AXPO Energy Reports

Impacts of the energy scenarios on distribution networks (short)

Contracted by AXPO

Date: May 4th, 2026

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Executive Summary

The aim of this study is to analyze the impact of the power system scenarios developed as part of the “Axpo Energy Reports” project on the requirements for distribution grids. The study focuses on the distribution grids in CKW’s service area. Similar to the “VSE Energy Future 2050” study, future electricity demand and decentralized generation are modeled using a bottom-up approach with a 15-minute time resolution at the building level. These time series form the basis for detailed grid simulations, which are used to identify grid bottlenecks, determine the resulting need for grid reinforcement measures, and comparatively quantify the effects of different scenarios and flexibility mechanisms on grid bottlenecks and reinforcement requirements. The results derived from this are then scaled up to the national level to enable an estimation of the grid expansion costs for the whole of Switzerland. The calculated grid reinforcement costs represent “additional investment costs” from the present date until the target year (e.g., 2050). Regular grid investments related to the aging of infrastructure, maintenance, and replacement cycles are not included.

The results consistently show that future grid expansion needs in distribution grids are primarily driven by PV-related feed-in and not solely by conventional demand growth. In PV-dominated scenarios, the negative peak of the aggregated net load in the CKW area significantly exceeds the positive load peak. This implies that grids must increasingly be designed not only to supply the load but also to transport large surplus quantities from decentralized generation.

This explains why the PV scenario incurs the highest grid expansion costs, while the nuclear, gas, and wind scenarios exhibit the lowest costs in grid levels NL4–NL7. Synthesis 1 (S1, Renewables + Gas) and Synthesis 2 (S2, Coexistence) scenarios fall in between, with S1 being closer to the PV scenario, while S2 represents a more balanced development path that places less strain on the grid.

The PV scenario results in the greatest demands on grid expansion in the distribution network. Flexibility measures such as PV feed-in limitation at the building connection point (i.e., Hausanschlusskasten – HAK), the grid-friendly use of decentralised battery energy storage in households, and demand response have the potential to reduce the required grid expansion costs by up to approximately 60% compared to a scenario without any flexibility.

The nuclear scenario, as well as the gas and wind scenarios, exhibit the lowest grid expansion costs in grid levels NL4–NL7, as decentralized PV penetration is significantly lower, and the negative peak of net load remains below the positive load peak.

Scenario S1 can be classified as an “in-between” scenario but remains clearly PV-dominated. Consequently, S1 imposes a substantial strain on distribution grids, yet this remains well below the PV-only scenario. Scenario S2 imposes less strain on distribution grids than S1 and less than the PV scenario. However, the burden on grids due to S2 remains higher than that of the nuclear, gas and wind scenarios. The results demonstrate that a more diversified technology mix with lower PV penetration can significantly reduce grid load without substantially limiting the electrification of heating and mobility.

The results also show that the majority of grid reinforcement costs occur at the lower grid levels, particularly with moderate flexibility. Maximum flexibility is particularly effective in reducing the need for grid reinforcement in the low-voltage grid; once this is reduced, the remaining costs increasingly concentrate on the medium-voltage grid and substations.

Not all grid reinforcement costs are attributable to line overloading. Overvoltage exceedances are frequently observed, particularly in scenarios with a high share of PV. In some substations where the PV share is relatively low and the positive maximum net demand is higher, as in the nuclear power scenario, undervoltages are also observed, which are mainly caused by high demand. Grid reinforcements implemented to address overloads often also reduce overvoltages; however, these persist in some areas, particularly in the PV baseline scenario. As part of the measures for high

flexibility, including Q(U) support from PV, these voltage-related grid reinforcement costs are completely eliminated in NL7 across all scenarios.

Flexibility measures such as PV feed-in limitation, the use of grid-friendly battery energy storage systems to reduce feed-in peaks (peak shaving), controlled charging of electric vehicles, and the time-shifting of heat pump operation cannot completely eliminate the need for grid expansion, but they can significantly reduce it or delay it. At the same time, the results show that flexibility must be designed in a targeted manner: particularly in scenarios with less PV dominance, the simultaneous shifting of EV and heat pump loads can lead to rebound effects and new load peaks. The benefits of flexibility are therefore greatest when it is locally differentiated, temporally coordinated, and specifically targeted at existing grid bottlenecks.

The national projections should be interpreted as estimates for NL4–NL7 and not as exact forecasts, for the following reasons:

- They depend on the representativeness of the CKW supply areas considered for the Swiss distribution grid landscape.
- The status of the grids in the CKW supply area today is characterized as relatively strong, particularly the medium-voltage grids, resulting in the fact that the determined reinforcement requirements tend to be lower than in other Swiss grid areas.
- The NE3 grid reinforcement costs are not included in the extrapolation, as CKW's high-voltage grid is not considered structurally representative of Swiss high-voltage grids (see Chapter 3.7); As wind power is fed into the grid at this level, however, cross-scenario comparisons of the upscaled costs limited to NL4 through NL7 should be interpreted with caution.

Despite these limitations, the relative ranking of the scenarios and the significant cost-reducing effect of flexibility remain robust.

1. Introduction

The ongoing transformation of the European energy system is expected to significantly alter electricity generation, consumption patterns, and power flows across transmission and distribution networks. In Switzerland, the decarbonization of the energy sector is accompanied by increasing electrification of heating and mobility as well as a substantial expansion of renewable electricity generation, particularly photovoltaic (PV) systems. These developments are expected to increase electricity demand while simultaneously shifting generation towards more decentralized and variable sources.

At the national level, several long-term studies have examined possible pathways for the future Swiss electricity system. These analyses typically focus on the evolution of generation technologies and system adequacy. In this context, a higher-level study, AXPO Energy Reports, evaluates six alternative scenarios for the Swiss electricity system in 2050 developed by AXPO. Each scenario represents a distinct portfolio of power generation technologies, defined by different combinations of installed capacities of nuclear, gas, solar, and wind generation. The scenarios are designed to ensure sufficient domestic electricity supply while reflecting alternative strategic technology pathways for the future Swiss power system.

While national energy system studies primarily focus on generation adequacy and transmission-level impacts, the transformation of the electricity system also has profound implications for distribution networks. In particular, the large-scale deployment of distributed photovoltaic generation, electric vehicles, and electric heating technologies will significantly affect load patterns and power flows within medium- and low-voltage grids. These developments can lead to new types of network constraints, including reverse power flows and voltage violations.

The objective of this study is to assess the impact of the electricity system scenarios developed in AXPO Energy Reports project on distribution grid infrastructure requirements. The analysis is performed on focuses on the distribution networks within the service territory of CKW. Similar to the VSE Energiezukunft 2050[1] study, future electricity demand and distributed generation are modeled using a bottom-up approach with 15-minute temporal resolution at the building level. FEN collaborated with EBP for regionalization of national scenarios and creating time-series for end-users. These time series are subsequently used in detailed power flow simulations to identify network constraints and the required reinforcement measures.

In addition to evaluating grid expansion requirements for the CKW network, the study also extrapolates the results to the national level. By mapping the characteristics of the analyzed grid areas to clusters of Swiss utilities defined by the national regulator (ElCom), the results provide an estimate of the potential distribution grid investment requirements for Switzerland under the considered energy transition scenarios.

Through this approach, the study provides insights into how different technology pathways and operational flexibility measures influence future distribution grid expansion needs and highlights the importance of integrating flexibility into long-term grid planning strategies.

