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Final report

Firm PV Power Generation for Switzerland

Updates 2023 with scenarios including enhanced wind and nuclear production

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The authors of this report bear the entire responsibility for the content and for the conclusions drawn therefrom.

Summary

In the study "Firm PV Power Switzerland" from 2022, the optimal shares of curtailment of photovoltaics were calculated for various scenarios for the Swiss power supply with different shares of renewable electricity production and various assumptions regarding energy storage. The optimal shares of PV-curtailment are 10-30% of the energy that would be generated with PV over the year. The average electricity generation costs were in the range of 6-8 cts/kWh.

The energy debate has evolved greatly since early 2022. The risk of the winter power gap is weighted rather more heavily today - due to the war in Ukraine and the missing Framework Agreement with the EU. In this complementary study, the same optimization model is applied. We supplement the scenarios with current conditions - such as the limitation of electricity imports in the winter half-year to 5 TWh. We have also increased the expansion of wind power by 50% (to 3 - 6 TWh) and added scenarios with nuclear power (1 GW capacity). Wind and nuclear energy would thus each supply each approx. 5% of annual electricity production. The new modelling confirms the results of the first study. The costs are still in the range of 7-8.5 cts/kWh. The cost differences between the 9 new scenarios are small, within the range of the year-to-year variations and lower than the uncertainties. This means, that all modelled scenarios - with more or less wind and a one or zero nuclear power station - will work and result in acceptable cost ranges.

Although wind, nuclear and e-fuels based electricity are significantly more expensive to produce than PV in Switzerland, they reduce the overall average production costs. This is because they would run primarily in winter and thus reduce the need for oversizing PV.

Zusammenfassung

In der Studie «Firm PV Power Switzerland» von 2022 wurde die optimalen Anteile der Abregelung der Photovoltaik für diverse Szenarien zur Schweizer Stromversorgung berechnet mit unterschiedlichen Anteilen an erneuerbarer Stromproduktion und verschiedenen Annahmen zur Energiespeicherung. Die optimalen Anteile der Abregelung von PV-Strom betrugen 10-30% bezogen auf die jährliche produzierte PV-Energie. Die durchschnittlichen Stromerzeugungskosten lagen im Bereich von 6-8 cts/kWh.

Die Energiedebatte hat sich seit Anfang 2022 stark weiterentwickelt. Das Risiko der Winterstromlücke wird heute stärker gewichtet – auf Grund des Krieges in der Ukraine und der Situation bezüglich dem fehlenden Rahmenabkommen mit der EU. In dieser ergänzenden Studie wird das gleiche Optimierungsmodell angewendet. Wir ergänzen die Szenarien mit zusätzlichen politischen Bedingungen – wie z.B. der Limitierung des Stromimports im Winterhalbjahr auf 5 TWh. Zudem haben wir den Zubau des Windes um 50% erhöht (auf 3 bis 6 TWh) und Szenarien mit Atomkraft ergänzt (1 GW Leistung). Die Wind- und Atomenergie würden damit ca. 5 % der jährlichen Stromproduktion liefern. Die neue Modellierung bestätigt die Resultate der ersten Studie. Die Kosten liegen weiterhin im Bereich von 7 bis 8.5 cts/kWh. Die Kostendifferenzen zwischen den 9 neuen Szenarien sind klein. Sie liegen im Streubereich der jährlichen Unterschiede und sind kleiner als die Unsicherheiten. Das bedeutet, dass alle modellierten Szenarien - mit oder weniger Wind und mit einem oder keinem Atomkraftwerk - umsetzbar sind und zu akzeptablen Strompreisen führen.

Obwohl Wind-, Atom- und «E-Fuels»-basierte Elektrizität in der Produktion teurer sind als PV in der Schweiz, senken diese die mittleren Kosten leicht. Dies weil sie vorab im Winter anfallen würden und damit den Bedarf an Überdimensionierung der PV senken würden.

Résumée

Dans l'étude "Firm PV Power Switzerland" de 2022, les parts optimales de la régulation du photovoltaïque ont été calculées pour divers scénarios d'approvisionnement en électricité en Suisse avec différentes parts de production d'électricité renouvelable et diverses hypothèses concernant le stockage de l'énergie. Les pourcentages optimaux d'arrêt s'élevaient à 10-30% de l'énergie qui serait produite par le PV au cours de l'année. Les coûts moyens de production d'électricité étaient de l'ordre de 6 à 8 cts/kWh.

Le débat sur l'énergie a considérablement évolué depuis le début de l'année 2022. Le risque de pénurie d'électricité en hiver est aujourd'hui plus important, en raison de la guerre en Ukraine et de l'absence d'accord-cadre avec l'UE. Le même modèle d'optimisation est utilisé dans cette étude supplémentaire. Nous complétons les scénarios par des conditions politiques supplémentaires, comme par exemple la limitation des importations d'électricité à 5 TWh pendant le semestre d'hiver. Nous avons également augmenté de 50% l'augmentation de l'énergie éolienne (à 3 - 6 TWh) et complété les scénarios avec de l'énergie nucléaire (1 GW de puissance). L'énergie éolienne et l'énergie nucléaire fourniraient ainsi environ 5% de la production annuelle d'électricité. La nouvelle modélisation confirme les résultats de la première étude. Les coûts se situent toujours dans une fourchette de 7 à 8,5 cts/kWh. Les différences de coûts entre les 9 nouveaux scénarios sont faibles,se situent dans la fourchette des différences annuelles et sont inférieures aux incertitudes. Cela signifie que tous les scénarios modélisés - avec plus ou moins de vent et avec une ou aucune centrale nucléaire - sont réalisables et conduisent à des prix de l'électricité acceptables.

Bien que la production d'électricité éolienne, nucléaire et à base de biocarburants soit nettement plus coûteuse que celle de l'énergie photovoltaïque en Suisse, elle permet de réduire les coûts de production moyens globaux. Cela s'explique par le fait qu'ils fonctionneraient principalement en hiver et réduiraient ainsi la nécessité de surdimensionner les installations PV.

Main findings

- Overall, the results of the first study about Firm PV Power Switzerland of 2022 could be confirmed (https://www.aramis.admin.ch/Default?DocumentID=68985).
- The differences of the costs between all scenarios are small – smaller than the year-to-year variations and the uncertainties.
- All scenarios show acceptable cost ranges.
- The lowest costs arise in a scenario with enhanced wind energy and extended life time of one nuclear power station.
- Two non-intuitive facts became apparent:
    - Curtailing PV lowers the overall costs.
    - Adding low shares (in the range of 5%) of expensive electricity at the right time of year – in winter – can lower the overall costs. This reduces the need of over-building PV. They work as a kind of catalyst.
- Curtailment levels of 10 to 20% are optimal regarding overall costs. The big question is how to achieve this optimum and who is going to pay for this?
- Policy and regulation framework evolves slowly in the direction of valuing and enabling firm power – but further changes are yet needed.

Firm PV Power Generation Switzerland

Updates 2023 with scenarios including enhanced wind and nuclear production

Acknowledgements

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Major contributions for this report were made by Marc Perez (Clean Power Research USA), who modelled the results as well as Richard Perez (State University of New York at Albany), who gave general advice and did quality checks.

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1 Introduction

In May 2022 a first analysis on Firm Power Generation for Switzerland was published (Remund et al, 2022). We examined several ultra-high RE scenarios where PV and hydro would meet the bulk of the country's demand. Depending on future cost predictions for PV and batteries, and a small contribution from domestic or imported dispatchable resources, we showed that power production costs on the Swiss grid would range from 6 to 8 cents per kWh. Also, scenarios with no or only marginal imports – either of electricity or e-fuels – would lead to only slightly higher costs – due to the effects of overbuilding and curtailment. Our analyses showed that firm PV power is an enabler of the energy transition, lowering the costs significantly.

This report includes the results of an update of this study with additional scenarios and updated input data.

As in 2022 the same model of Clean Power Research was applied. Again, the optimum between overbuilding and curtailment was modelled. As in 2022 the Energy Perspectives 2050+ scenario (SFOE, 2021) was the basis of the analysis. As in 2022 only the electricity production was modelled without taking the grid within Switzerland into account.

For more information about the topic of firm power modelling we refer to mentioned predecessor project (Remund et al, 2022), a report on the subject by IEA PVPS Task 16 (Perez et al. 2023) and an additional publication by the same author team (Remund et al. 2023).

In the outlook of the precursor study in 2022 the following open issues were listed:

1. Nuclear power is not modelled;
2. Alpine PV has not been included;
3. The max. power load rises linearly to the foreseen overall electricity consumption
4. The effects of climate change have been neglected
5. Seasonal thermal storage is not modelled

This follow-up study tackles 3 of the 5 issues:

6. The effect of running 1 nuclear power station with 1 GW power is modelled
7. The load does not rise linearly but demand side management has been added (switch of load to noon)
8. Some aspects as warmer winter and more run-of-river hydro production in 2050 is taken into account.

The following two points have been neglected:

1. Alpine PV was neglected as the potential (2-3 TWh) is low in comparison to the potential on roofs (30-50 TWh)
2. Seasonal thermal storage (and also hydrogen production) is not taken into account

As in 2022 the results will show the amount of PV and wind which are cost-optimally overbuilt (and curtailed) and stored in Switzerland for a fully renewable energy system.

Six additional options – combined to nine new scenarios - are added to the general definitions of scenario 1 (100% RES). After publishing the first report it was criticized, that the amount of wind energy (2-4 TWh) is too low and much lower than the potential (10-20 TWh).

New limitations based on a new national law (Bundesgesetz über eine sichere Versorgung mit erneuerbarer Energie) were added. The maximum import of electricity during the winter half year is limited to 5 TWh. As a conservative approach the import capacity was limited to 4 GW during winter and 0 GW during summer.

Six additional options have been modelled (Nuclear 1-3 and Wind 1-3):

1. Option N1: no nuclear power station running in 2050
2. Option N2: one existing nuclear power station with 1 GW (see chapter 2.4)
3. Option N3: one new nuclear power station with 1 GW newly built
4. Option W1: Wind energy production fix at 3 TWh (no curtailment)
5. Option W2: Wind energy production fix at 6 TWh (including curtailment)
6. Option W3: Wind energy optimized (including curtailment) for the range between 3 - 6 TWh

The wind and nuclear options are independent and can be mixed to 9 possible scenario combinations:

	N1	*N2*	*N3*
W1	1	2	3
W2	4	5	6
W3	7	8	9

Costs assumptions have been revised partly and updated.

The period of the production data on which the analysis is based have been extended from three to five years (2018-2020 to 2018-2022). The method to determine the time series of wind energy has been updated as the existing wind energy data is too low to be upscaled to higher shares.

The optimization model needs two new modules:

1- optimization of wind energy

2- inclusion of nuclear power stations

Both options need some refinements in the dispatch rules.

For all 9 scenarios we include 4% (3.1 TWh) of flexible, dispatchable conventional generation based on e-fuels (without modelling or defining the source of the e-fuels). The 4% have been used already in the preceding study.

1.1 Firm Power Concept

For each scenario analyzed, the results will consist of: Least-cost firm power levelized cost of energy (LCOE), implied size of PV fleets, as well as curtailment (overbuilding or implicit storage are used as synonyms) and real storage (beyond existing hydropower storage resource) as defined in the Figure 1 below.

With the term “firm PV power” we designate PV power meeting the electricity demand 24/365.

