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SWEET Call1-2020:
PATHFNDR

Flexibility-aware planning of distribution network reinforcements

Technical report

Deliverable ID and name
D2.3.2a Report on describing the developed methodology for utility-scale infrastructure planning and the associated results

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Summary

This report describes a methodology developed in the context of the PATHFNDR project, allowing an electricity distribution utility to plan the required reinforcements / expansions of its network, in the long-term, while considering the possibility of resorting to flexibility procured by its customers as an option to postpone or completely avoid some network reinforcements. The developed so-called flexibility-aware distribution network planning (FADP) method is described in this report.

Following, the method is applied to a realistic test system (created based on real network data), illustrating the results that can be obtained by the method while allowing to make general conclusions.

1 Introduction

1.1 Motivation

The increased penetration of distributed energy resources (e.g., solar PVs), and electrification of demand for heating and mobility results in higher loading of the MV & LV electricity distribution networks, often beyond the limits which they were designed for. Electricity distribution utilities need to anticipate this evolution and timely take actions to ensure that the new flow patterns can be accommodated by their networks. That is, under all operating conditions, (i) network components (transformers, cables, lines) shall not be overloaded, and (ii) nodal voltages shall lie within acceptable limits. In other words, all potential operating conditions shall be feasible and acceptable.

Clearly, network reinforcements and/or network expansion are the ultimate ways of ensuring the aforementioned operational feasibility. However, such actions are associated with the following challenges:

1. They are costly. Especially if the (series of) expansion investments are not properly coordinated, among them but also, potentially, with other infrastructure investments.
2. They need time until they are materialized. Hence, they need to be planned well before the problems appear.
3. Since the appearance of network problems is heavily dependent on the investment choices of the end customers, the utilities face a high degree of uncertainty.

Large-scale infrastructure projects can face resistance from local communities, especially if they involve constructing new facilities or expanding existing ones in populated areas. This can lead to delays, increased costs, or even the need to redesign projects. A potential (provisional or permanent) alternative to network reinforcement is for a utility to set up mechanisms allowing it to procure flexibility services from its customers, so that network violations are managed by actively engaging all the network resources. End-customer flexibility could be provided either by controlling the active and reactive (P/Q) injections or withdrawals of active customers' components, such as PV inverters, batteries, or chargers of electric vehicles (EV), or by means of shifting in time the customers' demand for electricity (or simply reducing it at a given moment).

As a matter of fact, there is increasing regulatory pressure to electricity distribution utilities to consider also end-customer flexibility potential into their network planning processes. However, such a consideration faces the challenge that, while a network hardware investment is a measurable action completely at the hands of the utility, reliance on availability of customer flexibility is difficult for a utility to quantify (especially as part of its long-term planning process).

For customer flexibility to be included as part of a utility's network reinforcement planning process, a utility needs to enhance the process in order to be able to:

1. Include the expected available customer flexibility as part of its input scenarios.
2. Contrast the value of customer flexibility against the cost of network reinforcements.
3. Come up with a specific, measured need for flexibility.

4. Identity which (types of) customers can provide how much flexibility and under which conditions.

5. Achieve customer participation by introducing a remuneration that it is willing to offer to its customers for flexibility provision or a "penalty" (typically in form of a tariff) that customers who are not willing to provide flexibility shall pay.

1.2 Objective

To address the need outlined in Section 1.1, a methodology for "flexibility-aware planning of reinforcements in electricity distribution networks" has been developed as part of PATHFNDR's WP2 ("Pathways on a district/village/city scale"). Objective of this methodology is to simultaneously consider both network enhancements as well as utilization of customer flexibility as potential solutions for a utility to ensure that its electricity network is adequately dimensioned to serve the future needs.

Future evolution scenarios, availability of customer flexibility, cost of receiving this flexibility, as well as network expansion costs are inputs to the methodology.

In addition to making up a valuable methodology in the hands of Swiss DSOs (distribution network operators) supporting the energy transition, the developed methodology for "flexibility-aware planning" has an important role in the overall approach followed in PATHFNDR WP2 (illustrated in Figure 1): it allows to quantify the value of flexibility for a distribution utility. This is measured as the cost of network investments that would be required if a given amount (and type) of customer flexibility were not available to the utility.

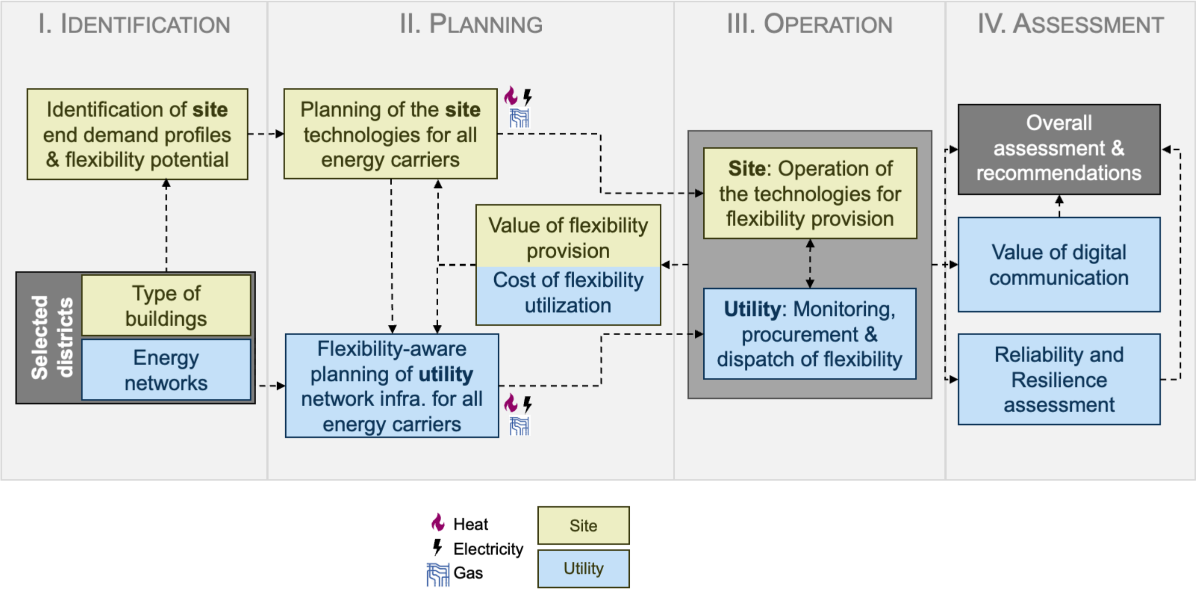

Figure 1. Workplan PATHFNDR WP2 "Pathways on a district / village / city scale".

2 Method description

2.1 Introduction

In the evolving landscape of power distribution networks, the integration of flexibility solutions has emerged as a pivotal strategy to enhance network resilience, efficiency, and sustainability. The developed flexibility-aware distribution planning (FADP) method is designed to optimize network performance by leveraging various flexible resources and technologies. This chapter describes the processes, and expected outcomes of the method, highlighting its role in distribution system planning.

The essence of the FADP method lies in its innovative approach to incorporating flexibility solutions into the distribution network planning process. Traditional planning methodologies often overlook the dynamic capabilities of distributed energy resources (DERs) and other flexible technologies, leading to suboptimal investment decisions and operational practices. Additionally, system operators typically consider worst-case scenarios (maximum load) in their planning studies, but with the increasing penetration of renewable energy sources and variable loads, these approaches may not accurately reflect the complex nature of modern energy systems. In contrast, the FADP method aims to harness these capabilities, thereby optimizing network performance and investment efficiency.

2.2 Methodology

2.2.1 Inputs

The FADP method requires two types of inputs:

1. The legacy electricity network and connected customers and resources
2. Scenarios corresponding to assumptions about how the resources connected to the network will evolve in the next decades (e.g. in the next 25-30 years), typically represented by a few representative years (e.g. 2030, 2040, 2050).
3. Assumptions about the flexibility potential and associated cost of the end customers.

The first type of input consists of a network model, i.e. its topology and the parameters of its various components (transformers, cables, lines) and a representation of all the end customers, expressed in terms of demand or generation timeseries (in, for example, 15’ or 1h resolution) as well as the network nodes to which its customer is connected. This information allows to run an AC power flow for each time instant, hence identifying the corresponding currents in all network branches and nodal voltages.

The second type of input consists of all the information required to represent the expected future distribution system. Namely: (i) potential network upgrades that are already planned, (ii) evolution of existing customers, i.e. decrease/increase of their base electricity demand, switch to heat pumps for heating, switch to electric vehicles, installation of PV and/or battery system, (iii) new customers. With the above information, the expected future currents and voltages can be estimated by means of AC power flow analysis. Hence, excessive loading of the network can be identified.

The third type of input consists in appropriately modelling the flexibility from different resources (in general, different modelling is used per resource type). For example, a (end-user) battery can be controlled in a “grid-friendly” manner (partially driven by congestion alleviation, rather than, for example, purely by self-consumption maximization), a PV can be curtailed up to a certain acceptable level, consumption of heat pumps and EV chargers can be shifted up to a defined number of hours. Optionally, a cost can be attributed to each “flexibility action”, corresponding to what remuneration would a customer require to make its flexibility availably to a utility. The FADP method, described in the following section, can identify the benefit of different levels of available end-user flexibility (benefit = savings in network reinforcements thanks to the utilization of flexibility) and compare it with the aforementioned “flexibility cost”, or, if such cost is not provided, use it to calculate how much a utility would be willing to remunerate its customers (as shown in the test case provided in this report).

The choice of scenarios, for each of which the “core method” (described below) is performed, is an input to the method, allowing to consider different potential future evolutions (customers choices, weather years, costs, etc.). This scenario-based approach allows for (i) a robust planning (ensure feasibility under different potential future evolutions), and (ii) optionally, a probabilistic planning (for example weighting the costs according to the scenario occurrence likelihoods).

2.2.2 Core method

The flowchart in Figure 2 presents the main idea of the proposed FADP method. The method consists of two steps, performed for each considered year (e.g. 2030, 2040, 2050) and variation (e.g. use of different weather years) of a future scenario:

1. Identification of network violations: In this step, the need for network upgrades is assessed assuming that no customer flexibility is available. This is performed by running a power flow simulation for each considered time instant (e.g., every 15’, or every hour as assumed in the flowchart). This step results in the identification of (i) which lines require expansion, (ii) the extent of their overloading, and (iii) the frequency of these overloads.

2. Network reinforcement considering flexibility resources: Following the identification of necessary branch upgrades in the first step, the core of the FADP method is executed. It consists of three basic “analysis blocks”:

    a. An “optimal dispatch” block, executed for each selected day (from step 1), aiming at identifying whether the overloads can be alleviated by utilizing the available flexibility of the resources, by solving a multi-period optimization problem considering a linearization of the electricity network (a so-called DC model).

    b. An “AC power flow analysis” block, executed for each time instant’s schedule that resulted from the “optimal dispatch” block, to check feasibility using the actual AC model of the network (hence, also considering voltages and reactive power).

    c. A “network reinforcement analysis” block, which, given the results of the two other blocks (2a and 2b) as well as the “network reinforcement rules” provided by the utility, suggest one or more network upgrades.

