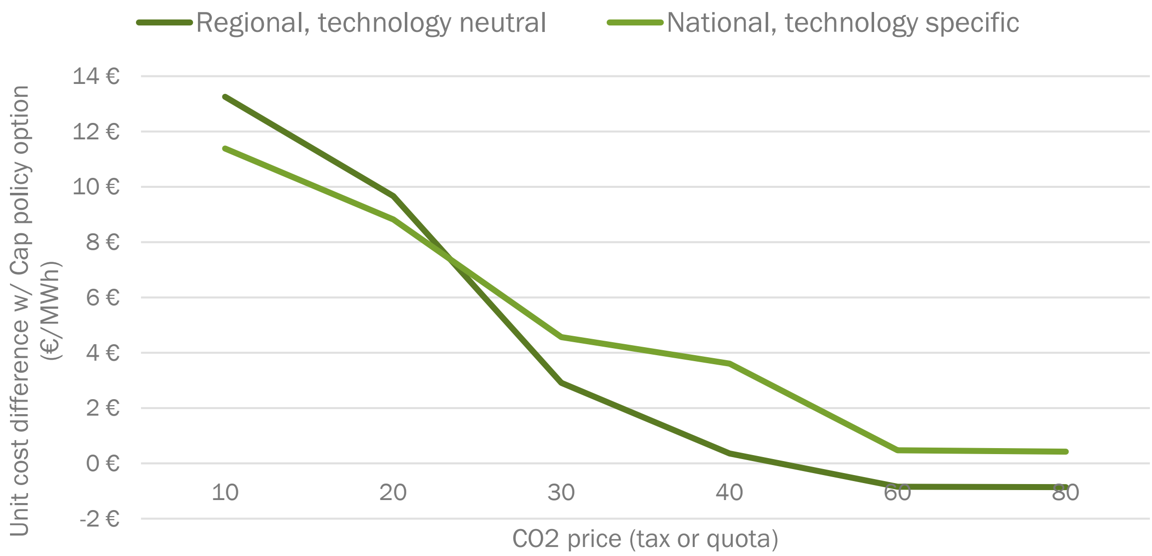


Figure 46 - Unit cost of electricity (excluding the cost of CO2) in each case compared to the Cap policy option (not plotted since = 0 by definition) in the Low scenario

Over the three countries, the yearly generation costs amount to around 121 Bn€ with the Cap option. Here, unlike in the Reference scenario, almost all options consisting in a support scheme associated with a carbon tax, are more expensive than the Cap option: if the support is national and technology-specific, this is true, even when the carbon tax is set at a high price.

However, the additional cost of the xFIT+0, xFIT+10 and xFIT+20 options are much lower than in the other scenarios (the maximum additional cost being 23 %). This is due to the fact that less renewables are required to reach the less ambitious CO_2 target set in this scenario; therefore the gains from lowering the cost of capital are limited. In addition, the “support + tax” market design still saves money (around 1.5 Bn€ or slightly more than 1 %) in the case of a regional support mechanism backed with a carbon tax high enough to make coal and lignite unprofitable. The mix is slightly more expensive (6-700 M€ or 0.6 %) if the support mechanism pursues national objectives such as those defined in the Low scenario.

6.2.1.1.1.3 “High” scenario

In the “High” scenario, the marginal cost of CO2 in the “Cap 234 $MtCO_2$” policy option is 179 €/MWh. In this case, the total installed capacity amounts to 648 GW, wind representing 30 % (197 GW) and solar PV around 18 % (118 GW). A limited proportion of the energy is spilled (1.5 % of the RES production, or 0.6 % of the consumption). Thus the RES deployment to reach this target is relatively similar to that of the “reference” scenario although it uses more solar PV in proportion.

The total cost per MWh of consumption is represented in Figure 47 whereas Figure 48 compares the different options with the ETS-only option. The rFIT+60 and rFIT+80 policy options allow to save around 4 €/MWh, whereas the nFIT+60 and nFIT+80 options save slightly more than 1 €/MWh in comparison to the ETS-only option.

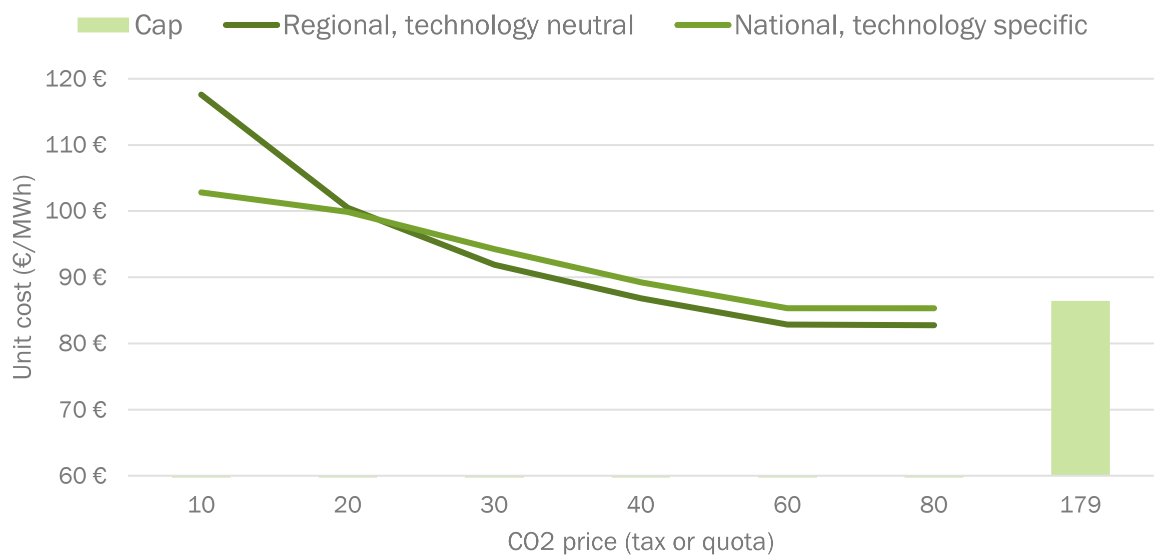


Figure 47 - Unit cost of electricity (excluding the cost of CO2) in the High scenario
The FIT+0 cases were not plotted, the unit cost of the rFIT+0 being very high compared to the others.

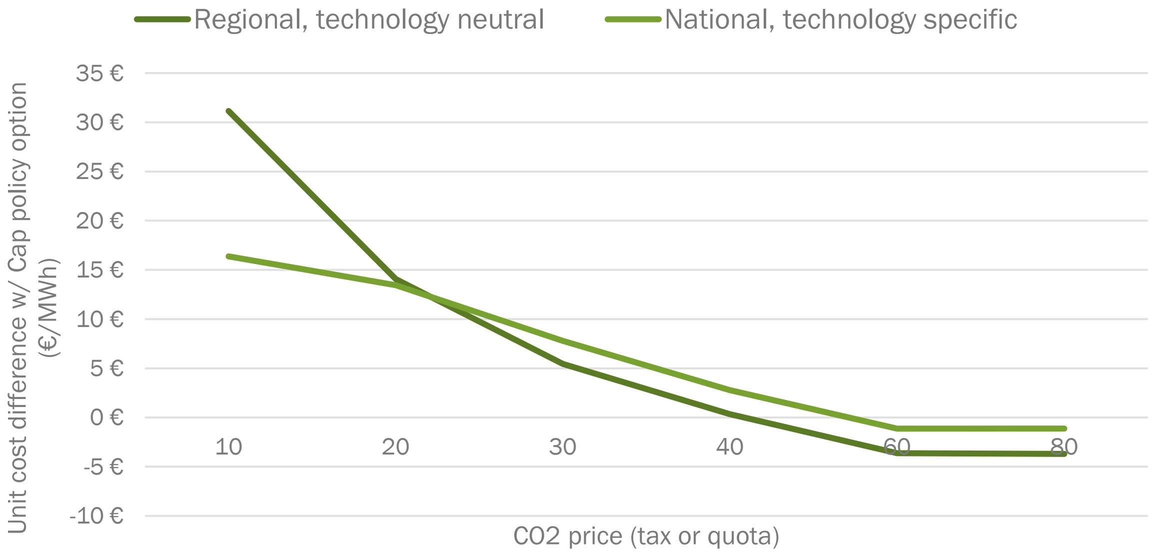


Figure 48 - Unit cost of electricity (excluding the cost of CO2) in each case compared to the Cap policy option (not plotted since = 0 by definition) in the High scenario The FIT+0 cases were not plotted, the unit cost of the rFIT+0 being very high compared to the others.

Over the three countries, the yearly generation costs amount to around 138 Bn€ with the Cap option. The options only consisting in a support scheme, even associated with a carbon tax at a low level, are significantly more expensive (up to 22 % if the rFIT+0 and rFIT+10 option are excluded) but, conversely, the "support + tax" market design saves almost 6 Bn€ (4.3 %) in the case of a regional support mechanism backed with a carbon tax high enough to make coal and lignite unprofitable and a bit less than 2 Bn€ (1.3 %) if the support pursues national objectives such as those defined in the High scenario.

6.2.2 Sensitivity to the discount rates hypotheses

6.2.2.1.1.1 "Reference" scenario

As it can be seen in Figure 49, the conclusions drawn in the previous part for the Reference scenario still hold under the alternative capital cost hypotheses.

Under the "Beyond 2020" original capital cost hypotheses, the xFIT+60 and xFIT+80 options save more money (compared to the Cap option) than under the Market4RES Reference scenario's capital cost hypotheses: - 4 €/MWh for regional, technology neutral penetration targets and - 1 €/MWh for national, technology-specific penetration targets, instead of, respectively - 3 €/MWh and – 0.3 €/MWh.

Under the "Optimistic" capital cost hypotheses, not only do these options save even more money but the xFIT+30 and xFIT+40 also become cheaper than the Cap option. This is because (supported) renewable becomes more affordable when compared to the other technologies. Thus, both rFIT+30 and nFIT+30 options save between 2 and 3 €/MWh and, when the CO_2 tax price is high (60 or 80 €/tCO_2), the nFIT saves 5.5 €/MWh and the rFIT saves as much as 8 €/MWh (9 % of the unit cost under the Cap option).

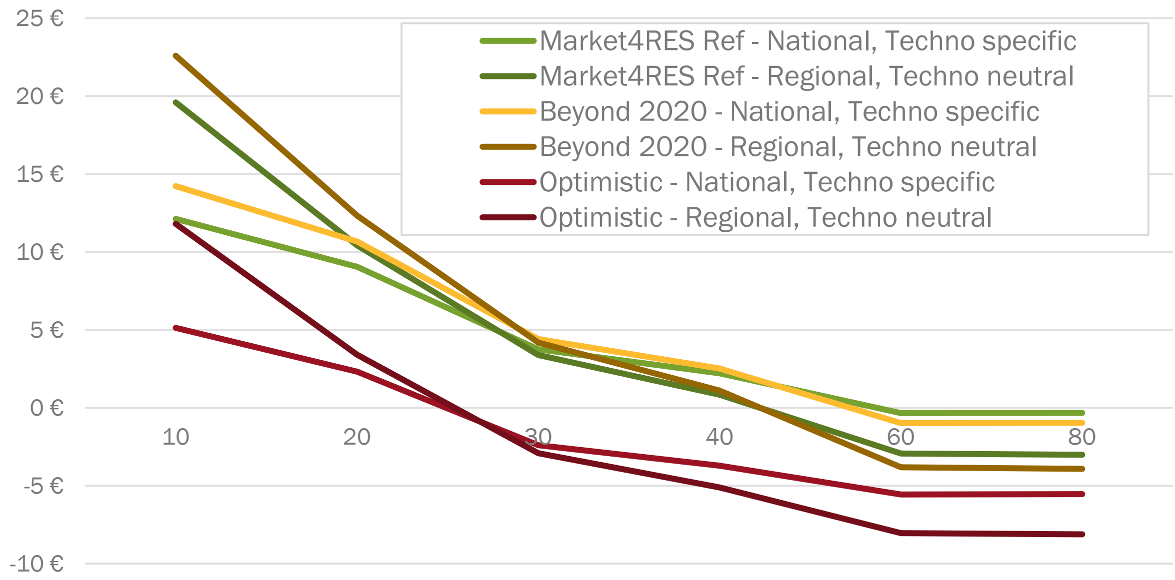


Figure 49 - Unit cost of electricity (excluding the cost of CO2) in each case compared to the Cap policy option in the Reference scenario including capital cost variants. The FIT+0 cases were not plotted, the unit cost of the rFIT+0 being very high compared to the others.

6.2.2.1.1.2 "Low" scenario

As shown in Figure 50, the results obtained for the "Beyond 2020 original" capital cost hypothesis are very similar to those shown earlier for the Low scenario with the default capital cost parameters. In comparison to a mere cap & trade system, the xFIT+60 and xFIT+80 policy options result in limited savings (around 1 %) when the target is set regionally and regardless of the technology, whereas they are slightly more expensive (by 0.7 or 0.8 %) when the targets are national and technology-specific.

Under the "Optimistic" capital cost hypotheses, savings appear at a lower CO_2 taxation level: 30 €/tCO_2 in the case of the rFIT (rFIT+30) and 40 €/tCO_2 in the case of the nFIT (nFIT+40). But the savings remain relatively modest in comparison with those observed in the two other scenarios (less than 1.5 €/MWh or 2 % of the unit cost in the case of a cap & trade, that, under the Optimistic capital cost hypotheses, amounts to 70.24 €/MWh) in the case of the rFIT+60 and rFIT+80, which, again, is due to the less ambitious CO_2 target set in this scenario and the more limited RES support effort required to reach it (especially at high CO_2 tax levels). Interestingly, the rFIT+40 is the most economical option, saving 2.6 €/MWh (or 3.7 % of the unit cost in the Cap case), because the RES proportion required in the mix for this level of CO2 taxation drops sharply between 40 €/tCO_2 and 60 €/tCO_2 and so does the relevance of reducing the cost of RES capital.

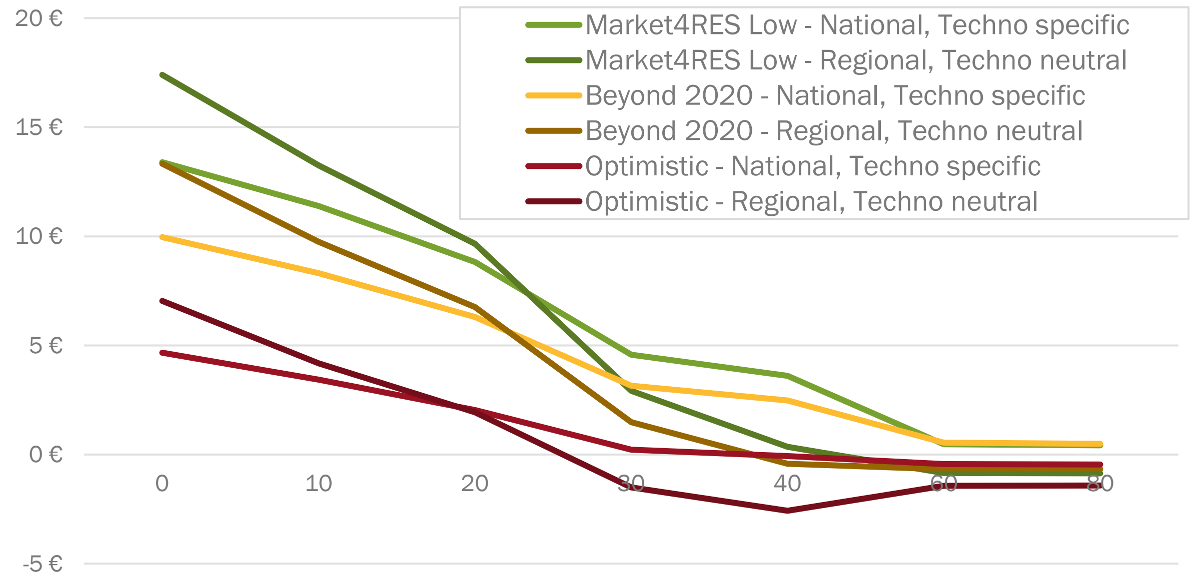


Figure 50 - Unit cost of electricity (excluding the cost of CO2) in each case compared to the Cap policy option in the Low scenario including capital cost variants.

6.2.2.1.1.3 "High" scenario

With regard to the sensitivity to the capital cost hypotheses, the "High" scenario behaves roughly like the "Reference" scenario and the conclusions are not changed (see Figure 51).

Under the "Beyond 2020" original capital cost hypotheses, the xFIT+60 and xFIT+80 options save more money (compared to the Cap option) than under the Market4RES High scenario's (default) capital cost hypotheses: almost - 5 €/MWh for regional, technology neutral penetration targets and - 2.2 €/MWh for national, technology-specific penetration targets, instead of, respectively - 4 €/MWh and – 1 €/MWh.

Under the "Optimistic" capital cost hypotheses, not only do these options save even more money but the xFIT+30 and xFIT+40 also become cheaper than the Cap option, (supported) renewable becoming more affordable when compared to the other technologies. Thus, both nFIT+30 and rFIT+30 option save between 0 and 2 €/MWh. When the CO_2 tax price is high (60 or 80 €/tCO_2), the nFIT saves 7.6 €/MWh and the rFIT saves as much as 10 €/MWh (10 % of the unit cost under the Cap option).