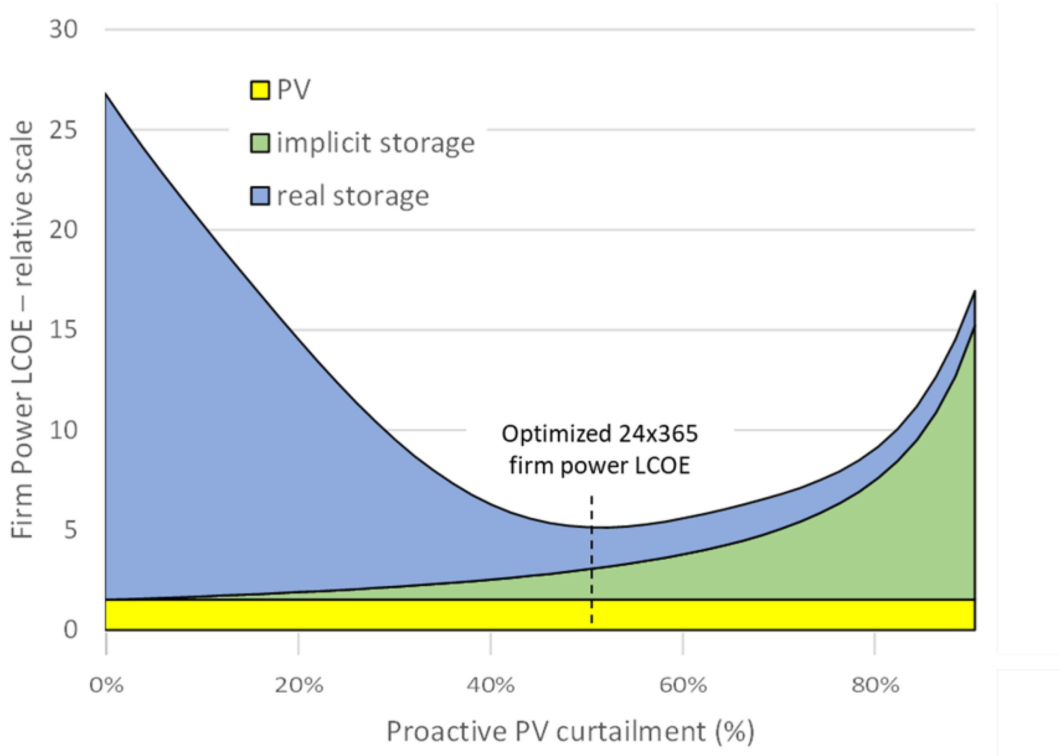


Figure 1: The influence of PV overbuilding on firm power generation LCOE. 100% overbuilding means, that 50% of the theoretical PV production is curtailed.

While unconstrained PV is inexpensive (apparently below grid parity), firming PV to meet demand 24/365 with storage alone (y-axis) is expensive. Overbuilding of PV plants reduces storage requirements to the point where firm PV power generation can achieve true (regarding overall LCOE including storage) grid parity (Perez et al., 2021; Perez at al., 2023 and Remund et al. 2023).

This work is focused on the guaranteed supply of electricity in every hour of a year. It optimizes the costs in a macroeconomic viewpoint. There is no modelling of grid (costs) and no market (merit order) modelling. We would like to mention that to foresee the market model in 2050 is also highly uncertain. The current marginal costs-based model is presumably not adequate for a system based on marginal cost-free energy.

2 Objectives

The objective is to show how much PV is cost optimally built in Switzerland to fulfil the net zero 2050 goal of the Swiss Federal Council.

Our power and not energy focused method shows the value of flexibility. The main question to be answered is how to optimally overcome intrinsic intermittency of PV and wind.

2.1 Key questions

Optimal solutions are assessed in terms of:

- Optimum storage requirements — quantified in terms of installed PV capacity-hours.
- Optimum overbuilding — quantified as a percentage above unconstrained PV capacity needed to meet energy requirements without curtailment.
- Overall (of all production and storage types) LCOE of optimally configured PV — quantified in cents per [firm] kWh.
- The updates of 2023 allow to compare the sensitivity regarding wind and nuclear energy production (with three levels of each production type)

We apply historical grid load data from the Swiss transmission system operator (TSO) Swissgrid and from the European association for the cooperation of transmission system operators for electricity (ENTSO-E) as basis to present the costs of achieving firm power generation capable of entirely displacing existing conventional generation (nuclear energy in particular) and including also future electricity needs for transportation and heating.

We analyze firm forecasts and firm power generation from the standpoint of existing distributed PV fleets. We define firm electricity generation as power follows the load securely.

Current installations are scaled up based on this spatial distribution. The case study spans the years 2018–2022, for which we acquired ENTSO-E historical hourly load data as well as PV, wind, hydro and nuclear production as corrected for import and export by Swiss Energy Statistics from Swiss Federal Office of Energy (SFOE).

2.2 PV Production and storage assumptions

We calculate the real and implicit storage (aka overbuilding or curtailment) requirements, as well as the corresponding capital cost premiums, and levelized energy production costs (LCOE). In addition to the capital cost (CAPEX) of PV and storage, LCOEs are also a function of the considered life cycle, the operation and maintenance costs (OPEX) of PV and storage as well as the Weighted Average Cost of Capital (WACC).

Real storage and implicit storage (overbuilding/curtailment) requirements are calculated as a function of:

The capital costs of PV and storage:

- a future scenario for 2050 with PV at CHF 790/kWp(stc) and battery storage at CHF 250/kWh (see chapter 3.3.1).

Further assumptions:

- round-trip efficiency of storage: 90%.
- Since the objective is to supply the demand 24/7 at high-penetration, there is no none PV fed battery recharge possibility at night or in off-hours. Storage can only be recharged when renewable production exceeds demand.

We also consider flexibility in the load that must be met by the given resources. Load flexibility is defined in terms of the fraction of energy allowed from external sources. External sources could be demand-side (e.g., efficiency, demand-side management) or supply-side, (e.g., from legacy or new dispatchable thermal generation). In this study, we consider two flexibility cases: (1) no flexibility, and (2) 10% supply-side flexibility from e-fueled dispatchable generation — note that the seasonal storage via e-fuels (H2, methane) will be modelled via this flexibility (see below).The financial specifics for PV assume:

- A 30-year life cycle;
- Operation and maintenance costs of 1% of CAPEX per year for PV;
- Operation and maintenance costs of 0.1% of CAPEX for battery storage
- A 4.0% Weighted Average Cost of Capital, representative of the PV installation mainly on rooftop. The same number was applied for all installation costs, which is underestimating the real costs as WACC e.g. for wind or nuclear power would be higher.

For a given time horizon, location, and PV configuration, the cost of firm PV power generation is obtained by extracting the lowest life-cycle cost combination of storage and overbuilding, sufficient to meet the firm forecast requirements.

We calculate storage and implicit storage requirements to firmly supply the demand of Switzerland. We apply the Clean Power Research Clean Power Transformation (CPT) model (Perez et al. 2019) to derive the optimum combination of real and implicit storage leading to the lowest possible firm generation cost.

2.3 Wind energy optimization

In the 2022 study, wind energy was taken into account but only with small numbers (2.2 – 4.3 TWh). In this study we modelled the effect of 50% more and varying wind energy shares between 3 and 6 TWh.

In Switzerland time series of wind energy available from ENTSO-E[1] are uncertain and include gaps. Wind energy production between 2018 and 2022 is very low (0.14 TWh) and localized to a few spots (Jura, Gotthard, lower Valais). Future time series with much more wind energy plants would result in much smoother curves due to geographical smoothing.

In a first step we selected the meteo stations and in a 2nd step we modelled them to be close to the ENTSO-E time series. We selected either locations which correlate with the given time series (> 0.4) or sites with high average wind speed for Switzerland (> 5 m/s on 10 m above ground). 29 sites are selected like this. They represent the potential wind areas of Switzerland quite well.

Wind speed is calculated with a simple method to a wind energy proxy with 3 m/s as minimum wind speed and 20 m/s as max. wind speed (100% of capacity). With help of a linear regression the proxy time series is adapted to the ENTSO-E time series (r2 = 0.67). This results in a time series similar to the ENTSO-E but a smoother (due to more geographical smoothing) and without gaps.

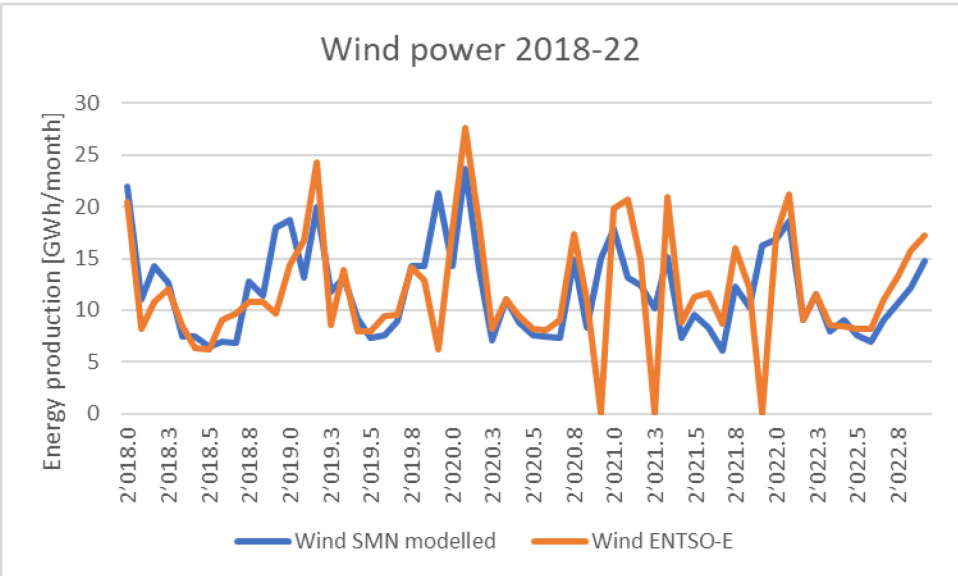


Figure 2: Modelled and measured time series of wind energy in Switzerland. SMN = Swissmetnet meteo station.

1 Source: https://transparency.entsoe.eu/

2.4 Nuclear energy

Assumptions for existing (old) and new nuclear power plants had to be taken.

Figures about costs of nuclear power in 2050 are very uncertain. Some publications (IEA, 2020) foresee low costs and support building new nuclear power stations. On the other side, there is the current experience with new nuclear constructions. The currently built nuclear power stations in Europe (Olkiluoto, Flammanville) and USA (Vogtle) are at least twice as expensive as planned) and the construction takes extremely long.

Finally, we decided to use also for nuclear the NREL Annual Technology Baseline (ATB) database. The numbers included in this database for nuclear are referenced to the US Energy Information Agency (EIA). The installation costs were set to 7200 CHF / kW for new nuclear and 1000 CHF / kW for extending lifetime by 10 years. We assumed a lifetime of 70 years for nuclear power station Leibstadt, running till 2054.

As stated before, we assumed that only one nuclear power station with 1 GW of power is running in 2050. This would be the power station of Leibstadt, which will be 66 years old in 2050 (all other power stations would be more than 70 or 80 years old).

Nuclear isn't curtailed but runs as base load during winter. However, the production is stopped between May and September (5 months) as we assume, that PV production will be that high, that base load nuclear will be extremely difficult to run technically and economically.

Social costs of nuclear due to limited liability of insurance aren't included.

3 Definition of Swiss Energy system

3.1 Introduction

The Swiss Energy System is defined in Table 6 in the Annex. Here we give an explanation of the terms and values used.

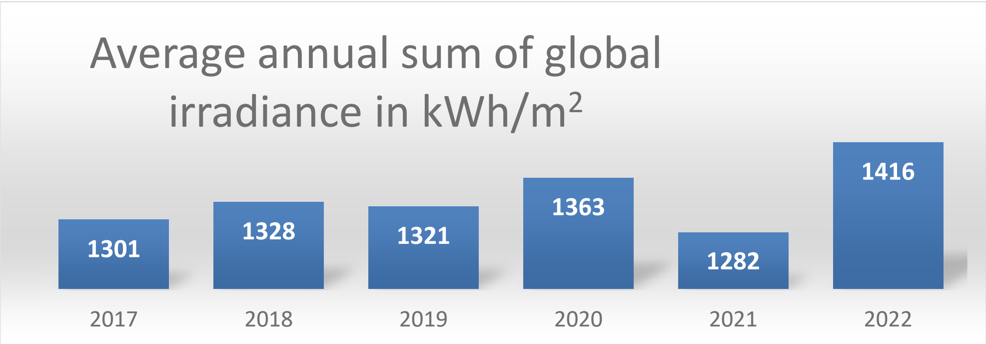
The existing system is based on the Swiss electricity statistics and hourly data of ENTSO-E[2] between 2018 and 2022. The numbers can be used to be scaled up for future scenarios. As the ENTSO-E source includes some missing values, it has been corrected to the Swiss electricity statistics[3]. PV production had to be gap filled as well. This was done with the aid of Swissmetnet stations. For those stations PV modules with an inclination of 15° South were assumed – this inclination resulted in the smallest deviations regarding the influence of the sun path.