[1] T. Demiray and T. Ingold, “Energiezukunft 2050 Auswirkungen auf die Verteilnetze”, VSE, Final Report, 2024. https://www.strom.ch/de/energiezukunft-2050/download

2. Studied region and the grid representation

The required grid expansion was examined on the CKW service territory. CKW serves more than 70 municipalities and approximately 57,000 grid connection points (HAKs). The network supplies around 1 TWh of electricity annually.

The Swiss grid layer classification used in this study is:

- Network Layer – NL3: High voltage (HV) grid
- NL4–NL5: Medium voltage (MV)
- NL6–NL7: Low voltage (LV)

The network infrastructure includes:

- High-voltage grid (NL3): 80 km underground cables and 380 km overhead lines
- 20 HV/MV substations
- Medium- and low-voltage networks (NL4–NL7)

3. Methodology

The analysis links national energy system scenarios with detailed distribution grid simulations. The methodological framework consists of several steps. First, national electricity system scenarios are defined and combined with alternative flexibility sensitivities. These scenarios are subsequently regionalized to the service territory of the studied distribution grid (CKW). The national assumptions are translated into building-level electricity demand and distributed generation profiles with a temporal resolution of 15 minutes. Technology-specific models are applied to represent the operation of electric vehicles (EV), heat pumps (HP), photovoltaic systems (PV), and battery energy storage systems (BESS). The resulting time series are then used as inputs for detailed load flow simulations of the distribution grid to identify network constraints and the required reinforcement measures. Finally, the resulting grid expansion costs are calculated and extrapolated to the national level.

3.1 Scenario Definition

Future electricity demand and generation are derived from national energy transition scenarios for Switzerland in 2050. These scenarios represent alternative strategic pathways for the development of the Swiss electricity system and differ primarily in their assumed portfolios of generation technologies. In particular, they reflect different combinations of installed capacities of photovoltaic, nuclear, wind, and gas generation while ensuring sufficient domestic electricity supply.

Six scenarios are considered in this study (Table 1):

- **Nuclear-focus**: Deployment of new nuclear capacity to replace retiring plants and provide reliable baseload generation. In the remainder of this report, this scenario will be referred to as **Nuclear** or **K**.
- **Gas-focus**: Construction of new gas-fired power plants providing flexible and dispatchable generation capacity. In the remainder of this report, this scenario will be referred to as **Gas** or **G**.
- **Solar-focus**: Large-scale expansion of photovoltaic capacity, making solar the primary electricity source. In the remainder of this report, this scenario will be referred to as **PV**.
- **Wind-focus**: Significant deployment of onshore wind power. In the remainder of this report, this scenario will be referred to as **Wind** or **W**.
- **Renewables + gas**: Combination of expanded renewable generation (mainly solar and wind) with new gas-fired plants providing backup capacity. In the remainder of this report, this scenario will be referred to as **RES+Gas** and **Synthesis I** (**S1**).
- **Coexistence**: Diversified system in which nuclear, renewable generation, and flexible thermal capacity coexist. In the remainder of this report, this scenario will be referred to as **Coexist.** and **Synthesis II** (**S2**).

The evolution of electricity demand is assumed to be identical across all scenarios. Demand increases due to electrification of transport and heating as well as population growth, while improvements in energy efficiency partially offset the increase in conventional electricity consumption. The national scenario parameters are subsequently regionalized to the study area and translated into building-level demand and generation profiles as described in the methodology section.

Table 1. AXPO national target scenarios and considered flexibilities for 2035 and 2050. All units are in TWh, except for BESS which is declared separately. BESS values are presented for sensitivity "flex".

	PV		**Nuclear**		**Gas**		**Wind**		**RES[2] + Gas (Synthesis 1)**		**Coexistence (Synthesis 2)**	
	2035	2050	2035	2050	2035	2050	2035	2050	2035	2050	2035	2050
PV Ground	1.2	3.3	0	0	0	0	0	0	0.9	3.1	0.5	1.5
PV Roof	24.3	43	11.5	16.2	11.5	16.2	11.5	16.2	24.4	32.2	22	25
PV Alpine	0.9	2.3	0.5	0.7	0.5	0.7	0.5	0.7	0.4	0.5	0.2	0.2
Wind	0.3	0.5	0.3	0.5	0.3	0.5	1.4	13.5	0.7	5.1	0.7	2.2
Res. BESS (GWh/GW)	8.3/4.2	12.1/6.1	7/3.5	7.6/3.8	7/3.5	7.6/3.8	7/3.5	7.6/3.8	9.5/6.4	10.1/5	8.3/4.1	8.7/4.3
Conv. demand	50.6	46.5	50.6	46.5	50.6	46.5	50.6	46.5	50.6	46.5	50.6	46.5
HP	7.4	10.0	7.4	10.0	7.4	10.0	7.4	10.0	7.4	10.0	7.4	10.0
EV	6.8	15.2	6.8	15.2	6.8	15.2	6.8	15.2	6.8	15.2	6.8	15.2
H2 production	2.2	9	2.2	9	2.2	9	2.2	9	2.2	9	2.2	9
Sensitivities												
Base	☑	☑	☑	☑								
Flex	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑
Maxflex	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑	☑

3.2 Flexibility sensitivities

To evaluate the potential role of operational flexibility in reducing grid expansion requirements three flexibility sensitivities are defined: **Base**, **Flex**, and **Maxflex**. These sensitivities represent increasing levels of distributed flexibility applied at the building level and are intended to assess how different operational strategies can mitigate peak network loading.

The **base** sensitivity represents a reference case without any additional flexibility measures. In this case, photovoltaic systems are allowed to feed their excess generation into the grid, no battery storage systems are modeled, and electric vehicle charging as well as heat pump operation follow their natural demand profiles without active load management. Only PV and Nuclear (wind and gas) scenarios are tested for the base-scenario to assess the extremes.

The **flex** sensitivity represents a moderate level of flexibility. In this case, several measures are implemented to reduce PV feed-in peaks and shift the HP and EV demand from traditional evening peak hours. Photovoltaic generation is curtailed at the grid/building connection point (Hausanschlusskasten, HAK), limiting the maximum feed-in to 70% of the installed DC capacity. In addition, a share of new PV systems is assumed to be equipped with battery energy storage systems (BESS) with a power rating equal to 0.8 kW per kWp of installed PV capacity. The battery energy capacity is defined by a C-rate of 2 kWh/kW. Furthermore, residential electric vehicle charging is partially shifted away from evening peak hours by reducing the probability of charging during evening peak hours between 16:00 and 21:00 by 20%.

The **maxflex** sensitivity represents a high level of operational flexibility and includes stronger implementations of the same measures. In this case, PV feed-in is limited to 50% of installed capacity at the grid connection point. Battery storage deployment increases to 1 kW of battery power per kWp of installed PV capacity, with a C-rate of 1.5 kWh/kW. The probability of EV charging during the evening peak is reduced by 50%, shifting a larger share of charging to midday and nighttime periods. In addition, heat pumps are actively controlled to reduce evening demand peaks. Individual heat pumps may be temporarily switched off for up to three hours during the evening period between

[2] RES: Renewable Energy Sources

18:00 and 22:00, with the corresponding thermal demand compensated later during nighttime or morning hours.

Table 2 provides a summary of the flexibility sensitivities.