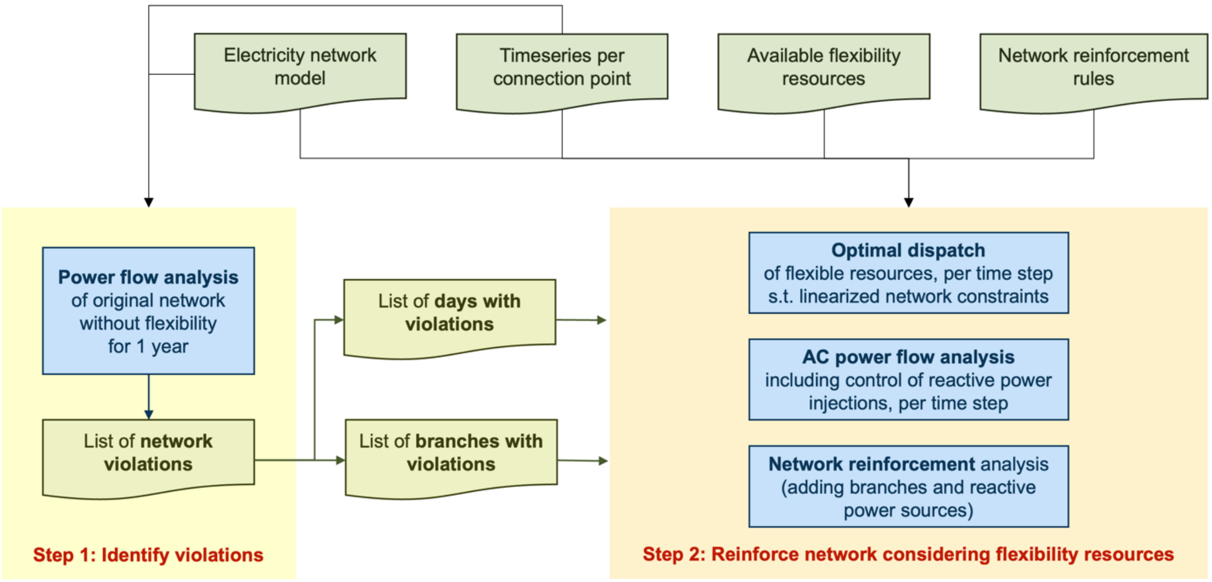

Figure 2. Flowchart of flexibility-aware electricity distribution network planning method.

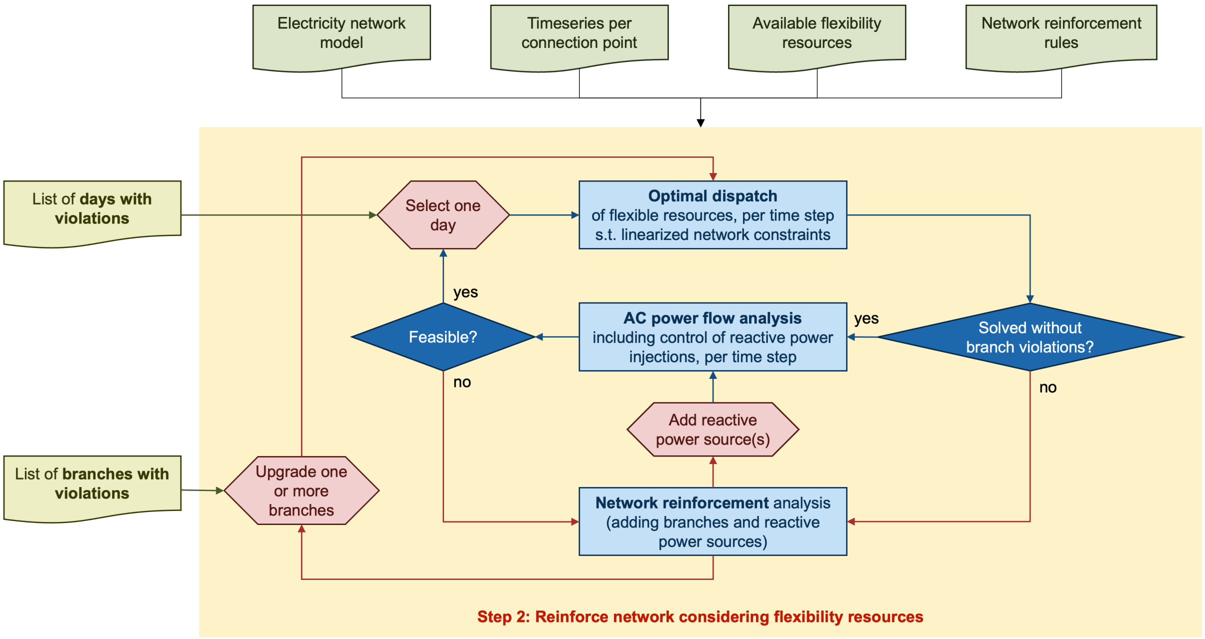

Figure 3. Flowchart of FADP core algorithm (step 2).

Figure 3 provides more details regarding the way that blocks 2a, 2b, and 2c interact with each other, forming a loop which is iterated until no further violations are observed.

The tools FlexDyn and FlexEco, which have been developed in-house by ETHZ-FEN[1] and are often used in various projects, have been utilized to perform, respectively, the power flow analysis and the optimal dispatch. However, using these specific tools is not a requirement of the method.

In the remainder of this section, each of the steps is briefly described.

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[1] Forschungsstelle Energienetze (Research Center for Energy Networks): https://www.fen.ethz.ch/de/

1. Identification of network violations

In the first step the methodology performs a set of power flow simulations to identify potential network violations, such as overloads or voltage violations (over- and under-voltages). In this step, the goal is to identify the critical infrastructure in future scenarios without considering the impact of flexible resources.

The results of the power flow simulations are post-processed in order to determine the branch upgrade requirements and their relevance measured in terms of frequency of occurrence and magnitude of violations. This information is important for the prioritization of investment needs. In addition, the days when the violations occur are identified, so that they are the focus of the analysis performed in step 2.

The post-processing consists of two parts. First, the power flow results are analyzed aiming at prioritizing the network violations and the corresponding requirements for branch upgrades. This prioritization is based on multiple criteria considering factors such as the severity of violations, the frequency and the duration of these violations. This analysis is performed to ensure that the network upgrades (which are to be proposed in the second step of the FADP method) are focused on areas that have the more significant impact.

Second, a temporal analysis of the power flow results is performed to identify specific days in which at least one network violation occurs. This analysis aims at creating a pool of days with network violations, that the analysis performed in the second step will focus on. By specifying these critical days, the proposed framework will focus on performing an operational analysis to efficiently dispatch the available flexibility resources in the distribution network and eliminate the network violations.

2a. Optimal dispatch of flexible resources

In the second step of the proposed framework, the goal is to effectively utilize the available flexibility from the distributed resources to eliminate the network violations in the power system. Per day (or set of days) with violation(s), a multi-period optimal dispatch problem is solved to identify whether the available flexibility can resolve the violation(s). In the context of PATHFNDR, FEN’s in-house tool FlexEco has been used for this purpose.

Objective of the optimization is to minimize the violations at the lowest possible cost. A so-called DC (linear) model of the network is used at this stage. Violations are expressed as maximum acceptable branch flows and/or as maximum acceptable power injections or withdrawals (which can correspond to voltage violations). To avoid infeasibility, these maximum limits are implemented as “soft” constraints. That is, violation of a limit results in a cost in the problem’s objective function. This cost increases proportionally to the amount of violation, while it is equal to zero if a constraint is not violated. This approach allows to receive, as an outcome of the optimization, the information of which branches still need to be upgraded to avoid all violations.

Flexibility is modelled in different ways:

- Shifting consumption of heat pumps (HPs) and EV chargers within a pre-defined timeframe (e.g. from 12:00 to 20:00). This corresponds to a situation where these resources are motivated (via a flexibility market or a dynamic tariff) to consume at different moments compared to when they would normally consume, or where regulation allows the DSO to control the devices (and remunerate the owner).

- Curtailment of PV generation. This corresponds to a situation where PV are either motivated (via a market or tariff scheme) to voluntarily curtail their injection to the network at moments when this causes a congestion, or there are mandated to do so by means of regulatory rules.

- Dispatch of charging and discharging of battery energy systems (BESS). This corresponds to the end-user batteries providing their flexibility to the system. Obviously, the available flexibility depends on the assumed size of the batteries (both power as well as energy capacity).

- Consumption of larger-scale energy conversion technologies, such electrolyzers or heat pumps for district heating. This part of the methodology is not presented in the remainder of this report, which focuses on HPs, EVs, PVs and BESS.

Even though longer-term flexibility can be also important, especially in the presence of long-term energy storage (such as hydrogen or thermal storage), the most common small-scale DER, covered in this report, are expected to contribute to the flexibility at the daily timeframe. Hence the choice of running the optimal dispatch for a time window of one or a couple of days. This is not a limitation of the methodology though.

2b. AC power flow analysis

Since the optimal dispatch (2a) is performed by means of a simplified (DC) model, its result shall be checked in terms of AC feasibility. For this, an AC power flow with reactive power control modelling is solved for each time instant resulting from the optimal dispatch (i.e., the AC feasibility of the schedule where flexibility has been used is checked). In the context of PATHFNDR, FEN's in-house tool FlexDyn has been used for this purpose. FlexDyn will modify the reactive power injections of the various resources, within their capability limits, to ensure that voltages are kept, if possible, within limits.

This step (2b) identifies violations that where possibly note detected by the optimal dispatch model (step 2a). These violations, together with the violations already detected by 2a (see Figure 3) make up a set of violations that the assumed available flexibility cannot alleviate. They fed to the network reinforcement analysis module (step 2c), for appropriate network reinforcements to be selected.

2b. Network reinforcement analysis

This step is executed only in the cases when the available flexibility resources could not alleviate all the violations. The objective is to identify appropriate network reinforcements. The main idea behind this module is to propose one network expansion action (e.g., addition of one branch) which is the most likely to have a beneficial effect in alleviating the violations. Following, steps 2a and 2b are executed again and, if the available flexibility still cannot result in full alleviation of violations, then another network expansion step is proposed by 2c. The iterations continue until all violations have been resolved.

This progressive network expansion, integrated into the iterative algorithm, aims at identifying a minimum number of network reinforcements which, combined with feasibility utilization, can alleviate the violations (identified in step 1). The logic according to which the network reinforcement analysis selects, at each step, the network reinforcement to be proposed is provided by the user as part of the "network reinforcement rules". Typically, these rules are to represent the utility preferences and practices. For example, the rules used to generate the results presented in this report are: It is assumed that the utility resolves congestions by adding a second component (e.g., a cable) parallel to the existing one. The new branch is identical to the existing one, hence its addition doubles the current capacity of the branch, while halving its reactance and resistance. Per iteration, the branch with the highest violation is selected for reinforcement.

