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Sektion Energieforschung und Cleantech

**Final report of 24 June 2025**

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# AGGREGATE

# The value of aggregators in a flexible and decentralized Swiss energy system

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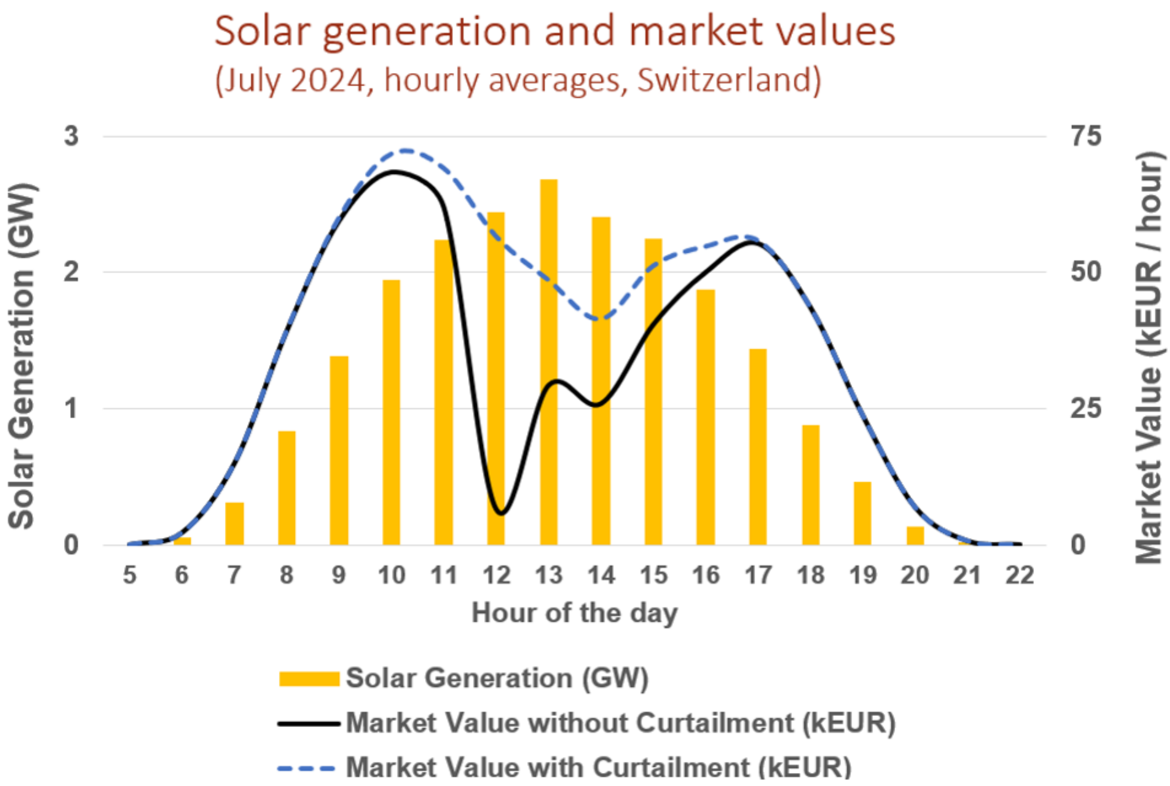


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# Zusammenfassung

In einem künftigen Elektrizitätssystem mit hohem Anteil erneuerbarer Energien und neuen Stromnachfrageanwendungen wird die Erzeugung konventioneller Stromerzeugungsanlagen allein nicht in der Lage sein, Angebot und Nachfrage auszugleichen. Die aktive Beteiligung dezentraler Energieressourcen wie Photovoltaik, Elektromobilität und Wärmepumpen ist notwendig. Aufgrund unvollkommener Information, begrenzter Rationalität und regulatorischer Hindernisse reagieren Haushalte jedoch oft nicht auf Preissignale. In diesem Projekt analysieren wir, welchen Wert die Flexibilität von dezentralen Energieressourcen für das Stromsystem haben kann und welche regulatorischen Massnahmen nötig sind, um das Potenzial auszuschöpfen.

# Résumé

Dans un futur système électrique avec une forte part d'énergies renouvelables et de nouvelles applications de demande d'électricité, la production des centrales conventionnelles ne suffira pas à équilibrer l'offre et la demande. La participation active des ressources énergétiques décentralisées, telles que le photovoltaïque, la mobilité électrique et les pompes à chaleur, est nécessaire. Toutefois, en raison d'une information imparfaite, d'une rationalité limitée et d'obstacles réglementaires, les ménages ne réagissent souvent pas aux signaux de prix. Dans ce projet, nous analysons la valeur que peut avoir la flexibilité des ressources énergétiques décentralisées pour le système électrique, ainsi que les mesures réglementaires nécessaires pour exploiter ce potentiel.

# Summary

In a future electricity system with a high share of renewable energy and new electricity demand applications, generation from conventional power plants alone will not be sufficient to balance supply and demand. The active participation of decentralized energy resources such as photovoltaics, electric mobility, and heat pumps is necessary. However, due to imperfect information, limited rationality, and regulatory barriers, households often do not respond to price signals. In this project, we analyze the value that the flexibility of decentralized energy resources can bring to the power system and which regulatory measures are needed to unlock this potential.

# Main findings («Take-Home Messages»)

- Flexibility provides economic value: Charging electric vehicles during hours of low prices and curtailing solar power during negative prices are the most important levers. Heat pumps offer moderate flexibility value compared to electric vehicle charging.
- Dynamic energy and grid tariffs are the most important policy measures to foster demand-side flexibility.
- Dynamic pricing can be combined with price insurance: A smart form of retail tariff, profile contracts, offers consumers optimal incentives for demand flexibility while protecting them from price level risks.

# Contents

# 1 Introduction

## 1.1 Background

The decarbonization of the energy sector is fundamentally reshaping the structure and operation of electricity systems across Europe. This transformation is driven by two main forces: increasing renewable energy deployment, and the electrification of the heating and mobility sectors through the deployment of heat pumps and electric vehicles (EVs). While these developments are essential to achieve global and regional decarbonization goals and meet climate targets, they also present significant challenges for maintaining grid stability, ensuring cost-effectiveness, and optimizing the operation of the power system.

In this context, flexibility— i.e., the ability of generation, demand, and storage to respond dynamically to price signals or system conditions—emerges as a critical tool to ensure system reliability, economic efficiency, and sustainability. Aggregators may play a central role in pooling consumers, producers, and prosumers, leading to expected efficiency and welfare gains. However, regulatory and incentive structures must be well designed to lift the full flexibility potential of aggregation and avoid regulatory arbitrage.

## 1.2 Project Goals

In this context, our project aims to quantify the economic value of electricity flexibility and outline policy recommendations to provide incentives for flexibility on the supply and demand side to be used optimally. To that end, we identify the economic value of aggregators in a flexible and decentralized Swiss energy system and provide guidance on a regulatory framework that reduces barriers to beneficial aggregation and avoids incentives for regulatory arbitrage. Furthermore, we study regulation on aggregators in Switzerland and derive policy conclusions to fill regulatory gaps. As Switzerland, unlike neighboring countries, does not have retail competition for regular household customers, the regulatory environment around aggregation significantly deviates from EU countries, where retail competition provides an additional pathway for aggregator access to flexible household assets.

## 1.3 Structure of this report

The remainder of this report is structured as follows. In the following sections, we present Policy Briefs for the three main contributions of this project, the long versions of which are either published in academic journals or can be found in the Appendix to this report.

The first contribution, "*Profile contracts for electricity retail customers*" relates to our core recommendation, the introduction of dynamic energy tariffs for retail customers. We study a specific type of tariff, which enables at the same time to provide incentives to react to hourly price signals, as well as stabilizing the monthly electricity bill so that customers do not suffer from high energy prices if wholesale prices increase. In that sense, it tries to square the circle of price exposure while keeping household energy bills stable.

The second contribution, "*Value of flexibility in Switzerland*" quantifies how valuable it is for decentral energy appliances to react to price signals, i.e. to act flexibly according to hourly price signals. First, we analyze this on the supply side in the context of solar panels and the reactions to negative prices (i.e. stopping solar production when prices turn negative). Second, we analyze this on the demand side for flexible charging of electric vehicles (EVs) and for running heat pumps flexibly.

The third contribution, "*Measures to promote electricity flexibility in Switzerland*" relates to policy measures that can be introduced in Switzerland to foster flexibility from decentral assets. It is a policy report written in the context of the Mantelerlass legislation, a major reform to electricity legislation in Switzerland. The report concludes with several main recommendations, among which are incentive regulation for distribution grid operators and the introduction of dynamic retail tariffs for energy and grid components of electricity prices.

## 2 Policy Brief: Profile contracts for electricity retail customers

Authors: Christian Winzer, Héctor Ramírez-Molina, Lion Hirth, Ingmar Schlecht

**Executive summary**

- Profile contracts offer hourly price signals with stable electricity bills for consumers
- They reduce bill volatility to similar levels as fixed price contracts
- Profile contracts restore flexibility incentives suppressed by fixed price contracts
- Profile contracts may reduce bill of flexible customers compared to fixed prices
- Demand for profile contracts expected to increase as load flexibility increases

**Outline**

Decarbonization involves a large-scale expansion of low-carbon generators such as wind and solar and the electrification of heating and transport. Both space heating and battery-electric cars have significant embedded flexibility potential. Granular price signals that convey abundance or scarcity of electricity are a precondition for customers or aggregators acting on their behalf to exploit this flexibility. However, unmitigated real-time prices expose customers to electricity price risks. To tackle the dual need of providing flexibility incentives while protecting customers from cost shocks, real-time tariffs with a hedging component can be a solution. In such contracts customers pre-agree an amount of energy and a consumption profile, while hourly deviations are charged at spot prices. In this paper we analyze design options by using a dataset of anonymized smart meter data and show that profile tariffs can bring electricity bill volatility to similarly low levels as fixed tariffs while providing full flexibility incentives from spot prices.

The results we present highlight the potential of profile tariffs to bridge the gap between real-time tariffs on the one hand and fixed tariffs on the other hand. The results also show that the introduction of a hedging component in real-time tariff already significantly improves bill stability, regardless of the precise implementation chosen. Unless future analyses reveal a significant benefit of more sophisticated profile shapes, it would therefore seem sensible to start with a simple baseload hedge, for which there is a liquid market to reduce transaction cost and avoid unnecessary risk premia for more complex products.

