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Towards more cost-effective PV connection request assessments via time-series-based grid simulation and analysis

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Abstract: Here, the authors present methodological improvements to one of the most often performed distribution grid analysis tasks in Europe today – the assessment of photovoltaics (PV) connection requests and the analysis of whether or not a most often costly local grid reinforcement becomes necessary. For this, the authors model a typical European low-voltage distribution grid with the request for a sizable PV unit at the fringes of the grid topology as it is often the case for PV units on farm buildings in rural areas. Such a set-up is a demanding constellation for grid operators, typically requiring costly grid upgrades.

1 Introduction

The state-of-the-art methods for assessing photovoltaics (PV) connection request rules are static analysis approaches such as the DACHCZ guidelines [1]. These guidelines define that the relative voltage rise (ΔV) incurred by the totality of all generating plants at their nominal or installed power rating ($P_{\text{installed}}$) compared with zero feed-in ($P=0$) must not exceed 3% voltage rise at any point of common coupling in low-voltage (LV) networks, and only up to 2% in medium-voltage (MV) networks. This voltage rise evaluation scheme is illustrated in Fig. 1 and is typically calculated under the assumption of having no load demand in the given distribution grid section.

Obviously, such an approach will be rather conservative. The implicit conservativeness of this grid planning approach is particularly obvious when considering that the European Standard EN 50160 [2] defines the variation of voltages in distribution grids can under normal operating conditions vary up to ±10% of the nominal operating voltage in 95% of 10 min intervals of the measured root mean square value within the interval of 1 week (for 5% of 10 min intervals, voltage can drop down to −15%). The typical result is thus that larger PV units cannot be connected to the distribution grid without prior grid reinforcement and its associated costs.

In an exemplary case study, we show that a time-series-based PV connection request assessment leads to a more detailed analysis, by calculating the bus voltage as well as line loading time-series for the whole distribution grid topology based either on the inclusion of actual grid measurements, i.e. load demand and other local power generation profiles, and/or synthetic but plausible load demand and generation profiles.

This approach provides better decision-support for distribution grid planning by analysing how close grid operation is to actual voltage and line loading limits in the worst case (i.e. maximum voltage and line loading) as well as providing the necessary data for a statistical analysis over longer time-frames, i.e. one full year.

Such previously unavailable insights can avoid costly grid upgrades that are otherwise deemed necessary.

2 Simulation platform DPG.sim

In order to overcome these limitations, the SmartGrid time-series-based simulation platform DPG.sim (Distributed Prosumer and Grid Simulation) is developed by ETH Zurich spin-off Adaptricity [3]. The detailed simulations and subsequent grid analytics provide valuable qualitative as well as quantitative decision-support for all aspects of distribution grid operation and planning. On the grid operation side, this includes notably the design and performance analysis of active network management operation strategies. On the grid planning side, this includes the integration of SmartGrid elements into distribution grid planning procedures.

The main advantages of the DPG.sim simulation platform are threefold: first, its possibility to realistically model and simulate the operation of active distribution grids as well as the temporal evolution of generation, load, storage states, and their operational control algorithms down to the level of individual households and household units. Its unique feature in this respect is its versatile Prosumer modelling approach (Fig. 2) [4], which allows capturing all relevant modelling details and operational constraints of controllable loads, distributed generation (DG), and storage as well as SmartMeter communication infrastructure (Fig. 3). Second, the ability to perform large-scale time-series simulations and operational (big) data analytics based on heterogeneous sets of grid data as well as end-consumer data sets by tapping into scalable cloud-based computation and data storage resources.

Third, data visualisation and statistics functionality that provides detailed insights into electricity grid operation and enable robust decision support.

3 Case study

In the following, a case study of a typical PV connection request for an exemplary European LV distribution grid is presented in order to illustrate the potential advantages of time-series-based grid simulation schemes for distribution grid planning tasks.

3.1 Benchmark LV grid

All grid simulation and analysis are based on a modified version of the urban LV distribution grid defined by the CIGRE Task Force C6.04.02 [5].