At the end of the execution of the algorithm, the utility will have a set of options, alleviating violations by means of network reinforcement and/or feasibility utilization. A cost-benefit analysis can be used to select the way forward, i.e. when to reinforce, how much to remunerate flexibility etc.

3 Application & Results

3.1 Introduction

The proposed FADP method has been applied in a few distribution networks, while it is to be further utilized throughout the PATHFNDR project. In this section, as an illustration of the utilization of the method and the conclusions that can be derived, we present the results received from applying the method to a reduced MV distribution network, calibrated such that it can realistically represent actual Swiss distribution networks as explained in the sequel.

3.2 Test system

3.2.1 Overall description

For each of a total of 122 LV distribution systems of a Swiss utility, two scenarios have been implemented for each of the years 2030, 2040 and 2050; (i) “Scenario 1”, implements the Swiss energy strategy targets from today until 2050, and (ii) “Scenario 2”, assumes that HPs and EVs penetrate at a faster rate than in Scenario 1, while PVs penetrate at a slower rate. Both scenarios, illustrated in Figure 4 and Figure 5, reach the same penetration targets by 2050.

Each LV network has been modelled at the level of house connection points (Hausanschlusskasten – HAKs). Today’s timeseries data have been used to model the conventional demand per HAK in 15-min resolution. According to each scenario’s assumed rate of penetration of the considered DER technologies (HPs, EVs and PVs), timeseries of HP and EV demand and of PV generation have been created, per HAK, based on measured data.

Following, per LV network, all HAK data where aggregated to form one single LV node (connected to the MV network) consisting of three types of demand (conventional, HP and EV) and one generation (PV), each expressed in 15-min resolution timeseries. Nine (9) days have been selected, so that for three seasons (winter, summer and intermediate) three types of days are considered (Sunday / public holiday, Saturday and weekday).

Finally, 15 of these LV nodes were selected (as explained in the sequel) and assigned to an IEE 15-bus MV network (one LV node per bus, plus one bus representing the connection to the HV network), as shown in Figure 9. The ratings of the branches of this MV network were calibrated such that the peak loading resulting solely by the conventional demand does not exceed 65% of the branch ratings. Such a loading is representative of the capacity of today’s electricity distribution network of the specific utility used in this example, but also, to the best of our knowledge, relatively typical for other Swiss utilities as well.

3.2.2 Scenarios

For the sake of simplicity, only two scenarios were selected. Scenario 1 implements, for this utility, the Swiss Energy Strategy targets for HP and EV penetration for the years 2030, 2040 and 2050, while it implements the updated “Mantererlass” targets for PV penetration. The 2050 HP, EV and PV penetration targets correspond, respectively, to 71%, 89% and 96% of the ultimate 2060 targets, which correspond to the ultimate (fully electrified) energy transition goals. Figure 4 shows the rate at which the 2050 targets are reached under Scenario 1 (starting from the 2023 penetration levels).

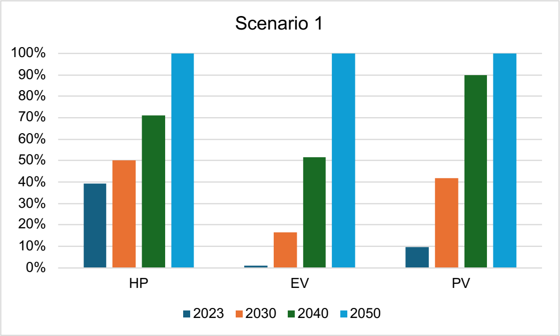


Figure 4. Scenario 1: Evolution of HP/EV/PV penetration until reaching the 2050 targets, expressed as % of the respective 2050 target.

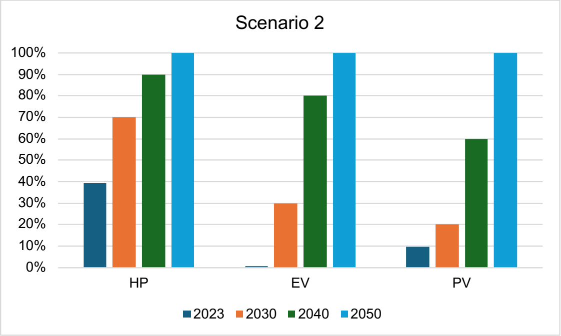


Figure 5. Scenario 2: Evolution of HP/EV/PV penetration until reaching the 2050 targets, expressed as % of the respective 2050 target.

Scenario 2 assumes that the electrification of demand (i.e., the penetration of HPs and EVs) happens faster than the energy strategy timeline, while PV penetration takes place at a slower pace (since, the pace assumed by the energy strategy is rather aggressive, as illustrated in Figure 5.

The role of Scenario 2 in our analysis is that it allows to consider a case where, in the short-term, HP and EV penetration might be the main driver behind network congestions, as opposed to Scenario 1, where PV is the DER with the fastest short-term penetration rate, hence creating a need for network reinforcements. For instance, in Scenario 1, PV penetration reaches 90% of the 2050 target by 2040, while HP and, especially, EV reach only 70% and, respectively, 50% of the 2050 target by 2040. This short-term (up to 2040) rate of adoption is inverted in Scenario 2.

3.2.3 Representative nodes

Since the network shall be dimensioned such that, it can accommodate the peak power flows, the different LV networks have been clustered based on their peak load and peak PV power generation in 2050. Figure 6 shows for all LV networks (in blue dots) the peak power injection from PV in 2050 versus the peak conventional demand (i.e. what the network is, approximately, dimensioned for today). Figure 7 shows the same peak power injection versus the peak total demand (i.e. including conventional demand, demand from HPs and demand for EV charging) in 2050. Finally, Figure 8 shows the peak conventional demand versus the peak total demand in 2050 The demand and generation peaks are computed based on the 15-min timeseries assuming no flexibility.

It is worth observing that, the implementation of the Swiss energy strategy results in the following, by 2050:

1. PV power injections are approximately 5 times today's peak power demand. Given that today's peak power demand loads todays network by up to 65% of its capacity, it is clearly expected that the network will not be able to accommodate the new PV injections.

2. PV power injections are approximately 2.5 times higher than the expected future peak power demand (i.e., the demand including new HPs and EVs). This clearly implies that PV penetration will be expected to be the main driving factor behind the need for network reinforcements.

3. The new peak power demand will be approximately 2-4 times higher than today's peak power demand. This clearly implies that, even in the absence of PV installations, the current network infrastructure will not be adequate to accommodate the targets of electrification of demand for heating and mobility in the absence of a mechanism to engage demand-side flexibility.

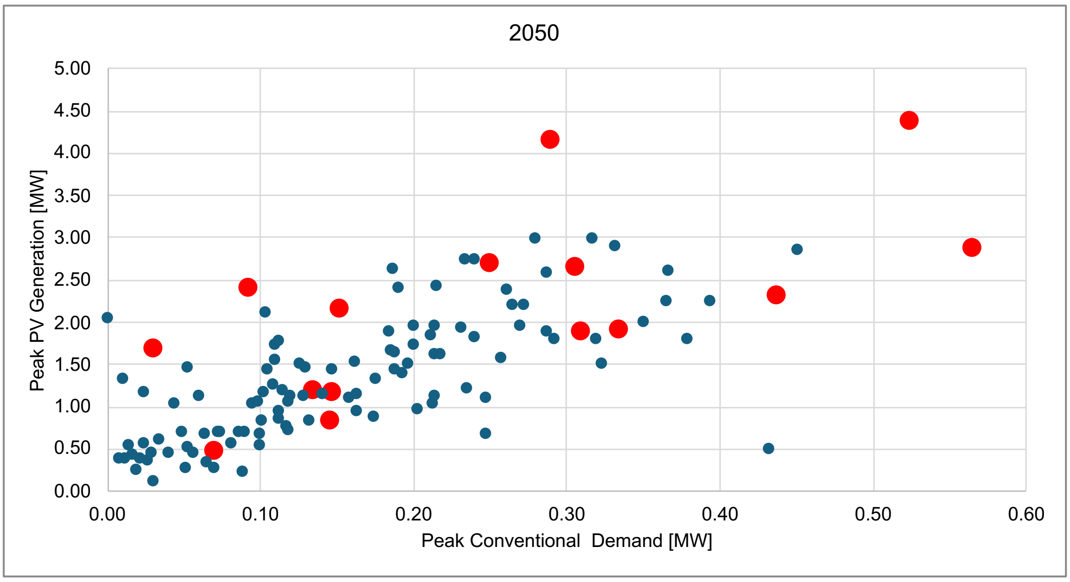


Figure 6. Peak PV generation in 2050 vs. peak conventional demand (as of today).

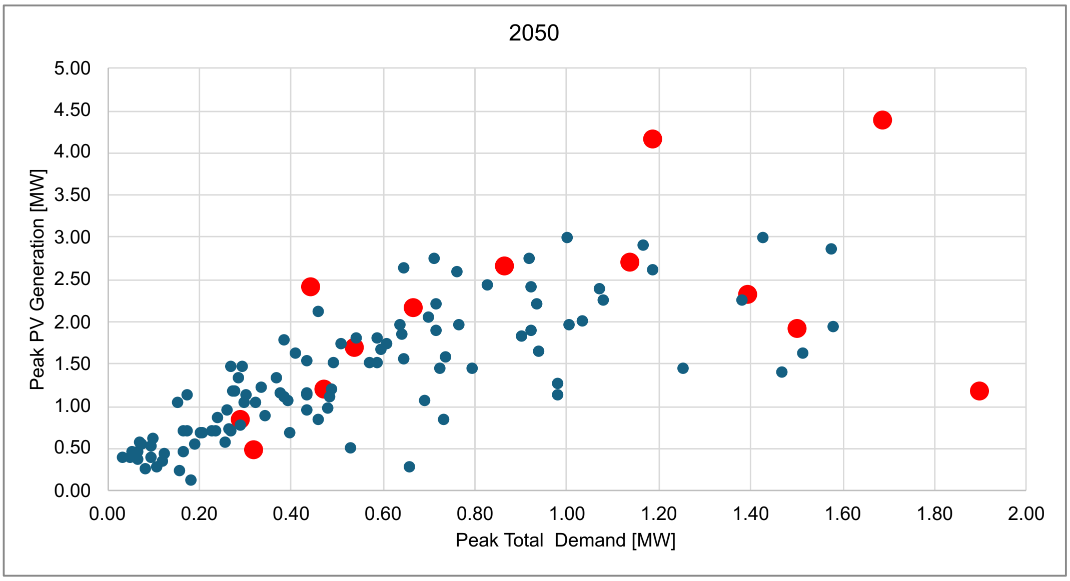


Figure 7. Peak PV generation in 2050 vs. peak total demand (incl. HP & EV) in 2050.