In addition to their risk-reducing impact, hedge contracts would also improve customer incentives both for load-shifting and for load saving. Customers who react to market prices by consuming less during high-price years or shifting load from high-price periods to low-price periods will benefit from lower average prices than their peers. By contrast to fixed price contracts, where incentives for load-shifting and load saving are quickly diluted, when the prices are averaged across a larger group of customers, profile contracts retain load-shifting and energy saving incentives even if prices are averaged across larger customer groups.

**Policy conclusions**

Retail hedging contracts could protect customers from price-surges caused by technical failures, extreme weather events or geopolitical supply cuts for long-enough until supply capacity is increased. At the same time, retail hedging contracts would expose customers to the full incentives of real-time prices, enabling them to lower their bill by reducing shortages through temporary load-shifting or load-reduction measures.

This is also an important insight for efforts to reform electricity markets. Most electricity utilities in Switzerland today offer predominantly fixed price tariffs. Also, as a response to the energy crisis of 2022, the European Commission has proposed a reform of EU electricity market, including a provision to mandate retailers to offer fixed-price fixed-term retail contracts. Our results show that such mandates could be improved by promoting profile tariffs rather than fixed tariffs that hamper flexibility use.

We show that already a simple baseload hedge significantly reduces bill volatility. While more fine-grained choices of hedge profile and scaling can improve the fit of the hedge, in our limited observation horizon of two years without a pronounced cold period, we cannot show the effect of hedge scaling during cold spells, for which it would be expected to be particularly helpful.

**Reference**

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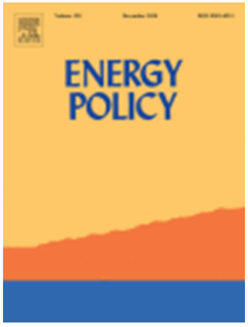


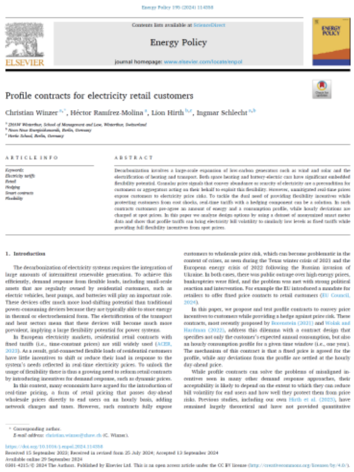
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Profile contracts for electricity retail customers

Christian Winzer[a,*], Héctor Ramírez-Molina[a], Lion Hirth[b,c], Ingmar Schlecht[a,b]

ARTICLE INFO

ABSTRACT

1. Introduction

# 3 Policy Brief: Value of flexibility in Switzerland

Based on report by: Héctor Ramírez-Molina

*See Appendix 1 for the full report.*

**Executive summary**

- Curtailing PV during negative prices improves system value but is hindered by inflexible incentives
- Flexible EV charging significantly reduces household energy costs under dynamic pricing
- Bidirectional EV charging adds the most value, often eliminating the need for battery storage – yet investment cost for bidirectional capabilities must be weighed against this
- Heat pumps offer moderate flexibility value compared to EV charging
- Dynamic tariffs greatly enhance the value of demand-side flexibility compared to flat rates
- Flexibility can deliver cost savings comparable to PV and battery investments, without upfront capital

**Outline**

The Swiss electricity system is undergoing a rapid transition driven by rising shares of renewable energy and electrification of end-uses like transport and heating. This shift increases volatility in electricity prices and puts pressure on distribution grids. Flexibility—defined as the ability of demand, generation, and storage to respond dynamically to price signals—is emerging as a critical tool to ensure reliability, economic efficiency, and sustainability. Aggregators play a key role in unlocking this flexibility by enabling small actors to participate in electricity markets and overcome structural market barriers.

It is important to estimate the value of flexibility for the Swiss electricity system because the size of potential benefits to be reaped from flexibility aggregation determines the appropriate level of priority for enabling regulatory access for aggregators for managing assets within households vis-à-vis other policy goals such as keeping transaction costs for existing utility companies low and enabling them to stay in control of the assets in their distribution grids.

*Negative prices and solar curtailment*

On the supply side, increasing solar PV capacity has led to a sharp rise in hours with negative wholesale electricity prices, especially during summer. Analysis from 2020 to 2024 shows that curtailing PV production during these periods could have added up to EUR 12.77 million in system value in 2024 alone. However, current incentive schemes like feed-in tariffs continue to encourage price-blind generation. Although the relative loss in market value reached 6% in 2024, the overall gains from curtailment are still too small to justify widespread investment in control systems for small-scale PV.

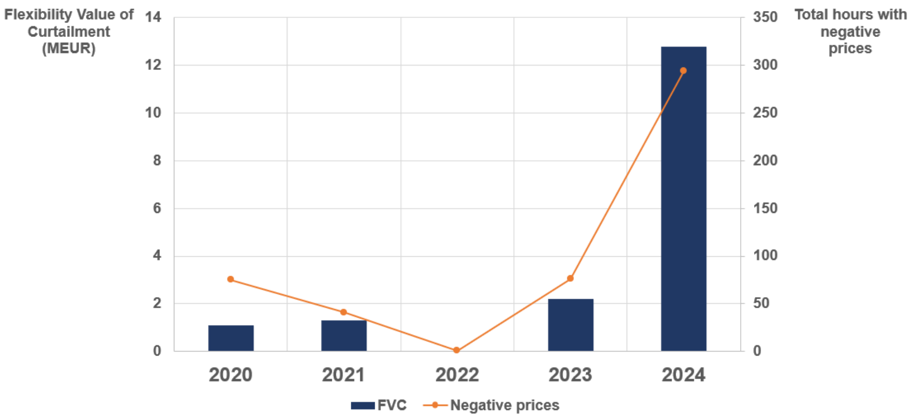

Figure 1: Total value of curtailing solar at negative prices in Switzerland, and number of negative prices for comparison

*Demand-side flexibility from EVs and heat pumps*

Demand-side flexibility, particularly from electric vehicles (EVs) and heat pumps, shows significant economic potential for households. In 2050 scenarios, flexible EV charging under dynamic tariffs can save households up to CHF 107 annually (for bidirectional charging, CHF 350 of cost savings is possible as an upper limit under full flexibility), while flexible heat pump operation is less relevant and can only yield up to CHF 70 even under daily flexibility assumptions. Overall, dynamic pricing alone can unlock value, especially from flexible EV charging, comparable to investing in rooftop PV and battery systems, i.e. without requiring additional investments.

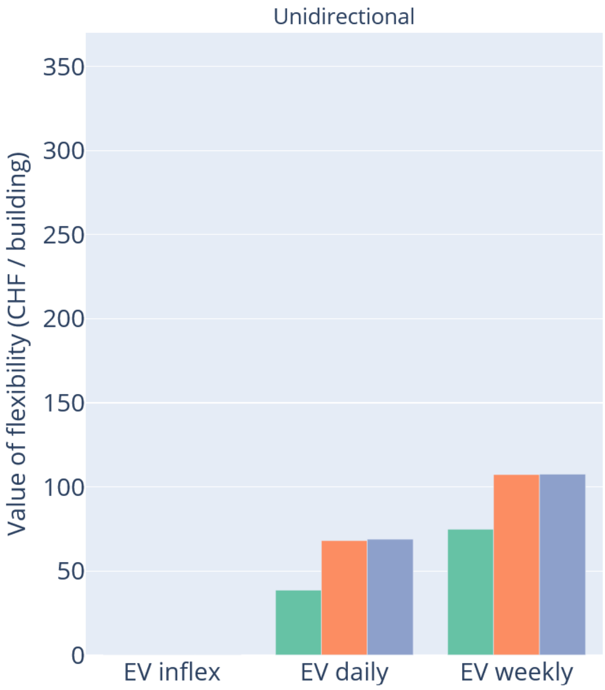


Figure 2: Average value of flexibility from EVs for Swiss single-family households in 2050

**Policy conclusions**

The findings for supply-side flexibility support exposing PV systems to dynamic prices so curtailment during negative price periods becomes incentive-compatible, rather than providing guaranteed minimum remuneration for solar electricity. Reforming feed-in support schemes and enabling curtailment control could improve system efficiency and reduce market distortions. Given the high relative cost of control infrastructure for very small solar plants, this also points to an overall greater efficiency of large plants, where such control infrastructure is more commercially viable.

For demand-side flexibility, the results highlight the importance of enabling flexible operation of EV charging and heat pumps through dynamic tariffs and appropriate regulatory frameworks. Policy efforts should focus on scaling dynamic pricing and ensuring consumer acceptance to unlock flexibility at scale and reduce system-wide costs.

**Reference**

The full study can be found in "*Appendix 1: The value of flexibility*", appended to this report.

# 4 Policy Brief: Measures to promote electricity flexibility

Considerations in the context of the Mantelerlass legislation

Authors: Ingmar Schlecht, Héctor Ramírez-Molina, Christian Winzer and Ali Darudi

*See Appendix 2 for the full report.*

**Executive summary**

- **Three purposes of flexibility.** Flexibility can generally be used for three different purposes.
  (1) Timing of consumption to coincide with **energy** abundance and low prices
  (2) Easing constraints on the **network**
  (3) Providing **balancing**
- **Monopoly for (1) and (2).** The first two flexibility uses can only be exploited by the regional utility, which has a monopoly on the supply of electricity for small customers in Switzerland.
- **Balancing (3) is small.** Private aggregators can only access one revenue stream: balancing. The balancing market is small compared to the capacity of new flexible assets.
- **Balancing aggregation is problematic.** Aggregators control assets otherwise served by the monopolist. This is complex and the current rules ignore that reducing consumption in one hour is likely to lead to higher consumption later, undermining system benefits.
- **Focus on energy and network**. Any regulation fostering greater use of flexibilities should thus focus on uses (1) and (2), i.e. energy and network.
- **Problems of flexibility markets.** Flexibility markets remunerating a deviation from a baseline often yield adverse incentives to increase the problem in the first place (inc-dec gaming).
- **Tariffs**. Dynamic grid and energy tariffs are preferable, as they avoid such incentive problems. Situational short capacity charges are a practical way to prevent peaks from EV charging.

**Outline**

In our report "Policy measures to promote electricity flexibility in Switzerland - Considerations in the context of the Mantelerlass legislation" (see Appendix B. ), analyse the Swiss policy framework for decentral flexibilities.

**Policy recommendations**

We recommend four interventions to improve the use of flexible demand assets.