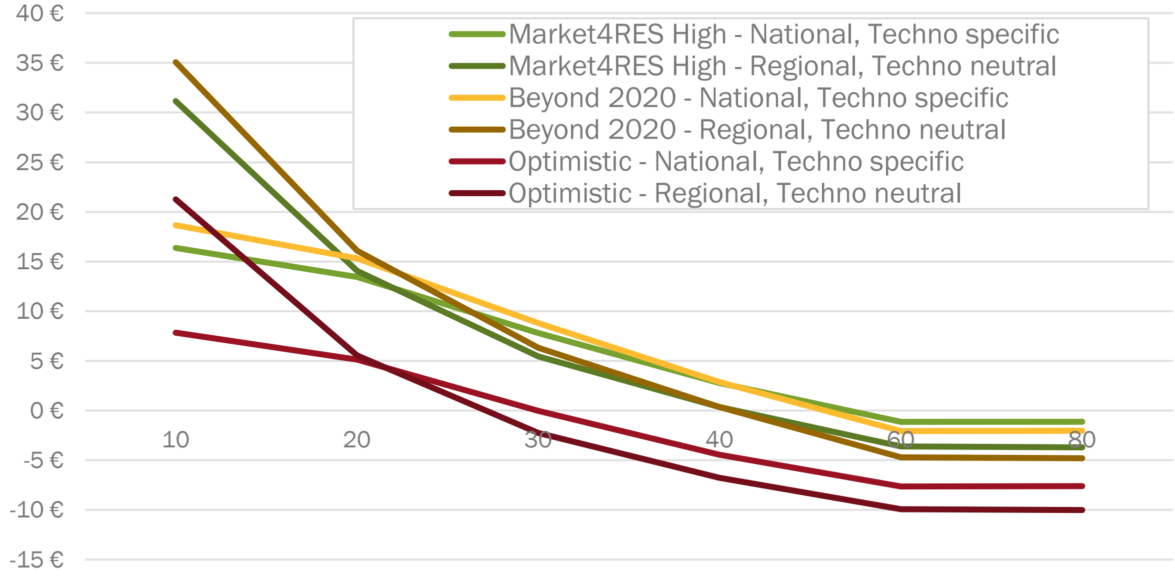


Figure 51 - Unit cost of electricity (excluding the cost of CO2) in each case compared to the Cap policy option in the Low scenario including capital cost variants. The FIT+0 cases were not plotted, the unit cost of the rFIT+0 being very high compared to the others.

6.3 Analysis and recommendations

The first thing that must be noted in the light of the previous results is that the modelling that was used is too limited here to understand well what would happen if we were to decarbonize deeply without CO_2 pricing. In this case, the simulations results exhibit such a high cost that it would undoubtedly trigger investment in flexible resources that are not represented in the tool we used, bringing the cost back to a much lower level.

The second result is that the CO_2 cap and tradable permits design is much more efficient to decarbonize power than forcing very high shares of RES into the power system through a very strong support until reaching the same GHG emissions level. Indeed, the CO2 price that results of such a system lets the market players take the cheapest decarbonization decisions in the first place. In comparison with replacing the coal-based production with gas-based electricity, investing in renewables remain a relatively expensive decarbonization option. Therefore, carbon pricing alone is naturally the optimal way to pursue CO_2 targets, all costs being otherwise equal.

But as we go deeper into decarbonization, we start needing higher proportions of renewables, for there is no more coal to turn off and replace with gas. In this perspective, it starts being interesting to find some way to limit the costs of renewable technologies and, in particular, of the variable renewable technologies (mainly wind and solar). Beyond being a mere incentivizing tool, support schemes (or at least some of them such as feed-in tariffs or "floating" feed-in premiums) help reducing the risk of investors by guaranteeing relatively stable cash flows over the entire lifespan of projects. By doing so, they also reduce the financial costs of such projects and, when aggregated, the cost of the energy transition. Thus, whereas a planned RES development based on such a support scheme alone is not the right tool to decarbonize the electricity, the third conclusion of this study is that such a policy accompanied with carbon pricing at a sustained level above 60 €/tCO2 would result in a cheaper electricity mix than if the energy transition had been the result of a cap and trade system alone. The economy on the capital cost of RES in the former case indeed outweighs the optimization loss resulting from moving apart the strict respect of the merit order of the different decarbonization options. Moreover, this result is not only true if the choice of the RES technology and location are let to the market (regional, technology neutral targets) but also if these parameters are centrally set (national, technology-specific targets), although to a lesser extent, which is dependent on the chosen set of targets. This was the case in two out of our three scenarios and, in the third, it cannot be said that an inefficient sharing is the main cause of the cost being higher than in the cap and trade policy since the RES deployment is much more modest, which also limits the interest of the explicit support.

This conclusion is obviously all the more relevant as the decarbonization target is ambitious, involving the use of large shares of renewables. Moreover, the required CO_2 price level (60 €/MWh) seems relatively high but it should be noted that it is far below the level that would be required to reach the same targets only through a cap and trade system. In addition, when WP5 scenarios were elaborated, the relative prices of coal and gas were very much in favour of the former, which results in this study in a relatively high CO_2 tax threshold to trigger disinvestment in lignite and hard coal. More recently, the evolution of these prices was more favourable to gas and, if this study had been done with updated fuel prices, the hybrid policy (explicit support plus CO_2 tax) would be preferable from an even lower level of CO_2 tax, which would also improve the feasibility (acceptability) of this option.

7 Impact of investors' risk on the evolution of the power system in presence of capacity remuneration mechanisms and in an energy only market (RTE)

7.1 Scope of the study

7.1.1 Aim of the study

Regarding investments in power generating units, but also medium-term decisions such as keeping a power plant in operation, the context has changed a lot over the past decade and will continue to evolve in this direction. Today's mature markets are characterized by a lack of demand growth and a growing deployment of renewables. Investors hesitate to trigger investments in new conventional units because of a huge uncertainty on the possibility to recover their fixed costs. Thus, the debate on missing money has evolved towards two main topics: the issue of recovering operating fixed and variable costs for existing plants on one side, and the issue of recovering fixed costs (including capital and operating costs) to trigger investment decisions on the other side. The current European market design include price caps that are suspected to limit the opportunity for peaking unit owners to recover their costs, leading to a sub-optimal investment.

Furthermore, as shown earlier (Figure 35), peaking units are relatively capital intensive when compared with other fossil fuel-based assets (and to a greater-extent fixed costs-intensive). Since they are ran only a few hours per year and therefore burn relatively small amounts of fuel, their fuel costs are limited in proportion. The question of the cost associated with this risk therefore adds up to the missing money problem: could the peaking units' revenues be made more predictable to reduce the risks associated with this type of investments?

This study aims at computing the long-term social value of completing an energy only market with such a capacity market under the different scenarios envisaged in this work package. More precisely, it assumes a continuous increase of the installed RES generating capacity towards the 2030 targets set in these scenarios to investigate whether capacity markets are relevant in a context of high RES penetration.

7.1.2 Methodology

In this study, we have analyzed the investment behavior to quantify the impacts on it of the risk for the investors in different market designs, namely:

(i) "EOM3", an energy-only market with a price cap (at 3,000€/MWh),
(ii) "CM3", an energy-only market (still with a price cap at 3,000€/MWh) enhanced with a capacity market,
(iii) and "EOM20", an energy-only market with a scarcity pricing mechanism during peak load hours (at 20,000€/MWh).

These situations were simulated on the long term with a tool based on System Dynamics modelling which integrates both new investments and closure decisions. The functioning of this model (named SIDES) was described in the first deliverable of this work package. Very importantly, in the context of this report, this tool does not take investors' and producers' risk aversion into account, i.e. these players will assess their options or projects in the sole light of their expected net present value, regardless of how scattered or centered (that is more or less uncertain) this value is. This type of behavior is rather unrealistic and, in practice, actual economic agents will tend to prefer, out of two projects with the same net present value, the one that involves the lowest level of uncertainty (the least risky one).

The evolution of the generation mix is obtained over several years by endogenous simulations of private investments in electricity power plants, and by mothballing some units or by decommissioning others. These decisions are made by a central profit-maximizing agent (there is no representation of strategic behavior here, and the short and long-term decisions are supposed to reflect a perfectly competitive situation) given a set of assumptions about the initial generation mix in 2015, structure of the annual demand curve, energy policy and macroeconomic scenarios. This investor is technologically neutral and anticipates the future on a five year period. When this agent makes investment decisions, he makes the assumption that the profit on the fifth year will remain the same until the decommissioning of the aging plant at the end of its lifetime.

7.1.3 Hypotheses

7.1.3.1.1.1 General hypotheses

The macroeconomic scenarios are the three scenarios developed in the first deliverable of this work package, *Description of planned analyses, scenarios and models for the post 2020 time* *horizon*. The geographic perimeter is limited to one country (France) and, similarly to the previous study on renewables support schemes and CO2 pricing, the scenarios have been extended to 12 years of consumption and RES load factors time series so as to better represent the range of variability of these parameters.

7.1.3.1.1.2 Simulated market designs

The first market design simulated in the study is based on an energy-only market with a price cap set at 3,000 €/MWh (equal to the EPEX SPOT price cap); the second one is an energy-only market with a price cap equal to the social value of loss of load. This last value is the theoretical one for an energy-only market when the generation is not sufficient to serve the total electricity demand. In the simulation we will consider a value of 20,000 €/MWh. Finally, the last market design is based on the same energy market as in the first case, enhanced with a capacity market.

7.1.3.1.1.3 Modelling of the capacity mechanism

The capacity mechanism modelled in this study has the characteristics of the French one[7] in that it is capacity-wide, based on an adequacy criterion defined as a target loss of load expectation, and the product duration is one year. There is, however, no prejudice about its centralized or decentralized nature. It is assumed that the costs of the capacity mechanisms will be totally transferred to the final consumers through the retail prices.

A capacity market requires the definition of a capacity adequacy target which is one of the main parameters of the mechanism. In these simulations, we will use a loss of load expectation target of 3 hours per year, over the several weather scenarios considered. Given the demand time series for a given year and a given scenario, this target defines the capacity needs of the system based on a normalized set of extreme conditions. This need is referred to as the “obligation” later in this chapter because, for an isolated country, it is the amount of domestic capacity that has to be secured by the agent(s) responsible for security of supply – this responsibility is often borne by the TSO but it may be passed on to suppliers or consumers, who have levers on their side to improve security of supply by reducing this need for capacity.

The certification of guaranteed available power plants is determined taking into account the forced outage rate of the considered power plants for each technology (as described in WP5). For RES certification, it depends on the average availability of those non-dispatchable resources during peak hours (also described in WP5).

Finally, the intersection of the capacity supply and demand will define every year the capacity price for a given year. In the SIDES model, the (capacity) demand is considered as inelastic and its level is set to the capacity adequacy target. The supply depends of every participant’s bids. For existing power plants, the bid will represent the difference between the anticipated energy revenues and annual operational and maintenance costs, which relies on the assumption that if the sum of the revenues from the energy market and the capacity market is not enough to make these plants profitable, they will be mothballed. For new power plants projects, the bids will represent the difference between the anticipated revenues and the fixed costs (annual amortization of the

[7] As defined in the French Law 2010-1488 (“NOME law”) and Decree 2012-1405 (in French).

investment added to the fixed operational and maintenance costs). Lastly, renewables benefit from feed-in-tariffs, which ensures their profitability through out-of-market support. Thus, they bid their capacity at a price of 0 €/MW.

7.2 Results

7.2.1 Economic efficiency in a risk aversion-free world

The economic efficiency is analyzed in the light of the social welfare and, as demand is supposed to be inelastic, the total cost of the mix is computed as a proxy to the social welfare (the higher the cost, the lower the social welfare). The total cost is measured as the sum of:

- the cost associated with non-served load
- the variable (fuel) costs burnt by generating units
- the fixed operation and maintenance cost of the power plants
- finally the money invested in new power plants.

The investment cost of pre-existing power plants and the cost of new renewables are not taken into account since they are exogenous parameters that, for a given scenario, do not change from one market design to the other.

7.2.1.1.1.1 Detailed analysis in the context of the Reference scenario

In 2015, as a starting point, the mix was set to that defined in the 2020 scenario, to the exclusion of hydro which is not modelled in the tool. As the contribution of the interconnections to security of supply is also missing (only France is modelled), there is an important lack of capacity at the beginning of the simulation (see Figure 52). This, however, largely disappears after three years and then is resorbed more slowly over the following decade if scarcity pricing or a capacity mechanism are part of the market design. In the capped energy-only market, investments are slower and some generating capacity is missing at the end of the simulation (as shown on Figure 53). More importantly, security of supply is not ensured in "permanent regime" since there remain around 20 hours of loss of load expectation at the end of the simulation.

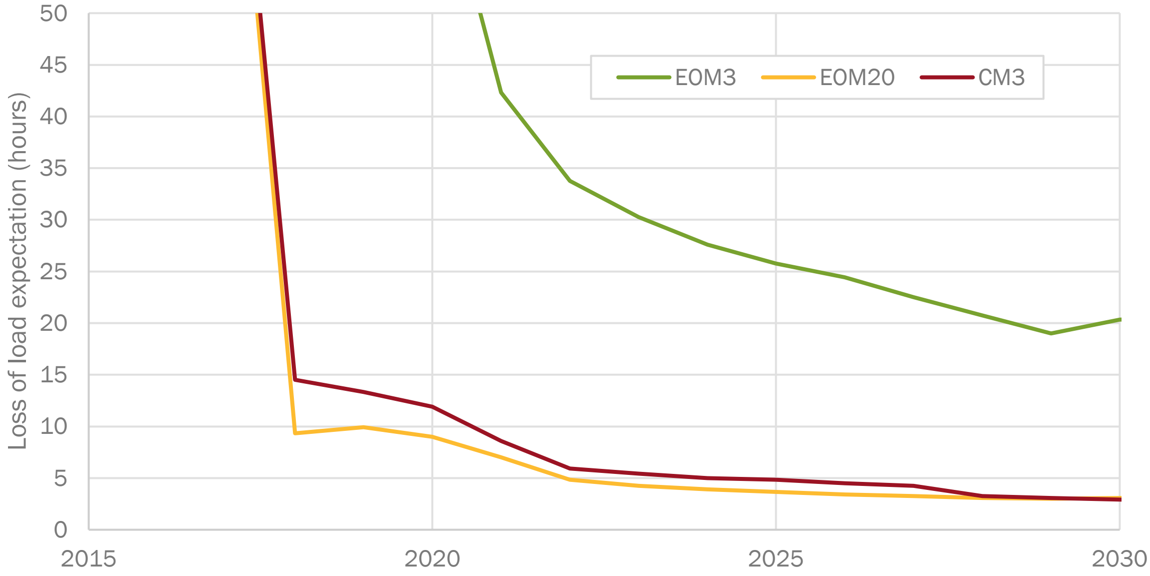


Figure 52 - Loss of load expectation year by year in the Reference scenario, for each market design.

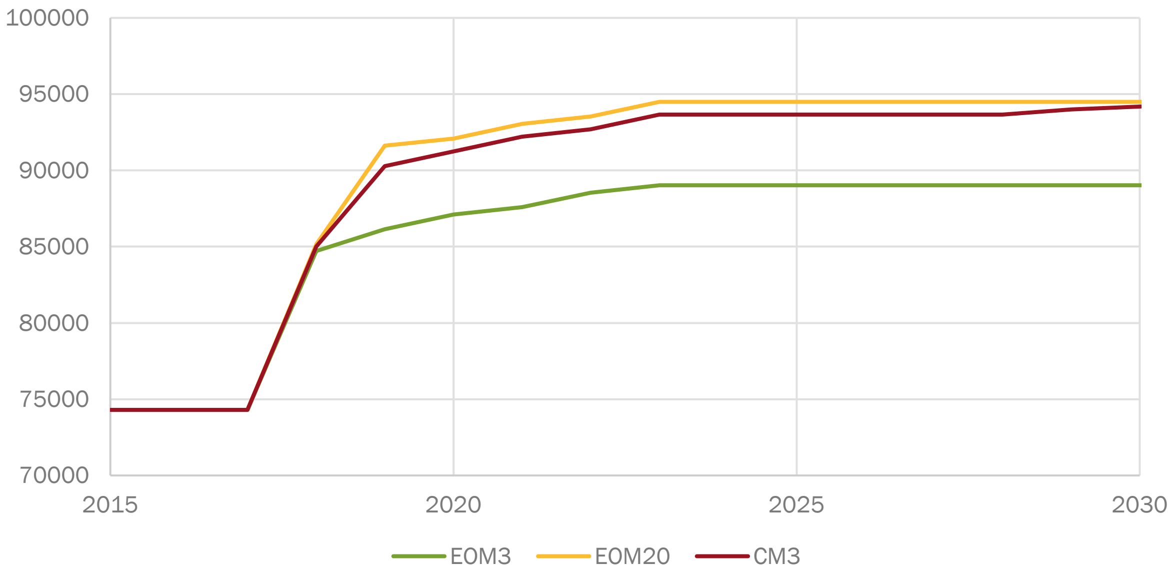


Figure 53 - Total thermal installed capacity over time, for each market design in the Reference scenario

This lack of capacity at the beginning of the simulation results in a very high cost of lost load. This cost is mostly concentrated over the few first years. Both EOM20 and CM (CM3) reach 3 hours of loss of load expectation at the end of the simulation (3.08 hours for EOM20 and 2.91 for CM3 in 2030). However, the cost of loss load is largely superior in the EOM3 scenario because there remain numerous hours of loss of load at the end of the simulation (20 hours).

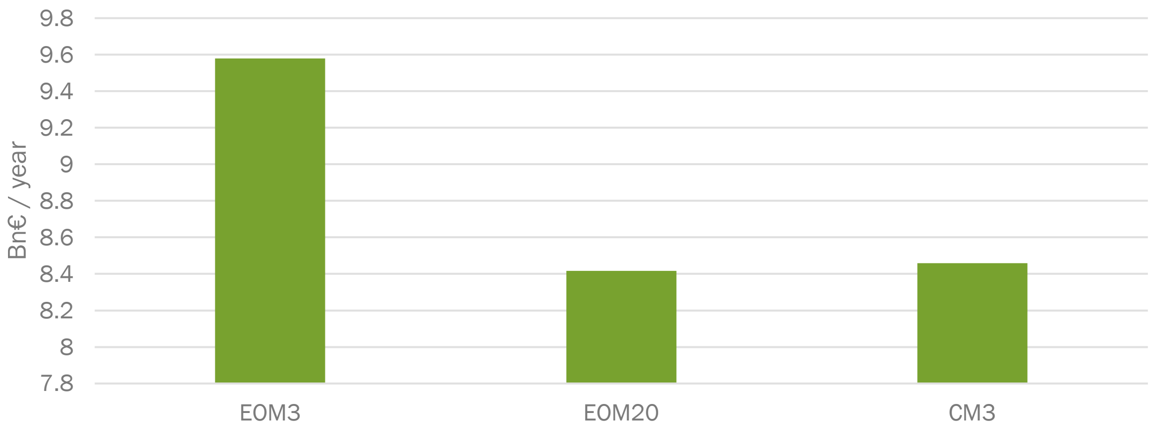


Figure 54 - Average annual cost of the loss of load according to the market design in the Reference scenario

Logically, the fixed operation and maintenance costs are higher (see Figure 55) in the case of EOM20 and CM than in that of EOM3, since these costs depend on the installed capacity, which is higher under the two former market designs. They are slightly higher under EOM20 than under CM3 for a similar reason: the capacity is developed earlier in EOM20.