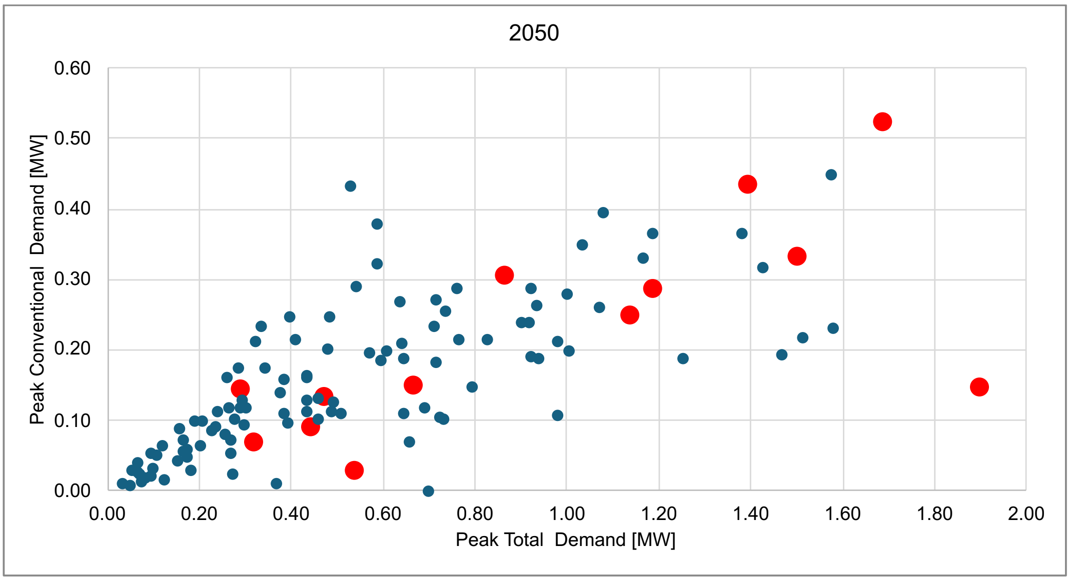


Figure 8. Peak conventional demand (as of today) vs. peak total demand (incl. HP & EV) in 2050.

The red dots in Figure 6-Figure 8 denote the LV systems that have been selected, in the test system, to be assigned to the each of the nodes of the 15-bus MV network. The selection was made such that a few representative LV systems are utilized, as well as the few LV systems which are somewhat different from the usual ones in terms of their peak PV vs. peak demand ratios. Figure 10 shows the assignment of the LV networks to the nodes of the utilized MV network (shown in Figure 9).

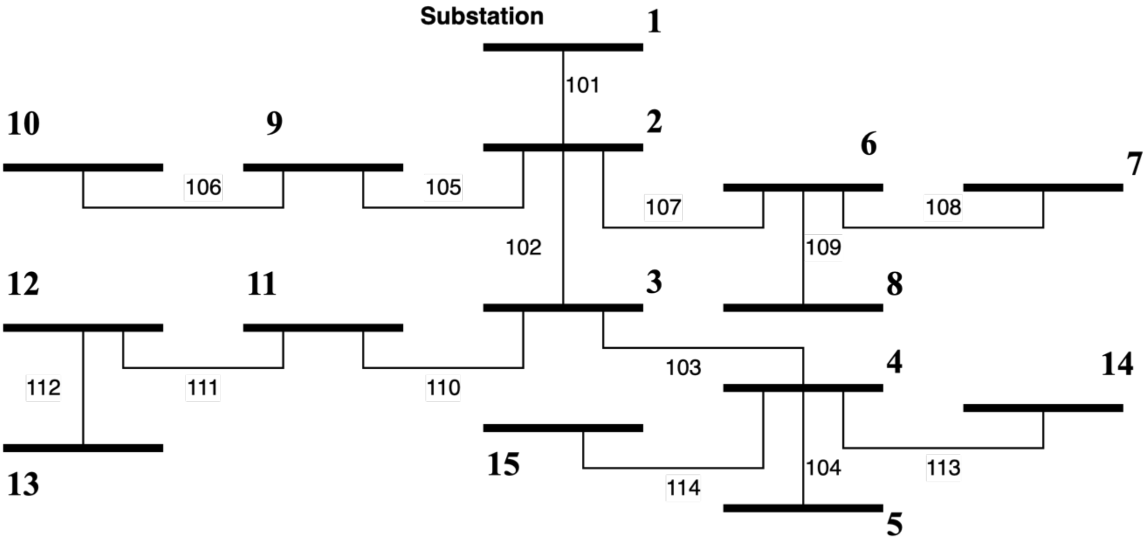


Figure 9. Simplified test MV network, connecting 15 aggregated real LV networks.

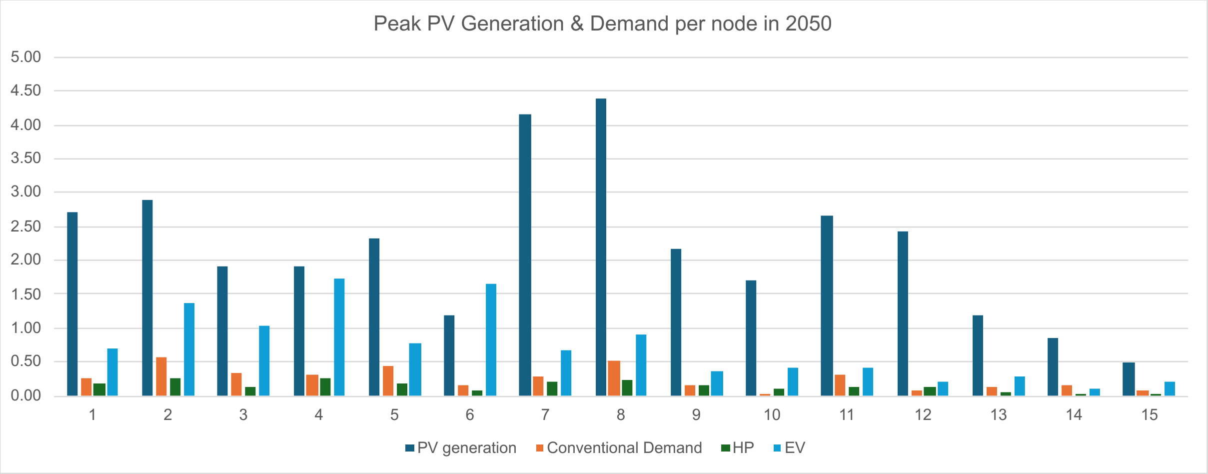
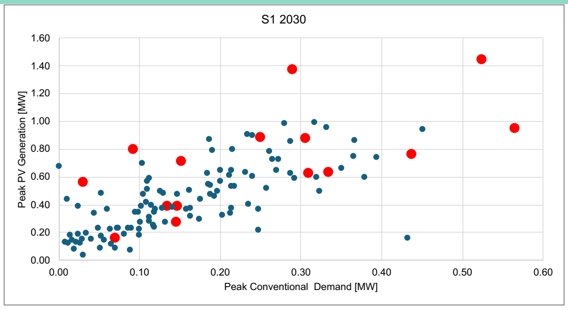
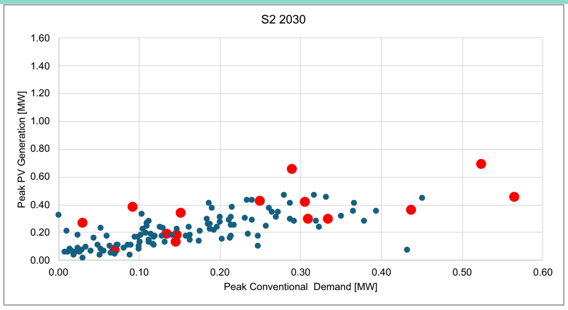
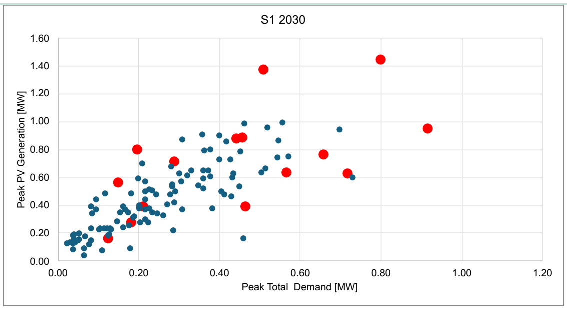
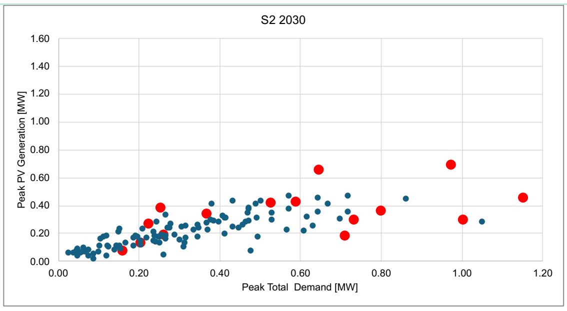
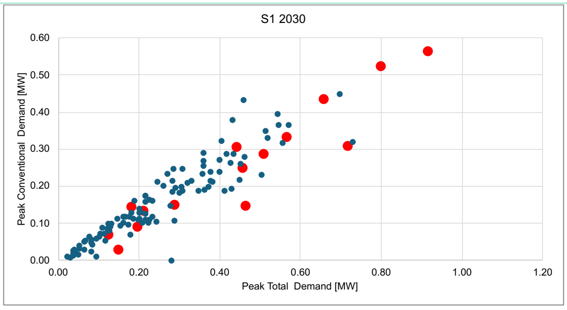
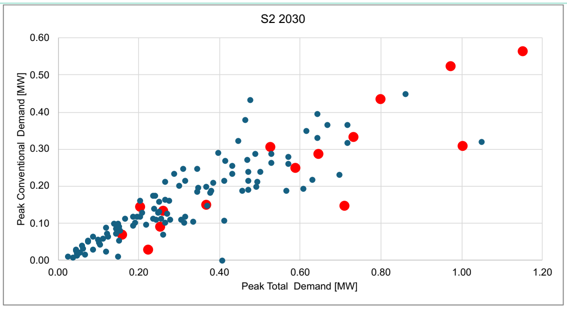


Figure 10. Peak PV generation and peak demand per node in 2050.

Finally, the figures in Table 3-1 show the evolution of the various LV networks according to the two considered scenarios in 2030.

Table 3-1. Peak generation and demand in all the LV networks in 2030 according to the two scenarios.

Scenario 1	**Scenario 2**
	
	
	

3.3 Method parameters

Without loss of generality of the method presented in Section 2, the following flexibility options and network reinforcement rules were used in the example presented in this report.

Demand-side flexibility:

- **HPEV-Flex 0**: No demand-side flexibility is assumed
- **HPEV-Flex 1**: Demand of heat pumps can be shifted between 09:00 and 24:00. The total energy demand of HP during these hours has to be met. Demand for EV charging can be shifted between 18:00 and 24:00. The total energy demand for EV charging during these hours has to be met.
- **HPEV-Flex 2**: Both demand of heat pumps and demand for EV charging is fully flexible to be shifted within a day. Total energy demand has to be met.