Table 2. Flexibility sensitivities: implementation assumptions

	Base	Flex	Maxflex
Photovoltaic curtailment (applied at grid connection point - HAK, in reference to kWp_{DC})	-	30%	50%
BESS	No BESS modeled	0.8 kW_{BESS}/kWp_{PV} C-Rate (kWh/kW): 2	1 kW_{BESS}/kWp_{PV} C-Rate (kWh/kW): 1.5
Electric Mobility private charging (Reduction of charging probability during evening peak hours)	-	20%	50%
Heat Pump shut off (for 3h during evening peak hours)	-	-	Turn off 18:00-22:00

3.3 Regionalization of electricity demand and generation

The national scenario parameters are translated to the regional level using a bottom-up regionalization approach. Electricity demand and distributed generation are spatially allocated to the buildings within the CKW service territory based on local characteristics such as building types, electricity consumption patterns, and available roof areas for photovoltaic installations.

Electricity demand is disaggregated into several components, including base electricity consumption, electric mobility, and electric heating. Photovoltaic installations are distributed across buildings according to the available installation potential.

For each building in the study area, annual electricity demand and generation profiles are generated with a temporal resolution of 15 minutes. In addition to building-level technologies, larger energy assets such as large photovoltaic installations and fast-charging hubs are connected at appropriate grid levels, typically between NL6 and NL4.

The resulting dataset provides time series representing electricity demand and distributed generation across the entire service territory and serves as the input for the subsequent grid simulations.

Following is the list of assumptions made while regionalizing demand and generation:

1. Heat pumps
   a. To determine the heating demand, its annual distribution, and to generate the 15-minute load profile for heat pumps, an hourly outdoor temperature profile for the canton of Lucerne from the year 2024 was used.
   b. To create the load profile for heat pumps, a maximum simultaneity of 70% of the respective installed capacity of the heat pumps was assumed to represent different operating modes. (Simultaneity is a measure of the proportion of all units operating simultaneously at their installed capacity)
   c. In the maxflex sensitivity, the intention is to reduce the evening peak load. The heat pumps were successively shut down during a 4-hour time window between 6:00 PM and 10:00 PM (individual heat pumps are shut down for a maximum of 3 hours during this time window). The corresponding heat energy was subsequently compensated for (late at night and in the early morning hours), limited by the installed capacity of the heat pump.
2. Electromobility

   a. Technological market trends were modeled based on the EBP ZERO E scenario[3]. This describes the evolution of the vehicle fleet and its breakdown by drivetrain technology.
   b. The load profiles for battery electric vehicle charging sessions were generated probabilistically for each charging station and charging type, using data from the Mikrozensus Mobilität[4].
   c. In the Flex and Maxflex sensitivities, the goal is to reduce the evening peak in households. The probability of a charging session starting in the evening (4:00 PM–9:00 PM) was reduced by 20% and 50%, respectively, with a corresponding increase during midday and late at night.
3. Solar PV and BESS
   a. PV curtailment is applied at the grid/building connection point (or after the inverter and self-consumption).
   b. In the flex and maxflex sensitivities, the maximum grid feed-in (at the grid/building connection point) is set to 70% and 50%, respectively, of the installed DC capacity in kWp.
   c. It is assumed that 50% of new PV systems will have a BESS starting in 2025.
   d. The capacityof the BESS is determined based on the installed kWp of the PV system and amounts to 80% or 100% of this in the flex and maxflex sensitivities. The energy of the BESS is modeled at a rate (kWh/kW) of 2 and 1.5, respectively.
   e. The BESS battery management system is applied in a simplified manner to reduce the PV feed-in peak at midday and to reduce the load peak in the evening (charging during excess PV generation starting at 12:00; discharging starting at 18:00).

3.4 Grid simulations

The regionalized time series for electricity demand and distributed generation serve as inputs for detailed load flow simulations of the CKW distribution network.

Grid planning is carried out using power flow simulations with a temporal resolution of 15 minutes for an entire year. This approach allows capturing critical operating conditions such as simultaneous photovoltaic export peaks and evening demand peaks.

Each HV/MV substation together with its downstream MV and LV networks (NL4-NL7) is simulated as an integrated system. However, simulations are performed separately for each substation area. The MV and LV grids are modeled in a coupled manner, enabling the analysis of interactions between grid layers.

For the simulation of the high-voltage grid (NE3), the aggregated demand and generation time series of all HV/MV substations are used.

3.5 Grid planning criteria and reinforcement measures

For the simulations, two types of constraints are evaluated: thermal loading limits of network assets and voltage limits at network nodes.

The following planning criteria are applied:

- Maximum loading of cables and transformers in NL4 and NL5: 60%
- Maximum loading of cables and transformers in NL6 and NL7: 100%
- Allowed voltage deviation at all nodes: ±10%

[3] Verständnis Ladeinfrastruktur 2050, Energieschweiz (Link)
[4] Mikrozensus Mobilität und Verkehr, Bundesamt für Statistik (Link)

Whenever these limits are violated, network reinforcement measures are applied following standard grid planning practices. These measures include cable reinforcement, installation of parallel cables, and transformer upgrades.

Voltage violations are primarily addressed through reinforcement of medium-voltage networks (when necessary) before applying measures in low-voltage networks. In addition to conventional measures, advanced voltage support through photovoltaic inverter reactive power control Q(U) is considered in the maximum flexibility scenarios.

3.6 Investment cost calculations

The costs of grid reinforcements are calculated using asset cost assumptions from the Swiss Association of Energy Utilities (VSE). Both capital (CAPEX) and operational expenditures (OPEX) are included.

Annualized costs are determined using an annuity approach based on a weighted average cost of capital (**WACC**) of **5%**, asset-specific lifetimes, and annual operation and maintenance costs corresponding to 2% of investment costs. The calculations are made using **real values** (not nominal). Ancillary construction services (e.g., cable digging costs, engineering, transformer building costs) are taken into account on a rule-based basis.

The calculated expansion costs are “additional investment costs” from today until the target year (e.g., 2050). Regular grid investments related to asset ageing, maintenance, and replacement cycles are not included.

The building and substation costs for HV-MV (**NL4**) are **not** considered. When HV-MV transformers are reinforced with larger capacities, it could require an enlargement of the existing building (if there is a building) and this enlargement with the substation technics (full upgraded substation) could cost MCHF 12 – 15 for CKW.

3.7 Upscaling to the national level

The grid expansion results obtained for the CKW NL4-7 networks are extrapolated to Switzerland following a clustering methodology developed by the Swiss electricity regulator **ElCom**.

Swiss utilities are grouped into 8 clusters based on **energy density** and **population density** of their service territories (i.e., *high energy density and high population density, high/low energy density and medium population density, high/low energy density rural, high/low energy density mountain region and low energy density touristic region*). In this study each HV/MV substation area of the CKW grid is treated as a representative of one of these utility clusters. The calculated grid investment results for medium- and low-voltage networks (NL4-NL7) are then linearly extrapolated to represent all 630 Swiss distribution utilities.

It is important to note that CKW supplies ~70 municipalities out of 2’136 in Switzerland. Consequently, not all types of utilities are represented by CKW: The CKW service territory does not serve low population, high energy density regions. In addition, the share of type of utilities in Switzerland is not the same in the CKW region. For example, the medium population low energy density regions served by CKW are over-represented for extrapolation (i.e., 7 substations, 35% of all CKW substations), while they constitute 16% (99) of 630 utilities in Switzerland. The medium population regions with high energy density served by CKW are underrepresented for extrapolation (5%), while they constitute 14% of 630 utilities.

In addition, the grids in the CKW region have **high heterogeneity**: the MV grids (NL4-5) of CKW are not homogenous in terms of grid capacity. Some NL4-5 grids are relatively stronger than others, resulting in relatively less investments for future scenarios. Each HV-MV substation and downstream grid is treated as a utility representing one of the ElCom Clusters. Due to this assumption, using regions with strong NL5 grids results in underestimating the upscaled costs by corresponding cluster.