The distribution grid (Fig. 3) consists of a 20 kV MV grid topology that supplies LV grid feeders via three separate 400 V transformer stations. The resulting 42-bus distribution grid

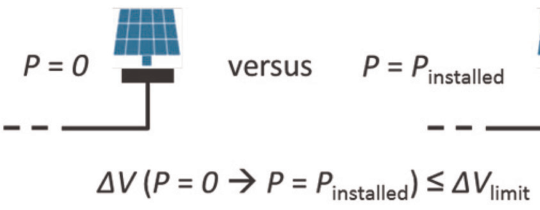

Fig. 1 *Voltage rise evaluation using DACHZ guidelines [1]*

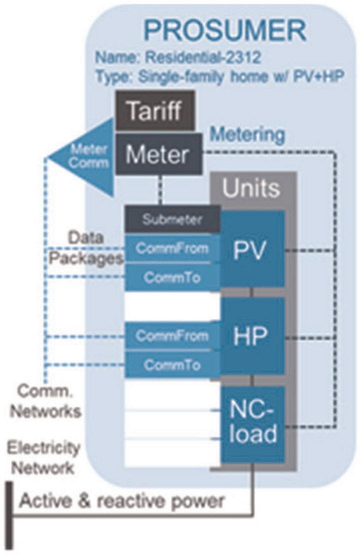

Fig. 2 *Prosumer modelling approach*

topology consists of typical residential, commercial, and industrial load types [5]. Typical full-year time-series of load demand with 15 min sampling time have been modelled and linked to the grid topology. A realistic PV power production profile has also been created.

The grid topology and the associated power consumption and load demand profiles are used in the following both for static grid simulations (snapshots) and for time-series-based grid simulations and statistical analyses.

3.2 Voltage rise calculation and DG hosting capacity

The classical PV connection request assessment according to the DACHCZ guidelines [1] allows for static voltage rise of up to 3.0%, or 0.03 per-unit (pu) at LV grid connection points.

Depending on the specific bus, i.e. its location inside the LV grid topology, a minimum of 30 kW (bus 17) and a maximum of up to 360 kW (bus 2) of DG can be hosted by the LV grid (Fig. 4). Significantly, more DG power can be hosted on the MV side of the distribution grid, e.g. >6.0 MW on each MV bus (buses 1, 19, and 40). The buses with the lowest DG hosting capacities are typically those buses with the largest (electrical) distance from the substation, respectively, the LV transformers, since those buses (buses 15, 16, 17, 18, and buses 37–39) are weaker than others.

Note that the following assumptions are being used for the calculations: bus 0 is the slack bus and is disregarded, a typical delta voltage rise constraint of 2% (MV) and 3% (LV) is defined as the constraint for limiting DG hosting capacity. In order to make the static voltage rise assessment less conservative, a minimum load situation, i.e. 1 May (3 a.m.), is considered instead of a more conservative but rather unrealistic no-load assumption.