Flexibility from PVs:

- **PV-Flex 0**: No PV flexibility. All its excess power is injected to the network.
- **PV-Flex 1**: PV can be curtailed at a cost that makes the optimal dispatch solver (step 2a in Section 2.2.2) use it as the last option (thus making demand-side flexibility preferable over PV curtailment).

Network reinforcement rules: The capacity of the branch with the highest overloading is increased by adding an identical new branch in parallel to the existing one. If needed a third, forth and so on branch is also added at the same or a subsequent step.

3.4 Results

This section presents results from running the FADP method for all combinations of flexibility options outlined in Section 3.3, for each year (2030, 2040 and 2050) of the two considered scenarios (presented in Section 3.2.2). To make the reading easier to follow, we first summarize the results, which are then presented in more detail.

3.4.1 Summary of results

1. As expected, the network cannot accommodate the PV power injections, especially from 2040 on. Network reinforcements are needed.
2. In the longer-term, demand-side flexibility cannot facilitate the very high PV injections. However, it can help postpone some network investments, especially if electrification of demand happens at a somewhat faster pace compared to PV penetration (Scenario 2).
3. In order to significantly reduce the need for network reinforcements, costumer flexibility shall include some way of curtailing PV injections (either actually curtailing available energy or storing in local batteries).
4. For appropriately selected amount of accepted PV curtailment, the savings in network reinforcements obtained by means of PV curtailment exceed the value that the PV energy would typically have in the wholesale electricity market.

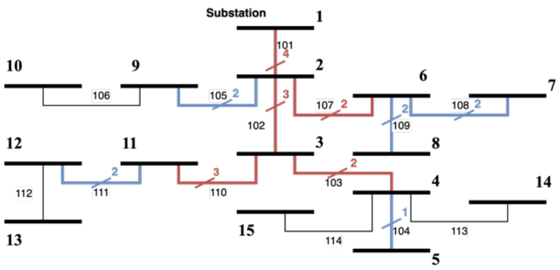
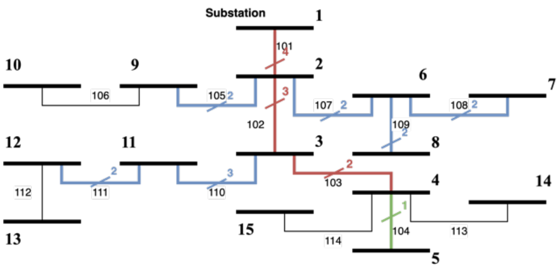
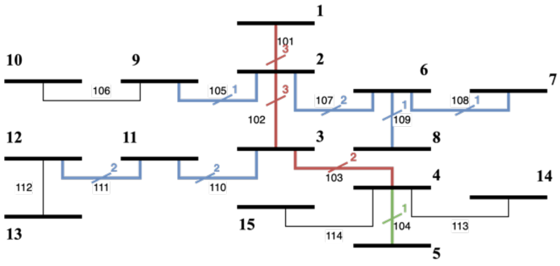
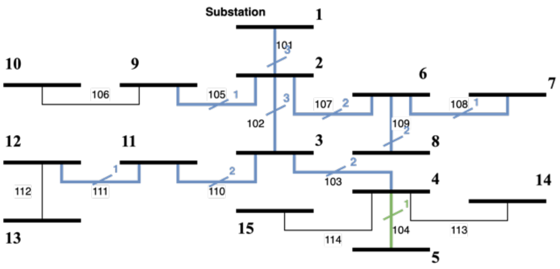
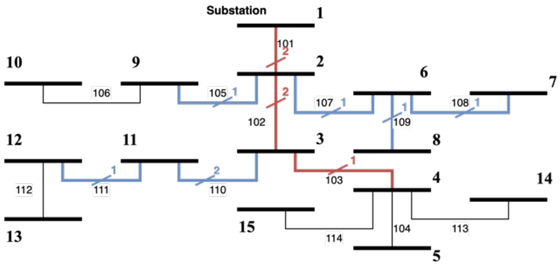
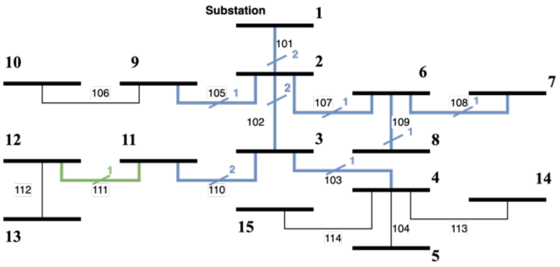
3.4.2 Running the FADP method without allowing PV curtailment

First, we run the FADP method without allowing for PV curtailment. Table 3-2 shows the branches added by the FADP method, per scenario, for each of the three considered years and for each of the considered HPEV flexibility availability options. The branch color denoted the year when the upgrade takes place, while the number next to it denotes the number of new branches that are added.

In Scenario 1, one can observe that demand-side flexibility can allow postponing two branch upgrades (branches 107 and 110). Eventually, however, many branches will have to be reinforced (a total of 9 or 10 depending on the available demand-side flexibility) from 2040 on. As we will show in the next two subsections, the main driver for these reinforcement needs is the excessive PV power injections.

In Scenario 2 (where PV penetration takes off at a slower pace), demand-side flexibility can allow postponing all network reinforcements for later (i.e., no reinforcements needed in 2030). One can observe (from the results in both scenarios) that when PV penetration approaches approximately 50% of the 2050 target (see Figure 4 and Figure 5) the distribution network cannot anymore accommodate all PV power injections; major network reinforcements are needed, even with high availability of demand-side flexibility.

Table 3-2. Branch reinforcement resulting from the FADP method without allowing PV curtailment.

	Scenario 1	**Scenario 2**
HPEV-Flex0		
HPEV-Flex1		
HPEV-Flex2		

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2050 —

3.4.3 Running the FADP method with PV curtailment

In order to estimate the impact of PV penetration and the value of PV curtailment (or regulation by means of batteries), we run the FADP method, now allowing for PV to be curtailed as a last resort action (i.e., curtailment has a considerable cost). Table 3-3 shows the results if there is no cap on the amount of PV that can be curtailed. Comparing the results with the ones without PV curtailment (Table 3-2) one can observe the following.

1. PV injections were the major driver of need for network reinforcements (more reinforcements and, also, need to perform them earlier).

2. If PV can be curtailed whenever needed, the electrification of demand alone (if it is not flexible) provokes need for network reinforcements later and to a lesser extent.

3. A combination of demand-side flexibility and unconstrained PV curtailment can completely eliminate the need for network reinforcements.

In the remainder of this section, we will investigate the impact of constraining the amount of PV energy that is deemed as acceptable (or realistic) to be curtailable.

Table 3-3. Branch reinforcement resulting from the FADP method with PV curtailment.

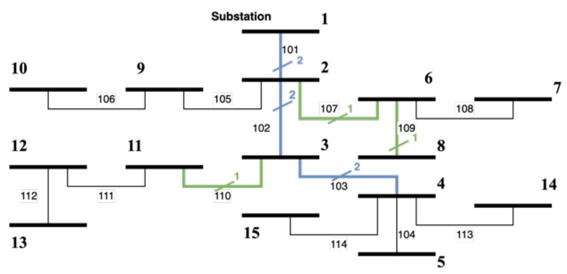
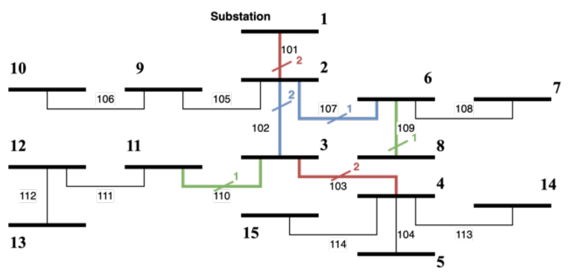
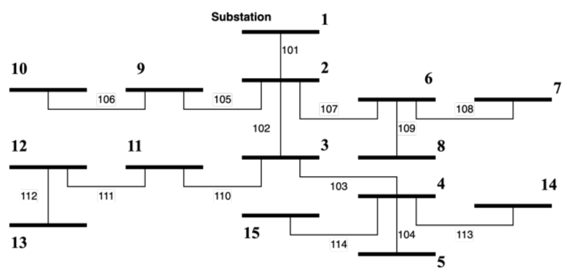
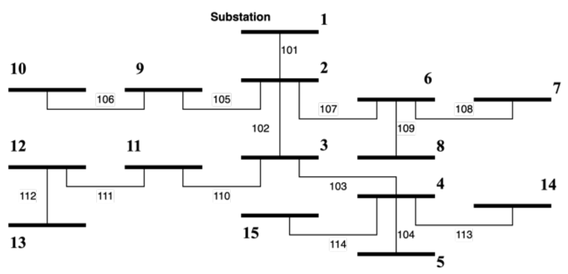
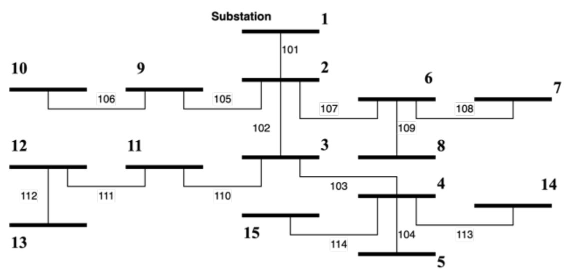
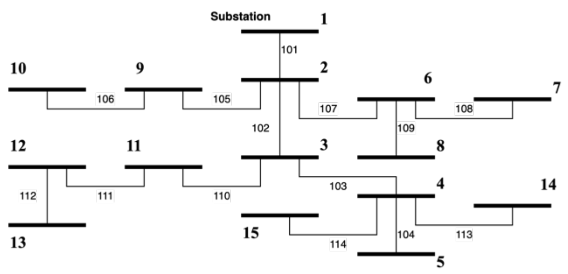
	Scenario 1	Scenario 2
HPEV-Flex0		
HPEV-Flex1		
HPEV-Flex2		

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Figure 11-Figure 16 illustrate, per scenario and per assumed available demand-side flexibility (HPEV-Flex0/1/2), the average PV curtailment, expressed as percentage of the daily available PV energy, that needs to be curtailed in order to avoid a branch reinforcement, grouped per considered year (2030, 2040, 2050). In these figures, the x-axis illustrates the branch reinforcements in an incremental manner (this means that all branches to the left of a branch name given in the x-axis are also reinforced). The y-axis shows the percentage of the available PV energy during this given day, that had to be curtailed to make the network feasible given the network reinforcements provided in the x-axis.

One can observe that the network planner can trade-off network reinforcement investments against a mechanism allowing it to receive curtailment of the PV injections when needed. From the customer side, such a curtailment mechanism can correspond to actual loss of available energy, but it can also correspond to a demand-side flexibility, for example by means of batteries (see Section 3.4.4).