As a new feature in this update wind energy is modelled based on Swissmetnet stations and adapted to the ENTSO-E time series.

The future system (2050) is based on the Swiss Energy Perspectives 2050+ (SFOE, 2021). This includes several scenarios of possible future energy systems fulfilling the climate agreement of Paris (1.5°C target).

3.2 Today's system

Today's system is defined as the average of the years 2018–2022. The years 2018-2020 were sunny, the year 2021 below average of last 6 years (but still sunnier than most years in the 1980ies and 90ies) and the year 2022 extremely sunny (the year with the highest level of irradiation during the last 40 years) (Figure 3). Opposite to the solar the hydro production was high in 2021 and low especially in 2022.



2 Source: https://transparency.entsoe.eu/

3 https://www.bfe.admin.ch/bfe/de/home/versorgung/statistik-und-geodaten/energiestatistiken/elektrizitaetsstatistik.html

Figure 3: Average global irradiance in the lower parts of Switzerland between 2017 and 2022. The average of 2001-2020 is 1250 kWh/m^2.

The today's yearly production in TWh is given as installed capacities and cost levels (in cts/kWh). Gross production is 70 TWh, net production 66 TWh. The losses are based on consumption of pumps for hydro power and on grid losses.

The system is defined by a high share of hydro power. This is separated into three types:

1. Hydro storage (large dams in the Swiss Alps mainly for seasonal storage),

2. Hydro pumped storage (mid-sized dams often combined with large seasonal storage dams) to store energy for some hours or days and

3. Run of river hydropower system (of the rivers flowing from the Alps to the borders).

New renewables are still relatively small but strongly growing. PV production is between 2018 and 2022 on average at 2.6 TWh, wind production at 0.15 TWh. PV installations are growing at a rate of about 30% annually. The annual increment of installed PV needs to be enhanced by a factor of two (from 1.0 GW in 2022 to 2 GW/year) to achieve the goals of net zero policy.

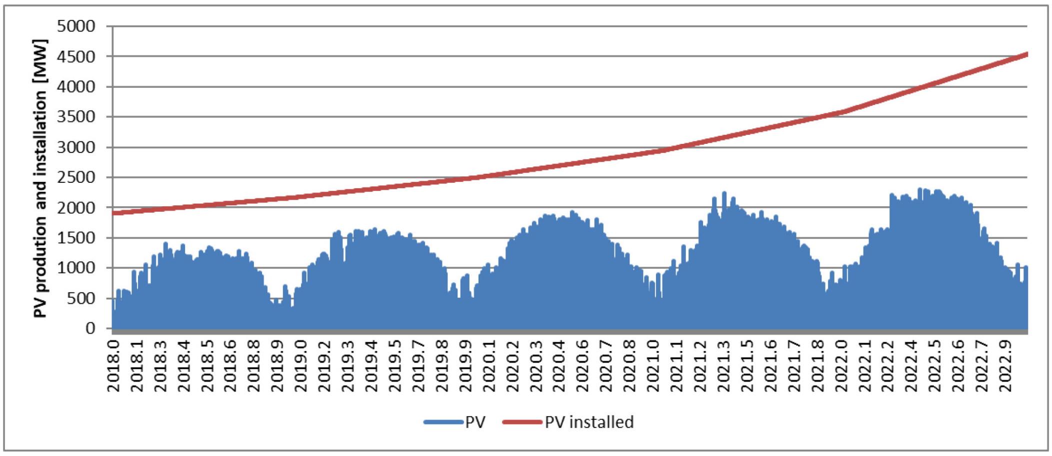


Figure 4: PV installed capacity (red line) and production (blue bars) 2018–2022.

Nuclear production is roughly 24 TWh. Four nuclear power stations at three sites are running . The construction of new nuclear is forbidden by law. There is no fixed deadline for the phase out of the nuclear power stations. However, as they were built between 1969 and 1984, they are already relatively old. Life time is expected to be further extended and foreseen between 50 and 60 years (with 2044 shutting down the last power station). The basic 2050 scenario sees no nuclear power stations and production.

However, there are ongoing discussion about extending nuclear life time also in Switzerland and few evaluate also new nuclear power stations (Schwarz and Renggli, 2023). To examine the effects of nuclear on the LCOE we added two options:

1. one with an extension of 60 to 70 years (with one running nuclear power plant with 1 GW power in 2050)
2. and one with a new nuclear power plant of 1 GW power.

Currently, electricity has a share about 25% of the energy consumption in Switzerland. 75% of the final energy consumption are non-renewables – all imported. In future (2050) this will change to 75% electricity and to 25% non-electricity based energy. The main scenario is highly based on electricity.

Since many years Switzerland is exporting electricity on the annual level. Those exports happen during summer time. In winter Switzerland is importing net electricity. This imbalance will grow when nuclear power is replaced mainly with PV.

Swiss electricity production does not follow the Swiss load. Swiss hydro power plants (storage and pumped storage) are exporting electricity to the surrounding countries during peak hours (morning and evening).

3.2.1 System data

The current system is defined by hourly values of three years 2018–2022 (Table 1) and includes the following parameters.

Table 1: Hourly parameters of the period 2018–2022.

Parameter	Abr.	Source	Remark
Load	L	ENTSO-E	Actual generation per production type
Nuclear	P_N	ENTSO-E	Actual generation per production type
Pumped hydro - storage	P_{Hp}	ENTSO-E	Actual generation per production type
Hydro storage (dams for seasonal storage)	P_{Hs}	ENTSO-E	Actual generation per production type
Hydro run of river	P_{Hr}	ENTSO-E	Modelled with measured meteo data at Swissmetnet stations; adapted to actual generation data; reduced summer and enhanced summer production due to climate change
Wind	P_W	ENTSO-E	Actual generation per production type; new time series based on Swissmetnet stations adapted to ENTSO-E time series
PV	P_{PV}	ENTSO-E Swissmetnet	Required a strong correction as in 2018 only a few PV installations were covered – and the coverage rose significantly till 2022 Gap filled with average of 20 Swissmetnet station data modelled to 15°S inclination
PV installed capacity	C_{PV}	SFOE	Modelled to hourly data
Import	P_I	ENTSO-E	Cross-border physical flow between Switzerland and the neighboring countries
Rest	R	Modelled	$R = L - P_N - P_{Hp} - P_{Hs} - P_{Hr} - P_W - P_{PV} - P_I$
Pumped hydro – consumption	L_{Hp}	Modelled	Negative part of rest (< -50 MW); sum of pump load & consumption < 2900 MW and scaled to match annual consumption
Hydro storage filling state	C_{Hs}	SFOE	Modelled from weekly to daily state
Inflow to hydro storage (net)	P_{HsiN}	Modelled	Delta of filling state. Shows approximately inflow due to snow melt
Inflow to hydro storage (gross)	P_{HsiG}	Modelled	Delta of filling state plus P_{Hs}, smoothed over 24 hours and scaled up to match yearly P_{Hs} production

Figure 5 shows the modelled inflow data – net and gross.

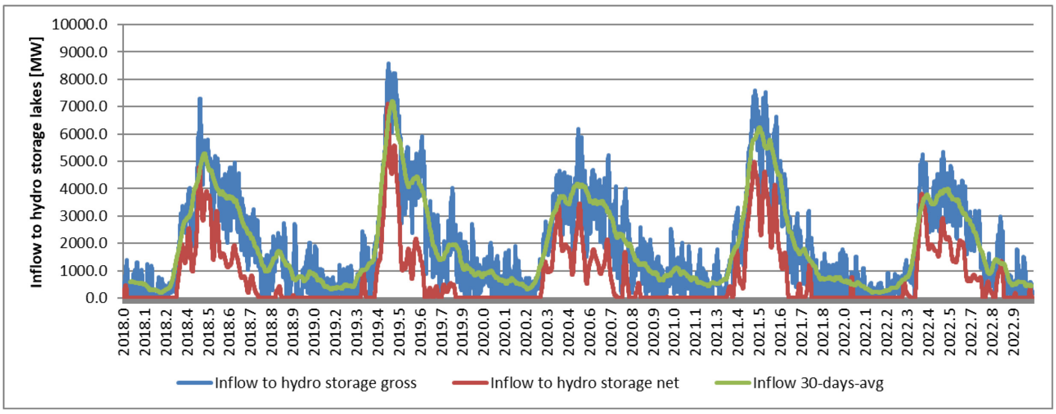


Figure 5: Modelled inflow to (seasonal) hydro storage expressed as potential electricity power in MW.

3.2.2 International grid connection

The European grid was started in 1958 on the Swiss border in Laufenburg. There the first lines were built between Germany, Switzerland and France. The Swiss grid is still highly interconnected with neighboring countries[4]. The electricity flowing through Switzerland is in the range of 50% of the electricity consumption within Switzerland. Italy depends heavily on the flow mainly from Germany. Electricity is generally imported in Switzerland during winter half year and exported during summer (up to 6 GW import and 8 GW export).

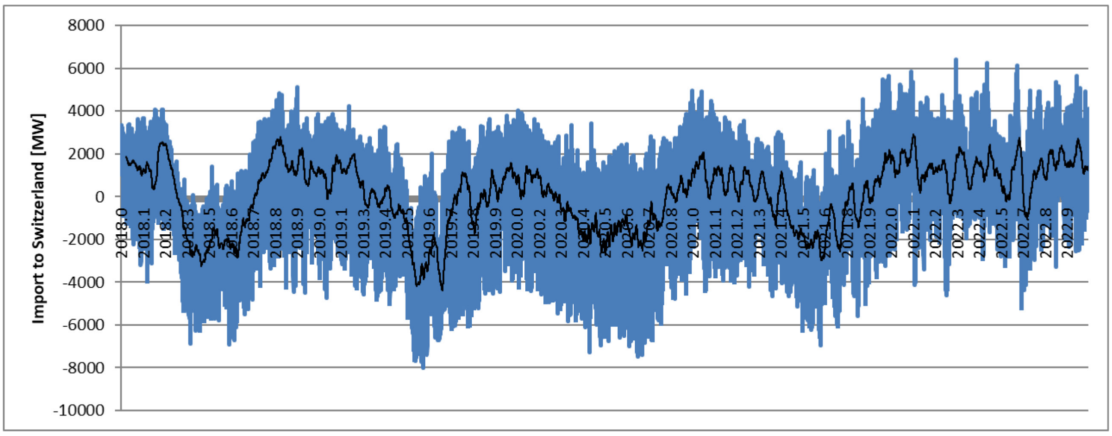


Figure 6: Import and export of electricity to Switzerland 2018–2022 (positive: import; negative: export). Black line: 15-days average.

Switzerland currently has no bilateral agreement with the EU regarding electricity due to a missing institutional agreement. Therefore, the market integration is limited and the outlook uncertain. Swiss utilities still take part in the day ahead

[4] https://www.entsoe.eu/data/map/

market EEX[5]. However, a part of the electricity balancing market and renewable certificates market are not open for Swiss companies.

Historically, the electricity price is defined during summer by the German / French market (EEX) and during winter by the Italian market. End customers pay about 15–25 cts/kWh. Market price during the last 10 years was about 5 cts/kWh. However, during winter 2021/22 the prices for day ahead electricity rose up to 20 cts/kWh.

The market price is based on old, amortized power plants. During the last 20 years this price was too low to make investments for new power plants economically interesting (called missing money problem of the European market system).

The near future is relatively uncertain. The new regulation by the EU, to reserve 70% of the capacity to cross-zonal electricity trade, poses new challenges to Switzerland[6].