Finally, the investment results of the HV grid (NE3) are not used in the upscaling, because the HV grid of CKW is not structurally representative:

- Switzerland has 2’335 km of underground cables and 6’594 km of overhead lines in its HV grids[5] with a ~3.5 ratio of overhead line to cable, while CKW operates 80 km cables and 380 km overhead lines in its HV grid, with a 4.75 ratio of overhead line to cable. In addition, CKW HV grid corresponds to only ~5% of the Swiss HV grids.
- Furthermore, high-voltage grids in Switzerland operate at different voltages. CKW uses 110 kV and 50 kV, resulting in higher transmission capacity than grid operators that use only 50 kV.

[5] ElCom Tätigkeitsbericht 2024

4. Results

4.1 Aggregated net demand (residual)

Across the entire analysis, the most important structural finding is that in high PV proliferation scenarios, future grid reinforcement investments are driven not primarily by conventional demand growth, but by the **temporal coincidence** (i.e., simultaneity) **of PV generation and demand** at the lower grid levels.

In practical terms, this means that in high-PV scenarios, the most severe grid loading situations increasingly occur during periods of strong PV surplus, rather than during the typical winter evening demand peak alone. To illustrate this mechanism, the maximum positive and negative values of the aggregated net-demand time series for the entire CKW region are calculated. The net-demand time series are obtained by subtracting the sum of distributed generation (including BESS discharging) at all HV-MV (NL4) substations from the aggregated electricity demand (including BESS charging) of all HV-MV (NL4) substations.

Table 3. Aggregated net demand time-series including NL4, NL5, NL6 and NL7 levels of 19 substations for PV and Nuclear (K) / Wind / Gas scenario for 2050: base, flex and maxflex, with positive and negative maximum power

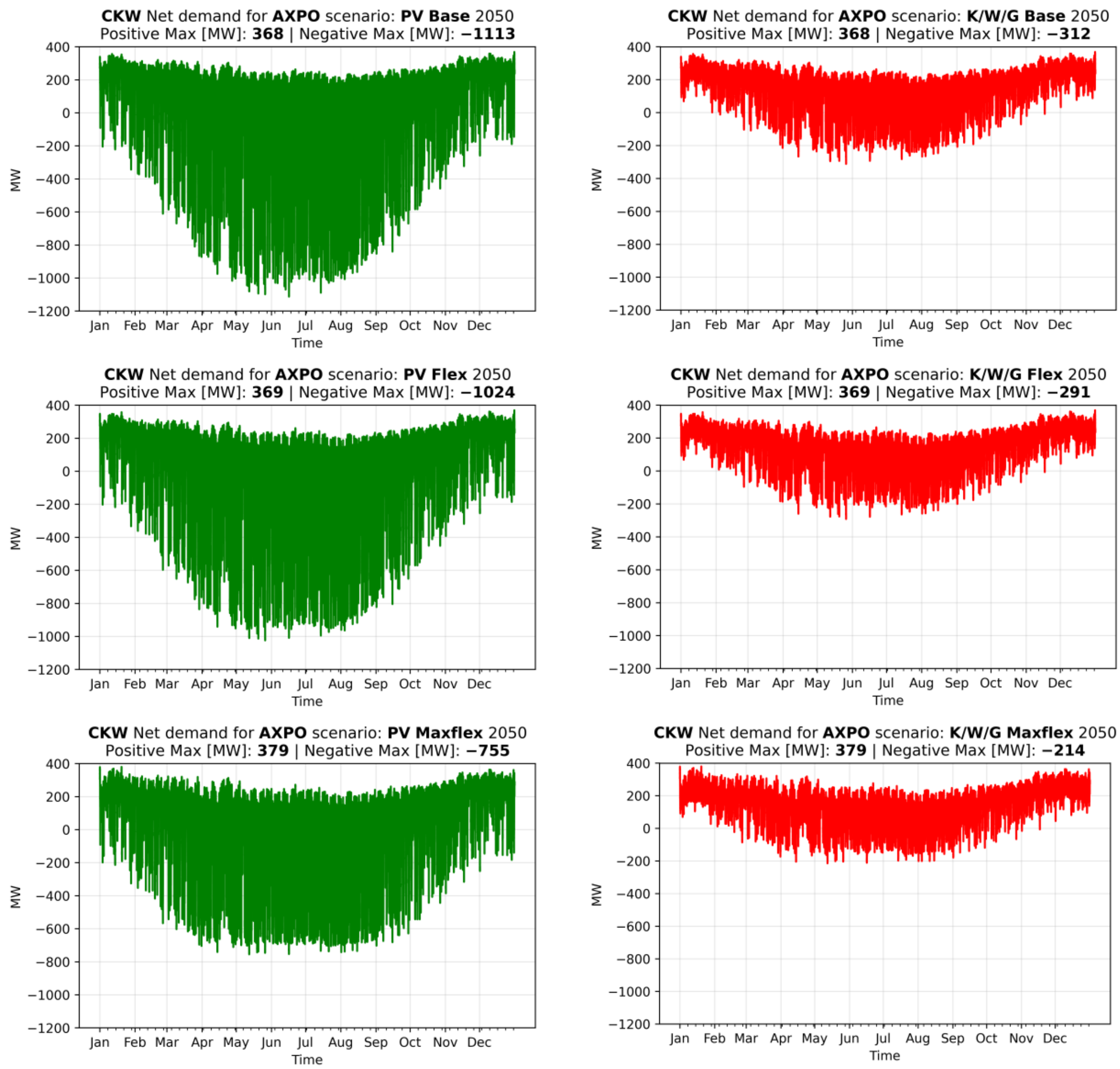

Table 3 illustrates the aggregated net-demand time-series for PV and Nuclear (the results for Gas and Wind scenarios are the same for NL4-7) scenarios for 2050. The Nuclear, Gas and Wind scenarios have the least PV proliferation, while having the same demand evolution.

In the aggregation process the demand and generation that are connected to NL4, 5, 6 and 7 are used, since they are driving the grid reinforcement investments in these grid layers. Positive values represent periods in which the upper grid layers (NE1 & NE3) supply the demand in NL4-7 and therefore can be referred to as “demand peaks”, whereas negative values correspond to periods in which surplus PV generation is exported from NL4-7 to upper grid layers, and therefore can be referred to as “PV peaks”.

While demand peaks determine the capacity required for supplying electricity during periods without solar generation, PV peaks determine the capacity required for exporting electricity back through the network during periods of high solar production. Because PV output across large regions is highly temporally correlated, these export peaks occur simultaneously across many substations and therefore propagate through multiple grid layers unless they are curtailed.

In Table 3 the impact of moderate flexibility (flex) and maximum flexibility (maxflex) measures on the “PV peaks” can be clearly observed. Note that the maximum negative demand for the CKW region due to the PV feed-in is reduced by **8%** from PV base scenario to PV flex scenario, and **32%** from PV base scenario to PV maxflex scenario. These reductions are in line with the previously reported findings[6], and depend on how the PV curtailment is implemented. PV curtailment takes place at the grid connection point, not directly at the inverter. This means that the generated PV power is converted in the inverter (minimal power loss), feeds into simultaneous self-consumption (general electricity, heating, and electric mobility), as well as charging the BESS. Only then it is checked at the grid connection point whether the remaining power exceeds the 70% or 50% limitation, and it is curtailed accordingly. The desired effect of curtailing feed-in is ensured, but due to losses and self-consumption, curtailment occurs less frequently and the curtailed energy is reduced. Under the assumptions in the model, the PV scenario results in an energy loss due to curtailment of 1.4% and 6.8% for the flex and maxflex sensitivities, respectively. This result depends heavily on the underlying assumptions and may vary accordingly depending on different assumptions, regions under consideration, and the grid level of the analysis.