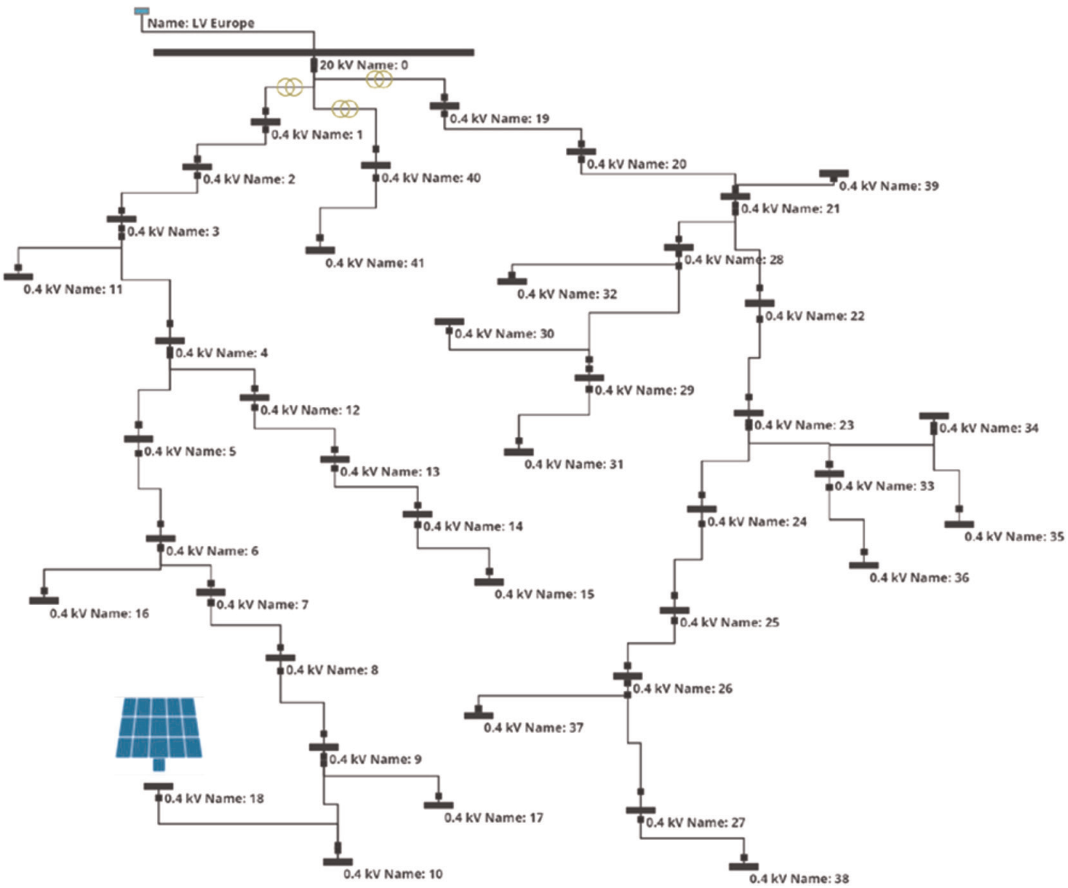

Fig. 3 *Urban LV benchmark distribution grid (CIGRE Task Force C6.04.02) [5]*

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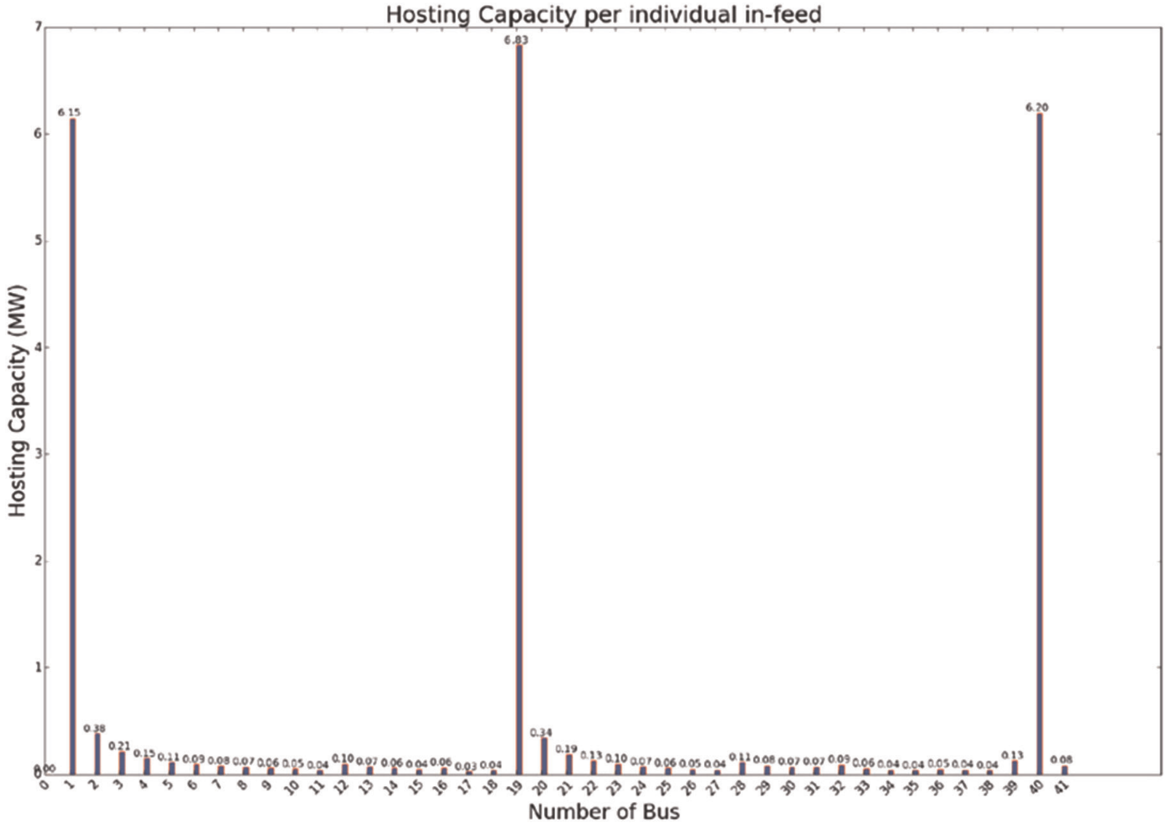