1. Incentives for DSOs
2. Spot-based energy tariffs
3. Dynamic grid tariffs
4. A real-time tariff publication platform
5. Device-specific suppliers

*Incentives for DSOs*

The regulatory framework for DSOs should include stronger incentives for DSOs to efficiently trade-off the usage of grid flexibility and further grid buildout. While the current NOVA principle, which stipulates that optimization of grid use is to be prioritized over grid reinforcement and grid buildout, is a good step in that direction, it remains hard to monitor for the regulatory agency ElCom. Regulation should be changed so it is in the self-interest of DSOs to make this trade-off efficiently. This requires changing from a cost-plus regulation to an incentive regulation (see the extensive literature on the subject, e.g. Joskow, 2014) and choosing the parameters of such regulation to incentivize the use of flexibilities.

*Spot-based energy tariffs*

We recommend mandating energy suppliers to offer spot-based energy tariffs. With spot-based we mean tariffs that are defined close to real-time, for example one day before delivery, so they can incorporate the structure (but not necessarily the level) of day ahead spot power prices. In Winzer et al. (2023b) we outline how profile tariffs enable such spot-based incentives for flexibility provision while protecting customers from changes in the level of prices and thus ensuring stable electricity bills for customers.

*Dynamic grid tariffs*

Grid congestions in the DSO grid are likely to be the most pressing reason why residential electricity flexibility will be urgently needed in the coming years. This is due to the foreseeable fast deployment of electric vehicles and heat pumps. While direct load control by DSOs presents a valid solution especially as a last-resort measure, it comes at the downside of being unable to take short-term preferences of customers into account adequately and balance the (time-variant) disutility of customers from such load control with the system need for them. Dynamic grid tariffs, that would be set in a similarly short-term manner as spot-based energy tariffs, for example day ahead, can do that. Customers facing such tariffs remain in control and are thus able to prioritize e.g. fast-charging when needed. An example of a highly dynamic grid tariff is Group-E's Vario tariff (Groupe-E, 2023). We recommend mandating DSOs to introduce dynamic grid tariffs to foster demand flexibility.

*Situational short capacity charges*

An easier to implement interim solution is the introduction of situational short capacity charges (German: "situative kurze Leistungspreise", see also Winzer et al., 2024, and Neon, 2024). They are capacity charges, so that they charge on a peak demand. They are situational (i.e. active only when a highly loaded grid can broadly be foreseen, such as only in winter evenings) and they are short (i.e. they look at the peak capacity only during a short time-period such as a multi-hour period and are charged for the single multi-hour period). This sets them apart from yearly peak capacity charges.

*Platform publishing real-time tariffs*

Digitalization and automation will play a vital role in the dissemination of dynamic tariff schemes, as constant monitoring of the electricity market and remote operation of flexible demand assets will be essential to its successful implementation. Therefore, a unified online platform where all stakeholders can have access to hourly tariffs and other important information can contribute to enhance the reach of these schemes and its transparency towards consumers. Especially, household energy management systems (EMS) are likely to access such a platform to optimize the consumer's flexibility dispatch.

*Device-specific suppliers*

We also believe it is worth investigating the option of allowing aggregators to fully supply energy to specific devices (heat pumps and electric vehicles), as a step towards partial liberalization. The advantage of such device specific suppliers is that they can manage the full value potential of flexible assets, from energy procurement to balancing provision, without a problematic split of responsibilities. Device-specific suppliers also have the advantage of being able to reap economies of scale when specializing in managing a specific type of demand asset which they manage in all of Switzerland or even internationally and can thus consider the full set of restrictions of such specific assets, like the charging properties of a specific car type or of a specific heat pump with thermal storage. To enable device-specific suppliers, careful regulation is needed that avoids consumers cherry-picking over time, by switching to the competitive market in times of low wholesale electricity prices and reverting to the main supplier in times of high wholesale prices. In ongoing work, we are advancing this idea.

**Reference**

The full study can be found in "*Appendix 2: Policy measures to promote electricity flexibility in Switzerland*", appended to this report.

# 5 Conclusion and outlook for future research

In the AGGREGATE project we quantified the value of flexibility from the decentralized energy resources PV, electric vehicles and heat pumps and derived both a tariff to foster use of such flexibility as well as further policy recommendations to that end.

In our first contribution, "*Profile contracts for electricity retail customers*" we outlined a tariff, which enables at the same time to provide incentives to react to hourly price signals, as well as stabilizing the monthly electricity bill so that customers do not suffer from high energy prices if wholesale prices increase. Within the paper, we discussed the optimal design of such contracts. We show that already a simple baseload hedge significantly reduces bill volatility.

Further analyses will be needed to empirically quantify the expected load-shifting and load-reduction potential for different contract designs, customer groups and shortage scenarios and quantify the impact on customer bills for a longer range of observation years. Other open topics include suitable hedging strategies and products for retail companies, the assessment of distributional implications or potential externalities caused by insufficient customer hedging, and the assessment of customer acceptance.

In our second contribution, "*Value of flexibility in Switzerland*" we quantify the value of decentral energy appliances to react to price signals, i.e. to act flexibly according to hourly price signals. Curtailing solar PV during negative price periods could have increased system value by EUR 12.77 million in 2024, as Switzerland experienced a record 294 hours of negative prices – a number that is likely to increase over the coming years with continued PV buildout. Despite this, current feed-in schemes prevent generators from reacting to price signals, particularly in small-scale PV systems, where investment in curtailment infrastructure is not economically viable. The relative value loss from not curtailing reached 6% of the PV market value, suggesting that curtailment incentives would be most effective for larger, controllable plants. On the demand side, flexible EV charging under dynamic tariffs can yield up to CHF 107/year in savings for households, and over CHF 350/year as an upper limit with highly flexible bidirectional charging. Heat pumps offer more modest value of flexibility, reaching up to CHF 70/year under daily flexibility in our modelling. Dynamic pricing significantly boosts the value of flexibility and can deliver cost savings comparable to rooftop PV and battery investments—without requiring upfront capital—highlighting the importance of tariff design in unlocking household flexibility potential.

In our third contribution, "*Measures to promote electricity flexibility in Switzerland*" we determine that Switzerland's regulatory and market framework currently limits the ability of households to fully participate in and benefit from electricity system flexibility. While technologies like EVs, heat pumps, and batteries offer significant potential to shift demand in response to system needs, existing structures – such as the monopoly in residential electricity supply and limited access to wholesale markets – constrain flexibility deployment. The balancing market, while technically accessible via aggregators, is too small (only 2.5% of wholesale market value) to be a major value driver for household assets. Moreover, its design introduces coordination issues such as "catch-up consumption," which can lead to new imbalances after flexibility events. These constraints suggest that relying on balancing services alone is insufficient to unlock flexibility at scale.

To make flexibility economically and operationally viable, we recommend shifting toward dynamic energy and grid tariffs, which can guide flexible demand away from peak grid times and high prices. Unlike flexibility markets, which are prone to manipulation (inc-dec gaming), dynamic tariffs reward behavior based on actual consumption and reduce perverse incentives. Interim solutions like situational short capacity charges can also help manage peak demand without requiring complex infrastructure.

# 6 National and International Cooperation

Our advisory group formed an integral part of our project and was our main cooperation vehicle for exchange with companies, industrial associations and the academics on our advisory board. We thank the advisory board members for their invaluable feedback throughout the project and for all the fruitful discussions we had during the project workshops.

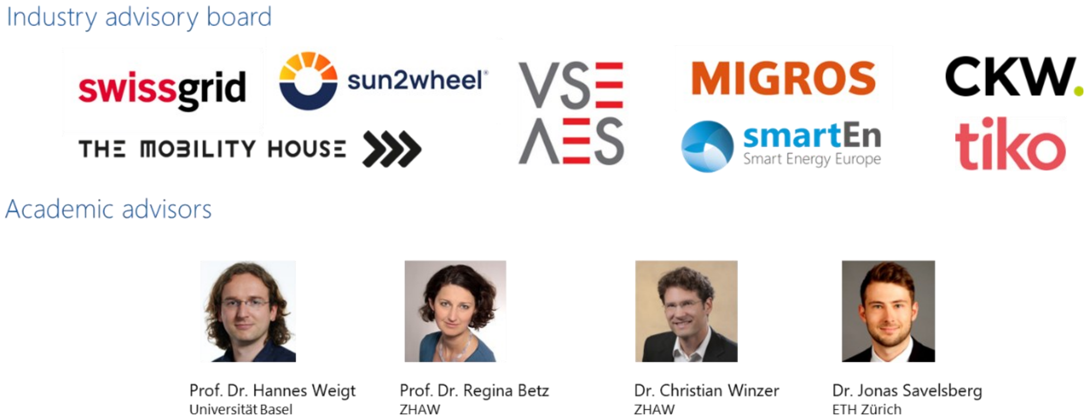


Figure 3: Composition of the project's advisory board

For our work on profile contracts for retail customers, we collaborated with Prof. Dr. Lion Hirth (Hertie School) and Dr. Christian Winzer (ZHAW Winterthur, SWEET PATHFNDR).

Furthermore, we collaborated with the Competence Center for Thermal Energy Storage from the Lucerne University of Applied Sciences (HSLU) on quantification of heating demand to better estimate the flexibility potentials in the heating sector.

# 7 Communication

As part of this project, we carried out three workshops with the advisory board of the project.

- On May 4th, 2023, we conducted the first project workshop in Zurich. All the project’s industry and academic advisors were invited to participate. The workshop featured three main presentations on results by the AGGREGATE team, summarising the progress done so far. Further external speakers enriched the workshop and enabled exchange with tangent research.
- On September 20th, 2024 we conducted our second project workshop in Zurich. The workshop featured three main presentations on results by the AGGREGATE team, summarizing the progress done so far. Active engagement by industry, associations, academics and the BFE enriched the workshop with fruitful exchange.
- On March 6th, 2025, we conducted our third and final project workshop. The workshop summarized all the main contributions of the project, from profile contracts over value quantification of flexibility and our policy recommendations.

The project results were also presented at several conferences and workshops.

- On July 25th, 2023, we presented our concept of “Device Specific Suppliers in a Monopolistic Retail Market” at the 18th European Conference of the International Association for Energy Economics (IAEE), which took place in MIlan, Italy.
- Finally, on October 5th, 2023, we presented our paper “Profile contracts for retail customers” at the 32nd Young Energy Economists and Engineers Seminar (YEEES 32) in Nuremberg, Germany.