4.2 Grid investments

Error! Reference source not found. provides the summary of positive and negative maximum demand values for all scenarios along with the results of grid investment costs.

Note that in all PV scenarios and sensitivities, and in S1 and S2 flex scenarios, the PV peaks are much larger than the demand peaks, therefore, the grid investment requirements are driven primarily by the PV peaks. In S1 and S2 maxflex scenarios, the difference between PV and demand peaks are much lower, and the grid investment requirements are driven by both demand and PV.

Error! Not a valid bookmark self-reference. and **Error! Reference source not found.** complement **Error! Reference source not found.** and present the grid investment results for each grid layer, while **Error! Reference source not found.** illustrates the impacts of sensitivities on selected scenarios. It is noted that despite flexibility measures aimed at reducing the peak demand in the case of electric mobility and heat, the maximum total load increases for the sensitivity Maxflex. The flexibility measures in the sensitivity Maxflex are implemented primarily at the household level and result in a load reduction at NL6-NL7. This is clearly visible in the comparison of expansion

[6] P. Cuony, H. Todorov, C. Bucher, “Ohne Leistungsregelung von PV geht es nicht: Systembetrachtungen für den Solarstromausbau”, Bulletin Electrosuisse, Dezember 2024

costs, which can significantly be reduced with sensitivities flex and maxflex, especially in scenarios where the expansion is driven by demand and not merely by PV excess.

*Table 4. Total and annualized grid investment costs along with annual operational costs in **MCHF** for CKW for **NE3-7** from today until 2050 per scenario and flexibility vs. the positive maximum power (demand) and the negative maximum power (generation feed-in) based on aggregated time-series of net-demand at all substations including all **NL4-7** demand and generation for 2050.*

Scenario	Flexibility	+Pmax [MW]	-Pmax [MW]	NL4-7 inv. costs	Ann. NL4-7 inv. costs	OPEX (NL4-7)	NE3 inv. costs	Ann. NE3 inv. costs	OPEX (NE3)
PV	No (Base)	369	-1'113	139.8	10.4	2.795	68.3	5.340	1.365
PV	Moderate (Flex)	369	-1'024	109.0	8.1	2.181	37.1	2.900	0.743
PV	Max. (Maxflex)	380	-755	47.5	3.5	0.950	3.6	0.283	0.072
Wind	Moderate (Flex)	369	-292[7]	21.4	1.6	0.428	6.4	0.501	0.128
Wind	Max. (Maxflex)	380	-215	16.4	1.2	0.328	6.4	0.501	0.128
K, Gas	No (Base)	369	-312	24.7	1.8	0.494	3.5	0.270	0.069
K, Gas	Moderate (Flex)	369	-292	21.4	1.6	0.428	3.5	0.270	0.069
K, Gas	Max. (Maxflex)	380	-215	16.4	1.2	0.328	3.5	0.270	0.069
S1 (RES+G)	Moderate (Flex)	369	-651	55.0	4.1	1.098	3.6	0.283	0.072
S1 (RES+G)	Max. (Maxflex)	380	-492	30.0	2.2	0.598	3.5	0.270	0.069
S2 (Coexis.)	Moderate (Flex)	369	-509	41.0	3.0	0.817	3.6	0.282	0.072
S2 (Coexis.)	Max. (Maxflex)	380	-382	23.2	1.7	0.465	3.5	0.270	0.069

*Table 5. Total and annualized (with "a") grid investment costs in **MCHF** for CKW per scenario and flexibility for grid layers NL4-7 for 2050*

Scenario	Flexibility	NL7	NL6	NL5	NL4	NL7a	NL6a	NL5a	NL4a
PV	No (Base)	39.4	38.1	11.2	51.1	2.9	2.8	0.8	3.8
PV	Moderate (Flex)	26.4	31.4	5.9	45.3	1.9	2.3	0.4	3.4
PV	Max. (Maxflex)	8.4	14.4	0.5	24.4	0.6	1.1	0.0	1.8
K	No (Base)	5.1	9.0	-	10.7	0.4	0.7	-	0.8
K, Wind, Gas	Moderate (Flex)	4.2	8.2	-	9.1	0.3	0.6	-	0.7
K, Wind, Gas	Max. (Maxflex)	2.3	5.0	-	9.1	0.2	0.4	-	0.7
S1 (RES+G)	Moderate (Flex)	12.5	17.5	0.9	24.1	0.9	1.3	0.1	1.8
S1 (RES+G)	Max. (Maxflex)	5.4	9.5	0.0	15.0	0.4	0.7	0.0	1.1
S2 (Coexis.)	Moderate (Flex)	9.8	14.7	0.6	15.8	0.7	1.1	0.0	1.2
S2 (Coexis.)	Max. (Maxflex)	4.5	8.2	-	10.6	0.3	0.6	-	0.8

Note that the nuclear, wind and gas scenarios lead to same grid investment costs in medium- and low-voltage distribution grids (NL4-7), because the generators are connected either at high-voltage grid (NE3) or extra-high-voltage grid (NE1). Therefore, only the results of nuclear scenario are provided and the results of wind and gas for NL4-7 are the same. In Wind scenario, the grid investment costs for the HV grid (NE3), are mainly driven due to the wind generation connected at the HV grid.

[7] The positive and negative maximum net demand values for Wind scenarios does not include the wind generation fed into the HV (NE3) grid at HV nodes. When the wind generation is included the values are **348** MW and -**497** MW for **flex** scenario and **358** MW and -**433** MW for **maxflex** scenario, implying that the grid investment requirements are driven by the wind generation combined with the excess PV produced in the lower grid layers.

It is noted that the grid connection costs for the generators connected to HV grid (NE3), including the dedicated transformers and substations and cabling for wind parks are not considered.

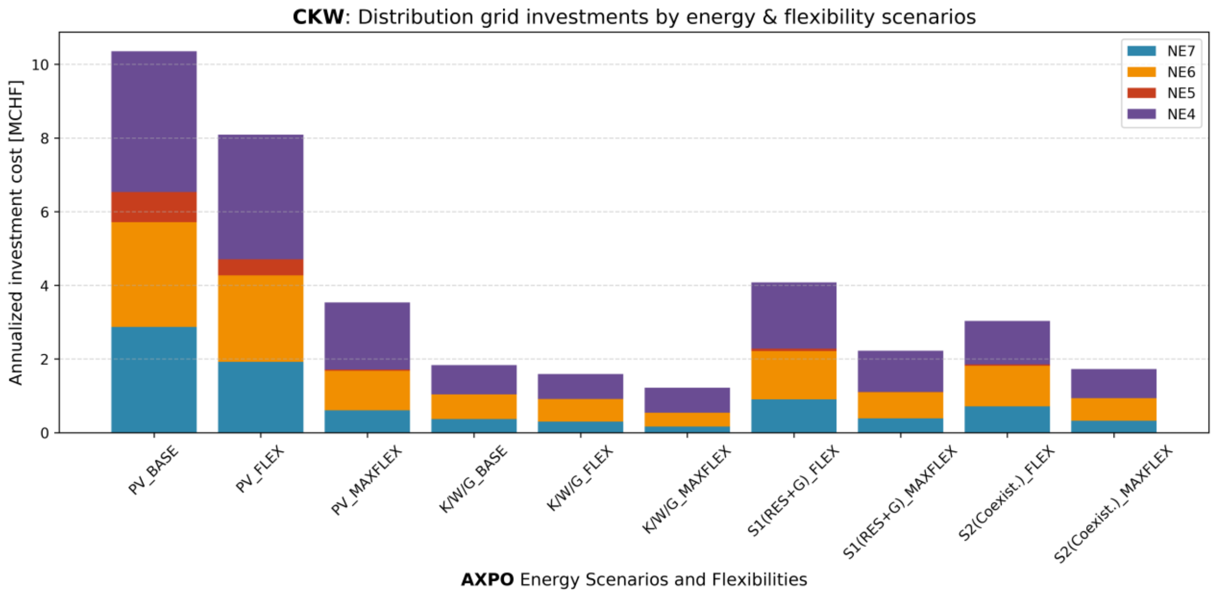

Figure 1. Total annualized investment costs for NL4-7 for 19 substations (CKW region) for each scenario and flexibility for 2050