Fig. 4 *Hosting capacity of individual buses of the urban LV benchmark distribution grid [5]*

3.3 Assessment of PV connection requests

We consider a connection request for a sizable PV unit of ~70 kW$_p$, corresponding to a roof-top area of ~400 m^2, for instance, on the top of a warehouse, at the *weak* bus 18 (Fig. 3).

The classical PV connection request assessment would allow a maximum of only 33 kW$_p$ (no-load assumption). The planned PV unit with 70 kW$_p$ would produce a higher static voltage rise of up to 6.45%. A grid connection according to DACHCZ guidelines would require a conventional grid upgrade, i.e. an LV cable with larger cross-section, potentially costing up to EUR 50,000.

Since the typical installation costs for a 70 kW$_p$ PV unit are currently estimated on average at about EUR 1350 per kW$_p$ (early 2017) in Germany [6], the total PV unit investment costs are about EUR 94,500. Thus, from a national economic perspective, the additional costs for proper distribution grid reinforcement are rather significant, i.e. >50% on the top of the PV plant investment cost.

There is thus a strong motivation for applying less conservative yet robust PV connection request assessment methodologies that are on average more cost-effective than the currently used DACHCZ guidelines.

3.4 Time-series-based grid simulation and analysis

In the following, we analyse how a time-series-based PV connection request assessment according to the European norm EN50160 [2] compares to the previous static voltage rise calculation. Contrary to the previous analysis, we now incorporate the available load time-series data for all LV and MV buses of the urban LV benchmark distribution grid. Such data could simply be obtained via existing SmartMeter measurements or via available load profile generators for residential and commercial customer profiles or a mix of the above.

Indeed would a time-series-based grid simulation clearly indicate that a large PV unit with 70 kW$_p$ would induce a significant maximum voltage rise of 1.07 p.u. (bus 18) as well as a maximum line loading of up to 82% (line 10–18) for a typical summer week (Fig. 5). The simulated voltage bands would thus respect the requirements of the EN50160 norm, which allows for a maximum overvoltage of up to 1.10 p.u. (10% overvoltage).

In a full-year simulation, the maximum voltage rise may go up to 1.076 p.u. and the maximum line loading up to 93.5% (Fig. 6, top). Throughout the full year, the loading of the critical line 10–18 is only very rarely >80% of the maximum allowable load, i.e. 47 h or 0.5% of the time (Fig. 6, bottom).

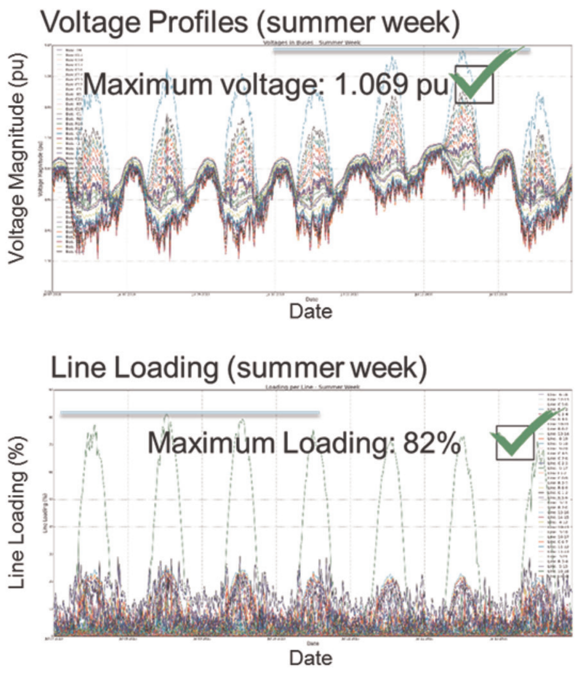

Fig. 5 *PV connection request for typical summer week – time-series based grid analysis allows much larger 70 kWp PV unit*