- On August 28th, 2024, we presented for a keynote at the AEE Congress in Pratteln/Baselland with first results from AGGREGATE modelling of the value of supply-sided flexibility (PV curtailment) and regulatory conclusions.

# 8 Publications

Winzer, Christian, Héctor Ramírez-Molina, Lion Hirth, Ingmar Schlecht (2024), “Profile contracts for electricity retail consumers”. Volume 195, December 2024. Energy Policy. Available as open access at: https://doi.org/10.1016/j.enpol.2024.114358

The further contributions can be found directly as appendices to this report.

# A. Appendix 1: The value of flexibility

Author: Héctor Ramírez-Molina

**Key messages**

- Curtailing PV during negative prices improves system value but is hindered by inflexible incentives
- Flexible EV charging significantly reduces household energy costs under dynamic pricing
- Bidirectional EV charging adds the most value, often eliminating the need for battery storage
- Heat pumps offer moderate flexibility value compared to EV charging
- Dynamic tariffs greatly enhance the value of demand-side flexibility compared to flat rates
- Flexibility can deliver cost savings comparable to PV and battery investments, without upfront capital

## A.1 Introduction

The decarbonization of the energy sector is fundamentally reshaping the structure and operation of electricity systems across Europe. This transformation is driven by two main forces: increasing renewable energy deployment on one side, and the electrification of the heating and mobility sectors through the deployment of heat pumps and electric vehicles (EVs). While these developments are essential to achieve global and regional decarbonization goals and meet climate targets, they also present significant challenges for maintaining grid stability, ensuring cost-effectiveness, and optimizing the operation of the power system.

In this context, flexibility— i.e., the ability of generation, demand, and storage to respond dynamically to price signals or system conditions—emerges as a critical tool to ensure system reliability, economic efficiency, and sustainability.

Other studies have looked at the role of flexibility and how it can be incentivized to facilitate the energy transition and improve system efficiency. Panos et al., (2019) developed a full energy system modelling framework to quantify the future flexibility needs of the Swiss energy system. They find, among other things, that the electrification of mobility and heating will significantly increase the total load and change the current load profile of the system, that the role of energy storage technologies will become more important for both the electricity and heat sectors, and that demand response from the buildings will be a crucial pillar of flexibility, with market design being one of the main tools to shape the provision of flexibility.

Rinaldi et al., (2022) compared the deployment of various flexibility options by 2050 in Switzerland using the electricity market model GRIMSEL-FLEX. They compare the deployment of different flexible technologies under different scenarios accounting for various rates of building retrofitting, technology substitution based on energy efficiency and heat pump deployment targets while optimizing the total solar photovoltaic (PV) and battery capacity at the national level. They found that the introduction of flexible assets (e.g., batteries, domestic hot water storage and heat pumps) increases self-consumption, PV power surplus absorption and PV deployment, as they reduce investment in electricity storage. Additionally, energy retrofitting investments in combination with heat pump-based space heating systems would have a large impact in reducing electricity storage deployment.

In this study, we analyze the value of flexibility in the Swiss electricity system, considering both the supply and demand sides. On the generation side, we quantify the benefit of curtailing solar photovoltaic generation during negative price periods, highlighting the market distortions introduced by support schemes like feed-in tariffs. On the demand side, we use the SwissStore model to assess the value of load-shifting in Swiss households, focusing on how residential consumers with flexible assets (such as

EVs, batteries, and heat pumps) can reduce energy costs and support the system when exposed to dynamic pricing.

The remainder of this paper is structured as follows. In Section A.2 we summarize the results of the value of flexibility form the decentralized supply side (i.e. curtailment of PV) while the demand side is presented in section A.3 .

## A.2 Flexibility on the supply side: Curtailment

### A.2.1 Negative wholesale electricity prices

In normal operation times of wholesale electricity markets, the marginal cost of the most expensive generation unit necessary to serve load determines the hourly power prices according to the generic merit order model. As such costs are always positive or zero in the merit order model, negative prices should not materialize. However, different factors can lead to negative prices. Historically, costly shutdown and startup of conventional power plants could be at least a theoretical reason. More recently, however, the main reason for negative prices to materialize is renewable generators that fail to stop production even when prices drop below their marginal cost of zero. Negative prices have become more prevalent in Europe as the RES installed capacity grows because of the lack of price responsiveness on both the demand and supply sides of the electricity system.

Historically, one of the main reasons for this lack of responsiveness, and therefore for the emergence of negative prices, is the widespread use of feed-in tariff (FiT) programs throughout Europe, including Switzerland's historic KEV regime. These schemes were designed as a strong incentive for the installation of wind and solar capacity by either paying a fixed price for every unit of energy produced (feed-in tariffs) or paying a premium over the market price of electricity (feed-in premium) during an agreed period, which usually spans over many years. FiT programs were very successful in rapidly scaling-up the renewable energy capacity in the European electricity system, however they also create a market distortion as non-price reactive producers are incentivized to maximize their production in periods when the feed-in price is higher than their marginal cost of production independently of the electricity system's current condition. In the case of feed-in tariffs, this is true for all time periods.

More recently, European countries such as Switzerland and Germany have introduced market premium regimes, where incentives from hourly electricity prices continue to provide (some) incentive to react to market price signals. In this support mechanism, a regularly recalculated market premium (so called "sliding premium") is paid on top of hourly wholesale prices. This often provides incentives for renewable producers to keep producing in negative prices only up to the negative value of the market premium. However, small retail customers with rooftop PV panels remain outside of this regime, leading them to continue to ignore wholesale power prices, and this contributing to the emergence of negative prices.

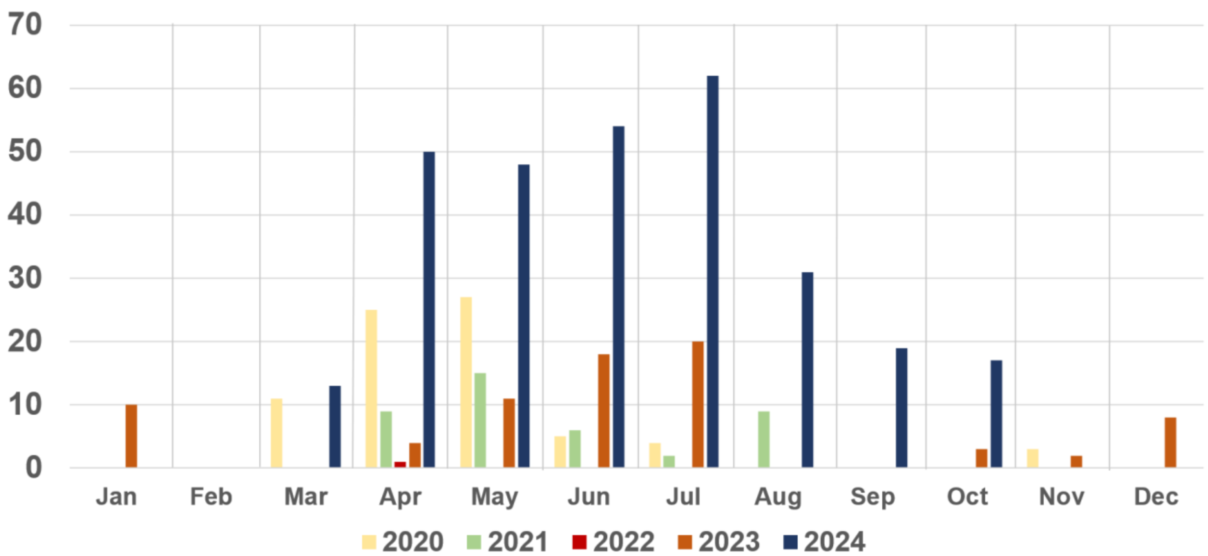

Figure 4: Total number of hours with negative prices (per month and year)

Figure 4 shows the cumulative number of negative prices in Switzerland for the period of 2020 to 2024. Here we see a clear seasonal behavior in which most negative prices occur during the spring and summer months (April to August) and while there are yearly variations, the trend seems to be upwards, with 2024 having the higher total number of negative price hours (294).

### A.2.2 Methods for generation-sided flexibility quantification

In this section we present the methodology to quantify the lost value of curtailment for photovoltaic (PV) generation in the Swiss electricity system for the period between 2020 and 2024.

It is important to clarify that in this section, we are not measuring the economic loss of the producer, because many of them earn revenues during negative price periods thanks to the production incentives given by support schemes (e.g., FiTs). The additional cost is then transferred to other market actors and end-consumers.

We define the Flexibility Value of Curtailment (FVC) as the economic gain at the system level if electricity generation would be curtailed during negative price periods. This definition is consistent with our concept of flexibility as this would occur if generators responded flexibly to price signals.

The calculation methodology is straightforward: we compare the hypothetical market value of curtailed PV generation $(Market\ Value_{curtailed})$ with the value of realized PV generation $(Market\ Value_{uncurtailed})$. The assumption when calculating the curtailed value is that PV generators would not produce if electricity prices were below zero, as the market value would be negative. Both values are computed according to the following equations:

$$Market\ Value_{uncurtailed_t} = p_{DA_t} \cdot pv_{gen_t} \tag{1}$$

$$Market\ Value_{curtailed_t} = \begin{cases} 0 & if\ p_{DA_t} \leq 0 \\ p_{DA_t} \cdot pv_{gen_t} & if\ p_{DA_t} > 0 \end{cases} \tag{2}$$

Where,

- $Market\ Value_{uncurtailed}$ is the realized market value of PV generation $(EUR/MWh)$
- $Market\ Value_{curtailed}$ is the hypothetical market value of curtailed PV generation $(EUR/MWh)$
- $pv_{gen}$ is the PV generation $(MWh)$
- $p_{DA}$ is the Day-Ahead electricity price for Switzerland $(EUR/MWh)$
- $t$ is the dataset's time resolution $(hour)$

Once these values are determined for each timestep; we can calculate the flexibility value of curtailment as their arithmetic difference, as shown in Equation (3).

$$\begin{aligned} &Flexibility\ Value\ of\ Curtailment\ (FVC) \\ &= \sum_t (Market\ Value_{curtailed_t} - Market\ Value_{uncurtailed_t}) \qquad \forall\, t \end{aligned} \tag{3}$$

For our calculations, we use data from the *Transparency Platform* of ENTSO-E (*European Network of Transmission System Operators for Electricity)* (ENTSO-E, 2025). We downloaded generation and day-ahead price data for Switzerland for the years 2020 to 2024.