3.3 The situation in 2050

In 2021, the Swiss government published an update of the Energy Perspectives – called 2050+[7] (SFOE, 2021). This report shows possible pathways to a climate neutral energy system. In this study we use the main scenario "ZERO Basis".

New (non-hydro) renewables will grow from 3 to 40 TWh. PV has and shows the biggest potential with 33 TWh. According to the Swiss Federal Office of Energy (SFOE) and based on their solar cadaster, 67 TWh of electricity can be produced on buildings. In reality, the rooftop potential is presumably lower and in the range of 50 TWh / 50 GW[8]. In this study, a maximum of 55 GW is applied which includes about 40 GW for rooftop and 15 GW of installations aside buildings (e.g. agri-PV, parking sites, floating PV). Wind energy potential would lie in the range of 9 TWh[9]. We included wind in this study between 3 and 6 TWh.

Also, hydro power is foreseen to grow. Mainly seasonal storage and hydro pumped storage capacities would be added. Seasonal storage is enhanced from 10 to 12 TWh (of which 10 TWh are maximally used in the model) according to the official targets and the Round Table discussions[10]. The price for these new systems is relatively high and would need special investments / securities by the

5 https://www.eex.com/en/market-data

6 https://www.swissgrid.ch/en/home/operation/market/european-market.html

7 https://www.bfe.admin.ch/bfe/en/home/policy/energy-perspectives-2050-plus.html

8 https://magazin.nzz.ch/nzz-am-sonntag/wirtschaft/solarenergie-ehrenrettung-ld.1679852?mktcid=smsh&mktcval=Twitter

9 https://www.newsd.admin.ch/newsd/message/attachments/72773.pdf

10 https://www.admin.ch/gov/de/start/dokumentation/medienmitteilungen.msg-id-86432.html

government. As the scenarios show differences regarding to amount of new hydro the costs are also slightly varied.

The official naming in the Energy Perspectives 2050+ is that 100% of the energy is produced within Switzerland. However, this isn't fully correct. The report includes 13.6 TWh of imported liquids based on Power to X technologies (PtL, based on renewables). Therefore, the share of energy produced in Switzerland is 84%. Additionally, the fuels for aircrafts are not included. About 20 TWh of renewable PtL is used for air transport at levels of 2019. Keeping the same levels of air transport, the real share of energy produced in Switzerland is 72%. Nonetheless, we use the term 100% in this report not considering the imported PtL and aside usage for air transport.

According the scenario ZERO Basis a small part of hydrogen is produced within Switzerland (1.9 TWh; to produce this 7.4 TWh of electricity is needed). The scenario is rather optimistic regarding efficiency measures. Total energy consumption will not grow much. One of the realistic reasons is that today many electric heating systems exist, which will be exchanged by heat pumps (saving 70% of the electricity). Oversizing was included in the modelling to a limited extent. In the scenario, 37 GW of PV is foreseen with 33.6 TWh of production. As 37 GW in Switzerland produce on average 37 TWh of energy peak shaving of 9% is included.

3.3.1 Cost levels 2050

There are no cost assumptions per technology published in the Energy Perspectives reports. The report only includes some general macro economical figures.

The definition of price levels 30 years ahead includes high uncertainties. Four different sources have been used as a basis: published papers (Figgener et al., 2019, NREL ATB[11]), Nexus-e reports (ESC, 2020[11]), conferences (EES 2021[12]) and selected Swiss experts, which have been interviewed. The reported values were included in the definition. As all PV includes mostly rooftop PV and labor costs in Switzerland are high, the LCOE of PV will stay rather high.

The most comprehensive work on costs and cost perspectives exists in the Annual Technology Baseline (ATB) of the US National Renewable Energy Laboratory (NREL)[13]. Those figures are the main source for the state of 2050. They include also small-scale PV and batteries.

Battery storage costs are currently still rather high – especially for small storage at individual houses. In future there is a big potential for cost reductions..

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11 https://nexus-e.org/documentation/

12 https://www.ees-europe.com/

13 https://atb.nrel.gov/electricity/2023/technologies

Storage / H_2 prices have been updated based on EES 2021 conference (Oct. 21) and on ATB figures as well as in an IEA report[14]. We assumed a mix of 30% small installations (< 10 kW), 40% mid-sized installations (10–200 kW) and 30% bigger installations (for Swiss conditions).

Costs of imported and exported electricity today is in the range of 5 cts/kWh (a bit higher for exports as Switzerland gains some net income (SFOE, 2021). The forecast for 2050 is almost impossible especially when taking into account the turbulent situation on the electricity market during the last months. Generally, higher costs are foreseen[15]. We assumed slightly higher costs for import (7 cts/kWh) and constant costs for export (5 cts/kWh), as Switzerland will tend to export more in summer and import more in winter in future based on the switch from nuclear to PV.

14 https://iea.blob.core.windows.net/assets/181b48b4-323f-454d-96fb-0bb1889d96a9/CCUS_in_clean_energy_transitions.pdf

15 https://www.handelsblatt.com/politik/deutschland/co2-und-erdgaspreise-studie-strompreis-steigt-bis-2030-um-50-prozent/27170486.html?ticket=ST-13976634-7m2L46hBf6kAVX9bDG0d-ap2

Table 2: Price assumptions for 2050. For PV and battery storage installation costs were used for modelling. For non-optimized production types, the energy costs.

Nr	Installation costs in CHF/kW	Approx. energy costs in cts/kWh
PV avg. on buildings	790	6.9
Battery storage[10]	250	9.0
Wind	1240	11.0
Hydro		6.0 (mix of new and existing)
Hydrogen[11]		10.0
Gas power station (gas and investment)	2000	8.5
Thermal electricity costs based on e-fuels		20.2
Imported electricity		7.0
Exported electricity		5.0
Nuclear extended (LTO) Extension of 10 years to total 70 years (till 2054)	1000	6.0
Nuclear new	7200	12.0*

* without costs of insurance – see chapters 2.4 and 4.4

3.3.2 Nine scenarios

The following 9 scenarios have been calculated (Table 3). All with 0% net yearly import and 4 GW max import/export capacity restrictions of electricity from neighboring countries and max. 5 TWh of import during winter. 3% are based on gas fired power plants based on e-fuels (plus 2% on thermal production mainly from waste).

Table 3: Nine scenarios used in this study.

No.	Scenario definition
1	97% renewable energy sources (RES) Switzerland including 3 TWh of wind and no nuclear
2	89% renewable energy sources (RES) Switzerland including 3 TWh of wind and 1 GW of life time extended nuclear
3	89% renewable energy sources (RES) Switzerland including 4.5 TWh of wind and 1 GW of new nuclear
4	97% renewable energy sources (RES) Switzerland including 4.5 TWh of wind and no nuclear
5	89% renewable energy sources (RES) Switzerland including 4.5 TWh of wind and 1 GW of life time extended nuclear

No.	Scenario definition
6	89% renewable energy sources (RES) Switzerland including 3-6 TWh of wind and 1 GW of new nuclear
7	97% renewable energy sources (RES) Switzerland including optimized 3-6 TWh of wind and no nuclear
8	89% renewable energy sources (RES) Switzerland including optimized 3-6 TWh of wind and 1 GW of life time extended nuclear
9	89% renewable energy sources (RES) Switzerland including optimized 3-6 TWh of wind and 1 GW of new nuclear

Table 4: Installed capacities in GW 2018–2022 and 2050 with scenarios 1–9. Opt. means: optimized. Seasonal Hydro storage capacity is in TWh. Batteries are optimized for all steps.

Type	2018–2022	2050 Sc. 1	2050 Sc. 2	2050 Sc. 3	2050 Sc. 4/7	2050 Sc. 5/8	2050 Sc. 6/9
PV	2.66	opt.	opt.	opt.	opt.	opt.	opt.
Wind	0.14	1.5	1.5	1.5	2.25/opt	2.25/opt	2.25/opt
Hydro (all types)	15.3	19.5	19.5	19.5	19.5	19.5	19.5
Nuclear	2.96	0	1	1	0	1	1
Therm. production (natural gas, biogas, e-fuels)	0.97	1.81	1.81	1.81	1.81	1.81	1.81
Seasonal hydro storage* capacity [TWh]	10	12	12	12	12	12	12
Batteries	-	opt.	opt.	opt.	opt.	opt.	opt.

* about 80% of the storage can be used in reality: this is considered in the model

3.3.3 Overview of the scenarios

Figure 7 summarizes the contribution of all supply-side energy sources in each scenario compared to the current situation. It clearly illustrates the central role to be played by new firm PV generation, ranging from 30% of total generation in scenarios #5, #6 and #8 and #9 to 38% in scenarios #1.

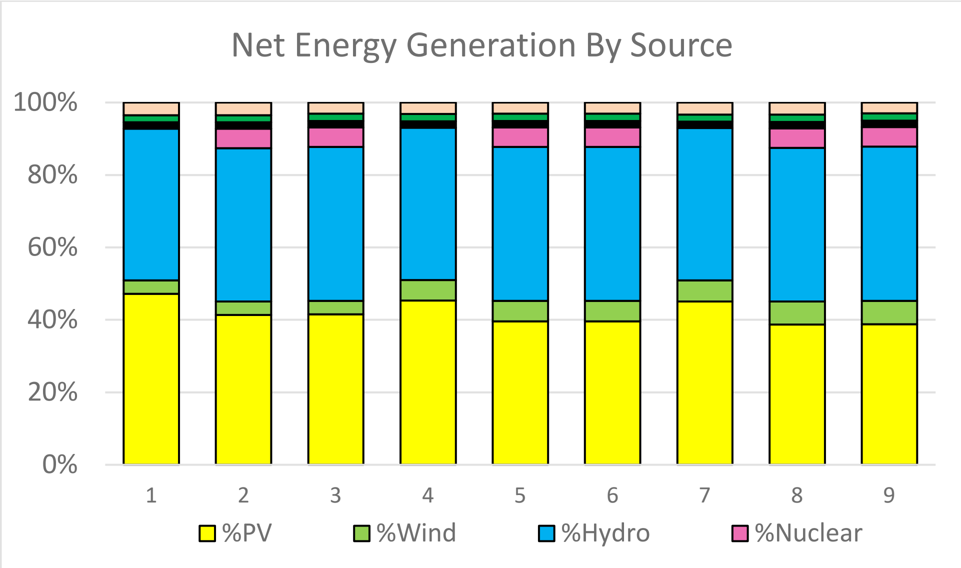

Figure 7: Supply-side electrical energy resources for all scenarios compared to the current situation. The bottom part of the figure provides details for the source labeled as ‘other’ in the top part.

3.4 Order of redispatch

The following Figure 8 shows the order of dispatch in the Clean Power Transformation (CPT) model. PV capacity is deterministic and dependent on curtailment which is a driving independent variable. Optimization happens on curtailment / overbuilding in order to minimized cost while respecting capacity and energy limits/ setpoints.

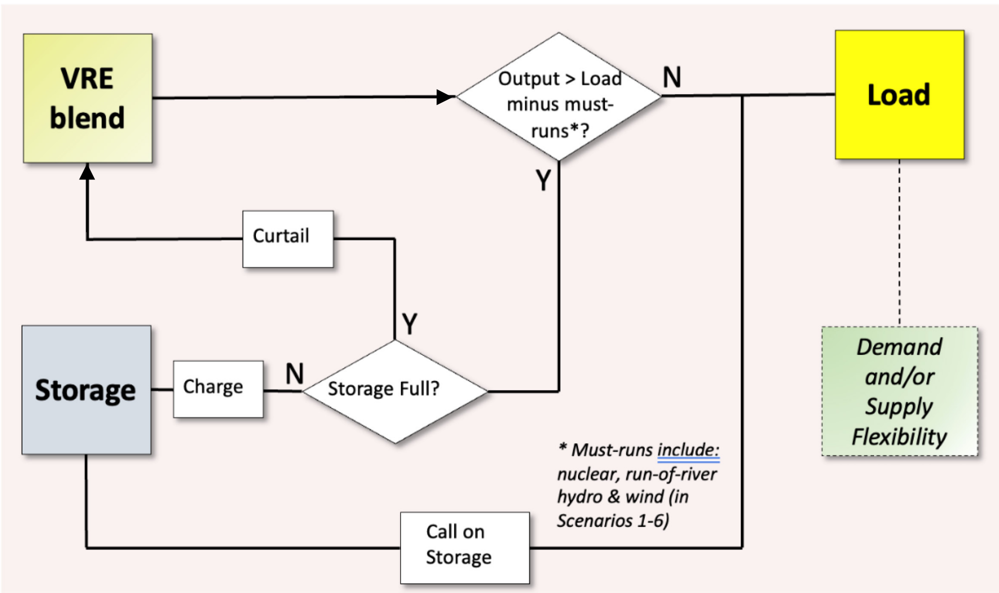

Figure 8: Dispatch model applied in the Clean Power Transformation (CPT) model. PSH stands for pumped hydro storage.

