PLANNING GRID EXPANSION WITH BATTERY STORAGE UNDER RENEWABLES SIZE AND LOCATION UNCERTAINTIES

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Overview

More solar and wind power installations will be connected to the grid in the coming years. As the distribution grid available capacity is increasingly saturated, a growing share of renewable connects to the sub-transmission grid (i.e., medium-voltage and meshed grid usually between 60-150 kV in place of lower-voltage and radially operated grid usually under 20 kV).

Among other flexibilities [1], battery storage can contribute to the congestion management on these grids, particularly near wind and solar productions. Battery storage can complement or substitute large-scale line reinforcement, making it valuable for grid expansion planning [2], [3]. Academic studies have long pointed out the benefits of planning generation and transmission simultaneously [4]. More recent studies consider storage in addition [5]–[8]. The underlying assumption behind these approaches is that some locational signal links generation and storage to the grid nodal conditions [9], [10]. [10]Although most System Operators plan expansion without accounting for the substitutability between generation, storage and transmission. It is partly because of the complexity of performing such a co-optimisation on an actual size grid. Also, the efficiency of locational signals in driving generators to ideal sites is limited theoretically [11] and in practice [12], [13]. Most papers in the literature focus on the transmission grid (high voltage transmission lines) with big concentrated renewable power plants remote from load areas, as is often the case in the US [14], [8]. In Europe, most renewable power plants connect to lower voltages as covered distances are shorter and low-voltage connection fees are less expensive. Flexplan methodology is an example of grid planning with storage on a multi-horizon with distribution and transmission grids in Europe [15].

Still, storage remains a potential asset for network expansion. Construction is fast, and location is flexible: it has less impact on the land than building a new line. Battery storage's economic lifespan is around 10 to 15 years, much smaller than a line's (50 years). The installed capacity is continuous, whereas a line capacity is discrete: it can accommodate small needs extending over less than a decade. This paper studies the interplay between storage and line investments, depending on different costs scenario and various renewable production configurations. It deliberately ignores the regulation aspects of storage ownership and contractualisation. The study focuses on estimating the potential value of storage as an alternative to grid investments with a systemic viewpoint.

Methods

First, we focus on handling an existing open-source package for power system optimisation on a series of basic cases for testing. Then, we address some caveats of the model (line representation and impedance update). Once the model is up and running, we run simulations on a highly simplified grid representing a typical grid situation on medium voltage in France with strong solar or wind penetration. A sensibility analysis is done on battery storage costs to evaluate its potential economic space as a grid expansion alternative. Critical aspects of storage valuation are identified throughout the study.

A review of co-optimisation for network and generation expansion planning can be found in [16], [7]. Several open-source models exist, among which are: Antares Xpansion (developed by RTE), OpenTEPES (developed by IIT Comillas), and PyPSA (developed by Karlsruhe Institute of Technology, maintained by the Technical University of Berlin). We chose to use Pypsa thanks to its extensive documentation and active community of users. Pypsa is an open-source python package performing simulation and optimisation of power systems (and energy systems). Various formulations allow solving the linearized equations when simulating while optimising dispatch and investments. This study uses power flow simulation with the DC approximation of AC (also known as linear power flow). An ex-post analysis ensures this approximation is valid: it checks the angle difference for each line's nodes, ensuring the values remain small (<30°) for all time steps. Linear optimal power flow formulation alternatives contained in Pypsa can be found here [17].

Pypsa's objective function is the maximisation of social surplus, i.e., the minimisation of the system costs. The decision variables are the unit commitment variables for all generation and storage assets, which are binary, and the investments variables for generation and grid which are continuous. The model's weakness is that line capacities are represented as continuous, and their impedances need to be updated. In reality, a line extension consists in building several parallel lines: the resulting line capacity should be an integer multiple of its nominal capacity, and the resulting equivalent impedance should be divided by the number of parallel lines. Two approaches are explored to circumvent this caveat. In the first one, a first optimisation is performed. The returned continuous values for line capacity variables are divided by the apparent nominal line power and rounded up to the next integer value. It fixes the number of parallel lines of the grid expansion candidates. The second approach proposes multiple and identical lines for each link, each one having a fixed capacity and being a candidate for expansion. This approach increases the number of binary variables in the optimisation, possibly slowing it a lot.

Results

The optimisation is run on a simplified grid. The adopted approach is a green field approach: there is no grid at the beginning of the optimisation. Storage candidates are located next to renewable power plants. Demand is located on another node. A virtual power plant called 'load shedding' located next to the demand meets the demand when the line capacity or renewable production is insufficient. Preliminary results show that storage value increases as line capacities shift from continuous to an integer. Indeed, representing line lumpiness enhances the battery storage value. Building a line can be more expensive than some small-scale storage that shifts renewable production to non-congested hours, with congested hours filled with load shedding or discharge of demand-located storage. The study then evolves to a multi-horizon optimisation. Different years are considered in this optimisation. The size and location are renewable capacities are represented with various scenarios. Preliminary results suggest that in the case of a temporary increasing need for grid capacity (with non-monotonous renewable capacity connected), the optimisation favours battery investments rather than a line investment. It reflects the shorter payback time of storage. This result aligns with other studies [18]. Eventually, a sensibility analysis with storage costs relative to line costs is done.

Conclusions

While co-optimisation of storage and grid investments may not provide the most realistic results for System Operators, this study explores the potential of storage if it could be ideally sized and located with regard to local grid conditions.

Battery storage can either complement or substitute grid investments, depending on system needs. Integer line capacity is critical to value battery storage, especially when considering a multiple-year horizon with time-varying renewable power capacities. Overall, current and forecast costs limit the use of storage as an economically feasible alternative.

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