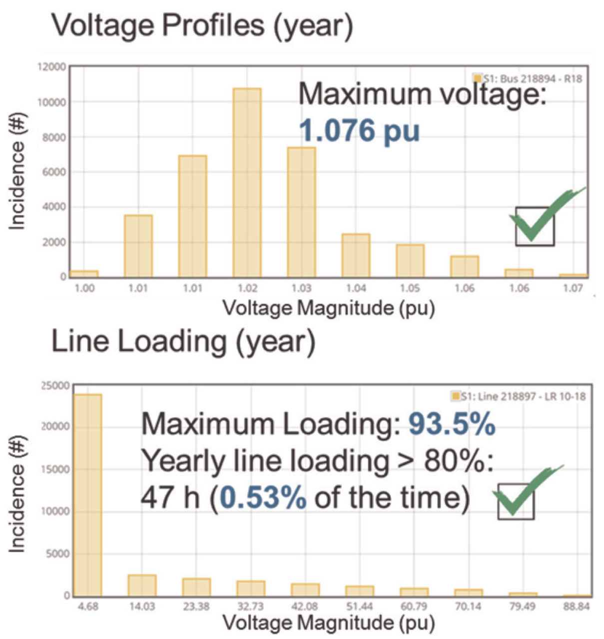

Fig. 6 *PV connection request for full reference year – time-series based grid analysis allows much larger 70 kWp PV unit*

With these quantitative results based on time-series grid simulations, the responsible distribution grid operator can thus approve the pending PV connection request. This cost-saving finding is robustly based on the clear indication that voltage band norms as well as line loading limits would be respected according to the full-year simulation of the reference year, i.e. consisting of altogether 35,040 steps with 15 min sampling time.

4 Conclusion

The results of this typical PV connection request assessment, one of the most commonly performed grid analysis task nowadays, illustrate that time-series-based grid simulations are able to provide valuable insights for distribution grid operation and planning.

By running detailed full-year grid simulations that incorporate all available grid measurements, as obtained by SmartMetering schemes or other sources, a larger DG hosting capacity is possible. Time-series-based grid planning can thus avoid otherwise costly conventional grid upgrades.

5 Acknowledgments

The main results of this case study have been obtained by Christos Antonakopoulos while pursuing his master thesis project at the ETH spinoff company Adaptricity under the supervision of Stephan Koch.

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7 Appendix

See Tables 1 and 2.

Table 1 Line data of urban LV benchmark grid [5]

Line	Res., Ω/km	React., Ω/km	Length, km	1, A
19–20	0397	0279	0.03	199
20–21	0.397	0.279	0.03	199
21–28	0574	0.294	0.03	140
1–2	0.284	0.083	0.035	318
28–29	0.574	0.291	0.03	140
29–30	0.41	0.071	0.03	240
29–31	0.41	0.071	0.03	240
2–3	0284	0.083	0.035	318
3–4	0284	0.083	0.035	318
4–12	0.497	0.086	0.035	193
26–37	0.41	0.071	0.03	240
28–32	0.41	0.071	0.03	240
12–13	0.497	0086	0.035	193
13–14	0.497	0.006	0.035	193
27–38	0.41	0.071	0.03	240
14–15	0.822	0.077	0.03	199
21–22	0397	0.279	0.03	199
22–23	0397	0.279	0.03	199
23–33	1.218	0.318	0.03	101
3–11	3.69	0.094	0.03	49
21–39	0.41	0.071	0.03	240
6–16	0.871	0.081	0.03	13–1
33–34	1.218	0.318	0.03	101
4–5	0.284	0.083	0.035	318
5–6	0.284	0.083	0.035	318
6–7	0281	0.083	0.035	318
7–8	0284	0.083	0.035	318
33–36	0.41	0.071	0.03	240
34–35	0.41	0.071	0.03	240
8–9	0.284	0.083	0.035	318
9–10	0.284	0.083	0.035	318
23–24	0.574	0.291	0.03	140
10–18	1.38	0.082	0.03	101
24–25	0574	0294	0.03	140
25–26	0.574	0.291	0.03	140
9–17	3.69	0.091	0.03	49
26–27	0.574	0.291	0.03	140
40–41	0261	0.071	0.2	254

Table 2 Transformer data of urban LV benchmark grid [5]

Transformer	Volt 1, kV	Volt 2, V	Rated power, MVA
0–1	20	0.04	0.5
0–19	20	0.04	0.55
0–40	20	0.04	0.5