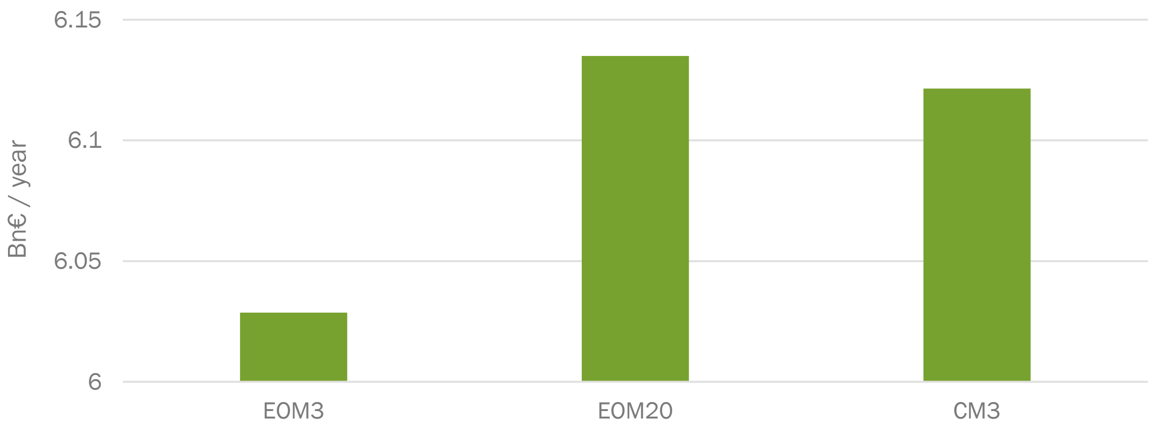


Figure 55 - Average annual fixed operation and maintenance costs according to the market design in the Reference scenario

Interestingly, CM3 is less greedy in variable costs than EOM3 and EOM20 (Figure 56) and, conversely, it involves more investments than EOM20 which, in turn, results in more investments than EOM3 (Figure 57). The latter fact is easy to understand: as seen above, less (and not enough) new capacities are invested under EOM3.

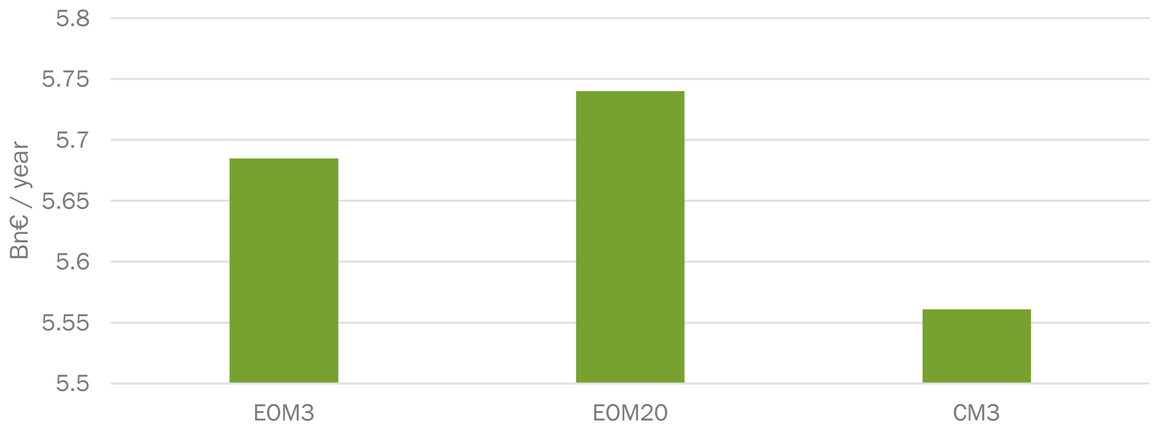


Figure 56 - Average annual variable costs according to the market design in the Reference scenario

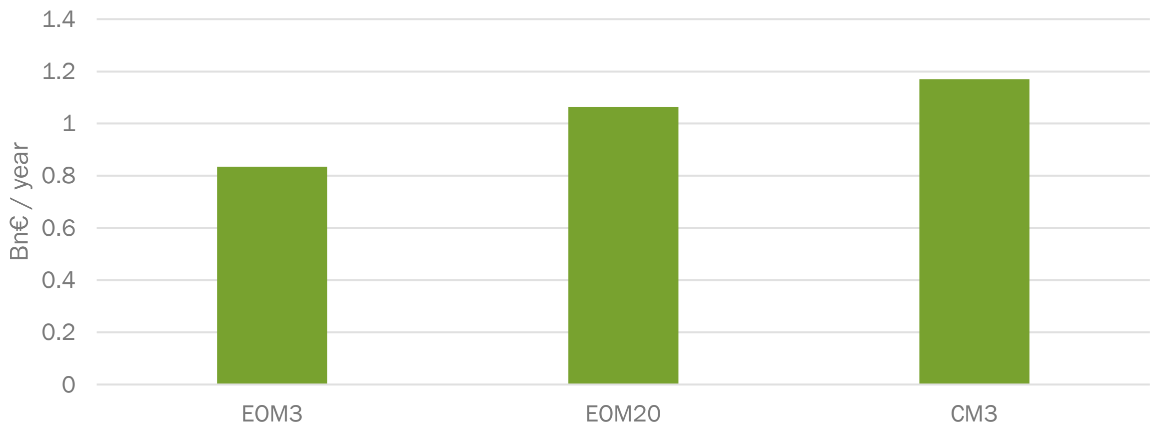


Figure 57 - Average annual investment costs according to the market design in the Reference scenario

The differences in variable and investment costs between CM3 and EOM20 are less straightforward and deserve to enter a bit more into the details of the technologies that are developed in both cases. Figure 58 shows that CCGTs were preferred under the capacity mechanism instead of OCGTs, which are deployed under scarcity pricing. CCGTs are more expensive to build but also more efficient and therefore have a lower fuel cost for the same amount of generated electricity. For a yearly number of hours of generation close to the point at which the total costs of these two technologies are equal, CCGTs' and OCGTs' relative merits are very close and, in this area, a relatively small difference in the value of input parameters may have driven the model to the observed difference in investment decisions. In particular, this may be due to the fact that a forced outage rate of 5 % was considered for CCGTs whereas it was set to 8 % for OCGTs, leading the former to benefit from more capacity credits in the capacity mechanism and therefore a better relative (*i.e.* in comparison to OCGTs) profitability under the CM3 than under the EOM20.

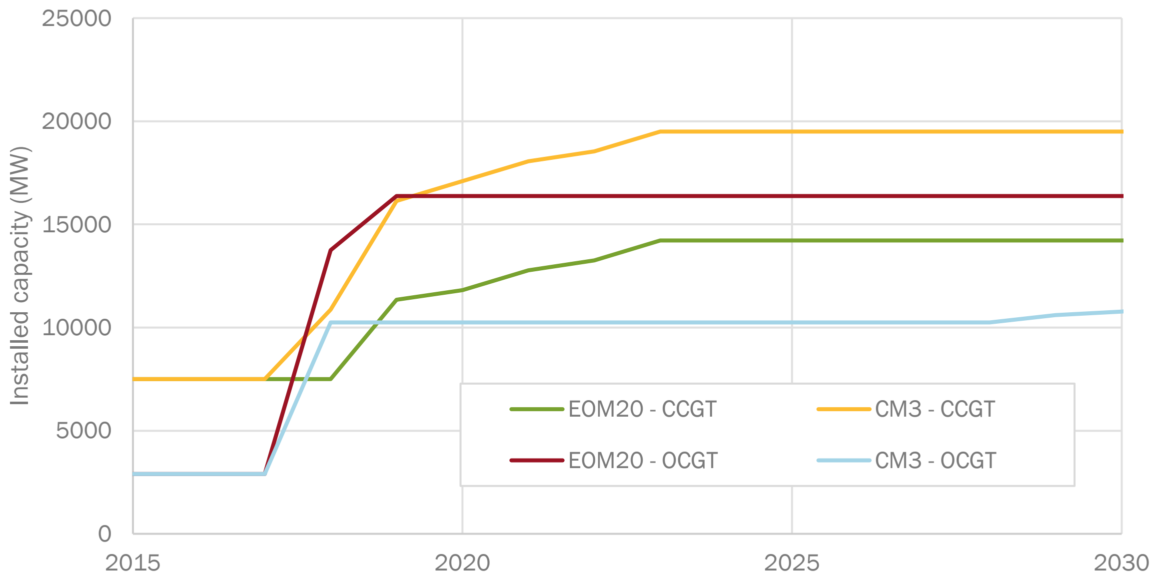


Figure 58 - OCGT and CCGT deployment under EOM20 and CM3 in the Reference scenario

Finally, the total cost ends up being lower when a scarcity pricing or a capacity mechanism were implemented than under the current market arrangements. In addition, we can see in Figure 59 that a capacity mechanism and a scarcity pricing perform similarly in minimizing total costs (and, therefore, in maximizing social welfare). In this particular scenario, the capacity mechanism even resulted in a slightly lower cost.

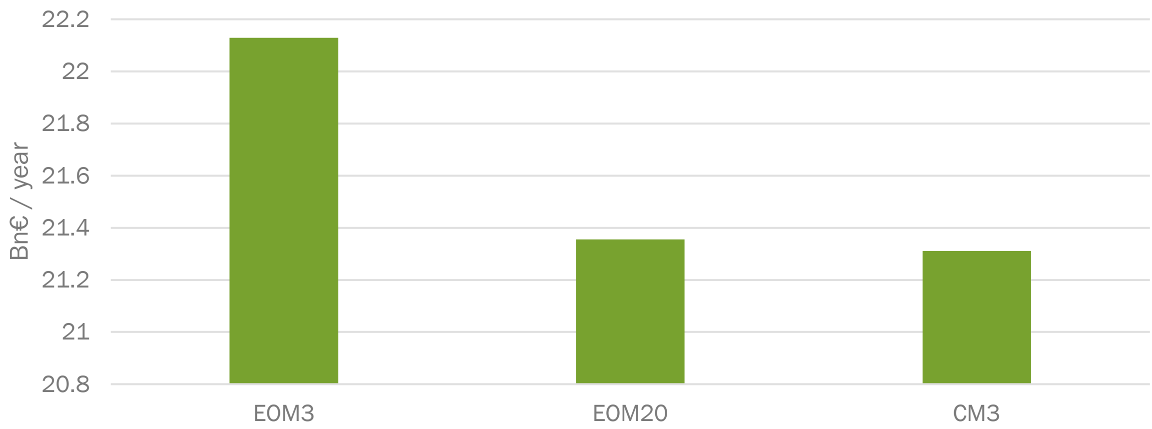


Figure 59 - Average total annual costs according to the market design in the Reference scenario

7.2.1.1.1.2 Results for the three scenarios

Figure 60 confirms the results that were obtained for the Reference scenario: scarcity pricing and completing the energy market with a capacity mechanism result in the same level of cost (and of social welfare) which is significantly lower than the cost resulting of a capped energy-only market.

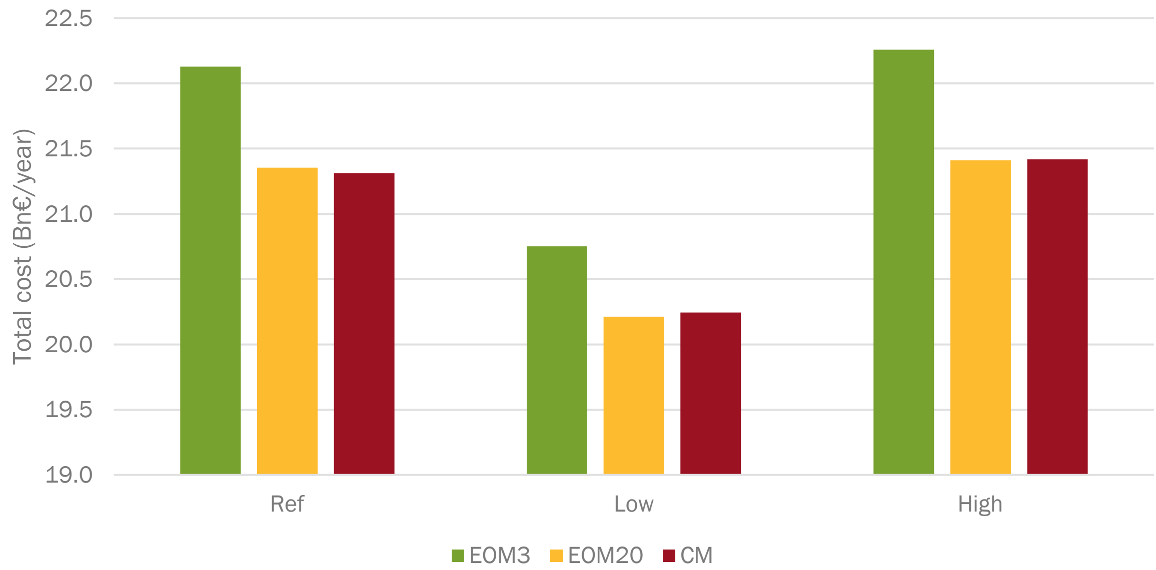


Figure 60 - Average total annual costs according to the market design in each scenario

Some small differences appear between the two former options but they are not systematic. From a modelling perspective, it must be noted that the investment decisions have a certain degree of granularity and that this is very likely to have led to these small differences in the total cost. Such differences can therefore not lead to any general conclusion regarding the relative economic performance of these mechanisms.

7.2.2 Impact of the market design on risk for producers

Whereas CM3 and EOM20 perform similarly regarding their economic efficiency if we make the simplification that the profit expectation is the only criterion that drives producers' investment decisions, results for the two scenarios may differ regarding another topic of interest to investors, which is the level of risk involved by such decisions. In fact, these simulations show that the variability of the peaking generating units' revenues differs greatly from one market design to another.

For instance, Figure 61 shows that, under EOM20, in 2030, in the Reference scenario, a peaking power plant would only make some net revenues in 5 out of the 12 weather (Monte-Carlo) scenarios. Among these years, it would earn a very limited amount of money in one of these scenarios (#2) and a gigantic one in another (#11). Thus, revenues in the latest weather scenario would represent as much as 65 % of the expected revenues of the power plant! The situation would be very different under the CM3 scenario, where the revenues of this power plant are not only drawn from the energy market when very high prices are reached, but also from the capacity market, ensuring the producer a much more predictable level of revenues.

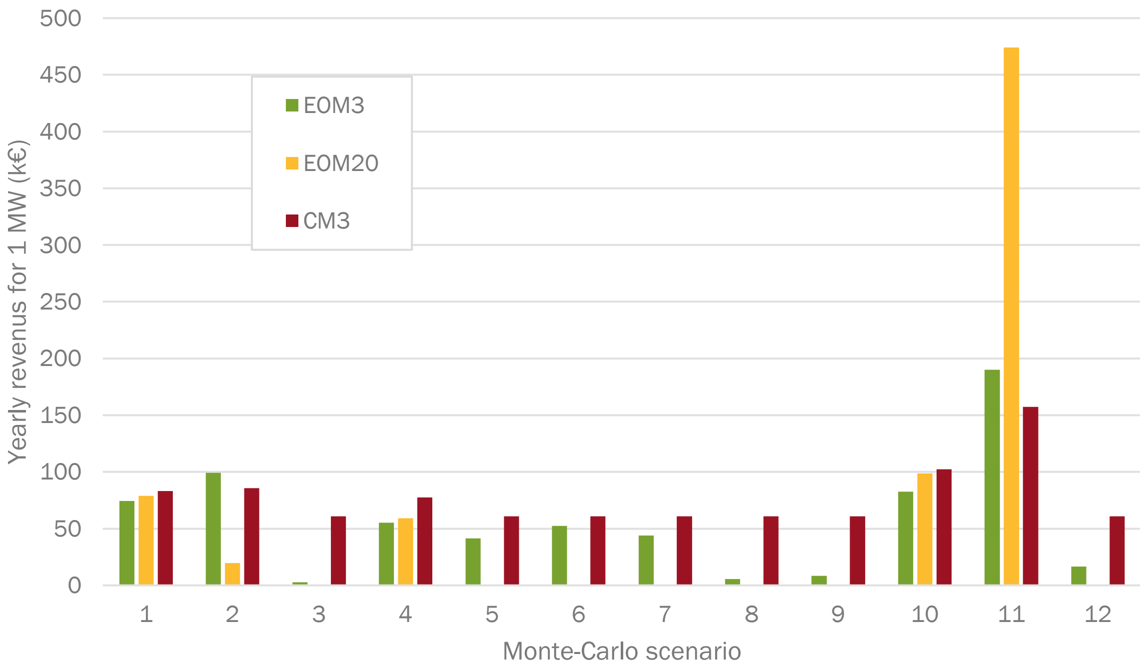


Figure 61 - Revenues of a peaking unit in 2030 according to the weather scenario and the market design option in the Reference scenario

Such results are not a coincidence. Figure 62 shows a more systematic analysis of this phenomenon. For each macroeconomic scenario and each market arrangement option, the standard deviation of the revenues of a peaking power plant (OCGT) across all weather scenarios has been computed for each simulation year, then divided by the average of these revenues (again, per year), leading to a relative standard deviation of revenues for each year. Then the average of this standard deviation over all years has been computed for each macroeconomic scenario and each market design option. This graph clearly shows that the EOM20 option involves much more risk for peaking units owners than the EOM3 and that the CM3 involves, risk. Schematically, scarcity pricing doubles the relative standard deviation of the revenues of such a power plant in comparison with the capped energy-only market, whereas the capacity mechanism halves it.