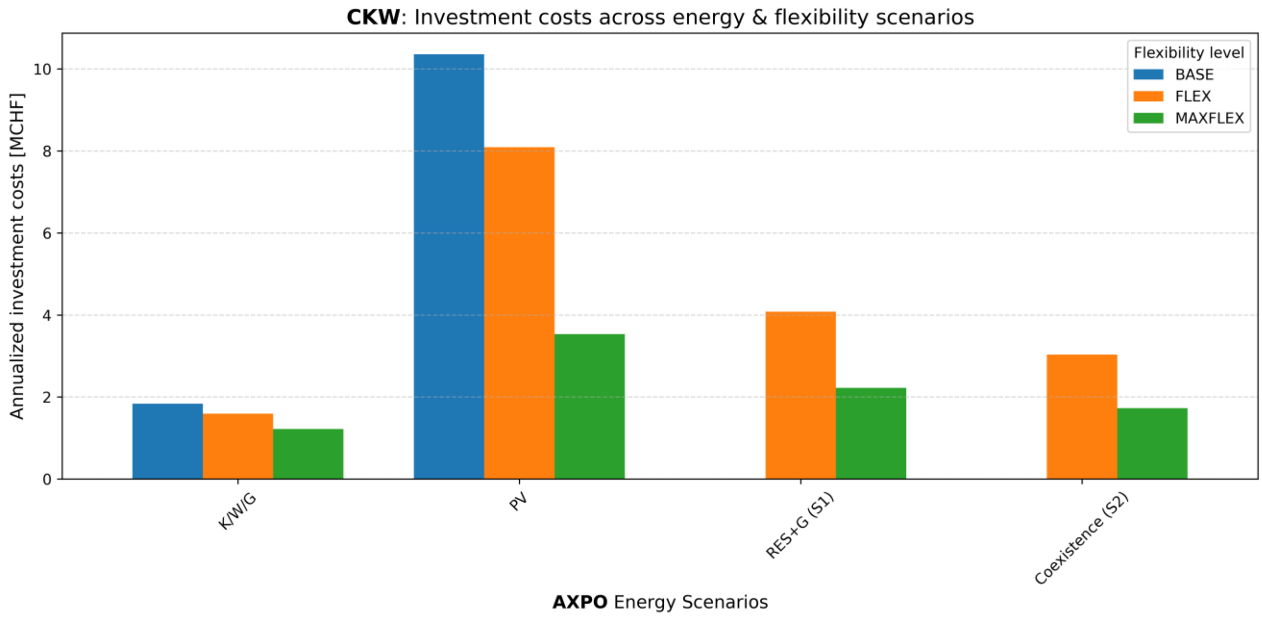

Figure 2. Total annualized investment costs for 19 substations (CKW region) for each scenario and flexibility for 2050

Table 6 and Figure 3 demonstrate the extrapolation results based on the results for the CKW region. Note that, as explained above in the Methodology section, upscaling is based on the assumption that each region served by an HV-MV substation represents a utility. Therefore, the upscaled results are heavily dependent on the representativeness of these substations for all Swiss utilities. It is important to note that if another set of substations are used, the national upscaling results will be affected accordingly resulting in slightly higher or lower costs for Switzerland. If more substations serving a more representative set of regions are used, the accuracy of the estimations can be improved. Within the scope of this study only CKW substations were available and used.

*Table 6. Extrapolation results for Switzerland for total investment costs and annualized costs in **BCHF** for each scenario and flexibility for 2050*

Scenario	Flexibility	Total investment costs	Annualized investment costs
PV	No (Base)	4.292	0.318
PV	Moderate (Flex)	3.374	0.250
PV	Max. (Maxflex)	1.538	0.114
K, Wind, Gas	No (Base)	0.792	0.059
K, Wind, Gas	Moderate (Flex)	0.689	0.051
K, Wind, Gas	Max. (Maxflex)	0.565	0.042
S1 (RES+G)	Moderate (Flex)	1.687	0.125
S1 (RES+G)	Max. (Maxflex)	0.978	0.073
S2 (Coexis.)	Moderate (Flex)	1.292	0.096
S2 (Coexis.)	Max. (Maxflex)	0.757	0.056

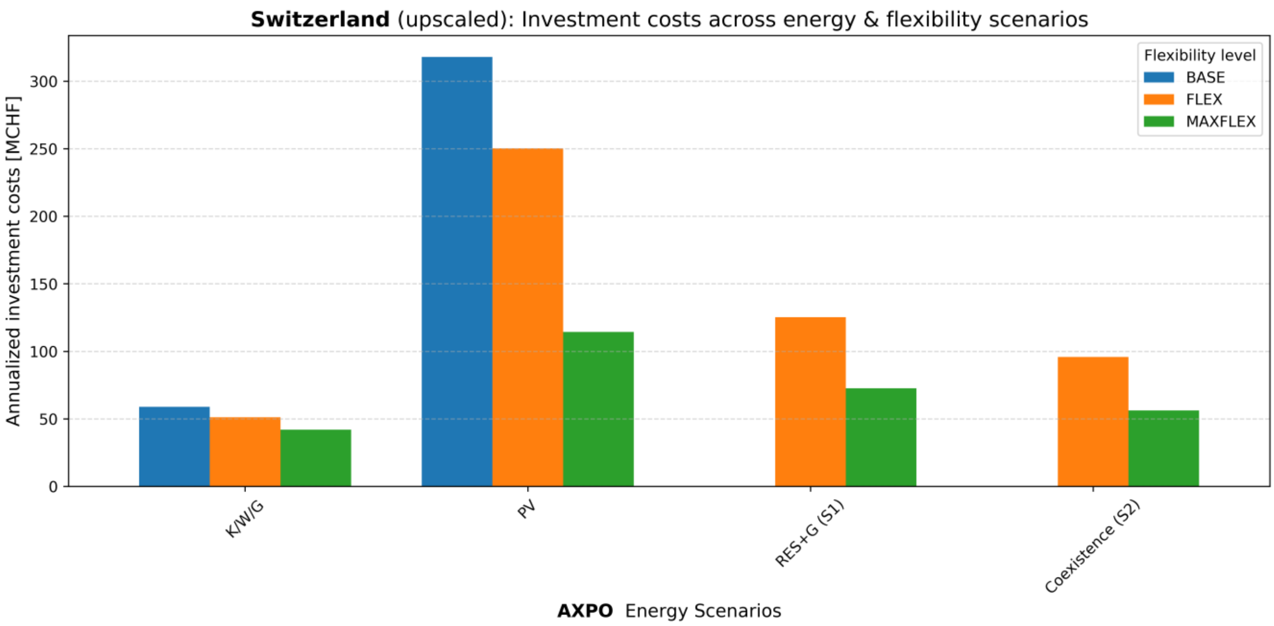

Figure 3. Total upscaled annualized investment costs for Switzerland for each scenario and flexibility for 2050

PV Scenario

As can be observed in Table 4 and

Table 5, the **PV scenario** results demonstrate the resulting impact. In this scenario, the maximum negative net demand for the CKW region reaches a magnitude significantly larger than the maximum positive net demand peak. In this scenario the grid must therefore be capable of accommodating export flows that exceed the traditional load peak of the system.

