

COST-BENEFIT ANALYSIS OF TSO-DSO COORDINATION TO OPERATE FLEXIBILITY MARKETS

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ABSTRACT

This paper presents the outcome of the cost-benefit analysis (CBA) for the different alternatives defined in the project SmartNet for the coordination between transmission system operators (TSOs) and distribution system operators (DSOs). The CBA compares five coordination schemes in three countries (Italy, Denmark and Spain) on the basis of several economic indicators. On top of them, it also calculates some non-economic indicators to enrich the analysis. The main results for the Italian and the Spanish cases are presented in this paper.

INTRODUCTION

The replacement of fossil-fuel-based generation by renewable generation is leading to increasingly important challenges in terms of frequency stability, congestion management, voltage regulation and power quality, due to its variable behaviour. At the same time, there is a growing penetration of medium and small-scale, flexible demand and storage systems in distribution networks. These resources could potentially be available to provide network services if they are aggregated effectively and if there is an appropriate coordination between transmission system operators (TSOs), distribution system operators (DSOs) and aggregators.

For this reason, it is interesting to analyse to which extent distributed energy resources (DER) can replace traditional generation in the services provision to network operators. The participation of these distributed resources in the ancillary services (AS) markets will require a change in the roles of the distribution companies, as well as greater cooperation and coordination between them and the transmission system operators. This was recognized by the European Union itself in its Proposal for a Directive on common rules for the internal market in electricity (Article 32, [1]), where it gives the distributor the responsibility to manage the congestion that may appear in its network and

enables it to establish market mechanisms to acquire the necessary flexibility to do so, but not to balance the system frequency, whose management remains in the TSO's hand.

The project SmartNet [2] compares five different TSO-DSO interaction schemes and different real-time market architectures [3], [4] with the aim of finding out which one could deliver the best compromise between costs and benefits for the system. For that purpose, an ad-hoc platform has been developed [5] to carry out simulations and perform a cost-benefit analysis to compare the costs needed to implement each TSO-DSO interaction scheme, especially the investments in information and communication technologies (ICT), with the benefits drawn by the system:

1. Centralised AS market model (CS_A): The TSO contracts AS directly with DER owners connected to the DSO grid. The DSO can procure and use resources to solve local grid issues, but the procurement takes place outside this centralised AS market.
2. Local AS market model (CS_B): The TSO can contract DER only indirectly. First, the DSO, via a local market, may procure resources for solving local problems and then an aggregation of the remaining resources is transferred to the TSO AS market.
3. Shared balancing responsibility model (CS_C): The TSO transfers the balancing responsibility from the distribution grid to the DSO. The DSO has to respect a pre-defined schedule and uses local DER (obtained via a local market) to fulfil its balancing responsibilities.
4. Common TSO-DSO AS market model (CS_D): TSOs and DSOs contract DER in a common flexibility market to minimise total procurement costs of flexibilities contracted by both operators.
5. Integrated flexibility market model (CS_E): TSOs, DSOs and Commercial Market Parties (CMPs) contract DER in a common flexibility market. TSOs and DSOs can both buy flexibility or sell previously contracted DER to the other market participants.

Each coordination scheme involves a different real-time market architecture. In order to compare which of these coordination schemes provides a better compromise between costs and benefits, plausible scenarios have been identified by 2030 for each of the countries with participation of TSOs or DSOs in the project (Italy, Denmark and Spain) and a specific simulation scenario has been developed. Due to the conceptual and practical complexity of the integrated market model (CS_E), this has not been finally developed in the project; moreover, the common market model (CS_D) has been divided into a centralized market, in which the optimization is carried out in a single step for the needs of the TSO and DSO (CS_D1), and in a decentralized market, in which a first viable solution is obtained for the DSO and the TSO is informed, so that, the TSO finds a solution compatible with the first one and that meets his own needs (CS_D2).

In parallel, three demonstration projects (pilots) for testing specific technological solutions are implemented in Denmark, Italy and Spain [6] to enable monitoring, control and participation in ancillary services provision from flexible entities located in distribution. Moreover, these pilots are aimed at uncovering regulatory, operational or implementation barriers.