We apply the CPT model to determine the optimum PV and battery resources needed to meet demand firmly at the least possible cost while dispatchable resources are optimally deployed toward this minimum cost/firm power generation objective. The results of this optimization include the required quantities of new battery storage, new PV, curtailed PV output (implicit storage), the electricity generation cost of the optimum supply-side/storage blend that will supply Swiss demand 24x365.

Each meteorological year (2018, 2019, 2020, 2021 and 2022) is modelled alone to show the sensitivity of inter-annual variations.

The annual (2020) dispatching of these resources is illustrated in Figure 9.

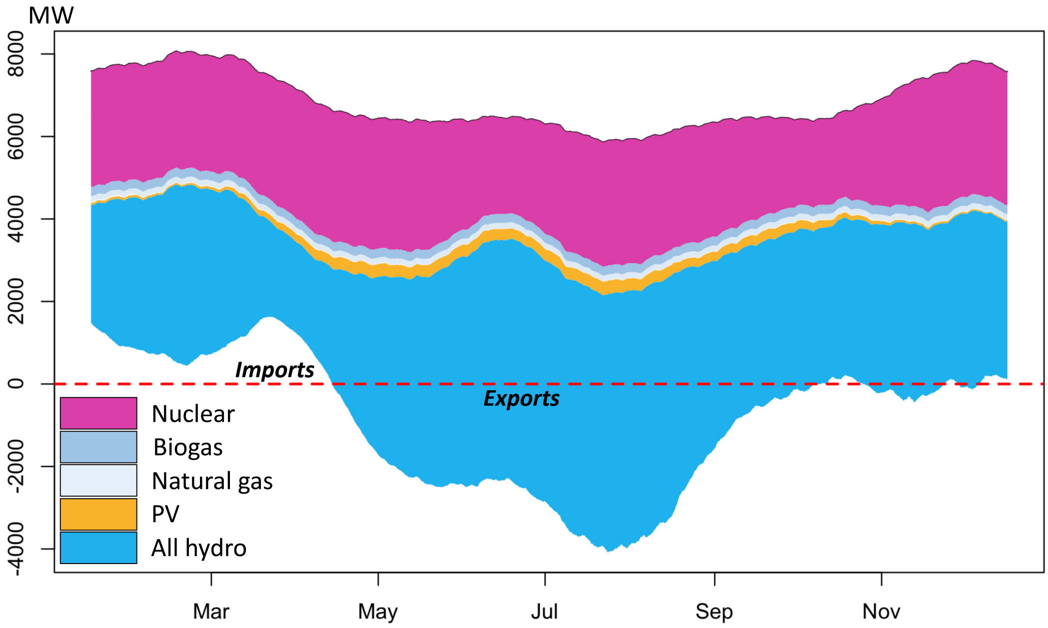

Figure 9: Annual dispatch of Swiss-based of supply-side resources for the year 2020. The top line of the stacked graph represents the Swiss grid load. “Biogas” is used as a proxy for thermal production based on renewables.

Net imports over the winter half year summed up to about 5 TWh during the last 20 years. This value is targeted also in the law and used as a limit in this study.

3.5 Climate change

We use a conservative approach as we do include climate change effects only partially:

1. Climate change will enhance the run-of-river hydro production in winter and lower it in summer (a switch of about 0.6 TWh until 2050).
   We included this change based on the RCP4.5 scenario of CH2018 datasets

(2018). Hydropower is enhanced by 7% in winter and lowered by 8% during summer.

2. Climate change will lower the duration of winter. Winter starts later and spring earlier. As the inflow to storage lakes is strongly reduced in winter a shorter winter reduces the need for seasonal storage of hydro is lowered. This effect could lower the storage need up to 10% - but due to the complexity his isn't taken into account.

3. Climate change will lower the heating needs – and enhances the cooling loads (which will be much lower than the heating loads in 2050). Both would be positive for integration of PV. Heat load needs were defined in the Energy Perspectives. In this study the same figures were used. Climate change wasn't taken into account.

The two latter effects will lower the seasonal unbalance.

As a new feature in this study, we included also some demand side management (DSM) effects throughout the day. The new, additional loads from e-mobility and heat pumps were moved within the day to fit the maximum of PV production. About 1 GW was shifted throughout the day.

This helps the integration within the day. However, the much bigger integration issue are the seasonal imbalance and demand side management can't be applied for those time scales.

4 Results

4.1 General overview

In Figure 9 we report the PV capacity, curtailed PV output (implicit storage), and battery storage required in each scenario to firmly meet demand on the Swiss power grid. The upcoming figures show the meteorological years separately.

New PV capacities (Figure 10 top) range from 30 GW (nuclear and enhanced wind) to 52 GW (scenario 1 with low wind an no nuclear). PV output curtailment (Figure 10, middle) ranges from 8-12% (scenario 8 or 9) to 25-32% (scenario 1). New battery storage requirements (Figure 10, bottom) range from 8-12 GWh (scenario 8 or 9) to 25-32 GWh (scenario #1).

In all cases, required battery storage is low, amounting to less than one hour of full PV capacity. The bottom line is that no new long-term storage is required beyond the small addition to the existing buffer hydro system (+10% / 1 TWh), as is often assumed when envisaging ultra-high PV or wind penetration. This observation corroborates results obtained in the US (Perez, M., 2020). 10–30 GWh of batteries also seem feasible compared to the expected electrical vehicle batteries, which will include about 200 GWh of battery storage. Accessing 10% of this storage with by-directional loading systems would reduce the need of extra storage significantly.

Figure 11 reports the blended all-resources power generation LCOEs on the Swiss power grid.

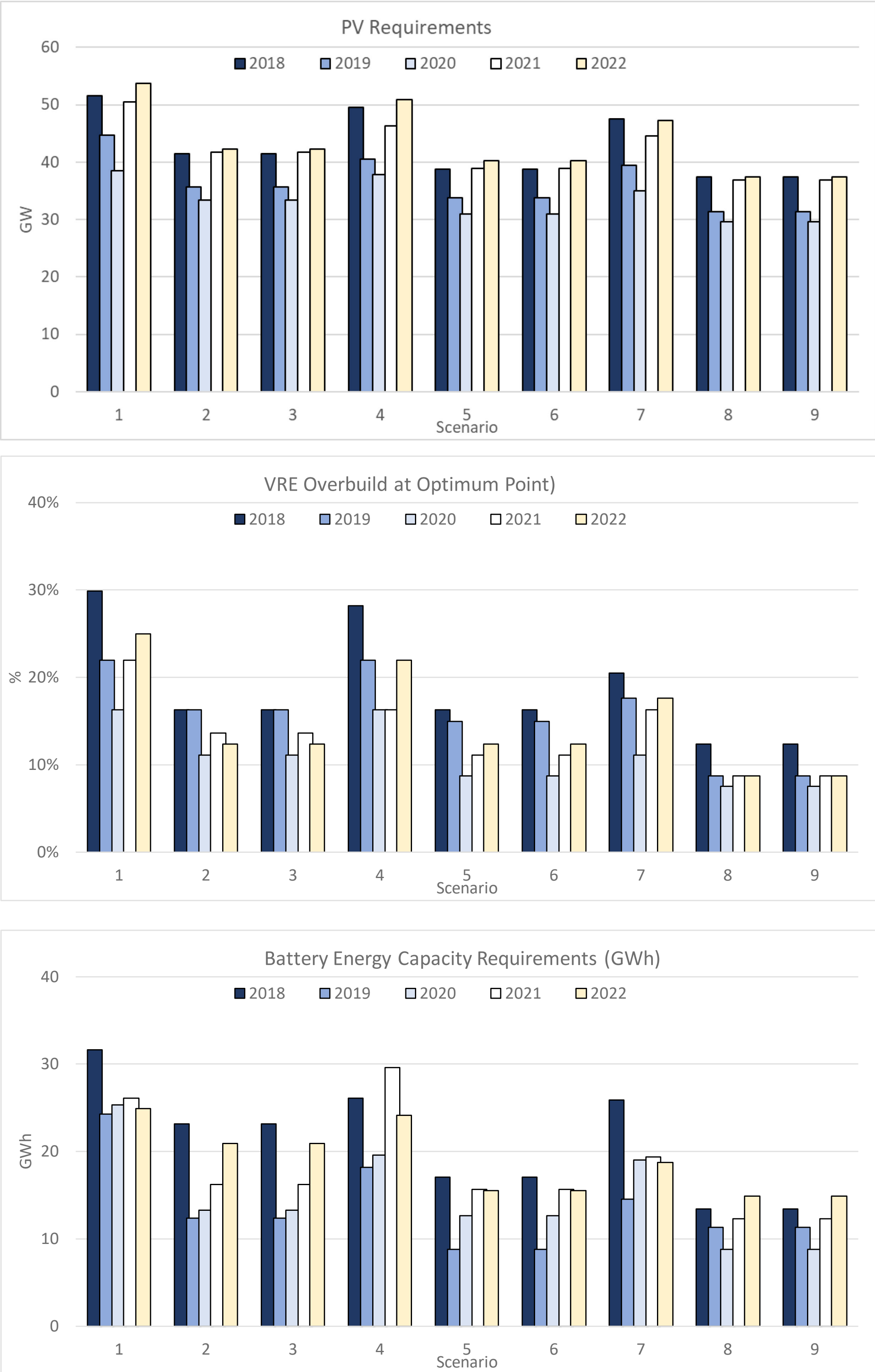

Figure 10: Total PV capacities (top), optimal curtailment (middle) and new battery storage for scenarios 1–9 and for the years 2018-2022.

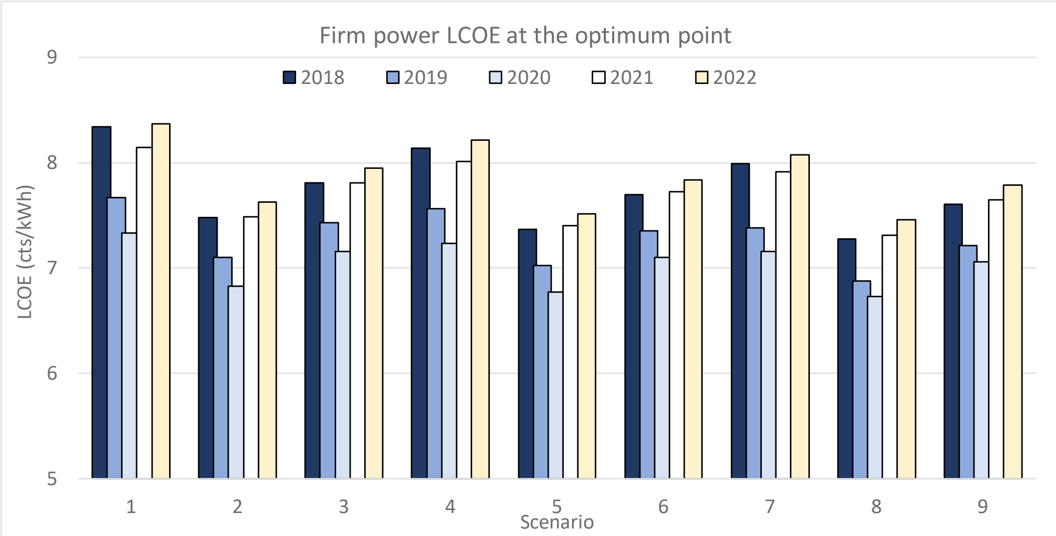

Figure 11: Swiss grid power generation costs for scenarios 1–9.