Worth noting is the fact that it is the summer days that create a need for network reinforcement or PV curtailments. By implementing a flexibility mechanism that does not curtail more than 20% of the available PV energy during the sunniest summer days, the utility can postpone the need for reinforcements and, when these are eventually made, limit them to solely the three major branches (101, 102 and 103). Combining such a mechanism with demand-side flexibility further decreases the need for PV curtailment.

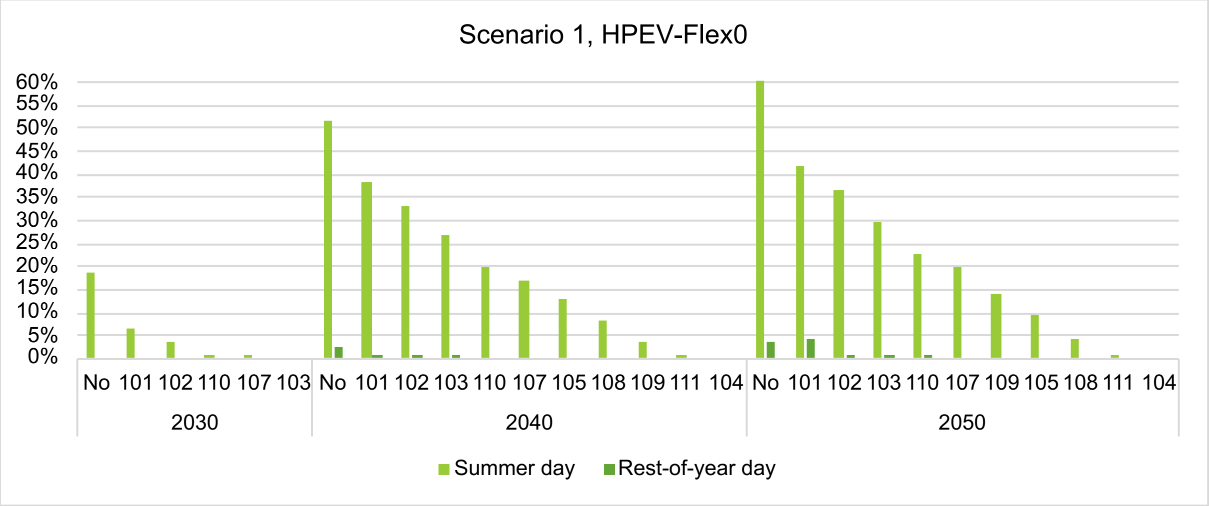


Figure 11. PV curtailment as percentage of its daily available energy.

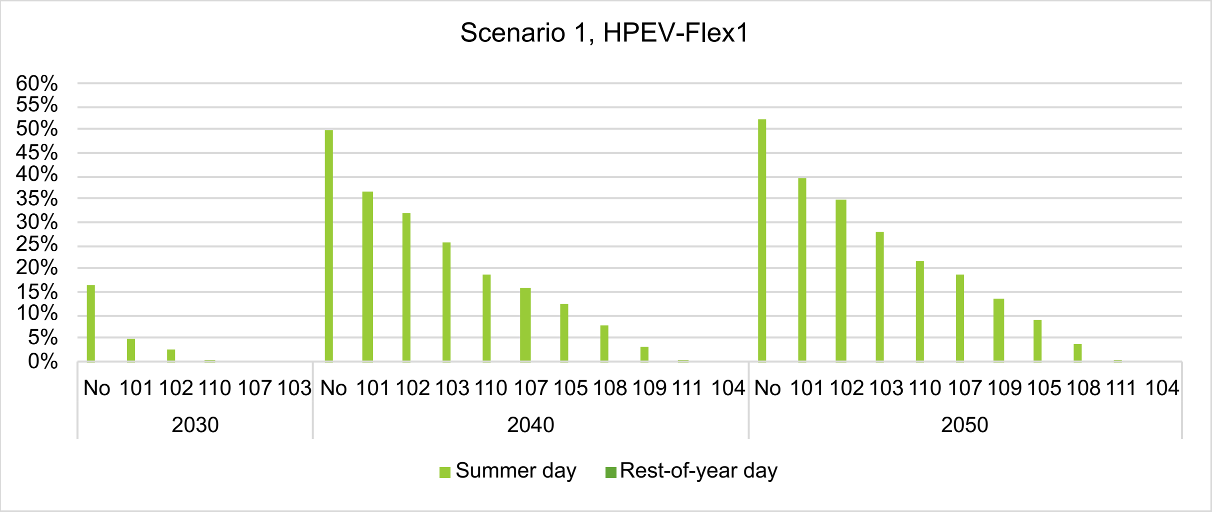


Figure 12. PV curtailment as percentage of its daily available energy.

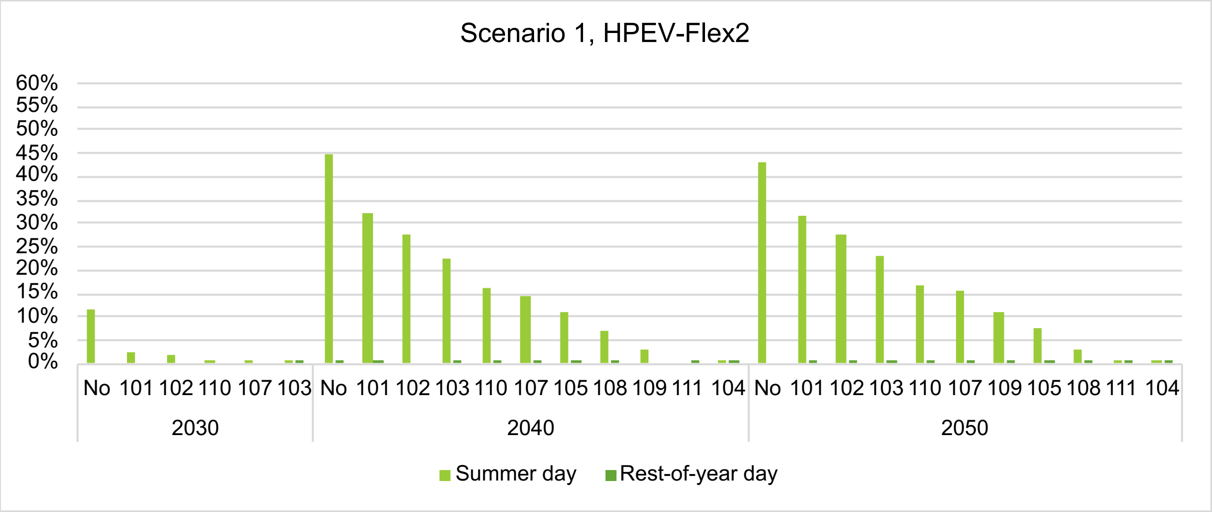


Figure 13. PV curtailment as percentage of its daily available energy.

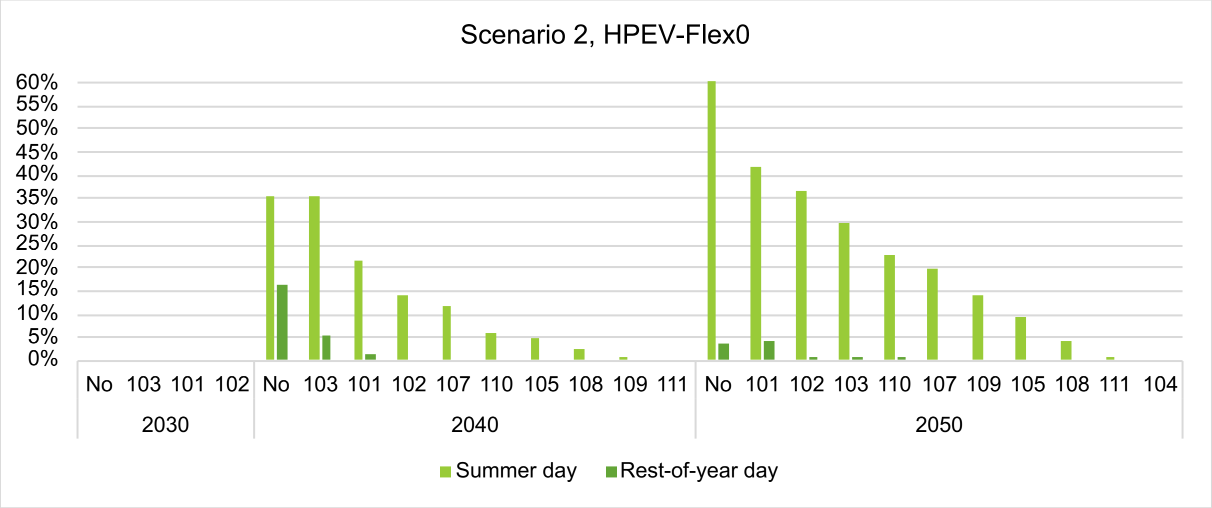


Figure 14. PV curtailment as percentage of its daily available energy.

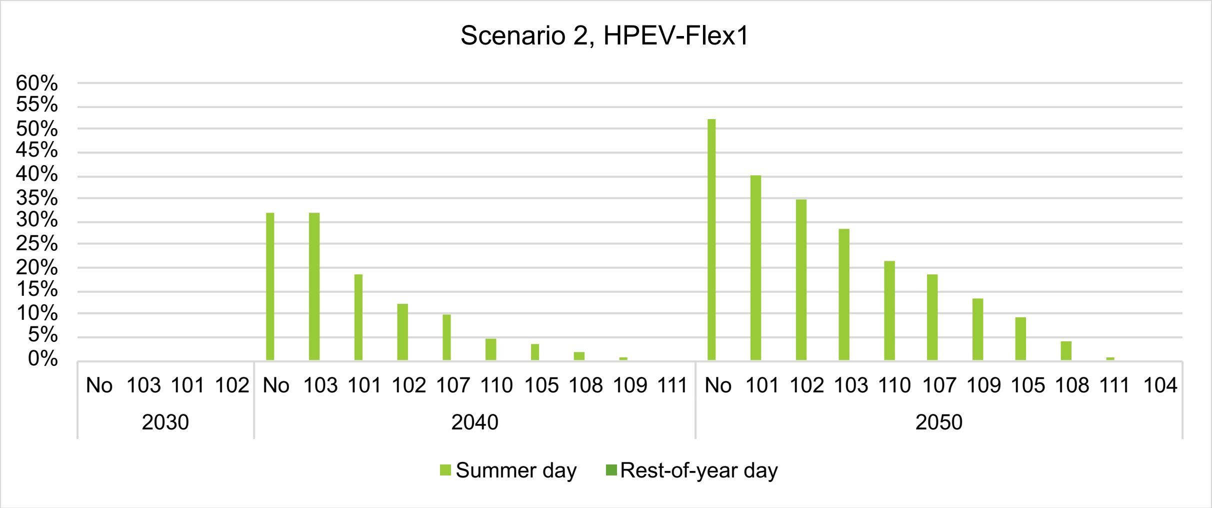


Figure 15. PV curtailment as percentage of its daily available energy.