This paper describes the main outcomes of the cost-benefit analysis which compares the different coordination schemes under three 2030-scenarios created for Italy, Denmark and Spain. The analysis is based on the results of the simulation performed within the SmartNet project.

SIMULATION ENVIRONMENT

The flexibility market considered in the SmartNet project, which is called “Integrated Reserve Market”, is aimed at solving real-time imbalances and congestions between intraday markets [2], [3]. The market horizon can vary as a function of the market requirements, but in general it would last from 15 minutes to 1 hour. When a market session is opened, bidders, which can be conventional and/or distributed energy sources at transmission and distribution networks, are asked to submit their flexibility bids. These can be in both directions, positive or negative, depending if they contribute to upward or downward balancing respectively. Complex bids including temporal and/or logical constraints are also allowed.

The simulation environment has been divided into three main layers, which are further detailed in [5]:

1. Market layer: This layer integrates the market clearing algorithms, which process the bids proposed by the different market players and returns the optimal activations aimed at restoring the system balance and solving/avoiding network congestions.
2. Bidding and dispatching layer: In this layer the bids that different agents (both traditional producers and retailers and aggregators that represent the numerous

flexible resources connected in distribution) send to the market layer are created. For that purpose, market players use different algorithms to process the available flexibility of energy resources into bids and to translate market results into activations. More details about this process can be found in [7].

3. Physical layer: This layer simulates the physical processes of the electrical network (transmission and distribution) as well as the generation, consumption and storage equipment connected to it. Therefore, it simulates the effects of the activations on transmission and distribution networks, including the physics of each (flexible and non-flexible) device connected to them.

With the data corresponding to each of the scenarios, the appropriate simulations have been carried out for the five coordination schemes in the three countries. In this way, it has been possible to calculate the foreseen productions by the different types of technology, the consumptions and the prices in each one of the network nodes for each programming period.

COST-BENEFIT ANALYSIS

The results of the simulation do not allow policy makers to identify the most efficient one in economic terms. Moreover, the efficiency may be different when looking at the power system in general or at its different agents. Therefore, a dedicated economic assessment is needed.

In order to facilitate the decision-making process, the economic assessment is performed by means of a cost-benefit analysis (CBA), where some indicators have been selected and converted into monetary units. These indicators represent the economic impact of the different coordination schemes at power system level. Then, the adequacy of the allocation of costs and benefits to the different stakeholders will be analysed, but this business-level analysis is not completed when writing this paper.

The selection of the indicators was based on a literature review, a consultation to the Advisory Board of the project and many internal meetings. These key indicators are representative, simple, objective, non-overlapping and can be easily monetised.

1. Total mFRR cost: This indicator includes the total balancing cost of the market defined in SmartNet. The energy activated is remunerated at the nodal price resulting from the clearing process. The mFRR activations in the SmartNet balancing market are aimed to solve the network imbalance and to avoid congestions predicted in advance for the next time step.
2. Total aFRR cost: This is the cost of re-balancing the system after the mFRR market. In this case, the bids submitted to the SmartNet market are ordered according to a system-wide merit order and the resulting price is applied as marginal price.

3. Unwanted measures: Each coordination scheme requires a different market setup and a different detail level for the grid model included in the market clearing process, which aims to solve and avoid congestion issues in the network. Some simplifications to allow a faster execution of the market clearing algorithm, may create infeasibilities when dispatching units cleared in the market. Hence, some bids accepted in the market may create congestions not identified by the grid model used. In this case, grid operators must take emergency actions to re-dispatch some resources aiming to solve real congestions in the grid. Since real unit cost are used to create the bids for the mFRR market, this parameter is monetised at the mFRR bid price.
4. Forecasting errors: This term also refers to deviations between mFRR market activations and real activations, but in this case, they are not owing to limitations in the grid models used, but because the requested flexibility cannot be physically activated due to either flexibility modelling errors and/or flexibility forecasting errors. Forecasting errors may result in partial activations of accepted bids or in activations of non-accepted bids. As the CBA is focusing at system level (and not at the business-case level), imbalance penalties are not advisable, because they usually express the cost of the aFRR required to solve them and it has already been accounted for in the second indicator. Thus, forecasting errors are valued at the mFRR market clearing price.
5. ICT costs: The term ICT cost comprises the communications and information technologies, focusing on the software for aggregation and market clearing processes. Only those ICT costs that are directly related to the implementation of each CS are considered. The ICT estimation involves large uncertainties on technology and cost development since energy markets and grids are developing currently and the target year 2030 is rather far. The focus of the analysis is on issues that can make differences between the coordination schemes.