Other sources of flexibility value on the supply side of the electricity system are not exhausted in our Flexibility Value of Curtailment estimate, e.g. participation in intraday and balancing markets. In these cases, a generator could react to intraday prices or energy balancing calls independently of the Day-Ahead market clearing prices. For example, they would curtail their generation if intraday prices became negative or if the generator provides negative grid balance services (i.e., there is oversupply of electricity). Concerning the value of intraday flexibility, it is not included in our computations due to the lack of historical intraday prices on ENTSO-E's *Transparency Platform*. However, given the rather illiquid Swiss intraday trading, it is likely to have been only a minor revenue contributor for Swiss supply-sided flexibility. This could change in the future, especially if Switzerland enters into an electricity agreement with the EU and electricity markets (including the intraday market) will be coupled across the borders.

### A.2.3 Results and discussion on generation-sided flexibility

The difference in market value of generated solar electricity between a scenario where production is curtailed at negative prices and a scenario where it is not curtailed at negative prices can be seen in Figure 5. The figure plots the average hourly results of total solar generation (yellow), $Market\ Value_{curtailed}$ (blue) and $Market\ Value_{uncurtailed}$ (black) for the month of July 2024 in Switzerland, according to equations (*1*) and (*2*). For the average solar generation curve, we see a typical daily summer profile. July 2024 is a month where that difference is particularly pronounced, but that month might be closest to future trends, as solar capacity is only bound to increase further in the future.

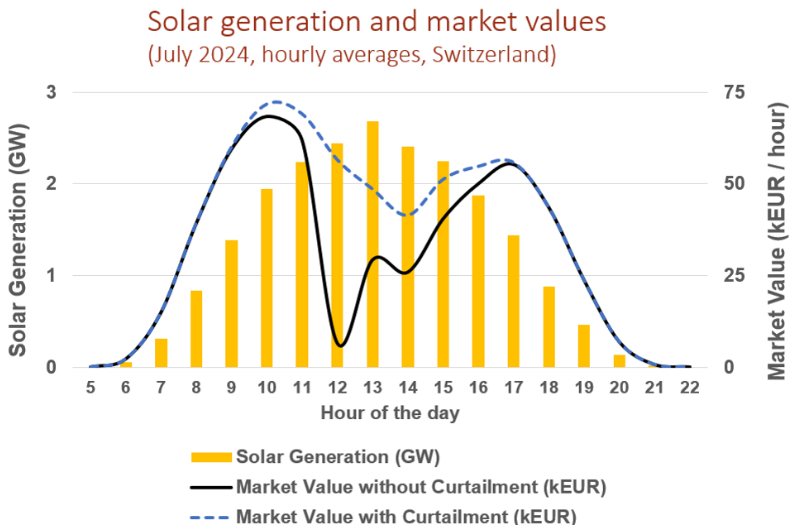


Figure 5: Average hourly solar generation and market value of PV in Switzerland for July 2024

During the first hours of the day the value of solar generation increases in sync with a higher electricity output, reaching a maximum value between 9:00 and 10:00 hrs. At this point we see the decoupling of the value curves with $Market\ Value_{curtailed}$ reaching higher average values. This means that in this scenario, generators have curtailed their production during negative price periods and hence, increased their average generation value.

The most striking result comes after the generation's market value peaks. Here, both market value curves fall as solar generation keeps increasing until reaching its maximum output at 13.00 hrs. However, even if there is a reduction in value when generators curtail their generation, the loss is not as drastic as when generation is not curtailed, which reaches a close-to-zero average value around 12.00 hrs. Finally, as solar generation starts to decline, the value of generation increases until it starts to fall again at 17.00 and couples again with generation. The area between the two value curves is the Flexibility Value of Curtailment (FCV), which can be calculated using Equation (*3*).

The dynamic seen in Figure 5 is the result of several factors acting simultaneously. Perhaps the most important aspect at play here are renewable energy support schemes. As discussed in Section A.2.1 , these schemes introduce market distortions as they prevent producers to be exposed to market prices. For example, power plants in a Contract-for-differences (CfD) – know in Switzerland as a Market

Premium contract - would only curtail for negative prices lower than their subsidy. For example, if the subsidy amounts to 50 EUR/MWh, they cut production when the price hits levels lower than -50 EUR/MWh.

Another aspect to consider is that a significant amount of solar generation capacity deployed is meant to maximize own consumption, shielding consumers from dynamic price signals and failing to provide incentives for consumers to invest in curtailment control technology. This results in a large amount of solar capacity that is connected to the grid, but it is impossible to control, it just injects to the grid the surplus energy after satisfying self-consumption needs.

Finally, during summer months when solar generation peaks, it drives electricity prices down during relatively low demand periods. That is why we see the value of electricity dropping when generation is maximized, because price-blind, uncontrollable PV capacity keeps producing despite low demand.

Table 1. Annual Flexibility Value of Curtailment (2020-2024)

| Year | Market Value (EUR / kW installed) | | Number of negative price hours | Curtailment Value (EUR per kW installed) | Flexibility Value of Curtailment (Million EUR) |
|---|---|---|---|---|---|
| | No curtailment | Curtailment | | | |
| **2020** | 22.91 | 23.29 | 75 | 0.38 | 1.10 |
| **2021** | 69.46 | 69.89 | 41 | 0.42 | 1.31 |
| **2022** | 238.37 | 238.37 | 1 | 0.00 | 0.00 |
| **2023** | 69.06 | 69.57 | 76 | 0.51 | 2.20 |
| **2024** | 37.43 | 39.84 | 294 | 2.41 | 12.77 |

Table 1 and Figure 6 show the total number of negative price hours and the Flexibility Value of Curtailment of PV generation in Switzerland for the studied period. The year with the higher number of negative price hours and Flexibility Value of Curtailment is 2024, with 294 hours and EUR 12.77 million.

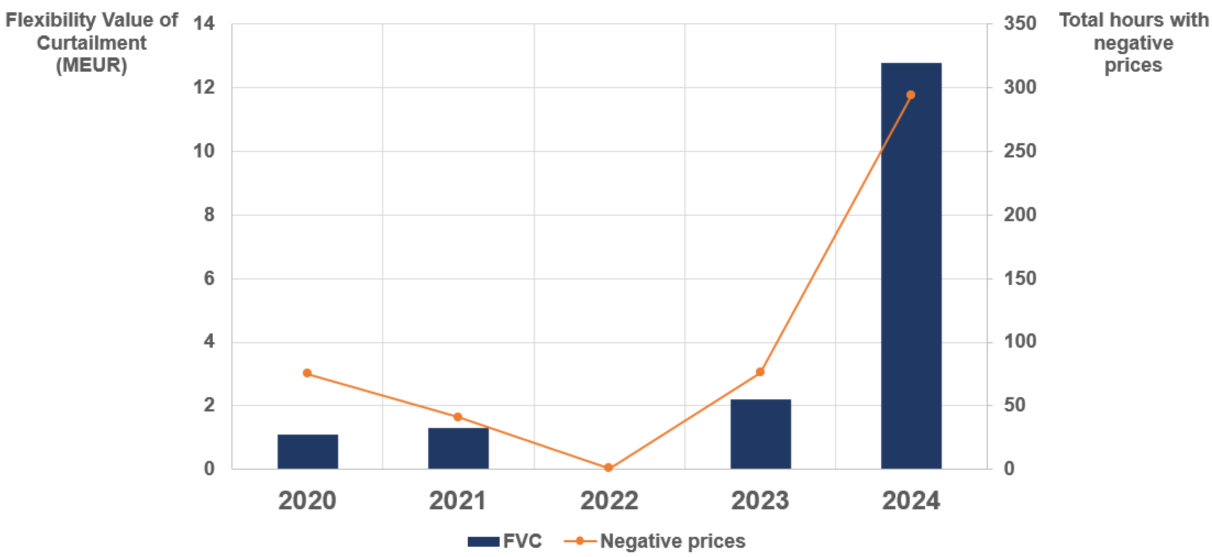


Figure 6: Annual Flexibility Value of Curtailment and total number of negative price hours (2020-2024)

Figure 7 shows the total annual market value of solar PV generation in Switzerland since 2020. The sum of the "*No curtailment*" and "*Curtailment (FVC)*" bars is the total market value in the curtailment scenario. Here we see that the market share of the Flexibility Value of Curtailment is small relative to the total size of the Swiss PV market. Also, we can observe how the effects of the 2022 European energy crisis on the total market value of PV electricity.

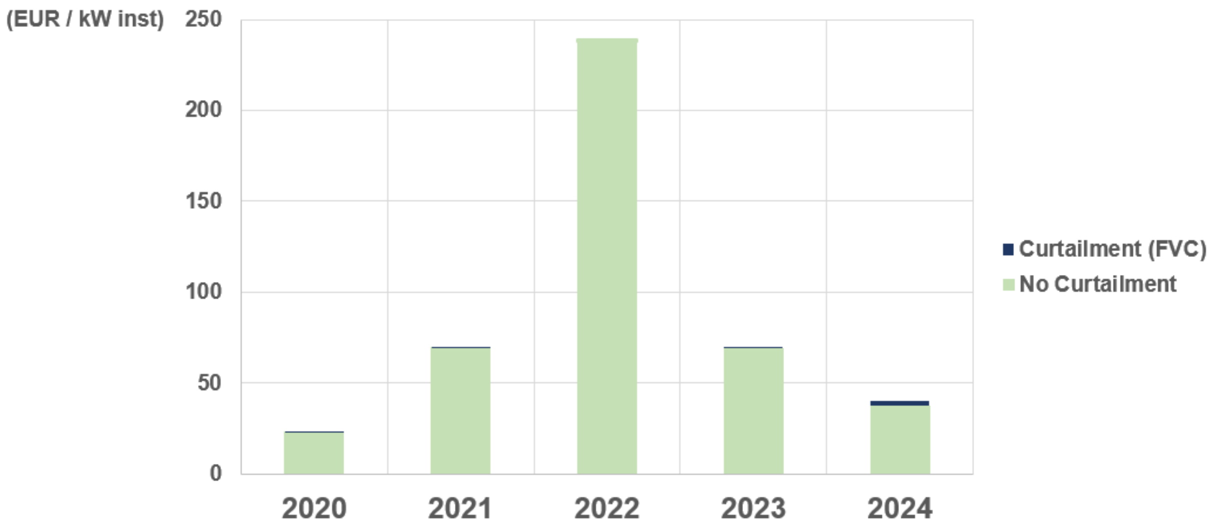

Figure 7: Annual market value of solar PV generation in Switzerland (2020-2024)

Figure 8 shows the absolute Flexibility Value of Curtailment's market share. We see that the higher market share reached only 6% in 2024, the year with the highest number of hours with negative prices, which means that failing to curtail, led to a market value reduction of 6% for each kW of installed capacity. Given the low additional value from curtailment, new investments in control systems for curtailment will only be profitable for utility-scale solar generation plants. Nevertheless, since this issue has become more prevalent over the past years, a higher value loss could materialize in the future, making investments in smaller plants also profitable.