This condition results in the highest infrastructure requirements among all scenarios considered. In the CKW service territory, the introduction of moderate flexibility (i.e., flex) reduces the total grid reinforcement requirements by roughly **22% in NL4-7** and **46% in NE3** compared with the base case without flexibility, while the adoption of maximum flexibility reduces the total investment costs by approximately **66% in NL4-7** and **95% in NE3** relative to the base case (Table 4 and Figure 1).

A similar pattern emerges at the national level upscaled results for NL4-7. For Switzerland as a whole, moderate flexibility reduces the total investment requirement of the PV scenario by approximately **21%**, while maximum flexibility leads to a reduction of roughly **64%** relative to the base case (Table 6).

Nuclear (wind and gas) scenario

In contrast the **Nuclear scenario (K)** is fundamentally different. Because distributed PV deployment is much lower than in the PV scenario, the resulting reverse power flows are much less severe. Consequently, the need for reinforcement is considerably smaller. Within the CKW territory, moderate flexibility lowers total investment requirements for NL4-7 by approximately **13%** relative to the base case, while maximum flexibility leads to an overall reduction of roughly **34%**. The national results follow the same trend. With moderate flexibility, total investment in the nuclear scenario decreases by approximately **13%**, while maximum flexibility reduces total investment by roughly **29%** compared with the base case.

The grid reinforcement requirements for NE3 are not affected by the flexibility measures. However, it is noted that the grid investments for the HV grid (NE3) in the wind scenario are **80%** higher than the NE3 grid investment in nuclear (and gas) scenario, mainly because the wind parks are assumed to be connected at NE3.

It is worthwhile noting that the benefit of moving from moderate to maximum flexibility for NL4-7 is smaller here than in the PV-dominated scenarios. This is a strong indication that the main value of flexibility lies in mitigating distributed generation peaks; where these peaks are limited, flexibility still helps with shifting the demand such as EV and HP operation from the traditional evening peaks, however, it is also noted that the benefits of demand flexibility can be hindered when the same type of flexibility is applied to all demand homogenously. This phenomenon is sometimes referred to as "rebound effect" because, for example, the residential EV charging is homogenously shifted towards nighttime, along with the shifting of HP operation, resulting in some situations in a new peak. Therefore, the implementation has to be carefully designed to unlock the full potential of demand flexibility.

Synthesis scenarios

The **Synthesis I (S1)** scenario occupies an intermediate position between the PV and Nuclear cases, but it is much closer to the PV scenario than to the Nuclear scenario. Synthesis I represents the more demanding of the two synthesis pathways. This is consistent with the scenario assumptions: S1 still contains substantial PV deployment in 2050, with a broader technology mix than the pure PV scenario. In the CKW territory, moving from moderate to maximum flexibility reduces the total grid investment requirements for NL4-7 by approximately **46%**. At the national level, the same transition reduces total investment by roughly **42%**. Relative to the PV scenario PV installed capacity is approximately **23%** less in S1, resulting in **50%** less investment costs for NL4-7 under **moderate flexibility** and by about **37%** under maximum flexibility. S1 still places considerable stress on the distribution grid, but the stress is meaningfully moderated by a more balanced technology portfolio. The impact of flexibility measures on NE3 investments is insignificant.

The **Synthesis II (S2)** scenario is less demanding than S1 and substantially less demanding than the PV scenario, while still remaining clearly above the Nuclear case. In the CKW territory, moving from moderate to maximum flexibility reduces total grid investments for NL4-7 by approximately **43%**. Relative to the PV scenario PV installed capacity is approximately **43%** less in S2, resulting in a **63%** reduction in total grid investment requirements for NL4-7 under moderate flexibility assumptions and a **51%** reduction under maximum flexibility. These results indicate that a diversified technology mix with somewhat lower PV penetration can significantly reduce distribution grid stress while still enabling electrification of heating and mobility sectors.

Flexibility sensitivities

A direct comparison of all scenarios under **moderate flexibility** shows a very clear ranking. Within the CKW territory, Synthesis I requires roughly **50%** less annualized investments for NL4-7 than the PV scenario, while Synthesis II requires approximately **63%** less, and the nuclear scenario about **80%** less. The national results follow almost exactly the same pattern.

Under **maximum flexibility**, the ranking remains unchanged, but the gaps narrow somewhat because the PV-heavy scenarios benefit most from stronger flexibility. In the CKW territory, Synthesis I requires approximately **37%** less annualized investments for NL4-7 than the PV scenario, Synthesis II about **51%** less, and the nuclear scenario roughly **65%** less. At the national level the same relative differences appear. The narrowing of the spread between scenarios indicates that strong flexibility measures are particularly effective in mitigating the additional grid stress associated with high photovoltaic deployment.

Impacts of scenarios on grid reinforcement requirements in different grid layers

Another robust finding concerns the distribution of investments across grid levels. In the CKW results, the sum of **NL6** and **NL7** investments (i.e., LV investments) is generally larger than the sum of **NL4** and **NL5** (i.e., MV investments) in the moderate-flexibility cases as demonstrated in Figure 1 and Table 4. This is consistent with the fact that most PV, residential EV charging, and residential heat pumps are connected at the lower grid levels.

Under moderate flexibility, the LV share (NL6 + NL7) of total CKW investment is about **53.0%** in PV, **58%** in K, **55%** in S1, and **60%** in S2.

Under maximum flexibility, however, the picture slightly changes. In PV, LV investment costs constitute **48%** of total investment cost and the share of MV (NL4 + NL5) investment costs is **52**% of the total investment cost. A similar shift occurs in K and S1, while S2 remains somewhat more bottom-heavy. This indicates that strong flexibility is particularly effective in suppressing LV reinforcement needs. Once these are reduced, the remaining investment burden becomes relatively more concentrated in MV assets that are less easily avoided.

Another important observation is the change in the share of HV grid (NE3) investments in total grid investments (NE3-7). Thanks to maximum flexibility measures, the share of the NE3 investments drops from **33%** of the total investments to **7%** in PV scenarios. Note that the required investments in NE3 in absolute terms drop by **95%** from **base** to **maximum flexibility** scenario. This drastic drop is directly correlated with the reduction in negative maximum demand (i.e., PV peak) from higher than **1 GW** in base and moderate flexibility scenarios to lower than **1 GW** in maximum flexibility scenario.

Dive into selected substations

The substation-level analysis (Figure 4 and Figure 5) further highlights the spatial heterogeneity of grid reinforcement needs. Certain substations repeatedly appear as investment hotspots across several scenarios. Across many scenarios, substations such as **SURSEE**, **HITZKIRCH**, **WILLISAU**, and **WOLHUSEN** appear repeatedly among the largest cost drivers.