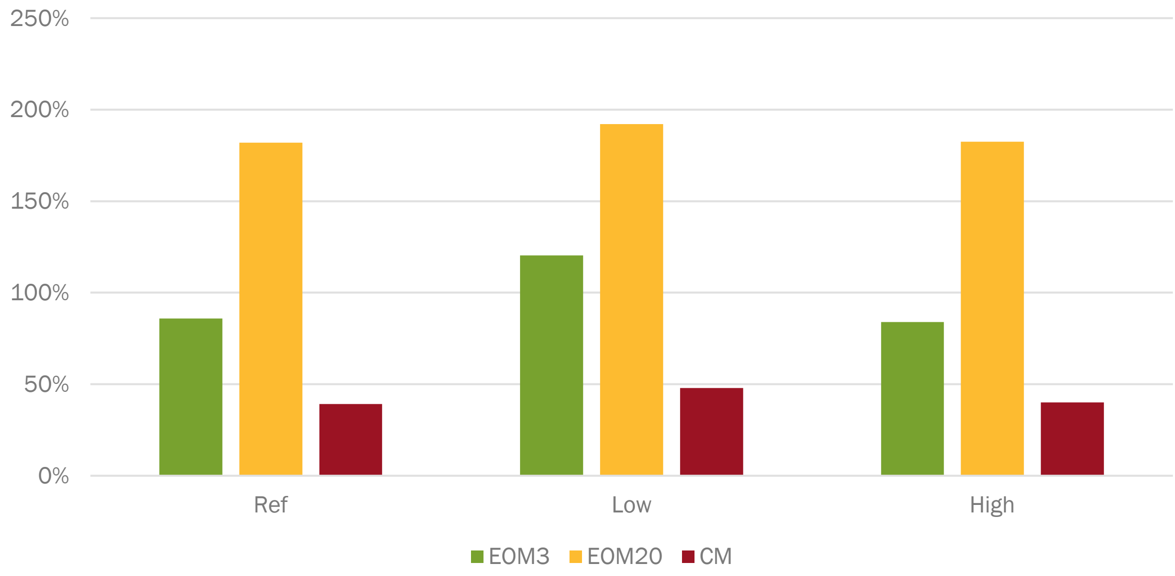


Figure 62 - Relative standard deviation of revenues for a combustion turbine, averaged over the simulation duration for each scenario and each market design option.

7.3 Analysis and recommendations

From the analysis of the economic efficiency discussed in paragraph 7.2.1, it turns out that setting up a scarcity pricing mechanism (EOM20) or a capacity mechanism is equivalent in terms of social welfare (or in terms of total costs) even if the results exhibit small differences due to the granularity of investment decisions. These two options are far better than the current market arrangement comprising an energy-only market with a wholesale price cap well below the cost of non-served load.

The conclusions could lead to the conclusion that the solution to the missing money problem could consist in abolishing the price caps in the wholesale market, which seems easier to implement than capacity mechanisms. Nevertheless, it is important to note that the impact of risk on investment decisions was not taken into account in this analysis.

For all scenarios, it clearly appears that the risk taken by power plant owners due to the variability of their revenues is much lower under a design including a capacity mechanism and a price cap at 3,000 €/MWh than under a price cap-free, energy only market. The consequence is that the capital costs are underestimated in this latter market design. Then, risk mitigation through the capacity mechanism would result in a lower total cost than under scarcity pricing at 20,000 €/MWh.

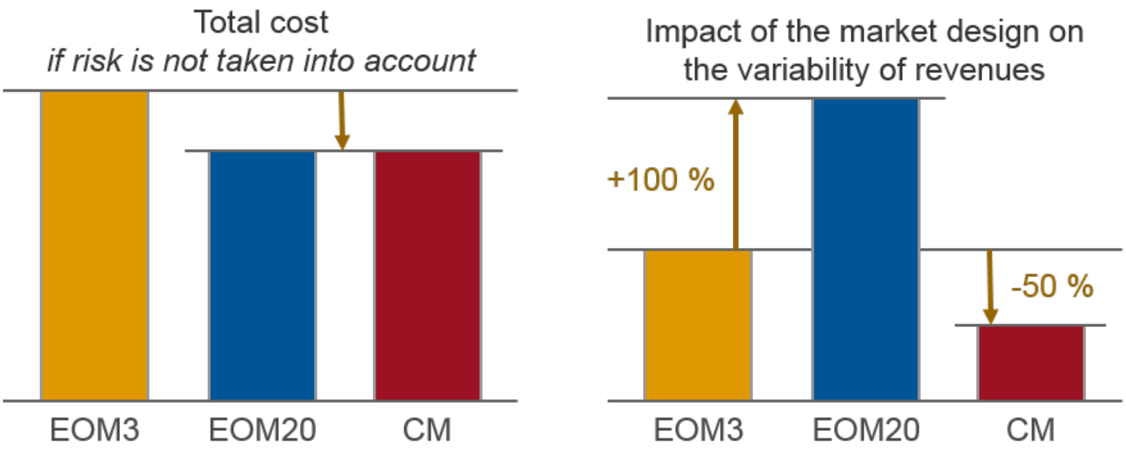


Figure 63 - Summary of the conclusion of the study: respective impacts of scarcity pricing and a capacity mechanism on economic efficiency (in the absence of risk aversion) and on the risk taken when investing in peaking units.

It implies that the capacity mechanism solution must be preferred over the energy-only market design with scarcity pricing. Not only does a capacity mechanisms ensure adequacy (providing a benefit when compared with an energy-only market with a 3,000 €/MWh cap), but it also mitigates the risk of peaking units projects, enabling their financing through cheaper capital to the benefit of the consumers (when compared with an energy-only market with scarcity pricing).

This has recently been confirmed by another study [10] based on the same modelling.

8 Interdependence of the costs of capacity remuneration mechanisms and RES support mechanisms

8.1 Introduction

The objective of the case study presented in the following is to assess the impact of support mechanisms for renewable energy sources (RES-E) as well as capacity (remuneration) mechanisms (CRM) on the dispatch and economic outcome of the European power system. In addition to their individual impact, their joint impact is assessed. The model used is SINTEF's EMPS tool, described in Market4RES deliverable D5.1.

8.1.1 Methodology

In order to study the effects of the both above mentioned market mechanisms, a case study with four different cases as depicted in Figure 64 has been built and analysed. The basis for the case study is formed by ENTSO-E's Visions (ENTSO-E 2016), specifically Vision 3 and Vision 4. In addition, two more cases with increased generation capacity are defined.

In order to assess the effect of RES-E, both Vision 3 and 4 are analysed. The assumption is that the extra RES capacity that is implemented in Vision 4 compared to 3 is triggered by a RES-E mechanism. The assessment of a CRM mechanism is carried out by increasing the installed generation capacity (specifically gas power), which is assumed to be supported by the CRM. This results into the additional case V35p. Finally, the joint effect of both policies is studied in case V45p, having increased renewable capacity as well as generation capacity. The "5p" in the scenario names V35p and V45p indicates a 5% increase in installed thermal capacity with respect to the original scenarios, V3 and V4.

- V3 Energy only market without any support
- V35p CRM without RES support
- V4 Energy only market with RES support
- V45p CRM and RES support

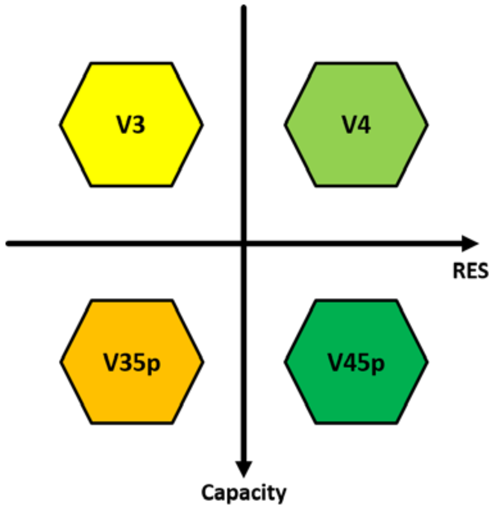


Figure 64: Share of RES and thermal capacity (Capacity axis) in the visions V3 and V4 resp. V35p and V45p

8.1.2 Implementing the ENTSO-E visions in EMPS

Based on the specification from ENTSO-E, datasets were set up in EMPS to reflect the visions given in (ENTSO-E 2016). Vision 3 and Vision 4 are chosen to be analysed in this section.

ENTSO-E Vision 3 – "National Green Transition"

This vision has good economic conditions with more financial support provided through existing energy policies. There is a weak coordination between the European countries and a minor will to introduce a European energy market with major changes. Support schemes may favour old technologies. Thus, new breakthroughs are not expected. CO_2-prices are at a level that gas power is preferred compared to hard coal. The demand can be modulated through demand response, but gas powered power plants are the main units that deliver backup capacity, since hydropower and a strong European interconnection are not developed to their full potential (ENTSO-E 2016).

ENTSO-E Vision 4 – "European Green Revolution"

This is the vision with the highest support for renewables and coordinated European energy policies. New market designs will come to be true with better integration of RES. R&D is financed to develop the needed technologies. CO_2 prices increase significantly. This will be in favour of gas power plants, which will push hard coal out of the market. Additional hydro-storage is built in order to compensate for fluctuations and as backup (ENTSO-E 2016).

Differences between the scenarios in ENTSO-E and EMPS

The data found in the ENTSO-E visions were considered in the case studies run in the European EMPS-model if procurable. For each vision, an own setup was made. Among others, input data covers marginal costs, transmission capacities, produced energy, and power plant types. As EMPS is a fully developed model with a mature simulation algorithm, it has been necessary to make some simplifications where data cannot be processed as provided by ENTSO-E (e.g. wind power production). On the other hand, some data could be considered in more detail in EMPS, but the data from ENTSO-E is insufficient for this (e.g. start-stop-costs for power plants).

One main challenge is the solar and wind production. Considering the installed capacities from ENTSO-E, the simulations showed great differences in the energy outcome w.r.t. ENTSO-e results (around 13% for combined PV and wind). This happens as ENTSO-E uses other time series for RES than the ones implemented in EMPS. In addition, the energy production from bio power and nuclear did not provide comparable results to those of ENTSO-E. To address this discrepancy for thermal power plants, input data from ENTSO-e considered in EMPS were finally those about the amount of energy produced, instead of the installed capacity. Hence, power plants have to fulfil the energy production limit set and the EMPS results for those power plants shall match the reported ENTSO-E production.

Resulting deviations in ENTSO-E and EMPS

The total deviation regarding the energy production between the ENTSO-E visions V3 and V4 compared to EMPS results is only about 1.4% and 2.2%, respectively. As said, most deviations occur in the production from RES. The sum of solar and wind production is in average 18% lower than that provided by ENTSO-E. The missing energy in both visions is then substituted by increased production from gas and coal power plants, mainly (see Table 38 and Table 39 in Annex 10.3.1).

Cases with increased production capacity

In addition to the original visions V3 and V4 from ENTSO-E, two cases were created with increased production capacity from gas power plants. In each country, the maximum peak load was identified and 5% of this value was added to the capacity of OCGT power plants (establishing cases "V35p" and "V45p" as seen in Figure 64). This responds to an average capacity increase of 160% for gas power per country, which may be as high as 800% in some countries with low production capacity from gas power (e.g. France, Finland, Switzerland or Serbia) and/or high peak demand. Figure 65 and Figure 66 show the resulting production per technology with 5% more installed gas power capacity in each country in the visions. The figures show results for all countries by technology (including only those countries where this technology exists). Thus, to the left, bio power plants are listed sorted by country. The same is provided for all technologies, where "iRES" corresponds to photovoltaic & wind and "misc" to other non-RES generation (e.g. non-renewable CHP, waste and other not clearly defined generation)

It appears that in both cases (V35p and V45p) the additional gas power replaces hard coal and lignite power plants. The highest change in production in both visions takes place in Germany, France and Poland.

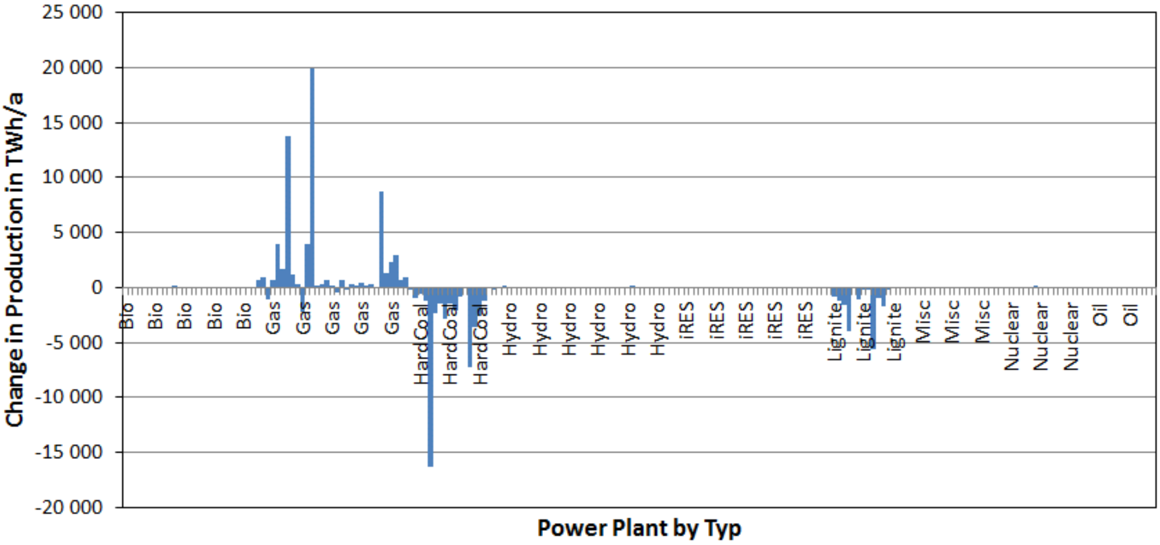


Figure 65: Change in production from V3 to V35p , where there is 5% more installed gas power

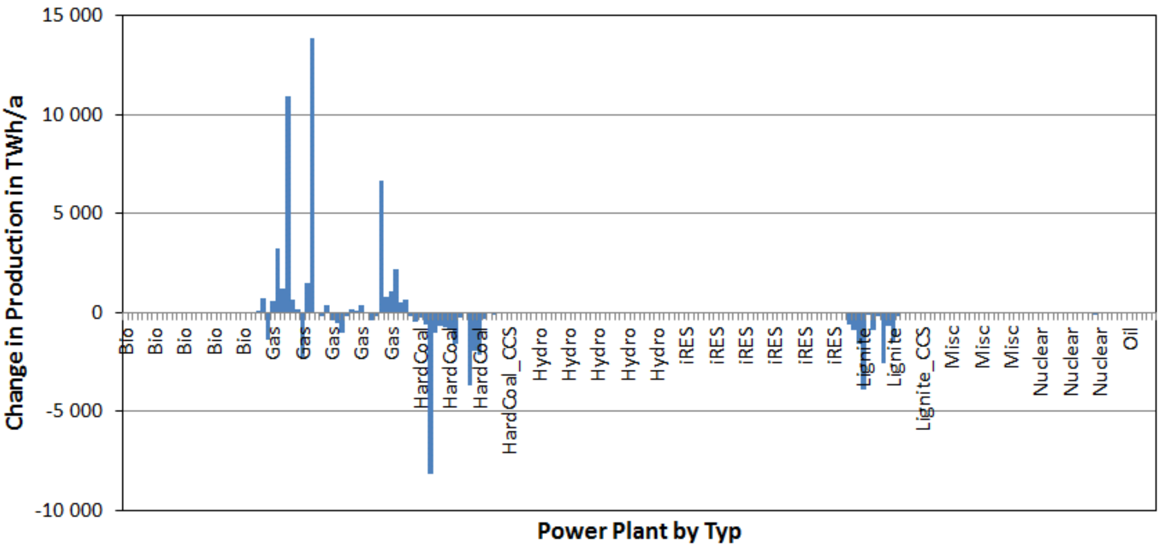


Figure 66: Change in production from V4 to V45p, where there is 5% more installed gas power

8.2 Results

8.2.1 Energy production and transmission

The simulation tool EMPS provides very detailed results for the modelled European system. For each country, the production per technology and time step can be obtained. Furthermore, the utilization of the grid and the hourly power prices in each areas may be computed for evaluation.

This section discusses the energy related results, like the production volumes or transmission network use.

Changes in the share of power production

The main difference between Vision 3 and Vision 4 results is the increased use of RES (intermittent solar & wind [here "iRES"], bio power, hydro) in the latter. As there is no significant change in the demand, the production from RES will consequentially replace fossil fuel production. This can be observed in Figure 67 for the comparison between Vision 3 and Vision 4, and in Figure 68 comparing the two visions with 5% more installed gas power capacity (V35p and V45p). The production from the above-mentioned RES increases while the production from fossil power plants (gas, hard coal, lignite) decreases in V4. The highest decrease in production form fossil fuel generation occurs in Spain, Germany, Italy and Poland, while the highest increase of RES production takes place in the same countries and, in addition, in France. This accounts for both figures.

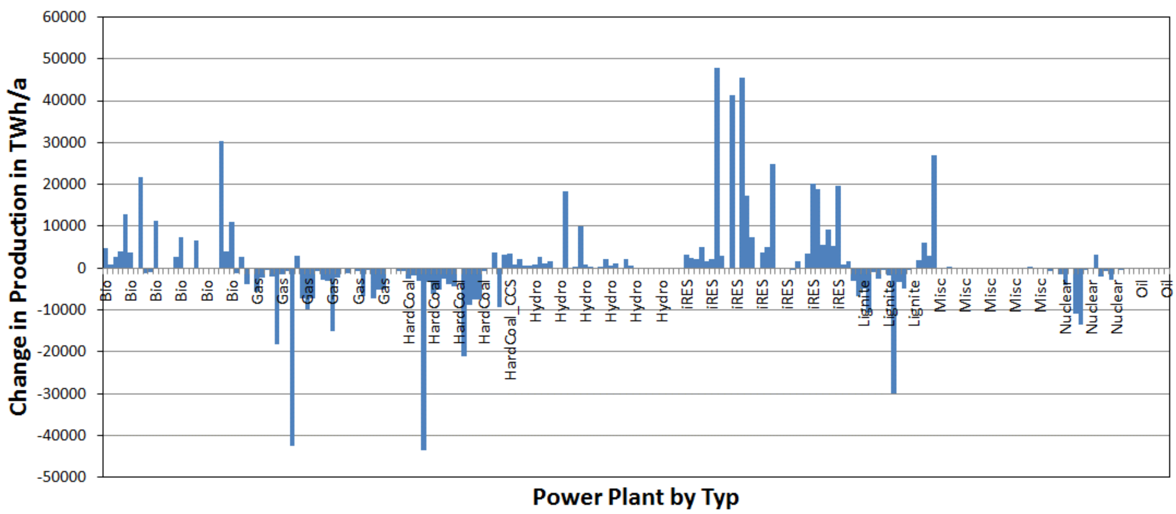


Figure 67: Change in production from V3 to V4

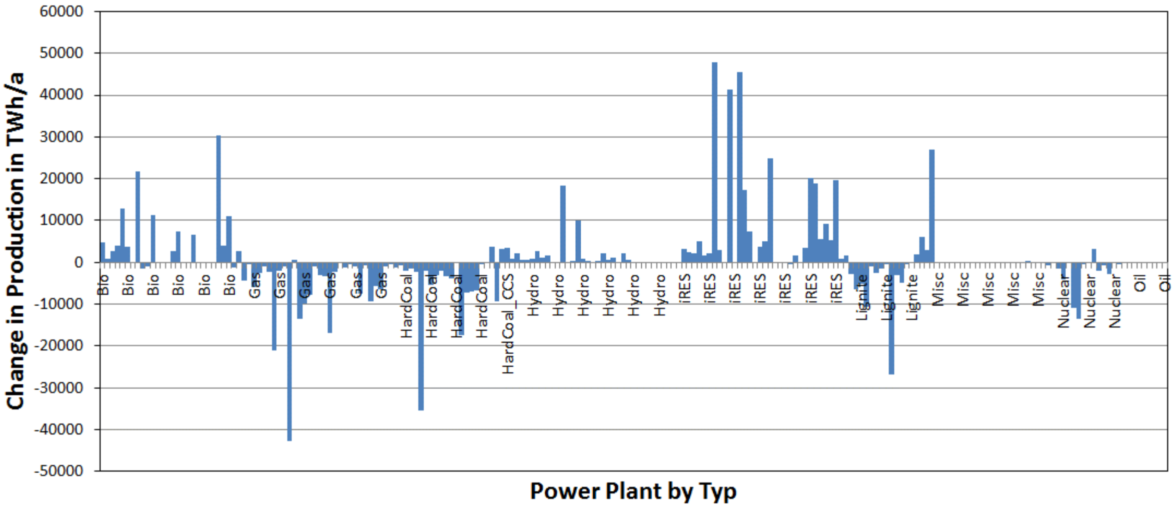


Figure 68: Change in production from V35p to V45p

Table 28 shows the production by technology in the four visions and the change in it between the original visions and the ones with increased gas power. The share of RES increases from 47% in V3/V35p to 57% in V4/V45p.