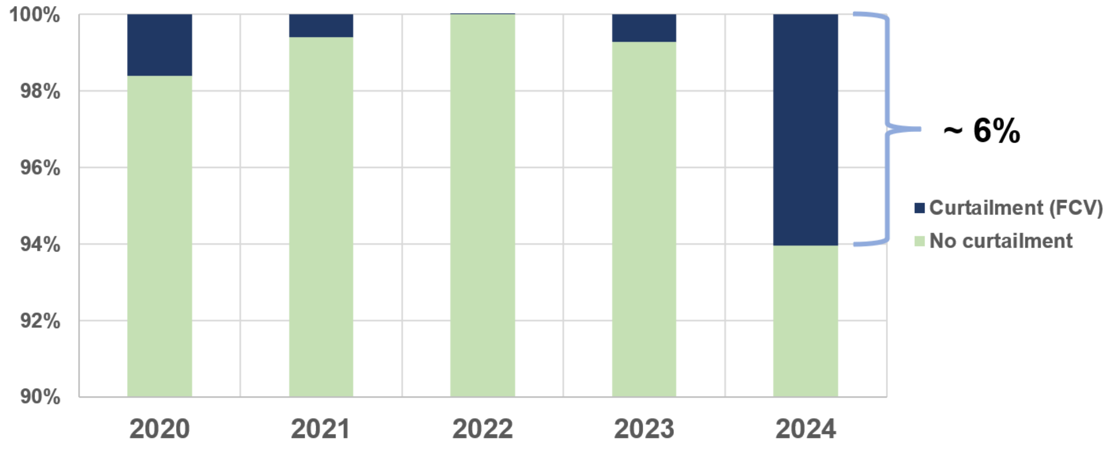

Figure 8: Share of the Flexible Value of Curtailment relative to the total market value when curtailing (2020-2024)

## A.3 Flexibility on the demand side: Smart charging and heating

In this section we estimate the value of load-shifting flexibility in the Swiss household sector for the year 2050. To achieve this, we use the household energy model SwissStore. We analyze the value provided to end-consumers by different energy assets (i.e., PV panels, batteries, heat pumps and electric vehicles) under different electricity tariff designs and technology combinations. A more detailed description of the model and the methodology to estimate the value of load-shifting technology is presented in sections A.3.1 and A.3.2 .

### A.3.1 SwissStore model description

SwissStore is a bottom-up investment energy model of the Swiss residential sector. The model integrates the electricity, heating and private electric mobility demand of households (HHs) and minimizes the total energy system costs under different policy, cost and electricity tariff scenarios.

SwissStore applies a linear optimization method to minimize the total lifetime energy costs of a given household. These costs include yearly energy consumption (electricity and heat), operational and annualized investment[1] costs. SwissStore follows a greenfield approach, meaning that the models simulate a full technology deployment for the modeled year, responding to different scenario assumptions[2].

The totality of the Swiss housing building stock is represented in the model with more than 330,000 housing archetypes, which account for 1,4 million residential buildings. These archetypes are based on the Federal Register of Buildings and Dwellings (FRBD), a comprehensive database of all buildings in Switzerland. Each archetype represents multiple buildings, aggregated according to relevant characteristics, i.e., age, household type (single or multi-family; SFH, MFH), urban typology (urban, suburban, rural), geographical location, among others.

SwissStore's modular design allows to configure different technology bundles for each building archetype, including investments in solar photovoltaic and LiNMC battery storage (Lithium Nickel Manganese Cobalt Oxide). Investments in PV capacities are constrained by the archetype's available roof surface[3]. In this way, it is possible to measure the effects in total system costs and investments for different scenario settings.

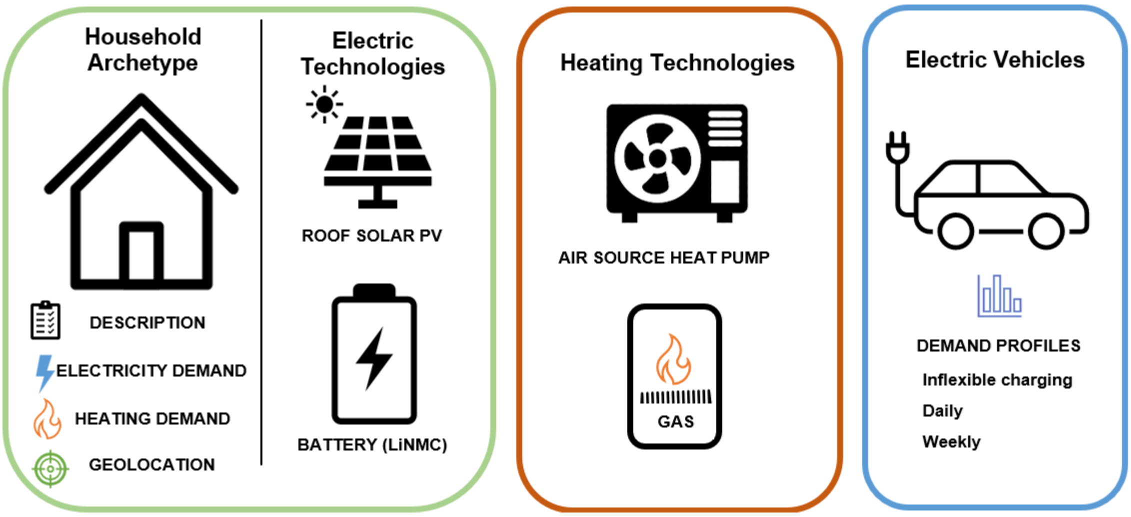


Figure 9. SwissStore's modules

**Modules**. Figure 9 shows SwissStore's modules. In green we see the HH archetype module, which describes the building's characteristics and the technologies in which end-consumers can invest, namely solar PV and battery storage. Various heating technology scenarios can be created by pairing a HH archetype with one of the heating technologies shown in the orange section. Finally, the electric vehicle (EV) module, shown in blue, includes a set of charging profiles that can be assigned to any given HH archetype. Alongside the profiles, we can set different charging flexibility time windows (i.e., inflexible, daily and weekly).

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[1] The model allows households to invest in PV, batteries, type of heating technologies, Seasonal Thermal Energy Storage (STES). Depending on the scenario definition, investments in any of the technologies can be disabled.

[2] The relevant scenarios for our current analysis are electricity tariff design, fossil fuel prices and future $CO_2$ taxes.

[3] Maximum battery capacity per household archetype is assumed to be 50% of the maximum possible PV capacity, hence being indirectly constrained by the roof surface. For example, if a household archetype can install a maximum of 10 kW of PV, the maximum constraint for battery capacity will be 15 kWh. This assumption follows the work of (Winzer et al., 2023).

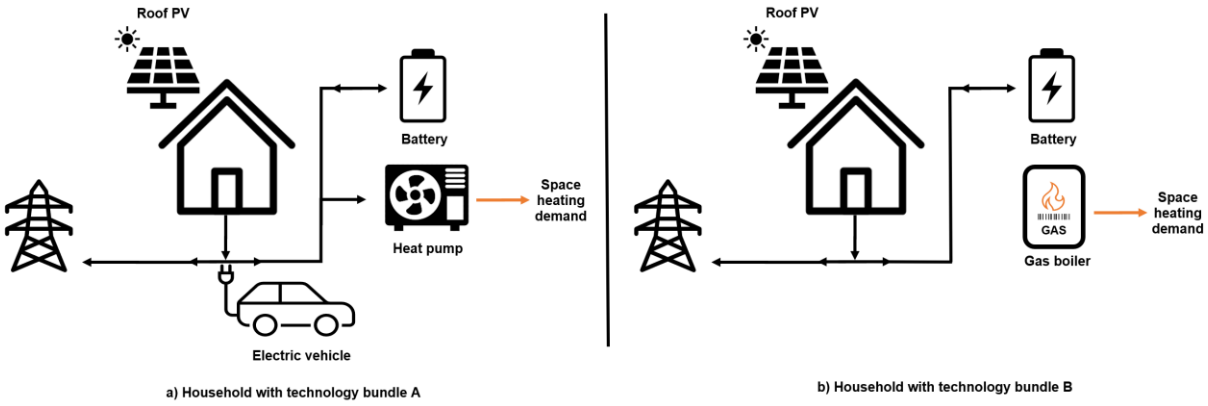


Figure 10. Different technology bundles for the same household archetype

Figure 10 shows two of the technology bundles assessed for this study. In Figure 10.A, the household owns an EV and uses a heat pump to fulfill its heating demand. In contrast, Figure 10.B shows the same household but, in this case, it does not have an EV and its heating system is powered with gas. In both cases, the household is connected to the grid and invests in roof solar PV and battery storage.

Heating demand profiles have a daily resolution and are an outcome of the Swiss Residential Building Stock (SwissRes) model (Streicher et al., 2019). This model simulates the space heating demand of households using information on building elements, envelope, historical weather conditions, among others. The data is retrieved from the FDBR and the Cantonal Energy Performance Certificate for Buildings (CECB) databases.

Inflexible electricity demand profiles are computed according to the methodology described in (Rinaldi et al., 2020). First, we obtain the average electricity consumption per square meter ($kWh/m^2$) for each household type and urban topology combination (e.g., SFH-Rural, MFH-Urban). We do this by distributing the national total electricity demand of the Swiss household sector across household types and dividing it by their total surface, using data from the FDBR database. In a second stage, normalized hourly consumption profiles are derived for each household archetype from real anonymized smart meter consumption data from various Swiss utility companies. These profiles represent the share of demand for each hour of the year, meaning that the sum of the profile is equal to 1. Finally, archetype-specific profiles can be computed by multiplying their individual surface area by the average demand per square meter and consumption profile of the household type.

EV demand data is sourced from the EWG project NETFLEX (Winzer et al., 2023). For our analysis, we randomly assigned a single EV load profile to each household and aggregated the demand according to different flexibility charging periods, i.e., inflexible, daily and weekly.