The total cost of each coordination scheme in each country is the addition of these five indicators. Moreover, the amount of CO₂ emissions has been assessed as an extra indicator. However, as the cost of the CO₂ tone was already included in the cost of the bids submitted to the mFRR market, this indicator must not be added to the cost of the other indicators to avoid double-counting.

RESULTS AND DISCUSSION

Figure 1 shows the cost of the mFRR market for the Italian case in the five coordination schemes considered. The lowest and the highest costs appear in CS_A and CS_C, respectively. On the one hand, CS_A disregards the limitations of the distribution network, so it can use cheaper resources to balance the system. On the other, the schemes with separate markets (CS_B, CS_C and CS_D2) have higher cost than the common market (CS_D1).



Figure 1. System balancing cost in the mFRR market in Italy

The mFRR market has a similar behaviour in Spain, as Figure 2 shows, although the difference of having common or separate markets is more evident, because the overall cost for the mFRR market is lower in Spain.

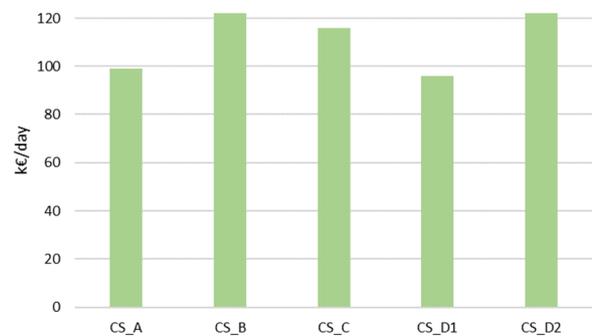


Figure 2. System balancing cost in the mFRR market in Spain

On the contrary, the simplifications in the market clearing process in CS_A increase the cost of balancing the system in the aFRR market and make CS_A the most expensive coordination scheme both in Italy and in Spain. As shown in Figure 3, the need for upward balancing (blue) is much higher than the need for downward balancing (orange) in Italy, since renewable sources provide a significant share of the energy matched in mFRR, but forecasting errors make necessary to partially replace them in aFRR. The schemes CS_A and CS_D1, in which the contribution of renewables is higher, present a higher aFRR cost as well.

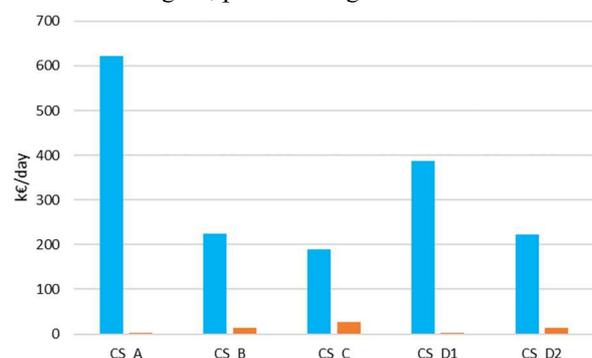


Figure 3. System balancing cost in the aFRR market in Italy

Figure 4 shows that this effect is not so strong in Spain, as renewable resources provide less mFRR regulation.

