Operational compatibility of intermittent renewables and conventional generation

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(1) Overview

Electric power systems all across Europe are undergoing drastic changes. To cut greenhouse gas emissions and for reasons of security of supply (in terms of strategic primary energy security), a massive deployment of renewable energy sources (RES) like wind and solar photovoltaics (PV) is currently taking place. These renewable sources are characterized by a high degree of variability and have a certain degree of unpredictability. A further massive deployment of these so-called intermittent renewables will render a net or residual load profile (as seen by the conventional dispatchable power plants) that is both lower and more volatile.

One must recognize, however, that with the amount of intermittent RES systems face today (which can be substantial (relative) amounts, such as in Denmark, Germany or Spain), flexibility is not (yet) a critical problem. This is due to a number of reasons. The first reason relates to the supply side. A significant amount of conventional dispatchable power plants is (still) in place. Though initially often not planned to run in cycling mode (e.g., on during day, off during night), or even as peak power plant, power plants such as gas fired combined cycles (CCGT) face no technical boundaries for such an operation. The second reason (demand side) is the relative lower load as seen by the conventional system. This is due to several reasons. The first is the economic recession which has been playing in Europe since the second half of 2008, and from which Europe so far has not yet fully recovered. Second, renewables have been strongly pushed over the past 5 years, often by royal subsidies, which has led in some cases (e.g., Germany) to a massive roll-out, and hence lower demand.

In the future, this setting might change, as on the demand side, an increase might be possible (economic revival, increasing degree of electrification) even when energy efficiency increases as well. On the supply side, old conventional power plants might be decommissioned, while investment in new facilities might be lacking. These elements, together with a further increasing deployment of intermittent RES, create a setting where flexibility will become a key issue.

Additional flexibility can be provided by different means. A first option is concentrated on the supply side and consists of additional flexible power plants, which would be typically combined cycle or open cycle gas turbines. A second option, also on the supply side, is RES curtailment (effectively reducing the output of RES, so regulating only in a downward direction). Through curtailment, zero marginal cost energy would be “wasted”, but this might be required to maintain system security, or could lead to a lower cost on overall system’s level (as this might prevent large power plants from shutting down). Recent evolutions (both technical and in terms of communication) have also activated the demand side. This constitutes the third option for flexibility. Flexible and attractive tariff schemes, especially with large industrial consumers, may lead to more possibilities for controlled load shedding, and the rolling out of smart grids could stimulate further demand response and demand shifting also at the retail level. Storage is the fourth option. Flexibility is provided by a temporal relaxation of the supply-demand balance (to some extent similar to demand shifting). The fifth option for flexibility is through a geographic relaxation, by setting up extensive grids. By wide geographic aggregation, RES intermittency can be smoothened out to some extent.

The aim of this paper is to identify from which level of intermittent RES penetration, combined with the conventional generation system, a system is no longer able to provide reliable electricity generation, and hence, other flexibility instruments (from the different options as listed above) are to be deployed, thereby effectively increasing the cost of RES integration. Towards this aim, a novel market model is developed and deployed, thereby extending and complementing existing analyses available from the literature. Focus is on the variable character of RES, rather than on the (limited) unpredictability.

(2) Methods

Conventional power plants have a number of technical constraints, which impact their flexibility, such as a minimum stable operating point, a start-up time, ramp-rates and minimum up and down times (these latter might not be real technical constraints, but rather operational restrictions taken into account by power plant operators not to compromise a plant’s lifetime). To evaluate the compatibility of RES and dispatchable generation, a market model optimizing the actual operation of a generation system with a share of intermittent RES is deployed. As is demonstrated in Table 1 below, computation times of typical methods such as Mixed Integer Linear Programming (MILP) increase heavily when (residual) demand levels are low compared to the overall system size, and/or these solvers can face difficulties in finding a feasible solution (if this exists). Hence, a new heuristic market model is developed and deployed, which is able to cope with variable and low net demand profiles in an efficient way. The method is based on an enhanced priority list (denoted EPL) which is used in a heuristic algorithm to come to a feasible solution, which is then potentially improved in further steps. Throughout the algorithm, specific focus is on feasibility towards the power plants’ dynamics (e.g., minimum operating points and minimum up and down times, important for a low load setting).