Table 31.Production in TWh/a in the four visions and the share of renewables

		V3	V35p	Change	V4	V45p	Change
Renewables	Bio	307	307	-0,01 %	431	431	-0,03 %
	Hydro	569	569	-0,01 %	633	633	-0,01 %
	iRES (PV & Wind)	1,071	1,071	0.00 %	1,369	1,369	0.00 %
	Other RES	8	8	0.00 %	11	11	0.00 %
	sum	**1,955**	**1,955**	**0.00 %**	**2,444**	**2,443**	**-0.01 %**
Thermal	Divers	0	0	0.00 %	0	0	0.00 %
	Gas	943	1,006	6.63 %	792	830	4.91 %
	Hardcoal	341	296	-13.23 %	220	197	-10.41 %
	Lignite	172	155	-10.17 %	140	127	-9.20 %
	Oil	0	0	0.00 %	0	0	0.00 %
	sum	**1,457**	**1,457**	**0.00 %**	**1,152**	**1,155**	**0.26 %**
Nuclear	Nuclear	738	738	0.00 %	704	704	-0.02 %
Total sum		**4,150**	**4,150**	**0.00 %**	**4,300**	**4,302**	**0.06 %**
Share of	Renewables	47.11 %	47.11 %		56.84 %	56.84 %	
	Thermal	52.89 %	52.89 %		43.16 %	43.16 %	

Exchange between the countries

To cover the local demand, energy can be imported from surrounding areas, and exported if there is a surplus in an area. Figure 69 and Figure 70 show the aggregated net energy exchanges over the simulation period for the four visions. As it can be observed in the figures, there are some main exporters (Great Britain, France) and some main importers (Italy, Poland, Belgium, The

Netherlands). The Nordic countries also export, but their possibilities are limited due to transmission capacity limits.

Comparing the two V3-visions, on the one hand, and the two V4-visions, on the other, one can realize that the results do not change much with the increase in the installed gas power capacity. Germany seems to shift from being a net-zero country in the V3 visions to being a net-importer in the two V4 visions with more RES. This might result from the low increase in the RES share from V3 to V4 in Germany (19%). The RES-increase in other countries is, on average, 55%, and it can get as high as 330%. The neighbouring countries' RES capacities, like Czech Republic or Poland, are twice as high in V4 as in V3. Thus, imports from Germany might no longer be needed. Germany could instead import cheaper energy from them or stop exporting energy further.

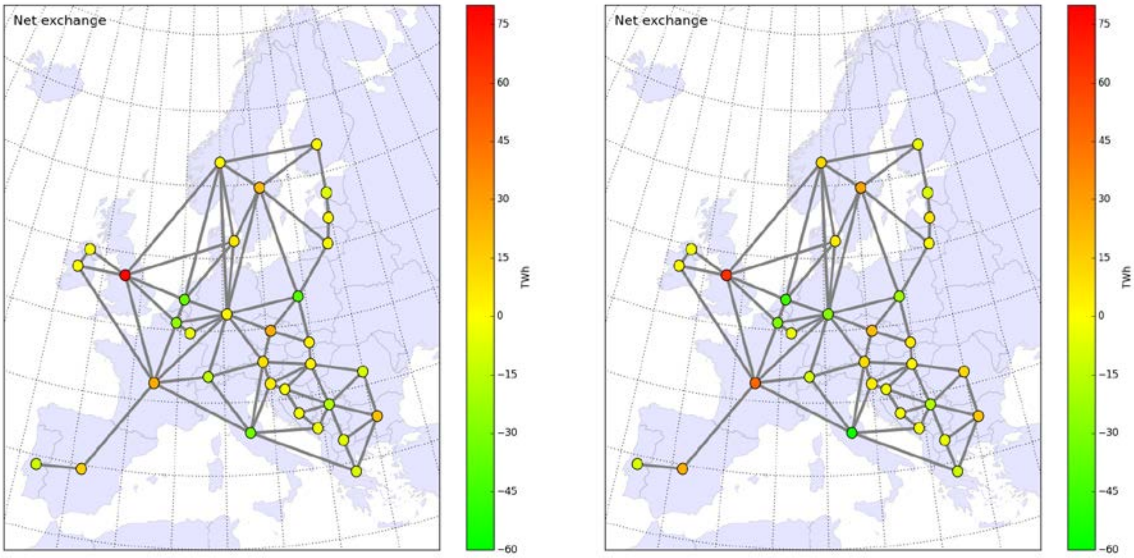


Figure 69: Net Exchange in the vision V3 and V4

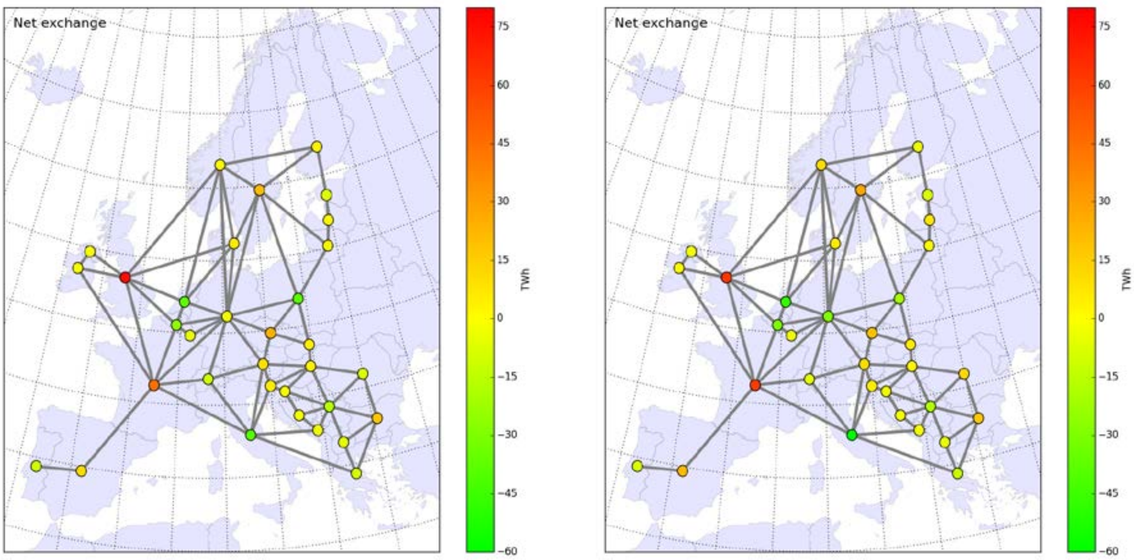


Figure 70: Net Exchange in the vision V35p and V45p

Utilization of the transmission lines and congestion rent

The utilization reflects the usage of the line, i.e. in how many hours of the year the line transfers energy. Some lines are utilized the whole time, like the submarine power cables in the North and Baltic Sea, as shown in Figure 71 and Figure 72. The utilization of these connections is being close to 100%. This applies to all four visions. From V3 to V4, an increase is only visible for connections of France and Sweden. Most connections in continental Europe are not utilized in every hour of the year. Thus, there might be free capacities in some hours that could be used more optimal with a better-coordinated energy system (production, transmission, consumption, storage) to relieve other connections.

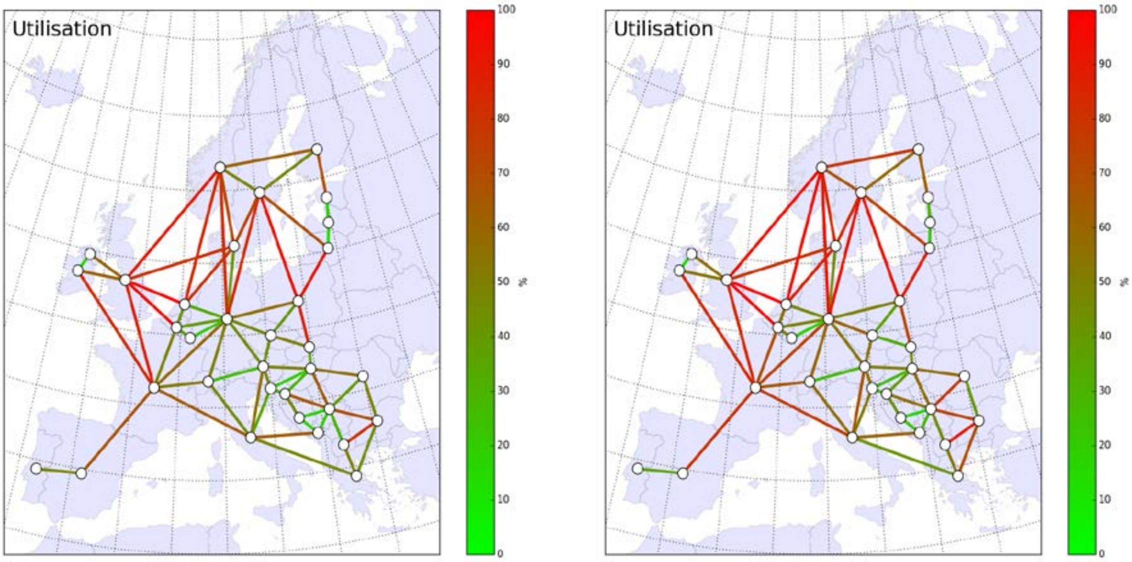


Figure 71: Utilization of the transmission lines in V3 and V4

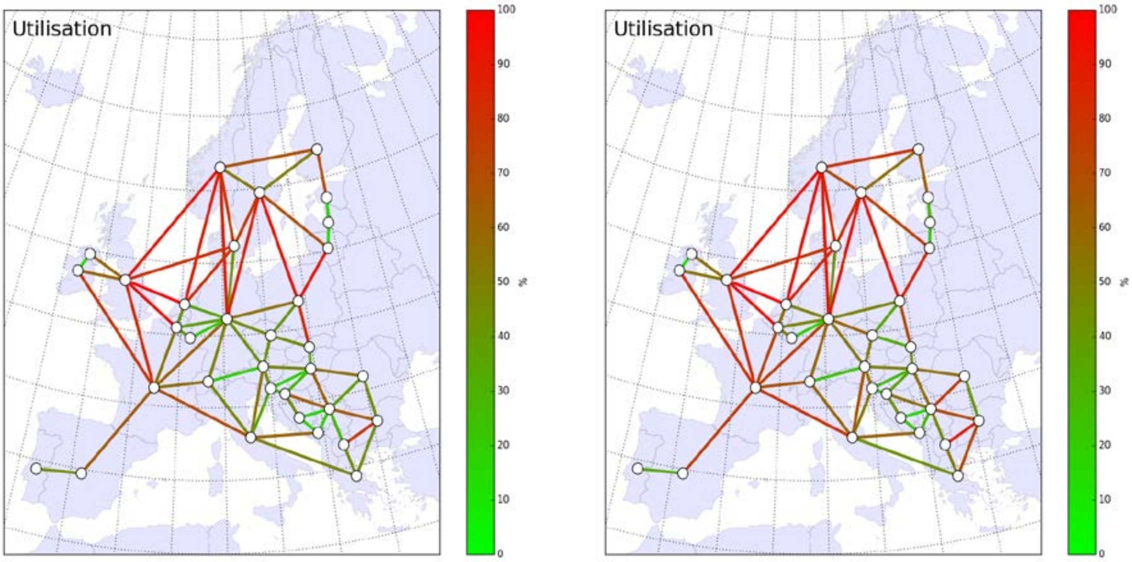


Figure 72: Utilization of the transmission lines V35p vs V45p

Countries with a high energy surplus, on one side of a line, and an energy deficit, on the other side of the transmission line, want to exchange energy. As mentioned before, some of the energy cannot be transported because the transmission lines do not have sufficient capacity. Then, the power price will get higher in the country with energy deficit and lower in the country with surplus w.r.t. limits are not considered. Based on the price difference and the transferred energy, a congestion rent is calculated, which TSOs receive.

In Vision 3, the highest congestion rent is seen on lines connecting Great Britain with Norway and continental Europe. Great Britain is exporting cheap wind energy, which reaches the capacity limits of the submarine cables. If more RES is installed (Vision 4), the energy supply costs in Norway (hydropower) and Sweden (wind, bio power) get cheaper and energy should be exported to continental Europe. The capacity of the cables is utilized to its full capacity as seen in the figures below. It is also possible that some lines/countries are used for bypassing energy (transit flows), e.g. from Great Britain via Norway to Germany.

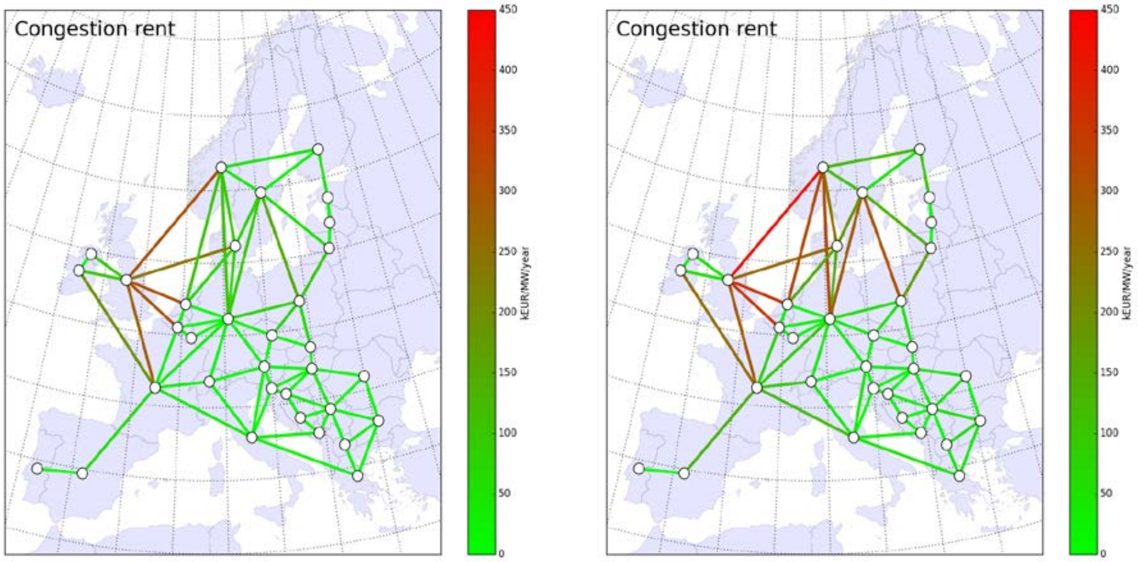


Figure 73: Congestion rent of the transmission lines in V3 and V4

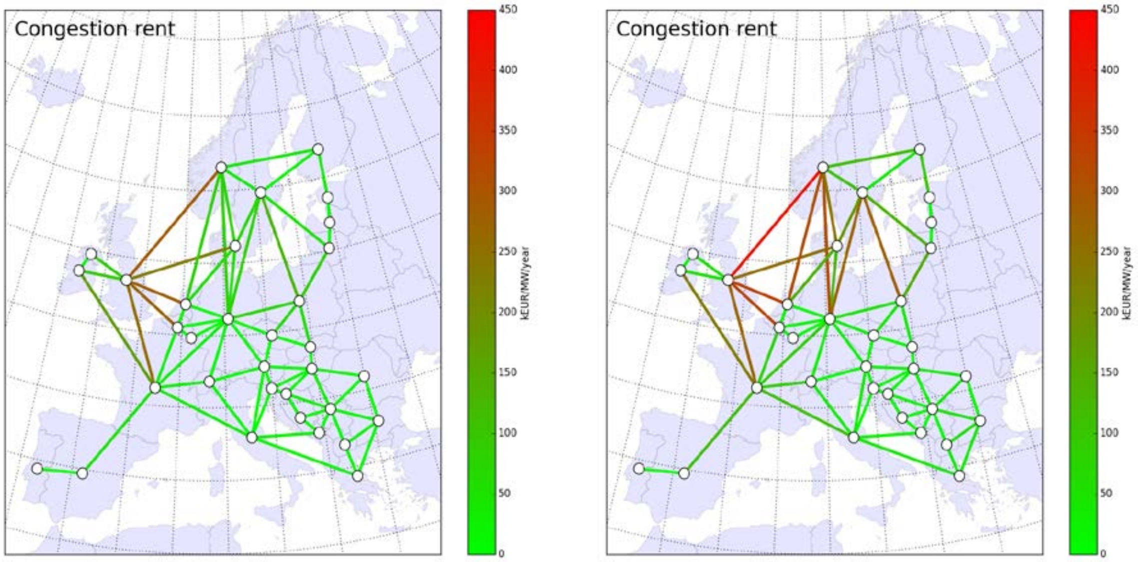


Figure 74: Congestion rent of the transmission lines in V35p vs V45p

CO_2 emissions

For the different power plants within the simulations, CO_2-coefficients for energy production (gCO_2/kWh) have been calculated based on the assumptions in (S. Völler 2014). Each type of generation has a coefficient and, according to the efficiency of the different power plants in the countries, a resulting emission of CO_2 per produced kilowatt-hour can be computed. For each of the four visions, CO_2-emission were calculated and sorted by type of power plant, as in Table 32.