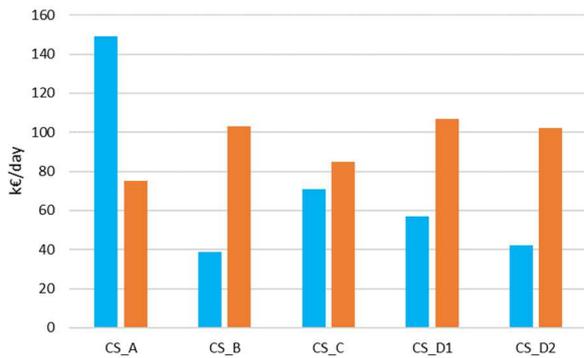


Figure 4: System balancing cost in the aFRR market in Spain

According to [8], CS_D1, which handles large amounts of DSO grid data and real time challenges, is the only one in which ICT investment cost are country-dependent. In any case, the results are very similar for Italy and Spain, which are the focus of this paper. As Figure 5 shows, upgrading ICT systems from CS_A to any other coordination scheme costs twice as much as the investment required in CS_A.

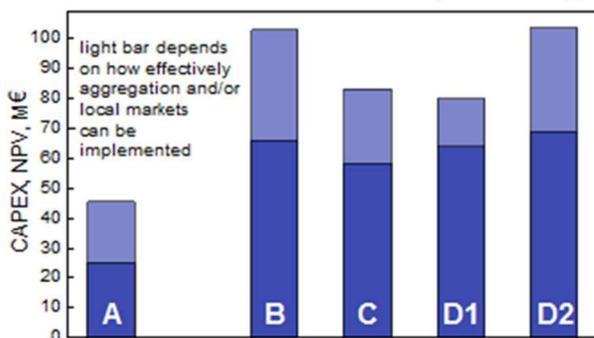


Figure 5. Investment cost estimates of aggregation and market clearing implementation in Spain (M€). For CS_B to CS_D2 the costs are upgrading costs from CS_A.

All the costs presented so far are converted into annual values, which is trivial for daily mFRR and aFRR costs, but requires the annuitization of ICT investment costs (considering a lifetime of 10 years and a 5 % discount rate), as presented in Figure 6 for the Italian case. The most expensive coordination scheme is CS_A and CS_C the cheapest one, being CS_B and CS_D2 relatively close.



Figure 6: Total annual cost in Italy (M€/year)

In Spain, CS_A is again the most expensive one, while the result for the rest is very similar, as Figure 7 shows. It is worthwhile to mention that the contribution of ICT costs to total cost is quite small in both countries.

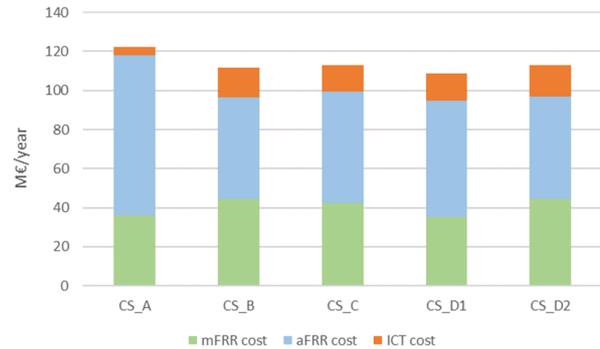


Figure 7: Total annual cost in Spain (M€/year)

At the time of writing this paper, the other two indicators (unwanted measures and forecasting errors) are being monetised, but the amounts of energy dispatched in each case can be found in Figure 8 (Italy) and Figure 9 (Spain). The two figures show the amounts managed by the TSO (left) and the DSO (right) for upward (blue) and downward (red) regulation, both for unwanted measures (dark) and forecasting errors (light).

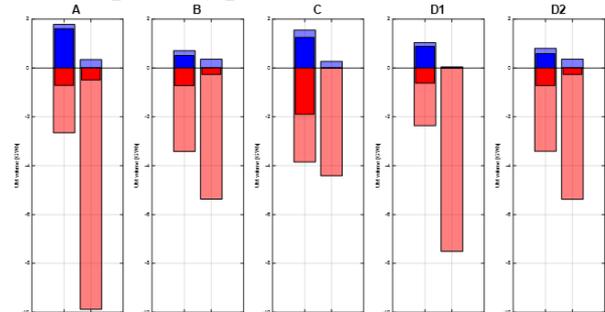


Figure 8. Energy managed by unwanted measures and forecasting errors in Italy (GWh/day)

In Italy, as it can be seen in Figure 8, the scheme which manages the highest amount of energy in these indicators is CS_A, mostly because of forecasting errors. On the contrary, CS_C is the one where grid operators (especially TSOs) take unwanted measures to re-dispatch the highest amount of energy due to network limitations.