Electricity price timeseries have been obtained from the FEM model (Darudi et al., 2024). Furthermore, in our model, we have integrated other costs such as carbon taxes and fossil fuel price projections. We use the scenarios from the Energy Perspectives 2050+ (SFOE, 2020) as the main source and depending on the policy scenario, different levels of carbon tax and fossil fuel price levels will be added to the total cost of fossil fuels and incrementing the total system costs accordingly.

SwissStore's full model description is currently being written into an academic paper. A confidential draft can be made available on request.

We describe the methodology and mathematical formulation for our analysis in Section A.3.2 . To improve the readability of the equations, the model's parameters are written in lower case while the endogenous variables are written in upper case.

### A.3.2 Methodology

We use a randomized sample of 2000 household archetypes to estimate the average value that end-consumers can obtain from using their energy assets flexibly. We limit our sample to single-family houses (SFH) across all Switzerland and we then expose them to a set of various electricity tariff designs and technology configurations.

It is important to note that our analysis only considers the benefits for residential end-consumers and the results shown in this report do not represent the system-level value of flexibility (e.g., balancing costs, deferred grid infrastructure investments). Also, since in this framework the electricity market is not modeled, individual residential consumer behavior (i.e., load-shifting, self-consumption, energy storage and grid injection) does not influence wholesale electricity prices.

The EV charging scenarios are presented in Table 2. For the scenarios with EV demand (i.e., *EV inflex*, *EV daily* and *EV weekly*), we randomly assign one of the 29 household-specific EV profiles from the NETFLEX dataset to each archetype in the sample. We also include a scenario without an EV in the household (No EV) with the goal of measuring the value of flexibility from heat pumps without the influence of EV charging behavior.

Table 2. EV flexibility scenarios.

| EV scenario | Description | Type of charging |
|---|---|---|
| No EV | Building without EV | - |
| EV inflex | Inflexible EV demand | Unidirectional |
| EV daily | Daily EV charging flexibility | Uni and Bidirectional |
| EV weekly | Weekly EV charging flexibility | Uni and Bidirectional |

We established a series of assumptions in our modeling framework to describe EV charging behavior. First, to guarantee comparability between consumers in the inflexible charging scenario (*EV inflex*), we assume the same charging behavior (i.e., they start charging their EVs at 18.00 hrs. at a maximum capacity of 11 kW until their daily demand is fulfilled). For the other scenarios, consumers can satisfy their aggregated daily or weekly demand, at any hour within the specific flexibility time window.

Second, the *EV daily* and *EV weekly* scenarios have both unidirectional and bidirectional charging enabled, while the EV inflex scenario can only perform unidirectional charging.  Lastly, we assume that EVs can charge, and discharge in the case of bidirectional charging, at any given hour of the day. We make this assumption because driving patterns are not yet implemented in our model and therefore, bear in mind that the values of flexibility from EVs shown in the following subsections are theoretical maximums. Although not ideal, this setting proves to be useful, as it allows to dimension and delimiting the scale of flexibility potential embedded in EVs.

Similarly to the EV charging scenarios, we set-up flexibility scenarios for the operation of heat pumps. In the *HP Inflex* scenario, we take the building-specific yearly total heating demand and distribute it to each hour of the year using space heating profiles from the FEM model (Darudi et al., 2024). For the *HP 4hr* and *HP Daily* scenario, we allow the heat pump to meet the space heating within a specific flexibility time window (4-hour and daily respectively), taking the HP Inflex demand profile as basis. We assume that the building's thermal inertia allows for the flexible operation of heat pumps as it works, in principle, as thermal storage.

Table 3. Heat pump flexibility scenarios.

| Heating scenario | Description |
|---|---|
| HP Inflex | Inflexible heat pump operation |
| HP 4hr | 4-hour heat pump flexibility |
| HP Daily | Daily heat pump flexibility |

**Electricity tariff design**. Table 4 shows the retail electricity tariff scenarios implemented in our analysis. These tariffs seek to reflect, according to our definition of flexibility, the two extremes of the flexibility incentive spectrum. The *Flat* tariff exposes consumers to a flat retail tariff with no feed-in tariff and since in this case it is impossible that consumers react to price signals, the value of flexibility, by definition, is zero. On the contrary, the *Dynamic* tariff, fully exposes end-consumers to price signals thanks as the retail price and the feed-in-tariff vary hourly. In this setting, consumers have full flexibility incentives in both the supply and demand sides.

**Tariff structure.** The electricity tariffs used in our simulation consist of the energy component, for which we use the hourly wholesale price timeseries from the FEM model, and all additional components (taxes, grid fees, etc), computed from Swiss retail electricity price data (Elcom, 2024) .For the *Flat* tariff scenario, the energy component of the retail price is simply the yearly average of the wholesale price. In the case of the *Dynamic* scenario, the energy component of the retail price is set to be equal to the wholesale electricity price and thus, can potentially change at every hour of the year. Also in this case, the feed-in-tariff could vary hourly as it is also equal to the wholesale electricity price.

**No PV scenario**. Aiming to observe the effect of the *Dynamic* tariff without own generation and consumption, we included the special scenario *Dynamic (No PV - Bat)*, in which we disabled household PV and battery investments. In this way, we can estimate the stand-alone EV and heat pump value of flexibility without the influence of these technologies.

Table 4. Electricity tariff scenarios.

| Tariff scenario | Tariff design | Description |
|---|---|---|
| Flat | Flat - no FiT | Zero flexibility incentives |
| Dynamic | Hourly - Hourly FiT | Full flexibility incentives |
| Dynamic (No PV - Bat) | Daily EV charging flexibility | Full flexibility incentives and disabled PV and battery investments |

**Technology combinations**. With the same objective of computing the value of flexibility of each asset independently, we set-up technology scenarios in which the asset of interest does not interact with the others. For example, when measuring *only* the value of flexibility from EVs, we can combine it with a gas heating system and depending on the tariff scenario, we can measure its value in combination with a PV and battery system (Dynamic scenario) or in complete isolation (Dynamic (No PV – Bat)).

**Energy bills and total annual costs**. Our modeling framework also allows us to compute the yearly energy bills for each household archetype (i.e., electricity and gas expenditures). This feature allows us to compare the effect of tariff design and flexibility in the household's annual energy demand expenditures (i.e., without considering investment and operational costs). When adding the annualized investment costs and operational costs of PV and batteries, we obtain the annualized cost of owning and operating the modeled energy assets.

**Objective function**. The total annualized cost is determined by the model's objective function, shown in Equation (4), which minimizes the sum of annualized lifetime cost of the deployable energy assets (i.e., PV and batteries), operational costs and energy expenditures. By convention, variables in capital letters are endogenous to the model, while the ones in small caps are exogenous parameters.

$$min\left\{C = C\_EL + C\_TH + \sum_{v \in V : v = \{pv, b\}} (LT\_COST_v)\right\} \tag{4}$$

Where,

- $C\_EL$ is the total annual cost of electricity ($CHF$)
- $C\_TH$ is the total annual cost of gas for heating ($CHF$)

- $LT\_COST_v$ is the lifetime ownership cost of a given energy asset $v$

Equation (4) includes the thermal energy cost component ($C\_TH$), which in this study's scope is limited to the annual gas bill. To calculate it, we consider the annual thermal energy demand of the building, the efficiency of a gas boiler and the cost projection for the year 2050. For households with a heat pump, this cost would be equal to zero, as the heating cost demand is met with electricity.

The lifetime ownership costs of PV and batteries follows Equation (5). The annualized costs were computed using a discount rate of 4%.

$$LT\_COST_v = (annual\_capex_v \ + \ annual\_opex_v) * OPT\_DEPL_v \tag{5}$$

Where,

- $annual\_capex_v$ is the annualized capital expenditure ($CHF$)
- $annual\_opex_v$ is the annual operational expenditure ($CHF$)
- $OPT\_DEPL_v$ is the optimal capacity deployment ($kW$ for PV systems and $kWh$ for batteries)

The electricity bill ($C\_EL$) is the total annual cost of electricity consumption and is calculated according to Equation (6):

$$C\_EL = \sum_t [(D\_GRID_t * \ d\_price\_el_t) - \ (Q\_GRID_t * \ q\_price\_el_t)] \qquad \forall \ t \tag{6}$$

Where,

- $C\_EL$ is the total annual cost of electricity
- $D\_GRID_t$ is the net electricity demand of the household at a given hour $t$
- $Q\_GRID_t$ is the net electricity supply to the grid at a given hour $t$
- $d\_price\_el_t$ is the retail price of electricity at a given hour $t$
- $q\_price\_el_t$ is the feed-in tariff at a given hour $t$

The variables for demand and supply are defined in the grid balance equation:

$$\begin{aligned}(D_{GRID_t} - Q_{GRID_t}) \\ &= d_{el_t} + D_{BAT_{EL_t}} + D_{HP_{EL_t}} + D_{EV_{EL_t}} \ - \ Q\_PV\_EL_t - Q\_BAT\_EL_t \\ &- \ Q\_EV\_EL_t \qquad\qquad \forall \ t\end{aligned} \tag{7}$$

Where,

- $d\_el_t$ is the inflexible electricity demand at a given hour $t$
- $D\_BAT\_EL_t$ is the battery's charging at a given hour $t$
- $D\_HP\_EL_t$ is the demand of the heat pump at a given hour $t$

- $D\_EV\_EL_t$ is the demand of the EV at a given hour $t$
- $Q\_PV\_EL_t$ is the PV generation at a given hour $t$
- $Q\_BAT\_EL_t$ is the discharge of the battery at a given hour $t$
- $Q\_EV\_EL_t$ is the discharge of the EV at a given hour $t$

$$C\_total = C\_EL + C\_TH \tag{8}$$

**Flex value equations**. From the previous equations, we see that it is possible to isolate the hourly behavior of EVs and heat pumps in terms of consumption and injection to the grid. To calculate the market cost of operating these assets, we multiply these values by the wholesale electricity price at a given hour $t$, following equations (*9*) and (*10*).

$$ev\_cost_t = \sum_t (Q\_EV\_EL_t - D\_EV\_EL_t) \cdot q\_price\_el_t \qquad \forall\ t \tag{9}$$

$$hp\_cost_t = \sum_t (D\_HP\_EL_t \cdot q\_price\_el_t) \qquad \forall\ t \tag{10}$$

To measure the value of flexibility, we calculate the difference in the market cost of operation (equations (8) and (9)) of the asset in a given flexibility scenario, relative to the inflexible scenario (*EV inflex* and *HP inflex*). As shown in equations (11) and *(12*) the value of flexibility for a given flexibility scenario ($ev\_scen$ and $hp\_scen$) would be the difference between the total cost for operating their assets compared to the total costs in the reference scenario (*EV inflex* or *HP inflex*).

$$ev\_flex\_value_{ev\_scen} = ev\_cost_{ev\_scen} - ev\_cost_{EV\ inflex} \tag{11}$$

$$hp\_flex\_value_{hp\_scen} = hp\_cost_{hp\_scen} - hp\_cost_{HP\ inflex} \tag{12}$$

Since in both scenarios, the EV and HP demand of end-consumers is satisfied, we can assume that the utility obtained for their service (i.e., the benefit of driving and having a warm house) is the same for all scenarios. Therefore, the value of flexibility represents the additional utility for end-consumers when their consumption behavior responds to electricity prices.