This model is used to run simulations with different generation system compositions (different power plants with specific dynamic constraints, different shares of intermittent RES). This way, a correlation/relationship is to be sought between electricity generation system characteristics and a maximum amount of RES that can be integrated. If a certain system composition turns out infeasible, one can see this as a requirement for one or more additional means of flexibility.

(3) Results

Some initial results are presented below. More elaborative results will be included in the full paper. Different electricity generation systems are deployed, ranging from 10 up to 100 conventional units. A reference demand profile is started from (5 day period in this case), from which a certain amount of intermittent RES is subtracted (methodological profile). The factor *FD* indicates the relative amount of RES being present (*FD* 0 means no RES, *FD* 2 means a significant amount of RES). Figure 1 presents the residual demand, i.e., demand after RES. The developed EPL market model is employed and demonstrates that in nearly all combinations (different systems + different amount of RES) a feasible operational mode can be found. Only in the case of the 10 power plant system and a high RES share (*FD* equal to 1.5 and 2), no feasible solution was found, as the flexibility offered by the limited amount of power plants in this case turns out to be insufficient.

The developed EPL model can be compared and benchmarked to a MILP market model. The relative differences in objectives are presented in Table 1. A positive relative difference indicates a better solution by MILP; a negative value indicates a better solution by EPL. As demonstrated, the EPL performs satisfactory. The EPL has a calculation time below 1 s for each simulation, while the MILP model faces much high computation times. The cases marked by a * indicate that the MILP was bounded by the imposed computation time limit of 3600 s. In these cases, the current best solution is provided, but this solution is not guaranteed to lie within the optimality gap of 0.5%. In 3 cases no solution was found by the MIP solver within the provided time (3600 s), although a feasible solution exists, as demonstrated by the EPL.

For the full paper, additional simulations are to be performed, on a wider set of systems, different technical parameters, different RES profiles and demand profiles.

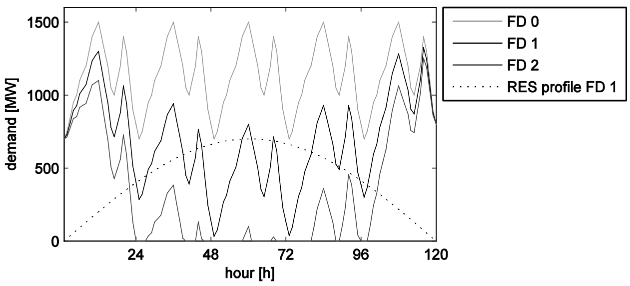

Fig. 1: Different demand profiles and RES profile, in the 5 day setting

# units	FD 0	FD 0.5	FD 1
10	-0.10%	0.31%	1.85%*
20	0.01%	0.29%	-
40	0.24%	-	0.58%*
60	0.06%	-	0.75%*
80	0.22%	-17.91%*	0.25%*
100	0.32%	-17.96%*	0.60%*

Table 1: Relative difference [%] between EPL and MILP objective with *FD* ranging from 0 to 1.

(4) Conclusions

Though results are still preliminary, and additional simulations are to be performed, the market model already illustrates that a conventional power system is able to absorb quite a significant share of intermittent RES, without having to rely on other flexibility instruments. A new market model is developed and deployed specifically towards this aim (i.e., to identify feasible operation modes of systems with low and variable residual demand).

In the full paper, results will be further generalized, and feasibility is to be characterized as a function of the relevant technical constraints of the available power plants, and the amount of both conventional power and RES generation, relative to the original demand.

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