In the PV scenario for 2050 without flexibility (base case), the **SURSEE** substation represents the largest outlier with total reinforcement costs exceeding **15 MCHF**. Even under moderate flexibility this substation remains the largest cost driver with roughly **12.8 MCHF** of required investment. The main driver of the grid reinforcements in **SURSEE** is the high PV feed-in: the negative maximum demand (i.e., PV peak) of the net-demand timeseries calculated at the **SURSEE** substation (NL4) is 137 MW in PV base scenario, 125 MW in PV flex scenario and 92 MW in the PV Maxflex scenario compared to 52 MW positive maximum demand (i.e., demand peak) in PV base and flex scenarios and 55 MW in PV maxflex scenario. A more drastic ratio of negative maximum demand to positive maximum demand is observed in **HITZKIRCH**, where the PV peak is 99 MW in the aggregated net-demand time series, while the demand peak 20 MW for PV base scenario, 90 MW vs. 20 MW in PV flex scenario and 65 MW vs. 21 MW in maxflex scenario. Similar patterns are observed in **WILLISAU** and **WOLHUSEN** as well. It is important to note that 25 MVA transformers are used at HV-MV (NL4) at some substations such as **WILLISAU**, **WOLHUSEN** and **HITZKIRCH**, and upgrading these relatively small transformers are the main contributors to the grid investment costs in these substations, especially in PV and Synthesis scenarios.

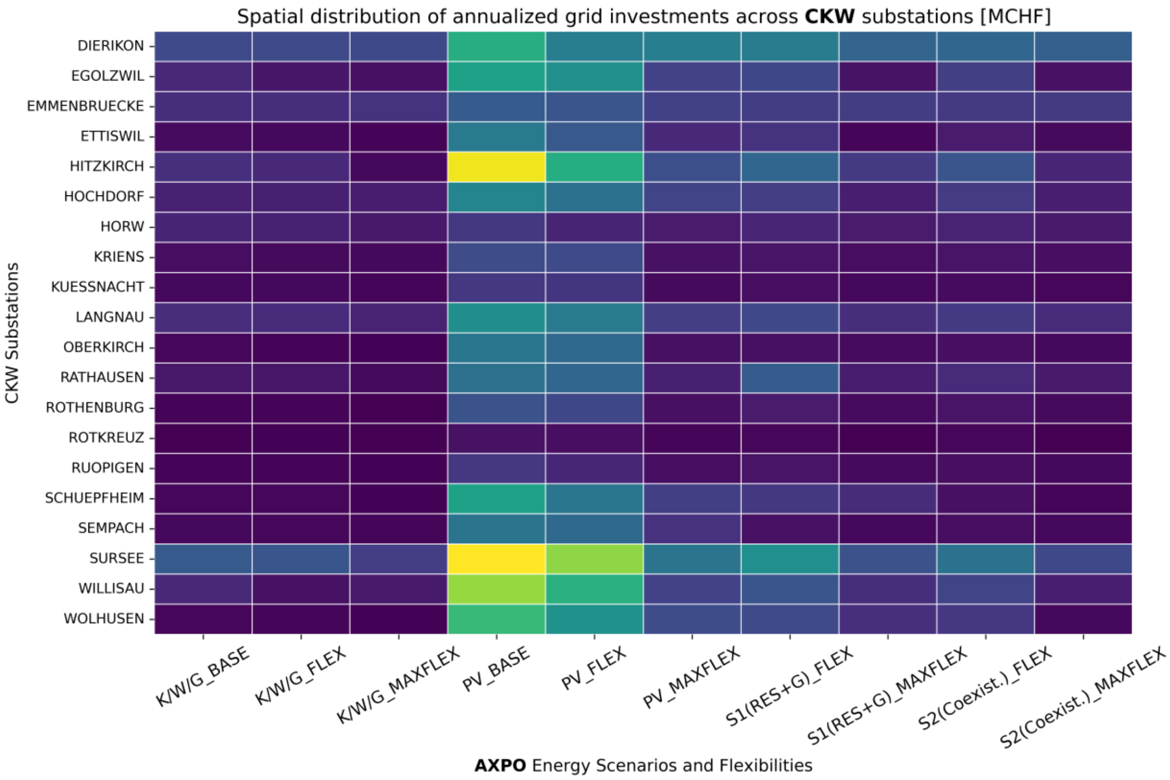

Figure 4. The heatmap of annualized grid investment cost for each substation for each scenario in 2050

It is important to note that not all grid investments are due to the overloading of lines. Especially in high PV scenarios, **overvoltage violations** are often observed. In some substations, in scenarios where PV proliferation is relatively lower and positive maximum net-demand is higher such as in Nuclear, undervoltage violations are observed as well mainly due to demand. The grid investments that mitigate the loading violations partially alleviate overvoltage violations as well, however, in some cases the overvoltage violations still persist, especially in high PV scenarios. For example, voltage-driven grid investment costs comprise **46%** of the total grid investment costs in **NL7** in **SCHUEPFHEIM**, **40%** in **WILLISAU**, **23%** in **HITZKIRCH** and **7%** in **SURSEE** in PV base scenario. This share falls to below **1%** for all substations in **PV maximum flexibility** scenario. The grid investment costs due to mostly undervoltage violations (demand-driven) in **RUOPIGEN** constitute **19%** and **7%** of the total grid investment costs in **NL7** in **S1 moderate flexibility** and **Nuclear base** scenarios, respectively, and voltage driven investments in NL7 are eliminated completely when maximum flexibility measures are adopted in both scenarios.

These results further demonstrate the heterogeneity among the CKW substations, regarding the required grid investments as well as the reasons for the grid investments in distribution networks.

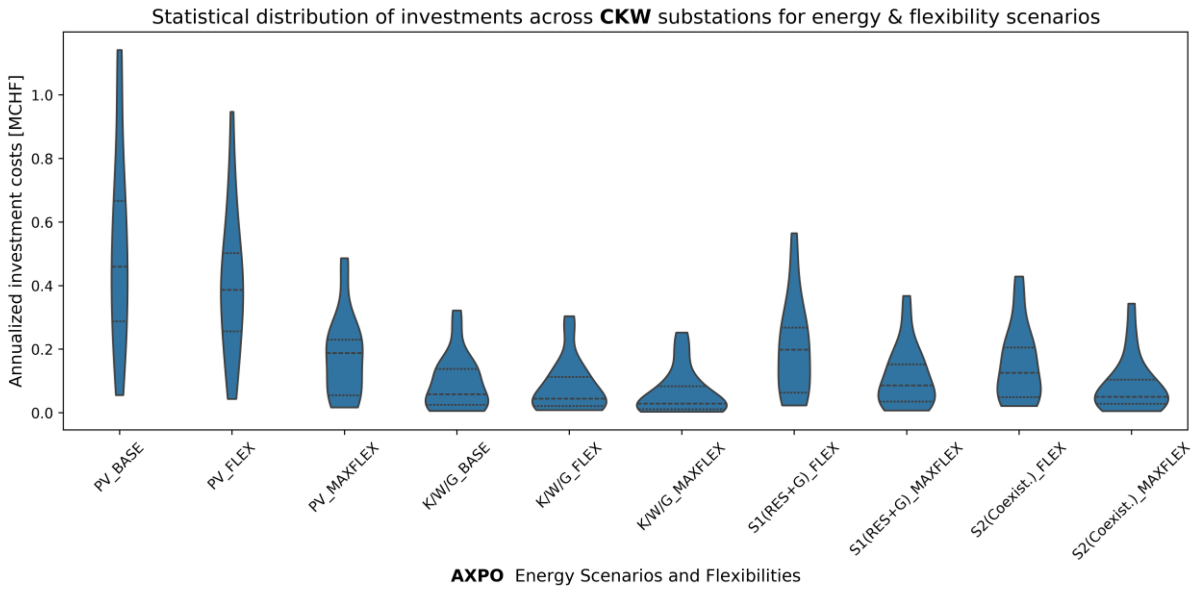

Figure 5. The statistical distribution of annualized grid investment costs for all substations for each scenario in 2050.