As assumed, the emissions from gas power increase in the visions with more installed gas power capacity (V35p, V45p), while the emissions from hard coal and lignite generation decrease. The total reduction of emissions in these cases is around 6%. Comparing V3 to V4, where more RES exists, the difference in emissions in the latter is about 30%, mainly coming from substituting hard coal and lignite with RES.

Table 32: CO_2-emissions in million ton CO_2 for the four visions

Technology	V3	V35p	V4	V45p	Change V3 vs V35p	Change V3 vs V4	Change V3 vs V45p	Change V4 vs V45p
Gas	661	699	565	584	5,8,%	-14,5,%	-11,6,%	3,3,%
Hardcoal	603	505	369	317	-16,3,%	-38,9,%	-47,4,%	-13,9,%
Lignite	414	365	248	212	-11,8,%	-40,0,%	-48,7,%	-14,5,%
Oil	0	0	0	0				
Sum	**1,678**	**1,569**	**1,182**	**1,113**	**-6,5%**	**-29,6%**	**-33,7%**	**-5,8,%**

Energy spillage

Table 33 gives an overview of the spilled energy, i.e. curtailed production from RES. A significant increase in spillages can be observed from Vision 3 to Vision 4, where there is more RES generation installed. When assessing the results in more detail, it can be observed that most of the generation curtailments happen in Norway and the UK, which is in line with the utilization factors of the cables used to export power from these areas.

Table 33: Energy spillage in the system

	V3	V3 5p	V4	V4 5p
TWh	1.6	1.4	8.8	9.6

8.2.2 System costs and economic results

The following section discusses the economic results in the different visions and changes between them. How do increases in RES energy production, or the additional production capacity from gas power, influence the power price, consumer/producer surplus or social welfare?

Power prices in the countries

Based on the available production capacity by technology, the demand, the marginal production costs, and transmission capacities, a power price is computed for each country/area and time step. The average power price over all years in the simulation period in each area/country lies between 75€/MWh and 125€/MWh (see Figure 75 and Figure 76). The lowest power price is computed for Great Britain, due to its large wind power production. The Nordic countries also have low power prices due to the large hydropower resources they have and, especially in Vision 4, due to the increase in wind power they experience. Continental Europe has high power prices but a relatively low price difference between countries due to the existence of a strong transmission system. Power exchanges from Great Britain and the Nordic Countries into the rest of Europe are limited by existing transmission capacities, and thus a high power price difference between these regions occur.

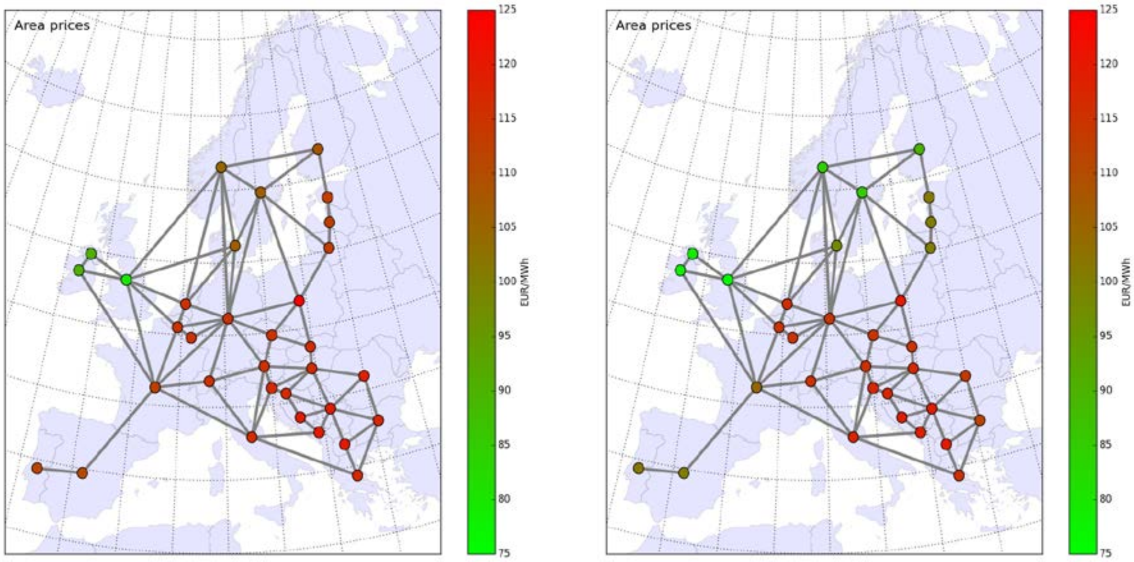


Figure 75: Average area power prices in V3 and V4

The same applies for the visions with 5% more installed gas power capacity. Here the average power prices decrease by 3.3% and 3.9%, respectively.

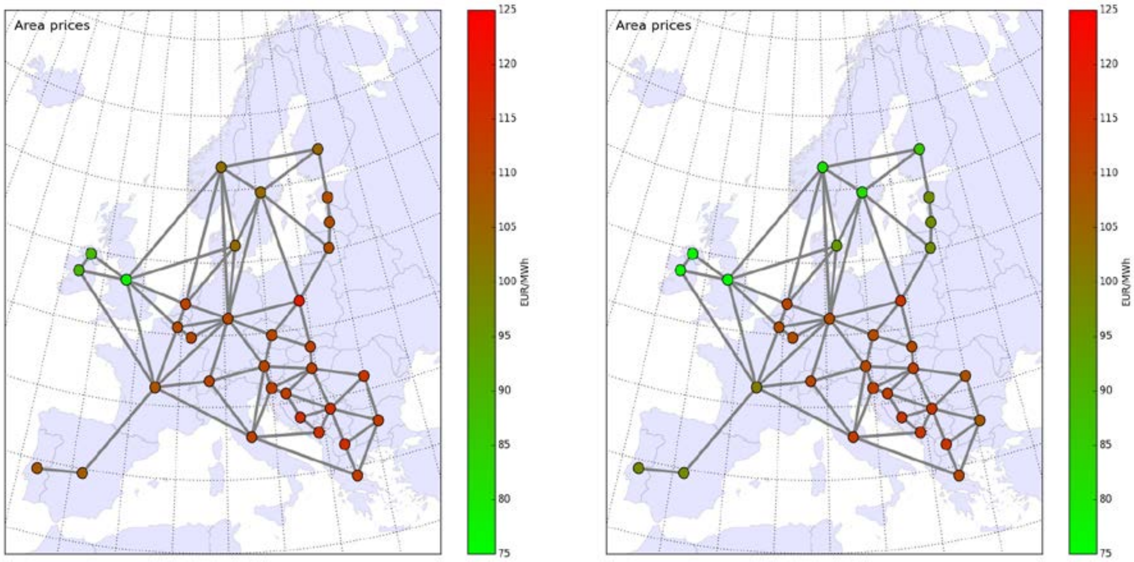


Figure 76: Average area power prices in V35p and V45p

The weighted average power price over all countries in the system (area prices weighted with the consumption in each area) is shown in Table 34 for the four different visions. It is decreasing from V3 to V4 (more RES) as well as with the installation of more gas power (from V3 to V35p, and from V4 to V45p).

Table 34: Weighted average power price over all countries in the corresponding visions

	V3	V35p	V4	V45p
Weighted average power price in €/MWh	110.88	107.18	105.74	101.53

Production capacity and annualised fixed costs

Table 35 shows the installed capacity for each technology in the corresponding vision and the annualised fixed costs based on (ENTSO-E 2016). The 5% extra gas power capacity in V35p and V45p is marked in red, which is the only difference between V3 and V35p, and V4 and V45p. The differences between the visions based on Table 35 are provided in Table 41 in 10.3.2.

Adding 5% more gas power in V35p and V45p results in around 30GW more capacity, but annualised investments of 2.2bn€ per year. Comparing V3 to V4, thermal capacity in the latter is lower by in 12GW (1.4bn€ less costs) while RES is lower 308GW. There is also an increase of the annualised fixed costs of 49bn€ in V4. Annualised fixed costs are about 21% larger in V4 than in V3. The change from V4 to V45p, then, is only marginal by adding extra gas power. The total capacity change between V3 and V45p is 328GW (+23%), and the annualised fixed costs are higher by 50bn€ (+22%).

Table 35: Installed production capacity and total annualized fixed costs for the four visions

Technology	Annualized fixed cost k€/MW/year	V3 Installed MW	V3 Costs m€/a	V35p Installed MW	V35p Costs m€/a	V4 Installed MW	V4 Costs m€/a	V45p Installed MW	V45p Costs m€/a
Lignite	182	0	0	0	0	0	0	0	0
Lignite new	225	49,353	11,102	49,353	11,102	43,146	9,706	43,146	9,706
Lignite CCS	292	0	0	0	0	6,207	1,813	6,207	1,813
Hard coal	182	0	0	0	0	0	0	0	0
Hard coal new	225	65,367	14,705	65,367	14,705	55,275	12,434	55,275	12,434
Hard coal CCS	292	4,593	1,341	4,593	1,341	6,495	1,897	6,495	1,897
Gas (OCGT)	76	186,672	14,110	215,931	16,321	184,008	13,908	215,376	16,279
Gas (CCGT)	95	93,336	8,891	93,336	8,891	92,004	8,764	92,004	8,764
Nuclear (PWR)	380	106,990	40,664	106,990	40,664	107,474	40,848	107,474	40,848
Oil	60	16,188	968	16,188	968	16,188	968	16,188	968
Other non RES	60	51,470	3,077	51,470	3,077	51,470	3,077	51,470	3,077
Wind	149	359,450	53,705	359,450	53,705	430,950	64,388	430,950	64,388
Solar (PV panels)	121	223,626	26,982	223,626	26,982	338,310	40,820	338,310	40,820
Other RES	319	1,754	560	1,754	560	2,446	781	2,446	781
Hydro dams	190	177,844	33,842	177,844	33,842	273,689	52,081	273,689	52,081
Hydro run-of-river	190	0	0	0	0	0	0	0	0
Bio	225	78,696	17,703	78,696	17,703	103,814	23,354	103,814	23,354
Sum Thermal		**573,969**	**94,857**	**603,228**	**97,069**	**562,267**	**93,415**	**593,635**	**95,786**
Sum Renewables		**841,370**	**132,793**	**841,370**	**132,793**	**1,149,209**	**181,423**	**1,149,209**	**181,423**
Sum		**1,415,339**	**227,650**	**1,444,598**	**229,862**	**1,711,476**	**274,838**	**1,742,844**	**277,209**

Thermal power plants

The revenues (power price multiplied with produced energy) for the thermal power plants and bio power are shown in Figure 77. Each dot represents one year out of the 75 simulation years in EMPS (1931…2005). It can be seen that the revenue varies over the years due to changes in climatic inputs (hydro inflow, wind speeds, solar radiation and temperature), while the rest of the parameters stay the same (marginal costs, capacities, demand…) for each vision. The difference between the maximum and the minimum over this period is around 38bn€ (13%) for V3/V35p, and 50bn€ (18%) for V4/V45p. The highest revenue for the power plant owners occurs in Vision 3 with low RES. Adding five percent more gas power, as described in 8.1.2, their revenues decrease. When installing more RES in the system the revenues decrease again, and even more with additional RES and gas power, as the production capacities of the latter increase and energy becomes cheaper. This is also shown in Table 34. For comparing the revenues figures, the 50%-percentile over the years was used for each vision and the annualised investment costs are taken from Table 35. Comparing the other visions to Vision 3, one can see how the revenues decrease while the investment costs increase. Neglecting production costs, and looking at the difference between market revenues and investment costs, the decrease w.r.t. V3 is about 20% in V4 and up to 27% in V45p.

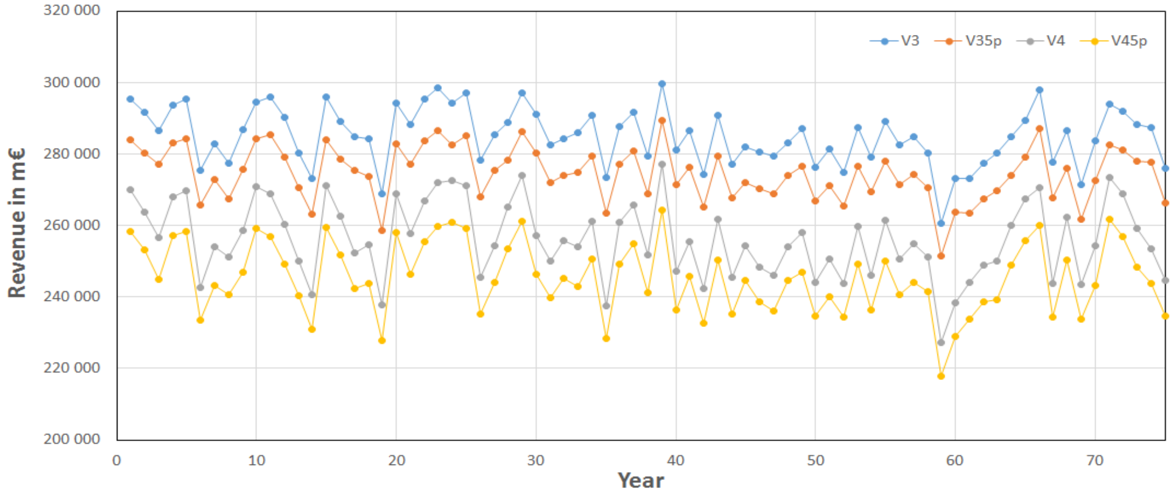


Figure 77: Revenues for the four visions for each of the 75 simulation years

Table 36: Revenues and annualized investment costs in million Euro per year for thermal and bio power plants

	Revenues (m€)	Change compared to V3	Annualized investment Costs (m€/a)	Change compared to V3	Difference (m€)	Change compared to V3
V3	285,402		112,560		172,842	
V35p	275,275	-3.5 %	114,772	2.0 %	160,503	-7.1 %
V4	254,836	-10.7 %	116,768	3.7 %	138,068	-20.1 %
V45p	244,549	-14.3 %	119,139	5.8 %	125,410	-27.4 %

Solar and wind power

The investment costs for photovoltaic installations and wind power have been calculated based on (ENTSO-E 2016), as shown in Table 36. For comparison, the revenues for these technologies are shown in Table 37. The 50%-percentile over the simulation period of each vision is considered for this. A detailed overview is found in the 10.3.3, in Table 42 and Table 43. As seen there, for some countries (Spain, Italy), photovoltaics can be profitable in V3 and V35p. In V4 and V45p, the investment costs get too high, by installing 50% more photovoltaic power. Wind power instead is profitable for most of the countries in all visions, as the investments are not so large, installing only 20% more capacity.

Table 37: Revenues and annualized investment costs in million Euro per year for photovoltaic and wind power

	Revenues (m€)			Annualized investment costs (m€/a)			Difference (m€)	
	Photovoltaic	Wind	Sum	Photovoltaic	Wind	Sum	Photovoltaic	Wind
V3	27,661	81,905	109,566	26,982	53,705	80,688	679	28,199
V35p	26,878	79,448	106,325	26,982	53,705	80,688	-105	25,742
V4	25,050	75,420	100,471	40,820	64,388	105,208	-15,769	11,032
V45p	23,610	70,020	93,629	40,820	64,388	105,208	-17,210	5,631

As already mentioned in 8.1.2, the outcome of the simulations for RES is different in the ENTSO-E visions from that and the EMPS simulations when the same installed capacity is used. The deviation is due mostly to the use of different time series for solar and wind. This might also lead to higher revenues for wind power, as shown in Table 37. Nevertheless, the table shows that photovoltaics in the visions V3 and V35p more or less earn revenues that are equal to its own investment costs. In the visions V4 and V45p, its investment costs increase (+51%) due to more the installation of more capacity of this type, while the power prices decreases (-11%) due to the availability of more cheap energy from RES. Both facts worsen economic results for these technologies, with costs getting as high as 160% of the revenues. For wind power, the investment costs increase by 20%, while the revenues decrease by around 9%. This leads to a reduction of the resulting net revenues by around 90% from 11bn€ to 6bn€, which is still a positive outcome. Comparing V4 to V3, the wind power generation in the latter gets only 39% of its revenues in the former. If wind power net revenues in V35p are compared with those V45p, the latter are as low as 22% of the former because of lower power prices.

Hydropower

Hydropower is an important source for ensuring a secure energy supply in many countries. Especially Norway is very dependent on the sale of hydropower. With an increase of installed capacity from RES (including hydropower), the power prices and hence the revenue of exporters of hydropower is reduced. This is shown in Figure 78 and Figure 79. The figures include all the countries in the system with their installed capacity of hydropower expressed in megawatt (blue line), sorted according the amount of capacity by country beginning with the largest (Norway). In addition, the range of revenues per installed megawatt is included in the figure. For this, percentiles of revenues for all the simulated 75 years have been calculated. The black bar lies between the 5% percentile (bottom) and the 95% percentile (top). Within this area, 90% of all revenue values from the years are situated, neglecting the highest deviations. The red dot on the bar is the median over all years. The variation is that large, because EMPS uses different hydro inflows for each year. In dry years with no rain, there is only a low hydro inflow and thus high power prices due to energy shortage. As a result, less energy is sold (e.g. due to reduced demand as reaction to the high prices) and the revenues may be lower as in other years with lower prices but more energy sold. In wet years with a surplus of hydropower, the power price becomes low and so may the revenue. The shown percentiles do not take into account, which value comes from a wet/dry year. They only show the range for the 75 years, based on the size of the hydropower plant in Euro per installed megawatt (= revenue divided by installed capacity).

As an example for Figure 78, for Norway the revenue range goes from 100 to 700 Euro per installed megawatt with a median of 400 Euro. Norway is dominated by hydropower and the price is mostly set by the average price on the European market. For Italy, the range is between 100 to 1000 Euro per installed megawatt, but with a median of around 150 Euro, meaning that revenues of 1000 Euro per installed megawatt occur quite rarely. The figure shows somewhat the trend that the revenues from hydropower in countries with a lot of installed capacity is lower than in countries with less installed hydropower and where hydropower does not dominate the generation portfolio. The reason is that hydropower can lower the influence of price peaks/variations. With smaller capacities installed or only run-of-river hydropower, it will get harder to affect the market. The figures shows this for the countries with less hydropower capacity, as their revenue per installed megawatt is higher (no smoothing effect of the power prices) and their revenue-variation is larger (the median of the percentiles is not in the centre but closer to the bottom, i.e. they are some few years with high prices).