Electricity production costs range from 6.8 cts/kWh (scenario 8, 2020) to 8.6 cts/kWh (scenario 1, 2018 and 2022).

Figure 12 illustrates the critical role of implicit storage on the bottom line. Without operationalizing PV overbuild and curtailment, production costs would be 80% higher for scenario 1 and 24-70% including new nuclear and wind.

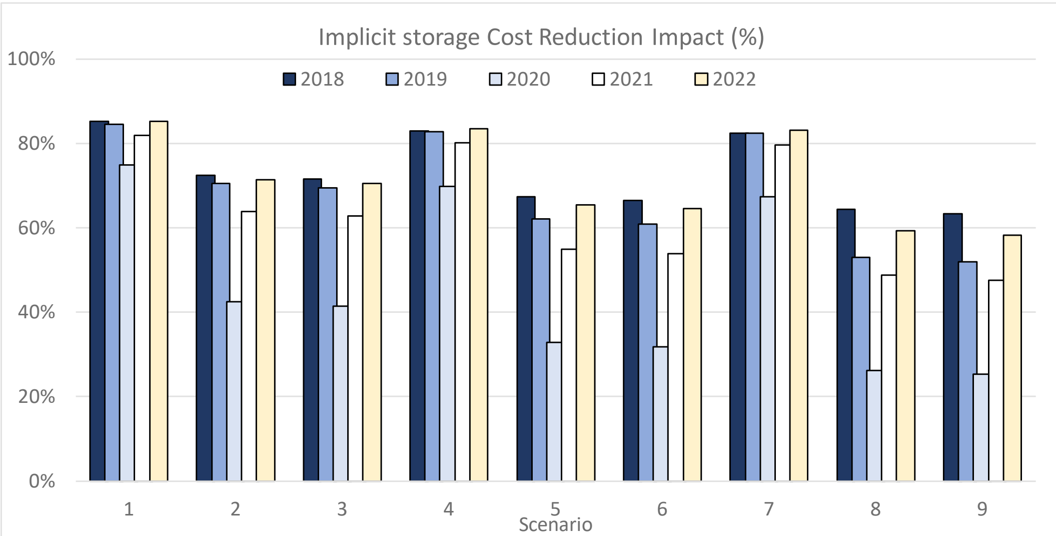

Figure 12: Cost reductions due to implicit storage (overbuilding).

The new annual dispatch of all resources is illustrated in Figure 13. Monthly means have been plotted to remove short-term fluctuations and improve visualization. The top edge of the graph represents demand on the Swiss grid. Note that the Swiss production is insufficient in winter and early spring, requiring imports from the rest of Europe. However, production exceeds demand in summer and is exported.

The production types are combined based on their flexibility. Must runs include run of river hydro and nuclear and existing PV and wind. Renewables include non-dispatchable new (added to existing) variable PV and wind. Storage includes only short term pumped hydro and batteries. Dispatchable include e-fuels based gas power, thermal production, import and hydro storage.

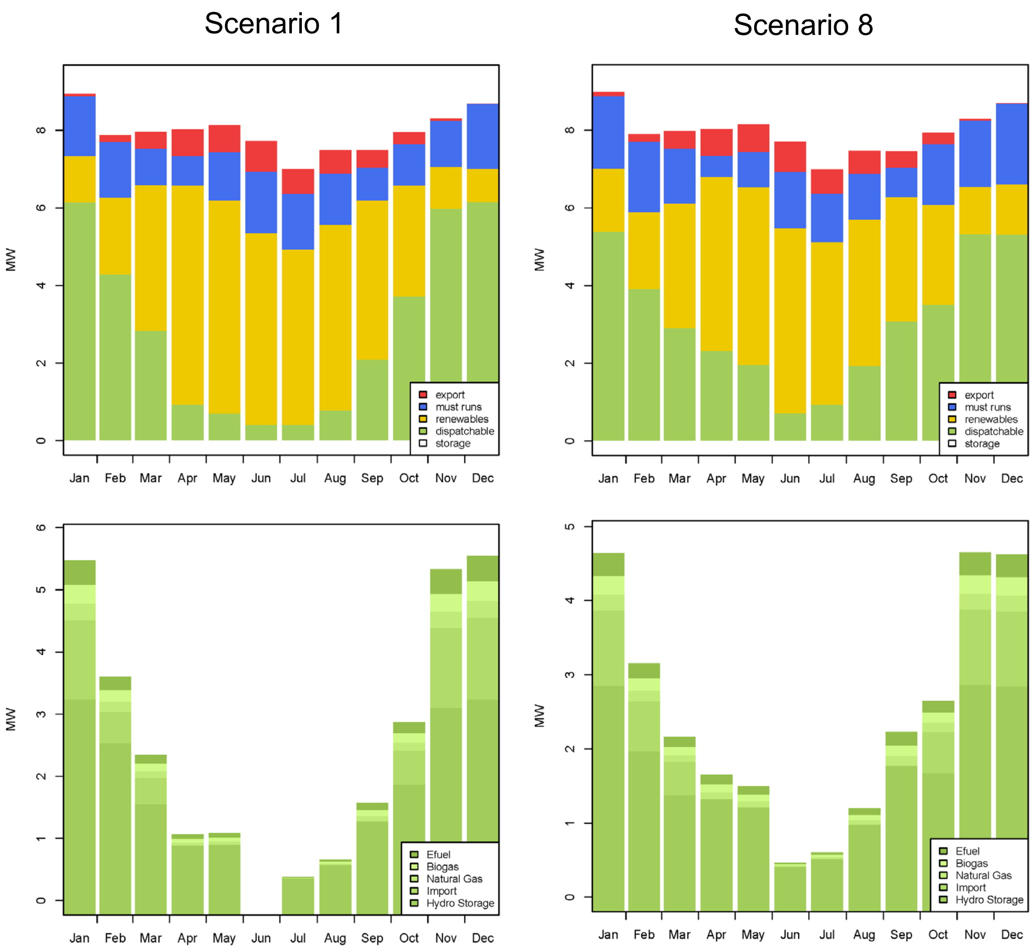

Figure 13: Annual dispatch of Swiss-based of supply-side resources for 2050 based on the meteorological year 2021 and scenario 1 (left) and scenario 8 (right). Top: Total production. Bottom: Dispatchable resources separately shown.

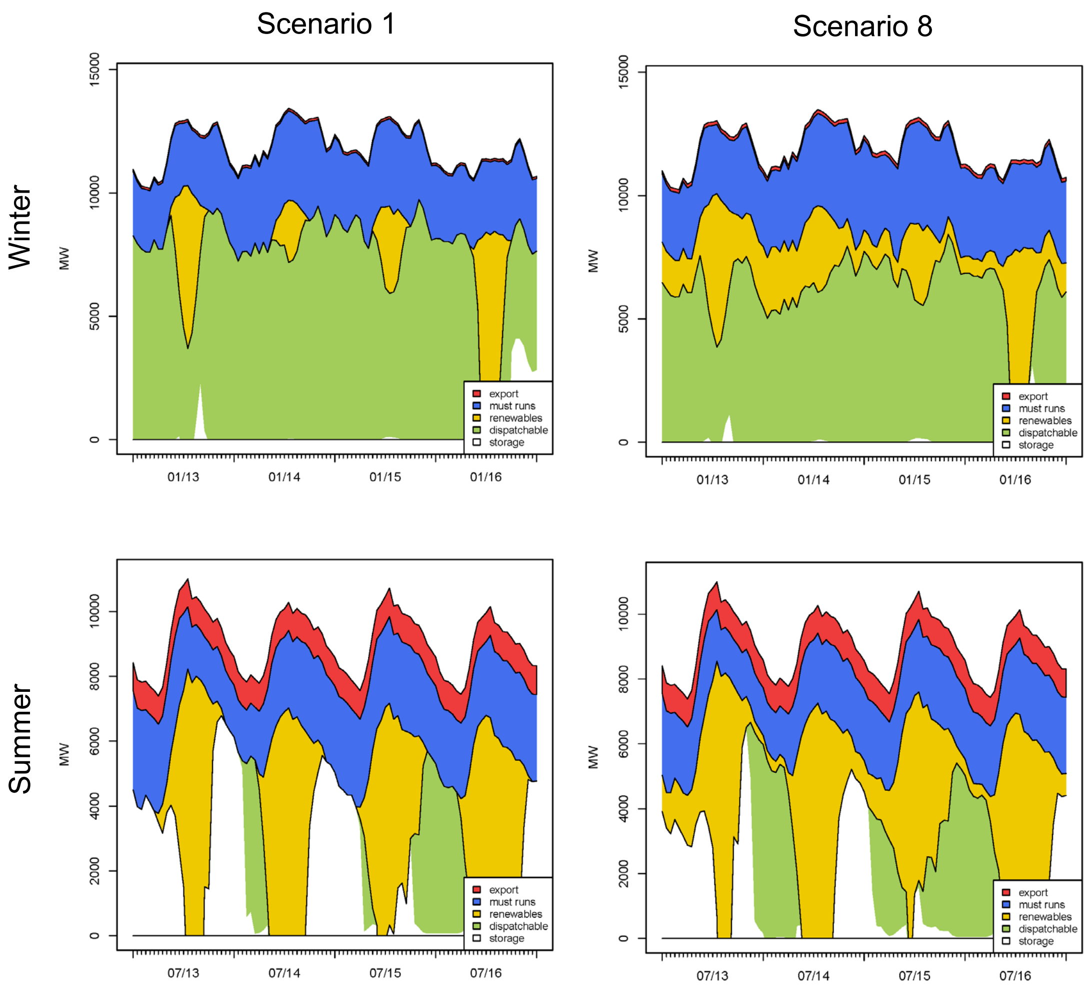

Figure 14: Hourly dispatch of supply-side resources for the meteorological year 2021 for scenarios 1 (left) and 8 (right) for 4 days in winter (top) and summer (bottom).

Electricity for battery charge and pumped hydro comes mostly from PV.

Figure 15 shows the share of energy production in scenario #8.

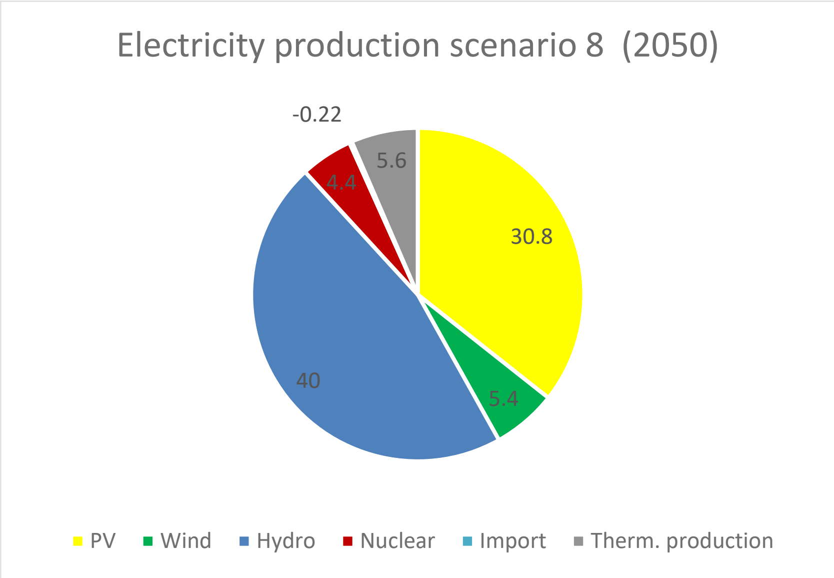

Figure 15: Share of energy production types in TWh for scenario #8 for 2050 (average over all meteorological years).

In Table 5 the main modelling results are listed.