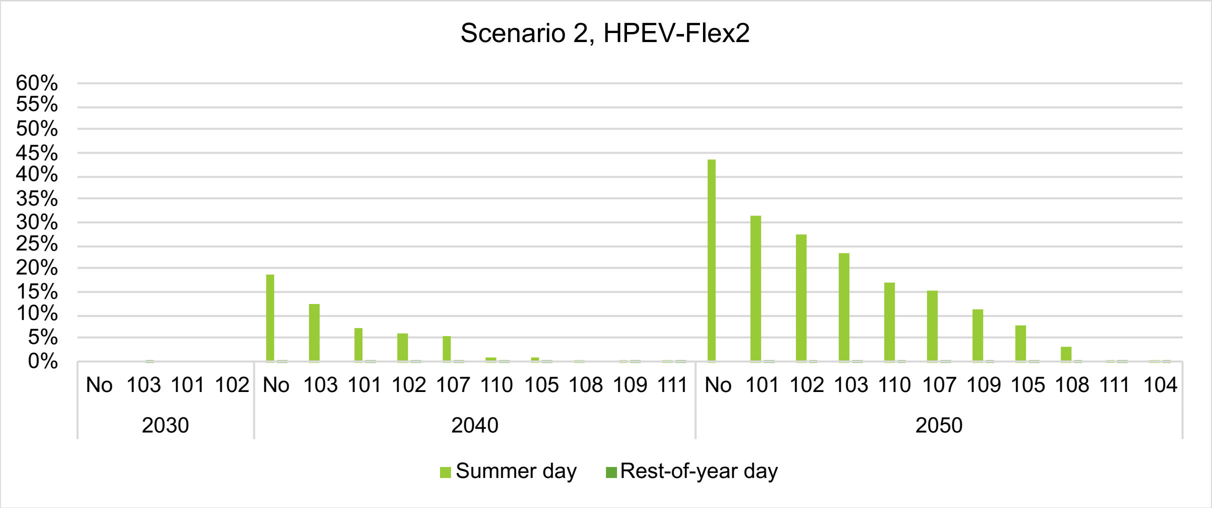


Figure 16. PV curtailment as percentage of its daily available energy.

3.4.4 Value of combining PV with batteries

To allow investigating the value of integrating customer-side batteries (sometimes installed together with a PV system with objective to increase the self-consumption of energy) into the flexibility provision mechanism, the two scenarios considered so far have been extended for each to include a case where it is assumed that part of the PV owners have also a battery system installed in their premises.

The new “sub-scenarios” were created as follows:

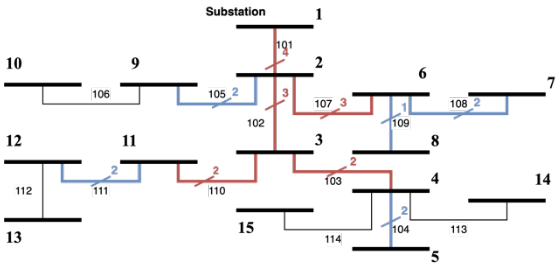
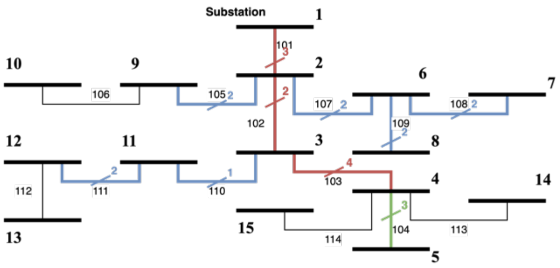
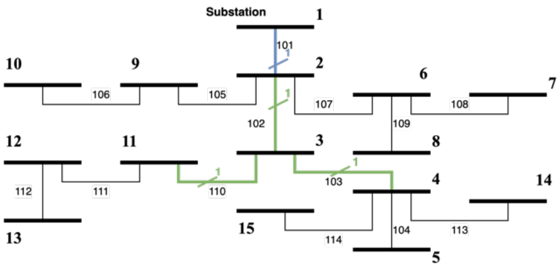
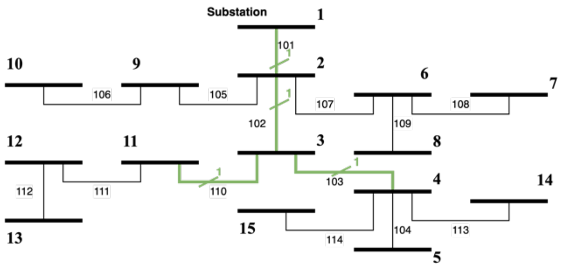
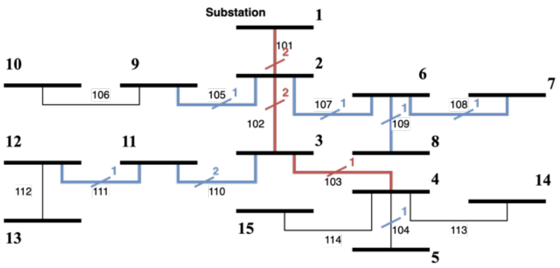
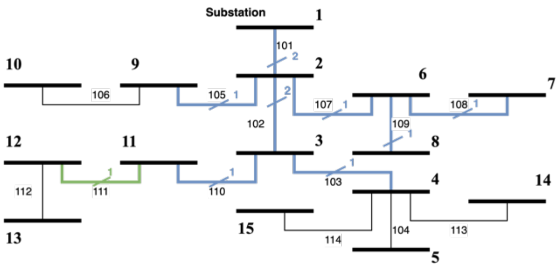
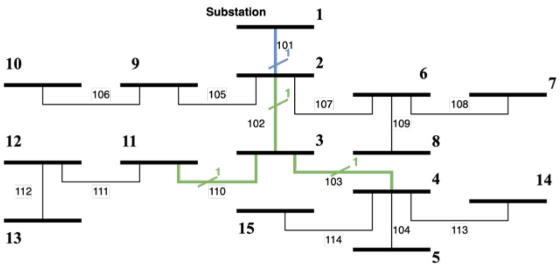
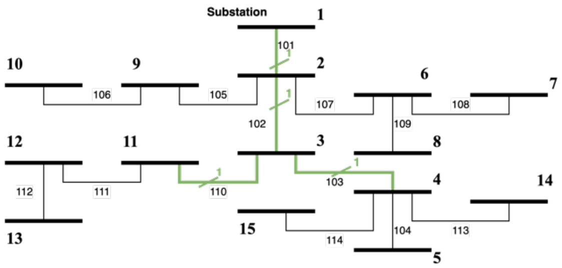
- Customers with a PV chose to install a battery that can store half of the maximum PV daily production and has a C-rate equal to two (i.e., a 10 kWh battery has a converter power capacity equal to 5 kW).

- In 2030, 10% of PV owners are assumed to have batteries. In 2040, 30% of PV owners have batteries and, in 2050, 50% of PV owners have batteries.

Table 3-4 shows the impact of availability of battery-provided flexibility on the required network reinforcements. No PV curtailment is allowed in these results.

One can observe that a “grid-friendly” utilization of the batteries allows to postpone or even completely avoid a significant amount of network reinforcements. Also, one can observe that the availability of (the here-assumed amount of) batteries reduces the value of demand-side flexibility. This observation shall not be a surprise. It is in line with the findings so far, that PV penetration is the main driver behind a need for network reinforcements. As a result, if the installed batteries are enough to alleviate the network violations due to the PV power injections, they will also be enough to alleviate network violations that were caused by the new electricity demand, hence making demand-side flexibility less relevant. Obviously, installing batteries comes at a cost for the customers. A cost-benefit analysis shall drive the customer and utility investment decisions.

Table 3-4. Network reinforcements w/o and with considering customer-level batteries.

		Scenario 1	**Scenario 2**
HPEV-Flex0	**w/o batteries**		
	with batteries		
HPEV-Flex2	**w/o batteries**		
	with batteries		

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3.4.5 Investment cost analysis: a “budget” for flexibility remuneration

Figure 17 shows the annualized cost for doubling the capacity of each of the branches of the utilized test system (presented in Figure 9). A discount rate of 5% was used with a branch lifetime equal to 35 years. OPEX was assumed to equal 2% of the CAPEX. CAPEX data for typical 1.5 MVA cables were used for all branches except 101 (6 MVA) and 107 (3 MVA). Branch lengths were assumed to be between 6km (branches 103, 108 and 114) and 17-18km (branches 107 and 101).

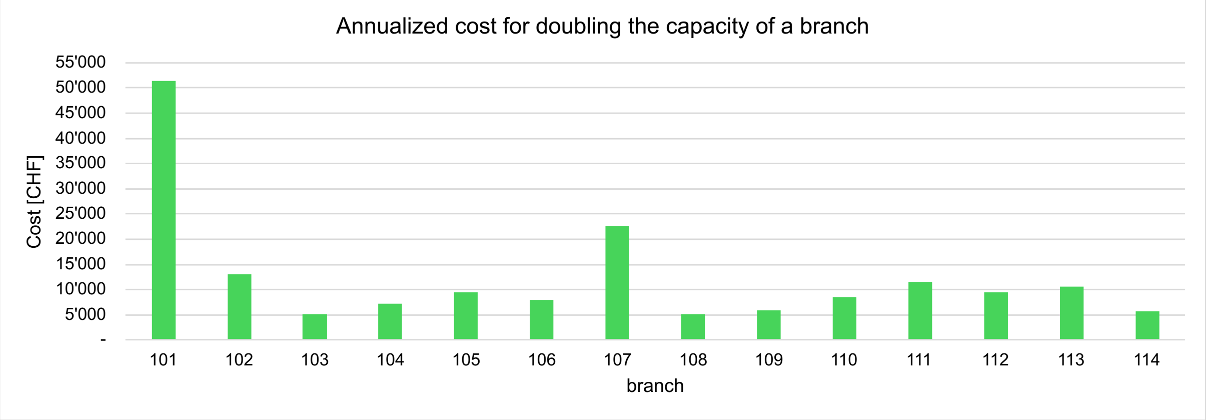

Figure 17. Annualized network expansion cost (includes CAPEX and OPEX).

Using this cost information, the network reinforcements presented in Sections 3.4.2, 3.4.3 and 3.4.4 can be assigned a corresponding annual cost for the utility. It is logical to assumed that a flexibility mechanism which allows to save (part of) the otherwise required network investments shall not cost to the utility more than what the investments would have costed. Hence, the annualized network expansion cost can be seen as corresponding to an annual “budget” that the utility would be willing to spend to procure flexibility services from its customers, if the latter allow to postpone the network investment.