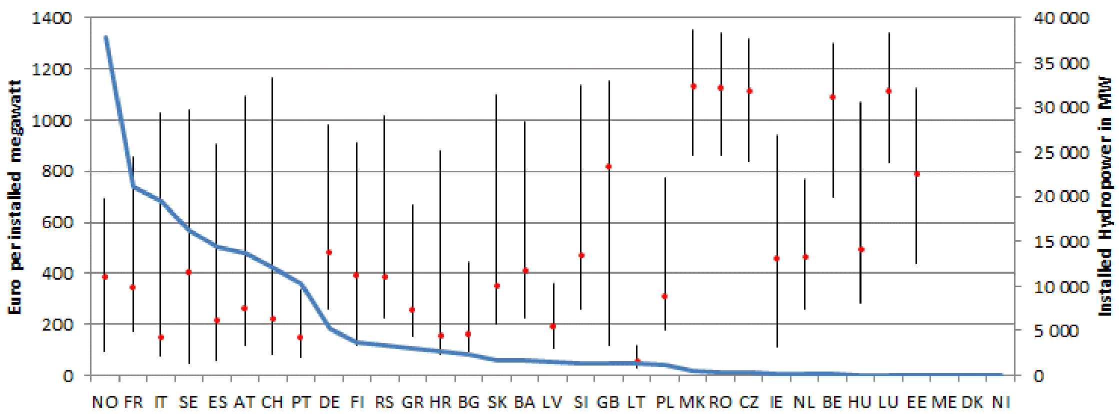


Figure 78: Revenue of hydropower plants in Euro per installed capacity and the installed capacity per country for V3

Comparing the results of V3 and V4, the revenue in the latter is reduced. With more RES, the power price decreases due to the availability of cheaper energy. For Norway, the revenue per installed megawatt is halved, with an increase of only 38% in the amount of installed hydropower (see Table 44: Installed hydropower and rated revenue in Vision 3 and Vision 4). Here also power prices of neighbouring countries, where energy is exported to, affect the result. The total increase of hydropower over all countries is 54%, while the total reduction of revenues is 22%, or 560m€ (based on the median). In total, the revenue per installed megawatt decreases by an average of 34%.

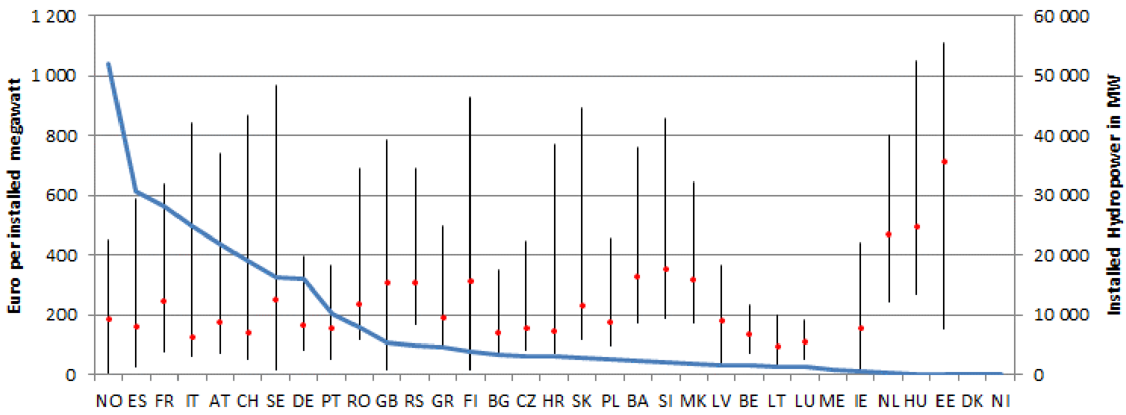


Figure 79: Revenue of hydropower plants in Euro per installed capacity and the installed capacity per country for V4

Producer/consumer surplus and social welfare

The social welfare (also socio-economic surplus) in EMPS is calculated as the sum of the producer surplus and consumer surplus as well as the congestion rents (only accounting for 0.06% of the social welfare). Table 38 shows the producer/consumer surplus, the social welfare and the investments (see Table 35) for the four visions.

Table 38: Overview of producer & consumer surplus, social welfare and investments in the four visions

		Producer Surplus in m€	Consumer Surplus in m€	Social Welfare in m€	Investments in m€/a
Results	V3	307,096	10,378,075	10,691,904	227,650
	V35p	293,235	10,394,360	10,693,647	229,862
	V4	329,252	10,706,343	11,047,630	274,838
	V45p	313,276	10,724,715	11,049,100	277,209
Change absolute	V3 vs V35p	-13,861	16,285	1,743	2,212
	V3 vs V4	22,156	328,268	355,726	47,188
	V3 vs V45p	6,180	346,640	357,196	49,559
	V4 vs V45p	-15,976	18,372	1,470	2,371
Change in percent	V3 vs V35p	-4.5 %	0.2 %	0.0 %	1.0 %
	V3 vs V4	7.2 %	3.2 %	3.3 %	20.7 %
	V3 vs V45p	2.0 %	3.3 %	3.3 %	21.8 %
	V4 vs V45p	-4.9 %	0.2 %	0.0 %	0.9 %

Installing more RES (V4) results in a surplus for both the producers and consumers, but due to higher investments occurring in these visions, producers end up being worse off. On the other hand, the consumers' profits and the social welfare can increase due to the installation of more RES. Installing more gas power (V35p, and V45p) reduces the surplus of the producers (lower power prices) and results in extra investments. In contrast, the consumer profits and the social welfare increase due the having more capacity available and lower prices. Thus, the largest social welfare is achieved in V45p with extra RES and extra gas power. Subtracting the investment costs from the gross social welfare (not considering them), the visions V4 and V45p turn out to have more or less the same outcome. Nevertheless, V4 is less negative to the producers.

The cost of RES-E support and CRM

In order to assess the costs of both types of mechanisms, the economic results for producers of the different cases are compared. Vision 3 is thereby interpreted as the base case, and differences w.r.t. the other cases are assumed to be caused by the mechanisms implemented.

The values assessed in the following are the short-term and long-term profits for producers. In the short-term, this is the producer surplus, as shown in Table 38, while, in the long-term, profits are equal to the producer surplus less the annualised investment costs.

The resulting long-term profits (including fixed costs) are shown in Figure 80. It can be observed that all profits are positive but decreasing with the application of RES support and CRMs. In order to be sustainable, a mechanism must cover the extra costs (here lost profit). On the one hand, implementing a RES-E support scheme, which will lead to about 10% more generation from RES in the generation mix, will have a cost for other producers of about 25,000 m€ per annum. On the other hand, implementing a CRM, which leads to a 5% increase in generation capacity (provided by gas power plants), will have an extra cost of about 16,000 m€ per annum for producers. In order to incentivise producers to invest in this capacity, this has to be financed by the mechanism.

However, implementing both mechanisms at the same time results in about 43,300 m€ per annum extra costs, which is about 2,000 m€ (or 5%) higher than the sum of the individual costs of the mechanisms.

Hence, when assessing the impact of additional market mechanisms on the economics of the power system, it is essential not to only evaluate them separately, but also investigate their interaction.

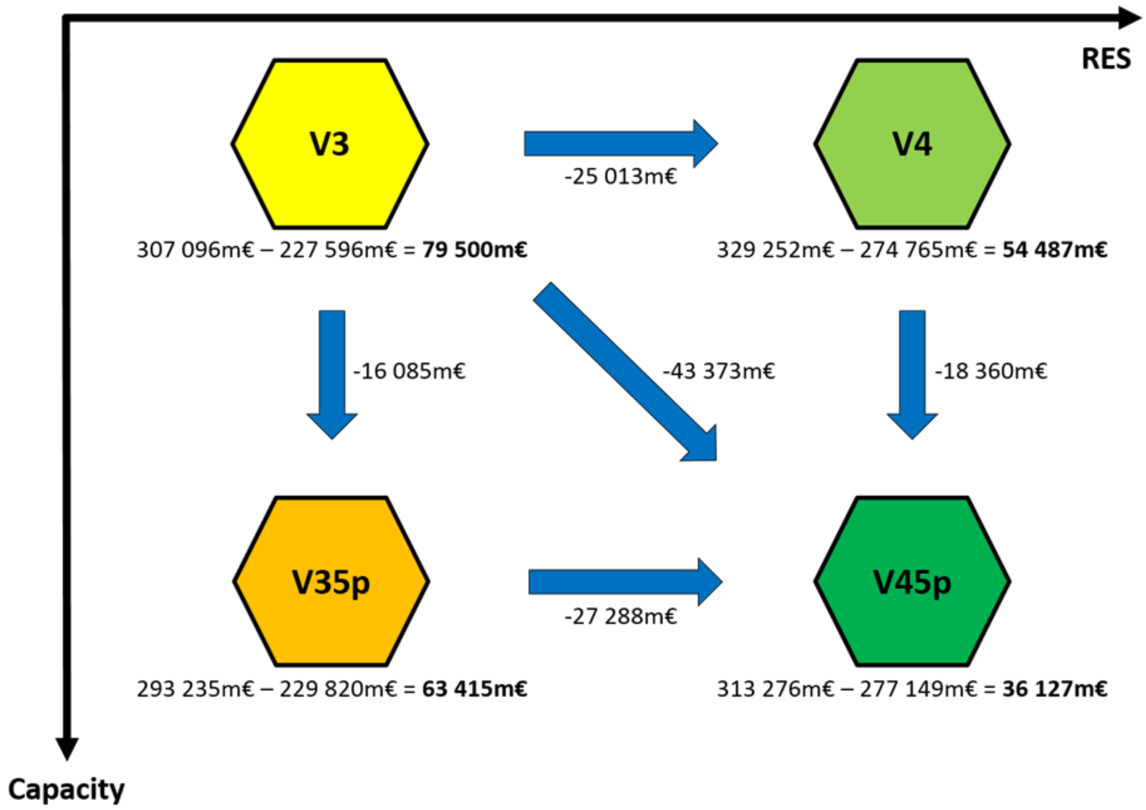


Figure 80: Producer profits in the four different visions

8.3 Conclusion

In order to analyse the impact of CRM (capacity remuneration mechanism) and support mechanisms for RES (renewable energy sources) on the development and operation of the system, four visions about the future evolution of the system in Europe have been defined and considered. A base Vision 3 considers the implementation of the Energy only market without any support for RES or CRMs. Vision 4 considers the application of the Energy only market and RES support. Both visions were initially developed by ENTSO-E. On top of the system developed in these two visions, the application of a CRM was considered to create two additional visions characterized by the installation of additional gas generation capacity amounting to 5% of the peak-demand per country. These resulted in visions V35p and V45p. Main results computed about the development and operation of the system for each vision are provided next:

- V3 – Energy only market without any support

  Used as a kind of base case with no support mechanism. The annualised fixed costs of investments are lower than the producer market surplus, which results in a net profit for producers.

- V4 - Energy only market with RES support

The producers obtain lower benefits in this vision, since with more RES the amount of cheap energy is increasing, leading to lower power prices and thus smaller market profits. Their profits (difference between producers' market surplus and annualised fixed costs) decrease from 79bn€ per year in V3 to 54bn€ in V4 (-32%). On the other hand, additional benefits are obtained in these cases by consumers. They get cheaper energy and the consumer surplus and social welfare increase by around 3%.

- V35p – CRM without RES support

  Increasing power capacity (here gas power) leads to lower electricity prices. Thus, the producer gets smaller profits, while investment costs are higher. Thus, producers' profits decrease by 20%. On the consumer side, the change is negligible.

- V45p – CRM and RES support

  The market surplus of the producers is smaller than under V4, but larger than under V35p. Considering investments in additional RES and gas power, net profits are 55% smaller than under V3, meaning this vision is the worst for producers. For consumers, and the social welfare, the difference between V4 and V45 is the same.

The main conclusions of the study are:

1. There is a significant extra cost for the system of implementing additional market mechanisms, such as RES-E support schemes and CRMs. In addition to their individual costs, there is also a non-negligible extra cost due to the interplay of these mechanisms.
2. With increased generation from RES-E, much more generation curtailment (of RES) occurs, indicating a non-complete integration of RES in the system. As the utilization factors of the transmission corridors (especially in Northern Europe) indicate, transmission expansions are necessary, in addition to a pure RES support scheme, to increase the level of integration of RES generation.
3. Additional transmission capacity could reduce the amount of spilled RES energy, allow renewables to replace further thermal generation in the continent, reward existing renewable generation capacity, and encourage the further deployment of cheaper and clean generation in Northern Europe.
4. In simulations conducted for a large number of climatic years, it was observed that higher RES support or payments within CRM would lead to lower power prices, resulting in lower and more variable market profits of producers, which could, in turn, raise the WACC of the corresponding investments.
5. Finally, applying a carbon tax (or adequate carbon permit trading schemes) seems to be necessary to keep prices high enough for RES to compete with generation from conventional sources in 2030 and beyond.

9 References

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10 APPENDIX

10.1 Appendix to the study on the impacts of RES support on the deployment of demand response

Data and hypothesis on installed capacities are taken from ENTSO-E TYNDP scenarios. Cost hypotheses mainly come from the IEA's Costs of generating electricity and World energy outlook. The different scenarios of power plants' availabilities are taken from the French adequacy report (RTE) or the TYNDP.

Table 39: Fixed (€/MW/year) and variable (€/MWh/year) costs of technologies

	2020 Scenario		2030 Low Scenario		2030 Ref scenario		2030 High scenario	
Technologies	Fixed Costs	Variable Costs	Fixed Costs	Variable Costs	Fixed Costs	Variable Costs	Fixed Costs	Variable Costs
Solar	*132*	0	*132*	0	*132*	0	*132*	0
Wind	*187*	0	*187*	0	*187*	0	*187*	0
Hydro run-of-river	*190*	0	*190*	0	*190*	0	*190*	0
Nuclear	*380*	15	*380*	15	*380*	15	*380*	15
Hard coal	*188*	45.93	*188*	59.38	*188*	100.43	*188*	100.43
Lignite	*188*	19.16	*188*	35.67	*188*	93.46	*188*	93.46
Gas (CCGT)	*95*	71.55	*95*	79.02	*95*	86.13	*95*	86.13
Gas (OCGT)	*76*	117.05	*76*	129.42	*76*	141.15	*76*	141.15
Oil (Comb. turbine)	*60*	248.22	*60*	264.44	*60*	245.58	*60*	245.58
Hydro dams	*190*	0	*190*	0	*190*	0	*190*	0
Loss of load	*0*	20,000	*0*	20,000	*0*	20,000	*0*	20,000
Industrial DSR 1	*10*	300	*10*	300	*10*	300	*10*	300
Industrial DSR 2	*15*	300.0001	*15*	300.0001	*15*	300.0001	*15*	300.0001
Industrial DSR 3	*20*	300.0002	*20*	300.0002	*20*	300.0002	*20*	300.0002
Industrial DSR 4	*25*	300.0003	*25*	300.0003	*25*	300.0003	*25*	300.0003
Industrial DSR 5	*30*	300.0004	*30*	300.0004	*30*	300.0004	*30*	300.0004
Industrial DSR 6	*35*	300.0005	*35*	300.0005	*35*	300.0005	*35*	300.0005
Industrial DSR 7	*45*	300.0006	*45*	300.0006	*45*	300.0006	*45*	300.0006
Industrial DSR 8	*55*	300.0007	*55*	300.0007	*55*	300.0007	*55*	300.0007
Residential DSR	*11 or 29*	50	*11 or 29*	50	*11 or 29*	50	*11 or 29*	50
CO_2 price	10 €/ton		31 €/ton		93 €/ton		93 €/ton	

Table 40: Constraints on installed capacities (MW)

	Constraints on installed capacities (MW)			
Technologies	2020 Scenario	2030 Low scenario	2030 Ref scenario	2030 High scenario
Solar	10,813	12,000	30,000	49,600
Wind	20,000	20,000	40,000	52,400
Hydro run-of-river	7,634	7,400	10,400	10,400
Nuclear	63,100	56,000	40,000	40,000
Hard coal	-	-	-	-
Lignite	0	0	0	0
Gas (CCGT)	-	-	-	-
Gas (OCGT)	-	-	-	-
Oil (Combustion turbine)	-	-	-	-
Hydro dams	8,000	8,000	8,000	8,000
Loss of load	-	-	-	-
Industrial DSR 1	≤ 1,000	≤ 1,000	≤ 1,000	≤ 1,000
Industrial DSR 2	≤ 1,000	≤ 1,000	≤ 1,000	≤ 1,000
Industrial DSR 3	≤ 1,000	≤ 1,000	≤ 1,000	≤ 1,000
Industrial DSR 4	≤ 1,000	≤ 1,000	≤ 1,000	≤ 1,000
Industrial DSR 5	≤ 1,000	≤ 1,000	≤ 1,000	≤ 1,000
Industrial DSR 6	≤ 1,000	≤ 1,000	≤ 1,000	≤ 1,000
Industrial DSR 7	≤ 1,000	≤ 1,000	≤ 1,000	≤ 1,000
Industrial DSR 8	≤ 1,000	≤ 1,000	≤ 1,000	≤ 1,000
Residential DSR	≤ 10,000	≤ 10,000	≤ 10,000	≤ 10,000

10.2 Appendix to the comparison of explicit RES support mechanisms and carbon pricing in terms of deployment of high shares of RES in the power system

10.2.1 Reference scenario

Policy option	CO_2 price	nFIT multiplier	rFIT multiplier
FIT+0	0 €/t	2.2064208984375	5.33203125
FIT+10	10 €/t	2.076416015625	2.5634765625
FIT+20	20 €/t	1.900390625	2.072265625
FIT+30	30 €/t	1.5283203125	1.6220703125
FIT+40	40 €/t	1.392578125	1.412109375
FIT+60	60 €/t	1.001953125	0.91796875
FIT+80	80 €/t	1.001953125	0.90234375
Cap	174.71 €/t		

10.2.2 Low scenario

Policy option	CO_2 price	nFIT multiplier	rFIT multiplier
FIT+0	0 €/t	1.8365478515625	2.252197265625
FIT+10	10 €/t	1.690673828125	1.97509765625
FIT+20	20 €/t	1.4716796875	1.7021484375
FIT+30	30 €/t	1	1.033203125
FIT+40	40 €/t	0.87109375	0.71484375
FIT+60	60 €/t	0.31640625	0.251953125
FIT+80	80 €/t	0.30859375	0.240234375
Cap	105.32 €/t		