Table 5: Main results of the modelling for scenarios #1-#9 (minimum and maximum values of yearly for the 2018-2022 results given).

Parameter	**Sc. 1**	**Sc. 2**	**Sc. 3**	**Sc. 4**	**Sc. 5**	**Sc. 6**	**Sc. 7**	**Sc. 8**	**Sc. 9**
PV installed capacity [GW] (avg/min-max)	48 39-54	39 33-42	39 33-42	45 38-51	37 31-40	37 31-40	43 35-47	35 30-37	35 30-37
PV curtailment [%] (min-max)	15-30	12-18	12-18	18-30	9-15	9-15	11-25	8-14	8-14
Wind installed capacity [GW] (min-max)	1.5	1.5	1.5	2.25	2.25	2.25	2.7-3.2	2.6-3.1	2.6-3.1
LCOE [cts/kWh] (avg/min-max)	8.2 7.5-8.6	7.4 7.0-7.7	7.7 7.3-8.0	8.0 7.4-8.3	7.3 6.9-7.6	7.7 7.2-7.9	7.8 7.2-8.2	7.2 6.8-7.5	7.6 7.2-7.9
Battery Capacity [GWh] (min-max)	19-36	13-23	13-23	19-30	12-20	12-20	14-23	9-15	9-15
Net Imports [TWh]	0.5	-0.2	-0.2	0.3	-0.2	-0.2	0.3	-0.2	-0.2

Overall, the results of the Energy Perspectives and the first Firm Power study 2022 could be confirmed. Results for all scenarios are given in Table 7 in the Annex.

4.2 Implicit storage impact

Figure 16 illustrates the importance of overbuilding and operationally curtailing the PV resource on the bottom line: production costs would be an average of 64% higher across all scenarios for all meteorological years.

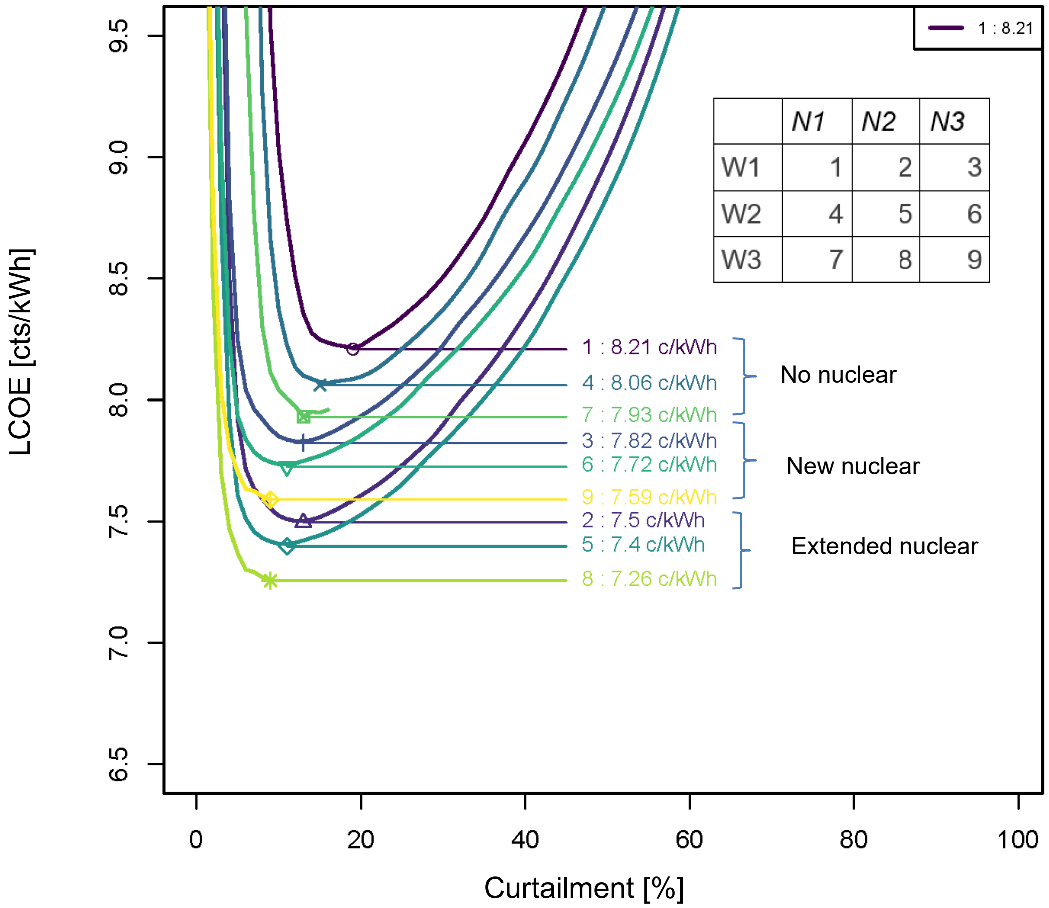

Figure 16: Electricity production cost on the Swiss power grid as a function of PV output curtailment for all scenarios for the meteorological year 2021.

The differences are visible, but in relation to the uncertainty of the cost assumptions and the year to year variability small. The scenarios without nuclear are showing slightly higher costs and curtailment. The scenarios with one extended nuclear power plant is somewhat lower and the scenarios with one new nuclear power plant in-between. In relation to the final consumer prices (production plus grid plus taxes sum up to about 30 cts/kWh) the differences in the sub-cents range are even smaller.

The values of implicit storage overbuilding for all years and scenario are visible in Figure 10.

4.3 Wind energy

The more wind energy the better. Or to be precise: more wind energy lowers the overall LCOE costs in the Swiss electricity system. It lowers the implicit storage needs of PV. Within the given range of 3-6 TWh optimally 2.5-3.1 GW of wind would be installed producing 5 – 6 TWh of energy (Figure 17).

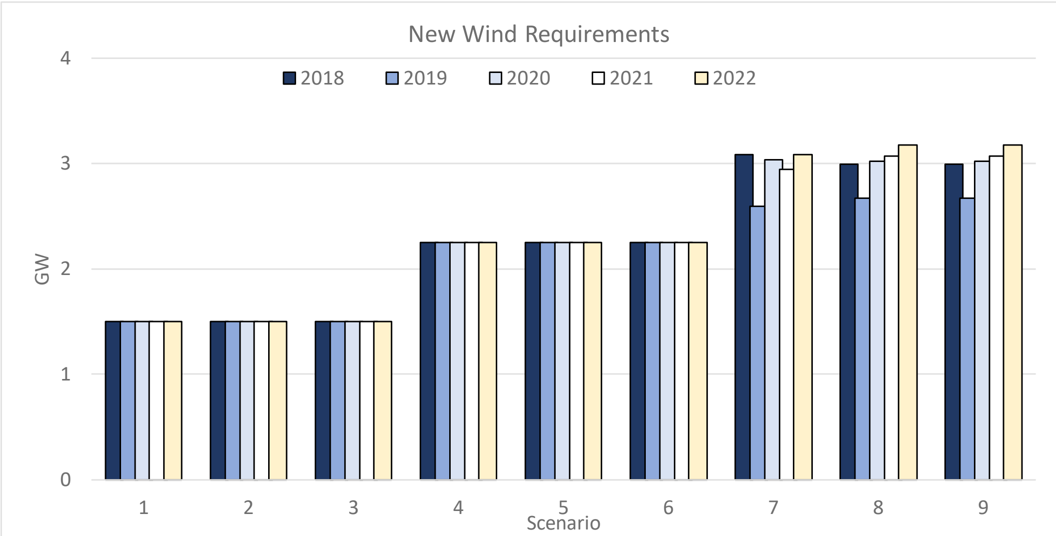

Figure 17: Wind energy capacities per scenario.

As for expensive electricity from e-fuels based gas power plants also expensive wind energy (using it in low shares) lowers the overall costs.

4.4 Nuclear energy

The same effect as for expensive wind can also be said for expensive nuclear.

Even running it only between October and April (7 months) and reducing full load hours compared to today by 40% compared to today the effect on overall LCOE is slightly positive. In our assumption 1 GW would produce about 4.4 TWh of electricity (5% of the annual electricity production in Switzerland). This would be a massive reduction compared to today (22.9 TWh / 35%).

We modelled only one GW of nuclear power during winter half year. This helps to reduce the winter import deficit and also the overbuilding of PV. Most presumably more nuclear wouldn't fit that well in the variable energy future and would induce much more stress on the system and would push costs up. However, this is an open issue.

No nuclear power station has been run for 70 years. Like this many uncertainties exist about the costs. Constructing a new nuclear power station would induce even higher uncertainties and it would take decades to build such a plant. Also, the national law has to be changed.

Additionally, we didn't model the social costs of nuclear power. The maximum value of the insurance has been limited for nuclear power stations to roughly 0.5 - 1.5 billion EUR based on different national laws and international agreements[16][17].Without such limitations nuclear power stations wouldn't have been and wouldn't be built today. It's almost impossible to insure against a GAU or a super GAU, which could cost up to 500-1000 Bio. EUR. The nuclear accident in March 2011 in Fukushima induced costs of about 200 Bio. EUR[18]. Those not-insured costs are socialized to the community. Assumptions of those costs are seldom modelled and very uncertain. They would be in the range of 5 – 600 cts/kWh (Laureto et al. 2020) for nuclear power, making nuclear power way too expensive.

4.5 Influence of different meteorological years

The five years (2018–2022), analyzed independently, lead to very comparable firm power production cost results overall as seen in Figure 11.

As stated in chapter 3.2 the years 2018-2020 were sunny, the year 2021 below average (but still sunnier than most years in the 1980ies and 90ies) and the year 2022 extremely sunny (the year with the highest level of irradiation during the last 40 years). Opposite to the solar the hydro production was high in 2021 and low especially in 2022.

The year 2020 shows the lowest overall costs with lowest LCOE and lowest battery capacities and implicit storage. The year to year variability is bigger than the differences between the scenarios. Scenario 1 with no nuclear and low wind in 2020 has a lower LCOE than Scenario 8 with nuclear and more wind for 2018, 2021 and 2022.

4.6 Conclusions

Our investigation shows that high-RES solutions for Switzerland, with PV playing a central role as a complementary resource to the country's hydropower system, are both physically and economically reasonable. Overall, the cost differences between the 9 scenarios are low. The range is in between 6.8 and 8.6 cts/kWh. This is lower than as 2022 and 2023 and within the uncertainty of the cost assumptions and within the yearly variability.

Like this it is important to state that operational costs in all considered scenarios are reasonable compared to current wholesale market prices. The presented costs are even reasonable when compared to earlier pre-crisis wholesale prices (4–6 cts/kWh) noting that these earlier prices do not fully factor-in environmental

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[16] https://www.bfe.admin.ch/bfe/en/home/supply/nuclear-energy/nuclear-energy-liability.html

[17] https://crsreports.congress.gov/product/pdf/IF/IF10821

[18] https://www.ncbi.nlm.nih.gov/books/NBK253929/

or strategic externalities which, as we see today with international tensions, can be consequential.

Enhancing wind energy lowers the price even if wind energy is more expensive than solar. Extending one nuclear power station (with 1 GW power) lowers the overall costs as well. This is surprising as both of them are more expensive than solar and the number of running hours for nuclear will be lowered.

Finally, we once again stress the importance of implicit storage (i.e., optimally overbuilding the PV resources). Not implementing this deployment strategy would result in much higher prices on the network. It is therefore important to operationalize and value optimal overbuilding and curtailment early-on, by e.g., implementing appropriate regulations that would lead to firm power monetization, instead of current run-of-the-whether PV production.

The study shows, that different pathways are feasible with more or less wind and with or without nuclear. The cost levels of energy production are all in an acceptable range. To get to the needed levels of capacities long term planning is needed – especially for the grid and for bigger investments like nuclear. This long term investment security isn't given today as there are no deadlines for phase out of the nuclear power stations.