For example, with reference to the results presented in Table 3-2, if the utility was to receive demand-side flexibility per each of the two considered options (HPEV-Flex 1/2), this can result to the annualized investment savings presented in Figure 18. This can be further translated to a maximum payment per shifted MWh of demand, based on the amount of load that needed to be shifted when running the FADP algorithm for various years, scenarios and demand-side flexibility options. For instance, the approx. CHF 28’000 per year that can be utilized for demand-side flexibility in 2030 using HPEV-Flex1 would correspond to a maximum flexibility remuneration of approx. 65 CHF/MWh (number computed based on the amount of demand shift required to make the problem feasible with less network expansion), while the CHF 70’000 per year investment saving that can be made using HPEV-Flex2 would correspond to a flexibility remuneration of approx. 95 CHF/MWh (more demand-shift is needed in this case). The way that such a remuneration could be implemented is beyond the scope of this report. It is covered in other work performed in PATHFNDR. For instance, depending on the regulation and operational practices, this relatively small customer demand-shift can be made mandatory, hence reducing the utility uncertainty over whether enough customers will sing up.

Another interesting example can be taken from the analysis performed to identify the value of PV curtailment (see table and figures in Section 3.4.3). Let us, for instance, focus on Scenario 1, year 2030. Figure 19 shows on the left y-axis an estimation of the maximum PV energy that would need to be curtailed annually per amount of network expansion (starting from no expansion and then adding progressively one additional branch per x-axis label), and on the right y-axis the figure shows the corresponding annualized network expansion cost. Figure 20 presents the maximum remuneration that a utility would be willing to provide for PV curtailment in order to avoid continue expanding its network. One can see that the more branches have been already planned for, the higher the amount the utility is willing to remunerate PV curtailment in order to avoid further network investments.

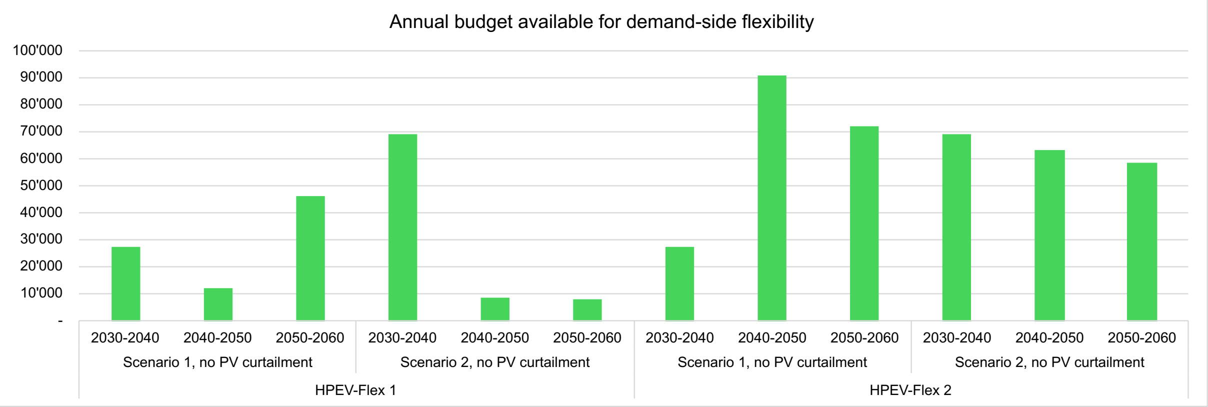

Figure 18. Network reinforcement savings that can be achieved by means of demand-side if PV curtailment is not an option.

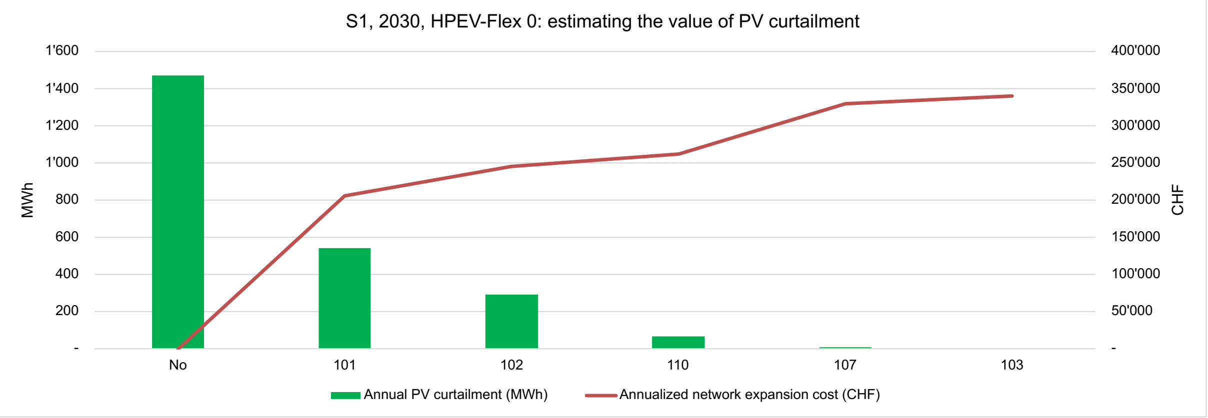

Figure 19. Estimated maximum required PV curtailment and annualized cost of network expansions.

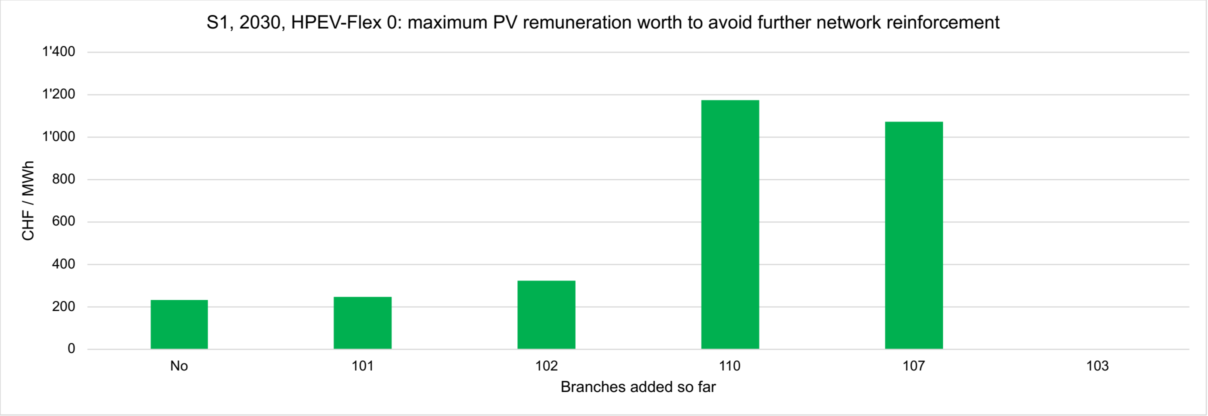

Figure 20. Estimated maximum PV curtailment remuneration that will allow the utility to make savings by avoiding network further reinforcement (which would be needed in order to accommodate the PV power injections if curtailment is not an option).

Clearly, the “budget for flexibility remuneration” will be very much network and case dependent. However, it is worth noting that, in the here-studied example, the remuneration values seem being in a range suggesting that it is probably more worth motivating customer flexibility rather than ensuring that the network is sufficiently reinforced to be able to accommodate a fully unconstrained loading. Especially in the case of PV curtailment, it is obvious that ensuring that every last available PV kWh can be injected to the utility network can be exorbitantly costly. It is interesting to note that the approx. 230 CHF/MWh that a utility would be willing to pay for PV curtailment in order to avoid making any network reinforcement by 2030 (see leftmost column Figure 20) is probably significantly higher than the wholesale electricity prices of very sunny summer days, with a lot of excessive available PV generation.

4 Conclusions

The increased penetration of distributed energy resources, such as solar PVs, and electrification of demand for heating and mobility results in higher loading of the MV & LV electricity distribution networks, often beyond the limits which they were designed for. Distribution utilities need to anticipate this evolution and timely take actions to reinforce or expand their networks. Simultaneously they can engage their customers in flexibility provision schemes aiming at reducing the peak power injections (e.g., due to excess solar PV feed-in) and withdrawals (i.e., demand). A methodology for "flexibility-aware distribution network planning" has been developed and applied in a plurality of MV & LV networks and future evolution scenarios in Switzerland. The scenarios corresponded to different proliferation levels of solar PV, electric heat pumps and electric vehicles. The key findings, so far, of these analyses are itemized below.

- The amount of MV- and LV-connected solar PV installed capacity that shall be achieved according to the Swiss energy strategy cannot be accommodated by today's MV & LV networks and operational practices, due to grid violations (i.e., voltage violations and thermal overloadings) resulting from the PV power injections to the networks. Significant network reinforcements and new operational practices will be required.

- The network violations are caused not only due to the cable and transformer thermal limits but, importantly, also due to overvoltages (this is not shown in this report). Depending on the legacy grid and the proliferation scenarios, voltage-driven problems may even appear prior to problems due to thermal overloading.

- Solar PV penetration is, in fact, the main factor driving the need for network expansion. If the distribution networks are upgraded so that they can host the solar power injections, they will be also able to host the demand by electric heat pumps and EV charging.

- From an economic perspective, reinforcing the electricity distribution network to a capacity that can host the highest possible PV power injection is not worth the cost. Accepting a certain level of PV curtailment might make more economic sense without compromising the targets for annual generation by renewables.

- Combining PV with battery energy storage systems (BESS), as well as installing utility-scale batteries, can allow to regulate the maximum PV injections, and, hence, reducing the need for network reinforcements. It is important to note that, for this to be achieved, BESS shall be operated with the objective to reduce the peak injections by excess solar PV generation without compromising the objectives for self-sufficiency, which can be simply achieved by delaying the charging of the batteries to "shave the peak" of the maximum solar feed-in.

- Shifting the demand (of heat pumps and EV charging) to coincide with the instants of maximum PV power injection can alleviate the grid violations. However, the limitation of such a reliance shall be noted: demand by heat pumps appears in winter, while residential EV charging is expected to start in the late afternoon or early evening[2]. Note that the heat-pump demand in summer due to water heating can coincide with the maximum PV feed-in. Managing PV-driven

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[2] Except if appropriate regulation or tariff schemes motivate the EV owners to charge during the day. Note that this might require appropriate infrastructure (e.g. possibility to charge at the workplace).

grid violations by means of demand-side flexibility has clear limitations and is case-depended (e.g. better suited for large cooling loads, or for EV charging during work hours).

- Mechanisms for demand-side flexibility is a valuable solution for distribution utilities to defer grid investments when electrification of demand takes place at a faster pace than anticipated (and faster than PV proliferation). In such cases the utility may not be able to catch up with the required network investments. This is especially valid for electromobility, which, in some regions, is growing the fastest. Recently, the significant impacts of "faster than expected" evolution of residential EV charging on the distribution networks were reported in the Dutch news[3], with utilities "requesting" their customers to delay their charging times, since the grids are not yet ready to absorb such a demand.

Flexibility utilization, itself, cannot completely avoid investments on each and every branch and transformer; however, it can reduce the number of investments and can help deferring (i.e., postponing) the investments to a later stage. The asset investment analysis exploiting time-series analysis is especially beneficial and utilization of flexibilities demonstrate potential, because the pace of proliferation is expected to be faster than the pace of upgrading the grid infrastructure.

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