10.2.3 High scenario

Policy option	CO_2 price	nFIT multiplier	rFIT multiplier
FIT+0	0 €/t	2.1331787109375	11.953125
FIT+10	10 €/t	2.02880859375	2.744140625
FIT+20	20 €/t	1.904296875	2.02734375
FIT+30	30 €/t	1.6337890625	1.6220703125
FIT+40	40 €/t	1.341796875	1.326171875
FIT+60	60 €/t	1.001953125	0.962890625
FIT+80	80 €/t	1.001953125	0.951171875
Cap	178.86 €/t		

10.3 Appendix to study on the interdependence of capacity remuneration mechanism and RES support cost

10.3.1 Differences in the results between ENTSO-E and EMPS

Table 41: Differences between the results from ENTSO-E and Vision 3 in EMPS (negative = more production in ENTSO-E)

	Gas	Gas CCS	Hard Coal	Hard coal CCS	Hydro	Lignite	Lignite CCS	Nuc-lear	Oil	Other non RES	Other RES	Solar & Wind	Dump Energy
AT	6,241	0	4,255	0	-151	0	0	0	0	0	-1	-1,669	0
BA	-1,168	0	0	0	10	465	0	0	0	0	0	-304	0
BE	11,988	0	0	0	-294	0	0	0	0	-17,215	-8	-6,732	-7
BG	5,185	0	4,122	0	5	2,534	0	-0	0	0	0	-1,756	-36
CH	-1,990	0	0	0	-178	0	0	-0	0	-3,957	-1	-883	0
CZ	-4,111	0	7,213	0	-460	3,701	0	-1	0	0	-0	-480	0
DE	37,715	0	96,203	0	18	10,068	0	0	0	-14,502	-70	-27,304	-353
DK	-10,418	0	-7,624	0	0	0	0	0	0	0	-21	-3,220	-194
EE	925	0	0	0	-1	0	0	0	-2,009	-125	-1	-264	-0
ES	77,807	0	6,510	321	-159	0	0	-224	0	-54,103	-219	-34,235	-1,176
FI	-551	0	8,675	0	19	-2,714	0	-5	0	-7,963	-71	-3,470	-527
FR	16,136	0	7,664	0	85	0	0	-65	0	-7,153	-112	-23,518	-26
GB	26,163	-2,023	14,259	6,391	-10,561	0	0	-5,214	0	-27,807	-4,141	220	-38,525
GR	-3,509	0	0	0	8	-2,105	0	0	0	0	-0	-3,361	0
HR	-1,403	0	4,627	0	-19	0	0	0	0	-874	1	-553	0
HU	-748	0	-206	0	0	0	0	-0	0	-3,249	-1	-974	0
IE	-1,018	0	0	0	0	0	0	0	0	-1,007	-158	-740	-1,952
IT	-23,868	0	49,799	0	-135	0	0	0	-282	-7,803	-3	-13,973	-304
LT	653	0	0	0	-0	0	0	-0	0	-2,176	-2	176	0
LU	-1,080	0	0	0	-710	0	0	0	0	-735	-0	-83	0
LV	-102	0	0	0	0	0	0	0	0	-2,365	0	-347	-89
ME	0	0	0	0	-2,170	-1,853	0	0	0	0	0	-32	0
MK	-1,285	0	0	0	-712	-262	0	0	0	0	0	-586	0
NI	177	0	0	0	0	0	0	0	0	-49	-74	-328	-1,576
NL	-11,727	0	-10,596	0	0	0	0	0	0	-27,203	-1	-5,326	-213
NO	770	0	0	0	-659	0	0	0	0	0	0	1,005	-18
PL	21,372	0	1,681	0	0	-2,021	0	-0	0	-34,490	0	809	-0
PT	695	0	0	0	19	0	0	0	0	-7,937	-9	-108	-0
RO	-6,379	0	7,178	0	-14,662	1,673	0	-0	0	0	0	-3,820	-1
RS	-1,511	0	0	0	18	-1,255	0	0	0	0	0	-1,573	0
SE	0	0	0	0	-304	0	0	-189	0	-56	-123	758	-337
SI	1,976	0	524	0	9	-117	0	0	0	0	0	-493	0
SK	-1,011	0	74	0	10	-488	0	0	0	-4,215	1	-611	0

Table 42: Differences between the results from ENTSO-E and Vision 4 in EMPS (negative = more production in ENTSO-E)

	Gas	Gas CCS	Hard Coal	Hard coal CCS	Hydro	Lignite	Lignite CCS	Nuc-lear	Oil	Other non RES	Other RES	Solar & Wind	Dump Energy
AT	13,721	0	3,054	0	-151	0	0	0	0	0	-42	-2,426	0
BA	881	0	0	0	10	-15	-2,343	0	0	0	0	-582	0
BE	16,587	0	0	0	1	0	0	0	0	-17,215	-73	-7,422	-80
BG	4,485	0	5,995	0	5	3,004	-6,728	-76	0	0	0	-2,867	-303
CH	522	0	0	0	-179	0	0	-5	0	-3,957	-31	-1,211	-48
CZ	4,671	0	4,232	0	6	-360	0	-4	0	0	-11	-839	0
DE	46,300	0	62,027	0	18	24,493	0	0	0	-14,500	-805	-32,441	-3,189
DK	-5,070	0	-9,646	0	0	0	0	0	0	0	-319	-4,148	-876
EE	1,520	0	0	0	-1	0	0	0	-1,925	-125	-11	-264	0
ES	63,361	0	3,962	-151	-160	0	0	-583	0	-54,103	-1,144	-41,278	-6,129
FI	-1,954	0	4,706	0	19	-2,977	0	-28	0	-8,017	-592	-3,447	-3
FR	22,121	0	5,395	0	86	0	0	-1,617	0	-7,153	-1,001	-31,743	-1,148
GB	41,282	-3,187	10,503	-4,694	19	0	0	-7,779	0	-27,807	-8,542	-2,182	-15,201
GR	-4,689	0	0	0	9	-518	0	0	0	0	-24	-4,876	-39
HR	1,507	0	1,573	-3,635	-19	0	0	0	2,159	-874	0	-553	0
HU	7,293	0	-308	0	0	0	0	-1	0	-3,249	-5	-1,759	-0
IE	-1,071	0	0	0	-0	0	0	0	0	-1,007	-744	-545	-2,848
IT	-9,073	0	33,669	0	-135	0	0	0	-282	-7,803	-107	-17,186	-2,867
LT	3,495	0	0	0	0	0	0	0	0	-2,176	-10	176	-0
LU	-461	0	0	0	-0	0	0	0	0	-735	-3	-83	0
LV	-2,254	0	0	0	0	0	0	0	0	-2,359	-95	-347	-454
ME	0	0	0	0	0	0	-523	0	0	0	0	-1,238	0
MK	-1,186	0	0	0	5	-847	0	0	0	0	0	-531	0
NI	1,484	0	0	0	0	0	0	0	0	-50	-146	-401	-1,018
NL	-1,766	0	-20,045	0	0	0	0	-3,287	0	-16,178	2,100	-6,090	-202
NO	-696	0	0	0	-1,013	0	0	0	0	0	0	1,161	-653
PL	42,154	0	5,951	0	0	15,957	-28,836	-0	0	-34,111	-30,262	-2,662	-338
PT	5,730	0	0	0	19	0	0	0	0	-7,937	-129	137	-3
RO	-604	0	1,540	-3,555	31	-1,022	0	-11	0	0	-59	-6,432	-515
RS	-1,666	0	0	0	18	3,662	0	0	0	0	0	-862	0
SE	0	0	0	0	-531	0	0	-2,387	0	-56	-1,239	876	-1,220
SI	1,613	0	-58	-794	8	1,060	0	-1	973	0	0	-691	-4
SK	2,372	0	699	0	9	539	0	-0	0	-4,215	-6	-1,059	-10

10.3.2 Change in installed production capacity and annualised fixed costs

The table below shows the changes in between the different visions.

Table 43: Change in installed production capacity and annualised fixed costs for the four visions

		Change in installed capacity in MW	Change in installed capacity in %	Change in costs in m€/a	Change in costs in %
V3 vs V35p	Sum Thermal	29 259	5,1 %	2 212	2,3 %
	Sum Renewables	0	0,0 %	0	0,0 %
	Sum	29 259	2,1 %	2 212	1,0 %
V3 vs V4	Sum Thermal	-11 702	-2,0 %	-1 443	-1,5 %
	Sum Renewables	307 839	36,6 %	48 630	36,6 %
	Sum	296 137	20,9 %	47 188	20,7 %
V3 vs V45p	Sum Thermal	19 666	3,4 %	928	1,0 %
	Sum Renewables	307 839	36,6 %	48 630	36,6 %
	Sum	327 505	23,1 %	49 559	21,8 %
V4 vs V45p	Sum Thermal	31 368	5,6 %	2 371	2,5 %
	Sum Renewables	0	0,0 %	0	0,0 %
	Sum	31 368	1,8 %	2 371	0,9 %

10.3.3 Solar and wind power – Revenues, installed capacities, investments

The following two tables show the installed capacity, revenues, fixed annualised costs (see Table 44 and Table 43) and the resulting difference for photovoltaic and wind power in the four visions.

Table 44: Installed capacity, revenues and annualised fixed costs for photovoltaic for the four visions

	Installed capacity in MW		Revenues in m€				Fixed annualised Cost in m€		Difference in m€			
	V3	V4	V3	V35p	V4	V45p	V3	V4	V3	V35p	V4	V45p
AT	3 500	6 500	408	397	384	361	422	784	-14	-26	-400	-424
BA	0	1 900	0	0	0	0	0	229	0	0	-229	-229
BE	5 740	6 740	564	548	531	500	693	813	-129	-145	-282	-314
BG	3 500	7 900	442	431	351	322	422	953	20	9	-602	-632
CH	3 000	4 500	376	365	352	330	362	543	14	3	-191	-213
CZ	2 000	3 500	210	204	196	184	241	422	-31	-37	-227	-238
DE	68 800	68 800	7 135	6 945	6 694	6 280	8 301	8 301	-1 167	-1 356	-1 608	-2 022
DK	3 430	3 430	410	401	352	336	414	414	-4	-13	-62	-78
EE	100	100	11	11	10	9	12	12	-1	-1	-2	-3
ES	30 000	58 000	4 860	4 702	4 438	4 215	3 620	6 998	1 240	1 082	-2 560	-2 783
FI	40	40	4	4	3	3	5	5	-0	-1	-2	-2
FR	30 000	49 600	3 688	3 568	2 984	2 806	3 620	5 985	68	-52	-3 000	-3 178
GB	5 800	5 800	400	394	355	334	700	700	-299	-306	-345	-366
GR	5 000	10 900	703	685	599	567	603	1 315	99	82	-716	-748
HR	100	100	12	12	11	11	12	12	0	-0	-1	-1
HU	200	3 600	25	24	23	22	24	434	1	-0	-411	-413
IE	50	50	4	3	3	3	6	6	-3	-3	-3	-3
IT	48 900	68 500	6 956	6 771	6 430	6 072	5 900	8 265	1 056	871	-1 835	-2 193
LT	20	20	2	2	2	2	2	2	-0	-0	-1	-1
LU	120	120	13	12	12	11	14	14	-2	-2	-3	-4
LV	20	20	2	2	2	2	2	2	-0	-0	-1	-1
ME	20	0	3	3	2	2	2	0	0	0	2	2
MK	40	1 040	5	5	5	5	5	125	1	0	-121	-121
NI	0	0	0	0	0	0	0	0	0	0	0	0
NL	8 000	9 100	795	774	760	714	965	1 098	-171	-191	-338	-384
NO	0	0	0	0	0	0	0	0	0	0	0	0
PL	1 000	5 300	112	108	102	93	121	639	-9	-13	-538	-547
PT	750	4 550	121	117	106	100	90	549	31	26	-443	-449
RO	650	9 450	79	77	65	60	78	1 140	1	-2	-1 076	-1 080

RS	10	3 410	1	1	1	1	1	411	0	0	-410	-410
SE	1 000	1 000	102	99	75	75	121	121	-19	-22	-46	-46
SI	1 116	1 920	139	135	130	122	135	232	4	-0	-101	-109
SK	720	2 420	79	77	73	69	87	292	-8	-10	-219	-223
sum	223 626	338 310	27 661	26 878	25 050	23 610	26 982	40 820	679	-105	-15 769	-17 210

Table 45: Installed capacity, revenues and annualised fixed costs for wind power for the four visions

	Installed capacity in MW		Revenues in m€				Fixed annualised Cost in m€		Difference in m€			
	V3	V4	V3	V35p	V4	V45p	V3	V4	V3	V35p	V4	V45p
AT	5 500	5 500	1 005	969	1 001	918	822	822	183	148	180	96
BA	640	640	82	79	82	74	96	96	-14	-17	-14	-22
BE	8 540	9 370	1 978	1 910	1 927	1 777	1 276	1 400	702	634	527	377
BG	4 000	4 000	628	607	597	536	598	598	30	9	-1	-62
CH	900	900	142	137	142	130	134	134	8	3	7	-4
CZ	740	1 250	137	132	137	126	111	187	26	22	-49	-61
DE	85 000	113 100	20 713	19 993	20 137	18 541	12 700	16 898	8 013	7 294	3 239	1 643
DK	10 460	11 460	2 674	2 620	2 308	2 192	1 563	1 712	1 111	1 057	596	480
EE	900	900	188	182	168	157	134	134	53	47	33	23
ES	49 000	49 000	10 593	10 277	9 382	8 913	7 321	7 321	3 271	2 956	2 060	1 592
FI	4 900	4 900	861	836	738	701	732	732	129	104	6	-31
FR	40 000	52 400	8 628	8 301	7 727	7 123	5 976	7 829	2 651	2 325	-103	-706
GB	54 870	60 370	12 238	12 042	10 669	9 968	8 198	9 020	4 040	3 844	1 649	948
GR	7 800	7 800	2 119	2 051	2 085	1 899	1 165	1 165	954	886	919	734
HR	1 500	1 500	226	217	229	207	224	224	2	-7	5	-17
HU	1 000	1 000	140	135	141	128	149	149	-9	-14	-9	-21
IE	5 700	7 100	1 257	1 239	1 033	974	852	1 061	406	387	-28	-86
IT	22 100	22 100	4 344	4 193	4 413	4 030	3 302	3 302	1 042	891	1 111	728
LT	1 000	1 000	228	220	196	185	149	149	78	71	47	35
LU	200	200	25	24	24	22	30	30	-5	-6	-6	-8
LV	1 480	1 480	327	317	288	271	221	221	106	96	67	50
ME	300	0	53	51	53	48	45	0	8	6	53	48
MK	0	360	0	0	0	0	0	54	0	0	-54	-54
NI	2 230	2 230	549	542	446	421	333	333	216	208	113	88
NL	12 000	12 800	3 452	3 337	3 404	3 130	1 793	1 912	1 659	1 544	1 492	1 218
NO	5 000	11 400	1 422	1 401	1 144	1 101	747	1 703	674	654	-559	-603
PL	10 000	15 600	2 790	2 681	2 683	2 384	1 494	2 331	1 296	1 186	353	53
PT	6 400	6 400	1 499	1 453	1 317	1 249	956	956	543	497	361	292
RO	5 500	5 500	928	893	883	800	822	822	106	71	62	-22

RS	0	1 000	0	0	0	0	0	149	0	0	-149	-149
SE	11 100	19 000	2 593	2 526	1 981	1 936	1 658	2 839	935	867	-858	-903
SI	240	240	31	30	32	29	36	36	-5	-6	-4	-7
SK	450	450	56	54	55	50	67	67	-11	-13	-13	-17
sum	359 450	430 950	81 905	79 448	75 420	70 020	53 705	64 388	28 199	25 742	11 032	5 631

Installed Hydropower and rated revenue

Table 46 shows the installed hydropower for the two vision V3 and V4 and the change per country. In some countries, the change might be very high looking at the percentage, but the total installed capacity is possibly still small compared to other countries or to the fossil installed capacity in that country. In addition, the rated revenues are shown. For each country, the income for hydropower was referred to the installed hydro capacity (as shown in Figure 80). For this, the 50% percentile of results over all simulations (for all years) has been taken as a reference.

Table 46: Installed hydropower and rated revenue in Vision 3 and Vision 4

	Vision 3		Vision 4				
Country	Installed hydropower in MW	50% Percentile of rated revenue in € per installed MW	Installed hydropower in MW	50% Percentile of rated revenue in € per installed MW	Change installed hydropower in MW	Change installed hydropower in %	Change in revenue in %
AT	13,777	262	21,737	174	7,960	58 %	-34 %
BA	1,666	413	2,278	327	612	37 %	-21 %
BE	130	1,090	1,437	136	1,307	1005 %	-88 %
BG	2,400	164	3,400	142	1,000	42 %	-14 %
CH	12,083	220	18,994	139	6,911	57 %	-37 %
CZ	397	1,112	3,058	157	2,661	671 %	-86 %
DE	5,198	483	15,950	164	10,752	207 %	-66 %
EE	20	791	20	715	0	0 %	-10 %
ES	14,400	217	30,655	158	16,255	113 %	-27 %
FI	3,740	393	3,740	311	0	0 %	-21 %
FR	21,100	344	28,200	246	7,100	34 %	-28 %
GB	1,317	819	5,268	307	3,951	300 %	-62 %
GR	3,047	261	4,626	188	1,579	52 %	-28 %
HR	2,700	159	3,000	147	300	11 %	-8 %
HU	100	492	100	496	0	0 %	1 %
IE	220	461	591	154	371	168 %	-67 %
IT	19,401	150	24,761	126	5,360	28 %	-16 %
LT	1,306	58	1,404	94	98	8 %	63 %
LU	20	1,116	1,344	107	1,324	6600 %	-90 %
LV	1,602	195	1,536	183	-66	-4 %	-6 %
ME	0		900	160	900	900 %	-
MK	461	1,133	1,704	318	1,243	269 %	-72 %
NL	203	462	203	467	0	0 %	1 %
NO	37,787	390	52,000	186	14,213	38 %	-52 %
PL	1,248	308	2,656	174	1,408	113 %	-44 %
PT	10,280	152	10,280	154	0	0 %	1 %
RO	400	1,129	8,000	238	7,600	1900 %	-79 %
RS	3,431	391	4,939	305	1,508	44 %	-22 %
SE	16,203	404	16,203	250	0	0 %	-38 %
SI	1,419	469	1,999	353	580	41 %	-25 %
SK	1,787	350	2,706	232	919	51 %	-34 %