4.6.1 Policy and Market

The lowest costs result in scenario 8 with about 35 GW PV, 3 GW wind, 1 GW nuclear (with extended lifetime), 10% PV curtailment and 12 GWh battery storage, including a 10% rise of hydro power generation and storage (plus 1 TWh), a rise in pumped hydro (from 2.9 to 5.7 GW) and an import of 5 TWh of e-fuels (for electricity generation).

How to obtain this optimum is another and big question. The current policy and regulatory framework most presumably will not induce enough investments to attain this: With bigger shares, PV will start to cannibalize itself. At noon there will be more PV than load and the prices will be zero or negative. Purely market-based models or power purchase agreements (PPA) will most presumably fail in this situation. Foreseen contract-of-difference agreements or feed-in-tariffs based on amortization can help to secure investments, but don't lead to firm power yet.

The electricity market in many Western countries and also in the EU and Switzerland is a copy of the market defined first in New England (USA) in the 1980s – with mostly fossil fuels, nuclear and hydro but without fluctuating renewable energies. It depends on marginal costs and the rule of merit order. Many countries added an incentive for renewables and a capacity market (Cramton et al., 2008) to reach more energy security as the energy only market did not induce enough investments into additional capacities.

Many countries like Germany, UK, Canada or USA are targeting a 100% RES based electricity system by 2035. As this production portfolio will rely only to a small extent on marginal costs a market based on marginal costs is at least debatable. A short literature review (IRENA, 2017; Peng & Poudineh, 2017, MacGill et al., 2020, Keppler et al. 2022) indicates that ideas exist. However, some argue (e.g. Zachmann et al., 2023), that marginal pricing is without alternatives. In any case, market design is very complex and changes may also introduce negative effects. We strongly advice to extend scientific foundation.

Specifically, how to value and secure overbuilding and thus minimize the overall costs is an open question. In other words: Someone needs to pay for the curtailment in order to secure investments and achieve the needed growth and numbers for PV and wind.

4.6.2 Grid regulations

In this study we didn't model the effects on the grid. Curtailing PV and wind helps to reduce the costs for enhancing the grid. The scenarios with moderate wind and nuclear presumably would lower the grid costs even more. Applying the firm power concept to grid regulations would lower the need to extend and enhance them. This is important as many DSOs are currently struggling to enhance the grid in the needed time. However, just to be clear: this doesn't mean, that grid enhancements aren't needed. Bottlenecks in the grid still need to be widened. A combined optimization of production, storage, curtailment and grid would be interesting and useful.

How to regulate curtailment on technical side on distribution grids is another question. IEA PVPS Task 14[19] is currently finalizing a report about this topic. The distribution grid operator of South Australia (SAPN)[20] introduced in 2023 a new smart and fair regulation to curtail PV on buildings. A new Swiss law ("Mantelerlass"[21]) (approved by Parliament in autumn 2023 with a popular referendum in summer 2024) allows the grid operators to curtail energy. This is good news and show that also grid regulations and DSO start to move. However, to reach the implicit storage optimum more changes will be needed. E.g. in Germany the TSO and DSO aren't allowed to include higher shares of curtailment in their long term grid plannings.

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[19] https://iea-pvps.org/research-tasks/solar-pv-in-100-res-power-system/

[20] https://www.sapowernetworks.com.au/industry/flexible-exports/

[21] https://www.bfe.admin.ch/bfe/en/home/supply/electricity-supply/federal-act-renewable-electricity-supply.html

4.7 Outlook

Different firm power studies throughout the world showed the importance of over-building. The optimum curtailment was found the range of 10-30%. Results of complex electricity and energy system models as nexus- e[22], Balmorel[23] or LUT_ESTM (Breyer et al., 2023)[24] often show lower curtailment rates in the range of 2-5%. The reason for those differences aren't obvious and known. Some argue, that the differences are due to the lack of sector coupling – but that is to be confirmed and at least doubted (as some of the firm power studies as [3] included e.g. hydrogen production).

Our firm power concept is a relatively simple approach based on spatially and temporally resolved renewable resources, investment and running costs and macro-economic optimization. It neglects the current market model and signals as well as grid congestions and sector coupling (or only indirectly by external drivers). The simple model has the advantage to include only a relatively small set of input variables and that it is optimized to a certain objective.

Nexus-e, Balmorel, LUT_ESTM or other complex model include many different parts including grid and market. This makes them complex and difficult to oversee all adjusting screws and sub-models. Many assumptions have to be taken also regarding the functioning of the market. Most of the models assume the same rules as of today. However, the existing electricity market induces wrong signals to achieve optimal energy systems.

Like this a direct comparison – a benchmark - of modelling results for the regions and assumptions would be of great interest. As long as the outcome is uncertain the next important steps – how to reach this optimum – can't be evaluated and decided.

[22] https://nexus-e.org/

[23] https://www.energyplan.eu/othertools/global/balmorel/

[24] https://static.agora-energiewende.de/fileadmin/Projekte/2021/VAs_sonstige/2021-05-28_Presentation_LUT_ESTM_Deep_Decarbonization.pdf

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Annex

Table 6: Input definitions and resulting optimized production values.

Energy production & import in TWh										
Type	**2018-2022**	2050 Sc. 1	2050 Sc. 2	2050 Sc. 3	2050 Sc. 4	2050 Sc. 5	2050 Sc. 6	2050 Sc. 7	2050 Sc. 8	2050 Sc. 9
PV	2.66	37.7	33.3	33.3	36.2	31.8	31.8	35.6	30.8	30.8
Wind	0.14	3	3	3	4.5	4.5	4.5	5.1	5.4	5.4
Hydro	38.3	40	40	40	40	40	40	40	40	40
Nuclear	22.9	0	4.4	4.4	0	4.4	4.4	0	4.4	4.4
Import	-1.5	0.5	-0.2	-0.2	0.3	-0.2	-0.2	0.36	-0.22	-0.22
Therm. production	2.6	5.7	5.8	5.4	5.5	5.4	5.4	5.6	5.6	5
Gross production	67.4	85.7	85.7	85.7	85.7	85.7	85.7	85.7	85.7	85.7
Net production	63	65	65	65	65	65	65	65	65	65
Check sums										
Total	65.1	86.9	86.3	85.9	86.5	85.9	85.9	86.66	85.98	85.38
New renewables	5.5	42.6	38.2	38.2	42.6	38.2	38.2	42.6	38.1	38.1
All renewables	43.8	82.6	78.2	78.2	82.6	78.2	78.2	82.6	78.1	78.1
Reduced renewables	38.8	0	4.4	4.4	0	4.4	4.4	0	4.5	4.5
Gas fired pp	0.7	3.8	3.9	3.5	3.6	3.5	3.5	3.7	3.7	3.1
Import (annual share)	-2%	1%	0%	0%	0%	0%	0%	0%	0%	0%
Share of CH EE	65%	96.4%	91.2%	91.2%	96.4%	91.2%	91.2%	96.4%	91.1%	91.1%

Installed GW										
Type	**2018-2022**	2050 Sc. 1	2050 Sc. 2	2050 Sc. 3	2050 Sc. 4	2050 Sc. 5	2050 Sc. 6	2050 Sc. 7	2050 Sc. 8	2050 Sc. 9
PV	2.36	47.8	38.9	38.9	45	36.5	36.5	42.7	34.6	34.6
Wind	0.08	1.5	1.5	1.5	2.3	2.3	2.3	3	3	3
Hydro	15.3	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5
Nuclear	2.96	0	1	1	0	1	1	0	1	1
Import	-1.5	0	0	0	0	0	0	0	0	0
Therm. production	0.97	1	5	5	5	5	5	5	5	5

Scenario definition		2050 Sc. 1	2050 Sc. 2	2050 Sc. 3	2050 Sc. 4	2050 Sc. 5	2050 Sc. 6	2050 Sc. 7	2050 Sc. 8	2050 Sc. 9
Headline										
Share of renewables	65%	96%	91%	91%	96%	91%	91%	96%	91%	91%
Net annual import	-2%	1%	0%	0%	0%	0%	0%	0%	0%	0%
Import restrictions TWh winter		5 TWh	5 TWh	5 TWh	5 TWh	5 TWh	5 TWh	5 TWh	5 TWh	5 TWh
Import restrictions GW	no (10 GW)	4 GW	4 GW	4 GW	4 GW	4 GW	4 GW	4 GW	4 GW	4 GW
Share of gas fired pp.	1%	4%	5%	4%	4%	4%	4.1%	4%	4%	4%
Thermal prod. [GW]	1	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81
Thermal prod. E-Fuels [TWh]	1.4	3	3	3	3	3	3	3	3	3
Thermal prod. [TWh]	2.6	5	5	5	5	5	5	5	5	5
Thermal prod. Renew. Share	46%	40%	40%	40%	40%	40%	40%	40%	40%	40%

Fuel costs	**Today**	2050 Sc. 1	2050 Sc. 2	2050 Sc. 3	2050 Sc. 4	2050 Sc. 5	2050 Sc. 6	2050 Sc. 7	2050 Sc. 8	2050 Sc. 9
Headline										
Natural gas	30	30	30	30	30	30	30	30	30	30
Emission rate [t CO2/MWh]	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Efficiency (gas -> electricity)	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Power station (invest., o&m) [CHF/MWh]	35	35	35	35	35	35	35	35	35	35
CO2 emission certificates [CHF/tCO2]	60	100	100	100	100	100	100	100	100	100
CO2 removal / sequestration [CHF/tCO2]		150	150	150	150	150	150	150	150	150
E-Fuel (green H2) [CHF/MWh]		100	100	100	100	100	100	100	100	100
Total natural gas / certif [CHF/MWh]	107	125	125	125	125	125	125	125	125	125
Total natural gas / sequestr [CHF/MWh]		145	145	145	145	145	145	145	145	145
Total E-Fuel (H2) [CHF/MWh]		202	202	202	202	202	202	202	202	202
Natural gas without certif	85									

Renew. Costs		2050 Sc. 1	2050 Sc. 2	2050 Sc. 3	2050 Sc. 4	2050 Sc. 5	2050 Sc. 6	2050 Sc. 7	2050 Sc. 8	2050 Sc. 9
Headline										
PV install. Costs [CHF/MWh]		790	790	790	790	790	790	790	790	790
PV prod. Costs [cts/kWh]		6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9
Wind [cts/kWh]		11	11	11	11	11	11	11	11	11
Hydro [cts/kWh]		6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00
Battery install costs [CHF/MWh]		250	250	250	250	250	250	250	250	250
Battery [cts/kWh]		9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Import [cts/kWh]		7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Export [cts/kWh]		5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0

Marginal Costs		2050 Sc. 1	2050 Sc. 2	2050 Sc. 3	2050 Sc. 4	2050 Sc. 5	2050 Sc. 6	2050 Sc. 7	2050 Sc. 8	2050 Sc. 9
Headline										
PV prod. Costs [cts/kWh]	2.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Wind [cts/kWh]	3.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Hydro [cts/kWh]	5.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Battery [cts/kWh]	20	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Import [cts/kWh]	5.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Export [cts/kWh]	5.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Gas based (EE) [cts/kWh]	10.0	20.0	18.0	18.0	20.0	18.0	18.0	20.0	18.0	18.0

Table 7: Average results of modelling based on 2018 – 2022 meteorological years. Imports will happen during winter time.

Scenario	PV installed	PV Prod.	PV curtailed	Battery capac.	LCOE	Thermal prod.	Imports
	[GW]	[TWh]	[%]	[GWh]	[cts/kWh]	[TWh]	[TWh]
1	47.8	37.7	25%	26.5	8.2	5.7	5.5
2	38.9	33.3	15%	17.7	7.4	5.8	4.8
3	38.9	33.3	15%	17.7	7.7	5.4	4.8
4	45.0	36.2	22%	23.5	8.0	5.5	5.3
5	36.5	31.8	13%	15.2	7.3	5.4	4.8
6	36.5	31.8	13%	15.2	7.7	5.4	4.8
7	42.7	35.6	18%	19.1	7.8	5.6	5.3
8	34.6	30.9	10%	12.2	7.2	5.6	4.8
9	34.6	30.9	10%	12.2	7.6	5.0	4.8