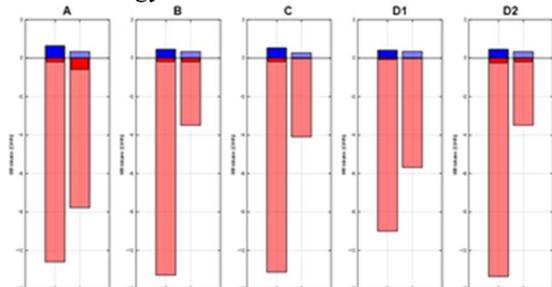


Figure 9: Energy managed by unwanted measures and forecasting errors in Spain (GWh/day)

In Spain (Figure 9), the amount of energy managed due to network limitations is quite low and very similar in all coordination schemes, though it is slightly higher in CS_A. On the contrary, forecasting errors are relatively high and, even if they are similar at transmission level in all schemes, the errors in distribution grid result in higher value in CS_A and CS_D1 compared to CS_B, CS_C and CS_D2.

CO₂ emissions are calculated by multiplying the generation of conventional devices at physical layer by their emission coefficient. Figure 10 shows that the difference in CO₂ emissions between different schemes in Spain is relatively low (less than 4%). Coordination schemes with higher unwanted measures and higher forecasting error have higher CO₂ emission as well.

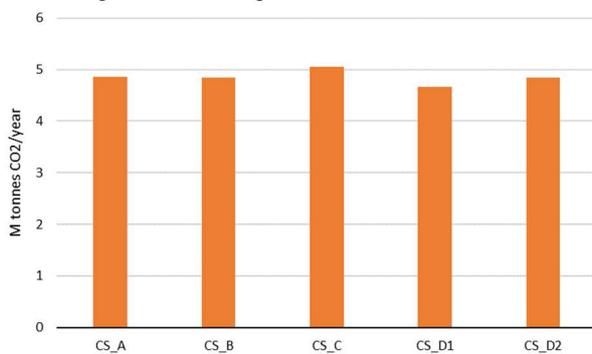


Figure 10: Comparison of annual CO₂ emission between coordination schemes in Spain (Million tons/year)

The scenarios used in the simulations are static, so that the agents' learnings from market participation cannot be captured. This is an especially important aspect in view of the high forecasting errors considered: although not included in this system-wide CBA, market agents will be exposed to imbalance charges, so they will reduce their expectations in the mFRR market to be on the safe side in case they make forecasting errors and avoid imbalance penalties. Therefore, a second round of simulations is under execution at the time of writing this paper.

CONCLUSIONS

The preliminary results for both countries seem to indicate a better behaviour of the CS_B, CS_C, CS_D1 and CS_D2 schemes with respect to the CS_A. However, out of these four coordination schemes, CS_D1 is the worst option in the Italian case, while in the Spanish case is the best one.

Regarding ICT costs, which are only 1-2% of the total cost of balancing, CS_A has the lowest investment costs and upgrading costs for CS_B and CS_D2 are the highest ones.

In Italy, CS_C implies managing a large amount of energy due to limitations in the modelling of the network during the market clearing, while in Spain these limitations are very low. On the contrary, in Spain the measures due to forecast errors are high, mainly at transmission level. The

allocation of a price to unwanted measures and forecasting errors will allow for a better comparison of the different alternatives considered.

These results from the CBA described in this paper must be enriched with the outcome of technological pilots, which are aimed at identifying regulatory, practical and technological barriers. The results obtained so far have not identified any major barrier of any of these types.

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