Finally, we aggregate the PV and battery capacity deployed and the flexibility value of all selected household archetypes and calculate the average values per building. We present and discuss the results in the following sub-section.

### A.3.3 Value of flexibility from electric vehicles for end-consumers

In Figure 11, we see a comparison of total annual value of flexibility from EVs for households in Switzerland for the year 2050. We show the results for a household with a gas heating system to obtain the value of flexibility from EVs without the interference of heat pump operation.

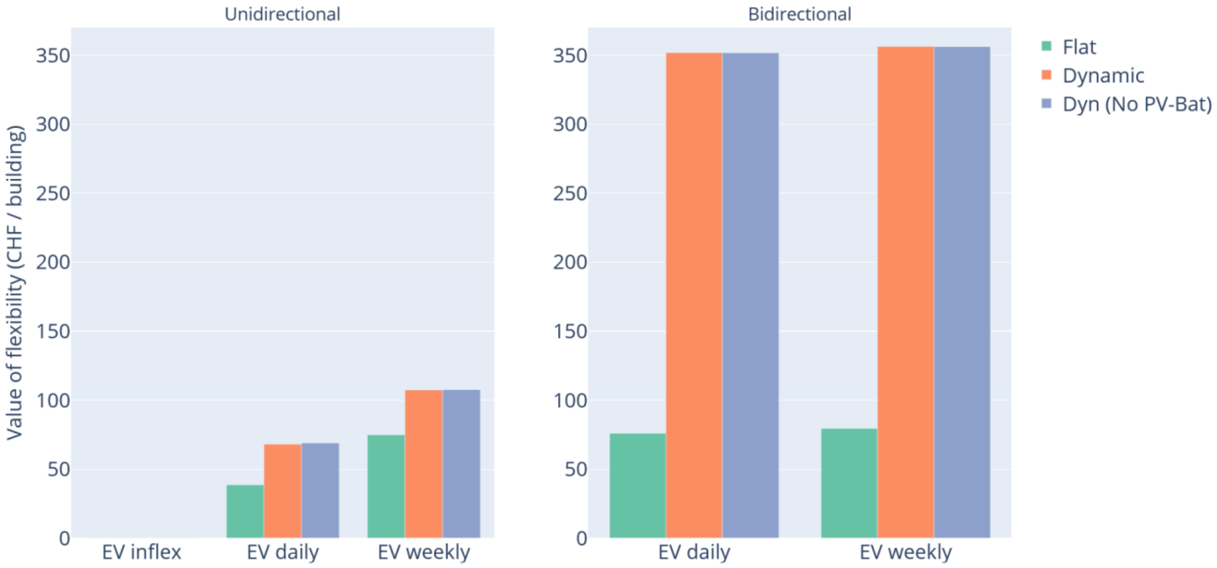


Figure 11: Average value of flexibility from EVs for Swiss single-family households in 2050.

In the case of unidirectional charging (left side of Figure 11), we observe that having more flexible charging, brings value to the end-consumer. The additional value of operating flexibly in the flat tariff scenario (green bar) is CHF 38 for the *EV daily* scenario and CHF 75 for the *EV weekly* scenario. We also see that exposing consumers to dynamic tariffs increases the value even more, as the value increases to CHF 68 and CHF 107 in the daily and weekly scenarios respectively.

For bidirectional charging, we see a very large increase in value, especially in combination with dynamic tariffs. In this case, the value of flexibility from EVs surpasses CHF 350 per year. Also, the value for weekly flexibility is only marginally higher than for daily flexibility. Importantly, for both unidirectional and bidirectional charging, having a PV and battery system does not increase the value of EVs significantly.

### A.3.4 Value of flexibility from heat pumps for end-consumers

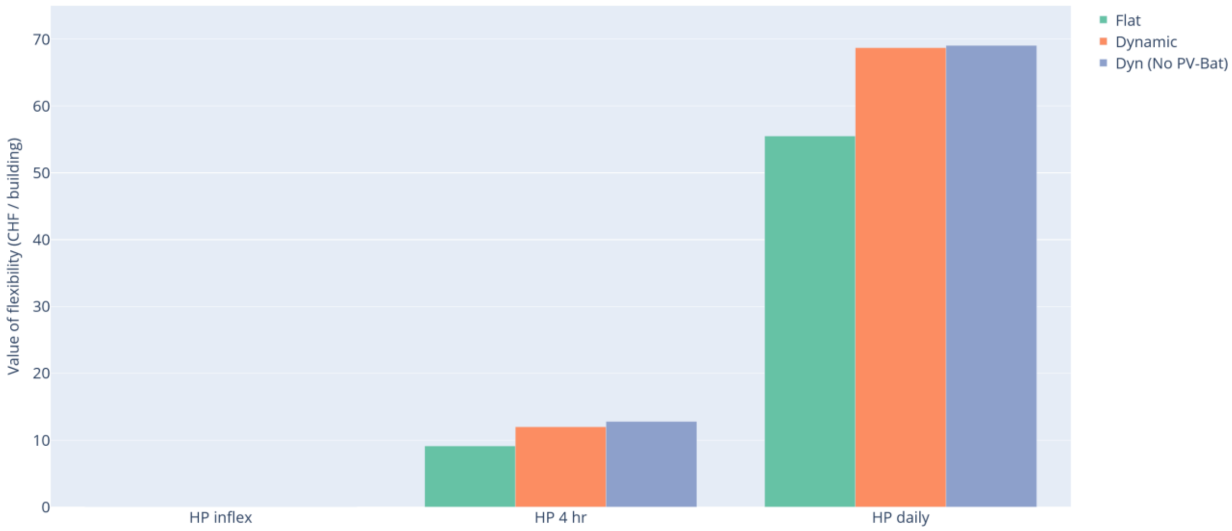


Figure 12: Average value of flexibility from heat pumps for Swiss single-family households in 2050.

Figure 12 shows the average value of flexibility from heat pumps in 2050 for Swiss single-family households without an EV. We see that similarly to EVs, the value increases with higher flexibility and exposure to dynamic tariffs. With a 4-hour flexibility period, the value ranges from CHF 9 to 13 between flat and dynamic tariffs. When having daily flexibility, the value increases significantly, reaching CHF 55 with a flat tariff and CHF 70 with dynamic tariffs. Finally, there is not a significant difference in the value if the household owns and operates a PV and battery system.

### A.3.5 PV and battery deployment

Figure 13 shows the average capacity deployment of PV on households with an EV and a gas heating system, where at first glance we see that the *Flat* tariff incentivizes the deployment of PV in all scenarios. This happens because, without time variability, *Flat* tariffs favor self-consumption and load shifting. Additionally, the installed PV capacity increases significantly when having bidirectional charging, increasing from a maximum of 3 kW per building in the unidirectional scenario to 4,5 kW per building with bidirectional charging. This increment can be attributed to the incentives to inject electricity to the grid with EVs, which results in higher PV generation.

Finally, when having bidirectional charging, the EV flexibility scenario (i.e., EV daily, EV weekly) does not affect PV deployment. That is not the case for unidirectional charging, where we see variability, especially between the inflexible and flexible EV scenarios.

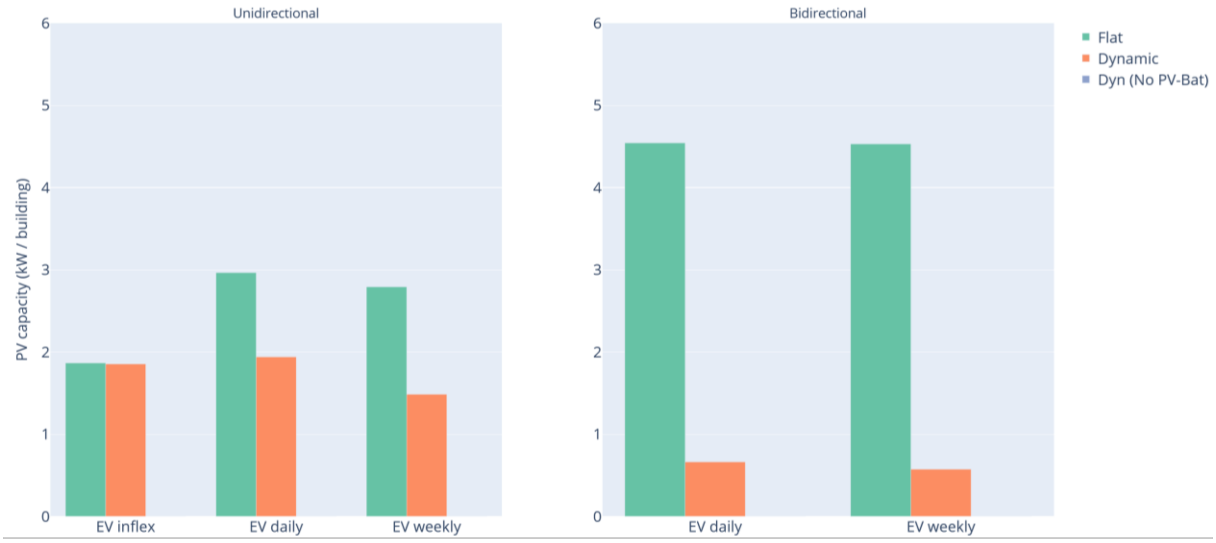


Figure 13: Average PV capacity installed per Swiss single-family household in 2050

Battery capacity deployment can be seen in Figure 14. Here we see how allowing for bidirectional EV charging completely substitutes battery investments, which makes sense considering our assumption of full discharging availability from EVs.

In the unidirectional scenario, the more flexible the EV charging, the less battery capacity is installed.

This happens because the additional flexibility reduces the need to store electricity in during higher price periods to meet the EV demand.

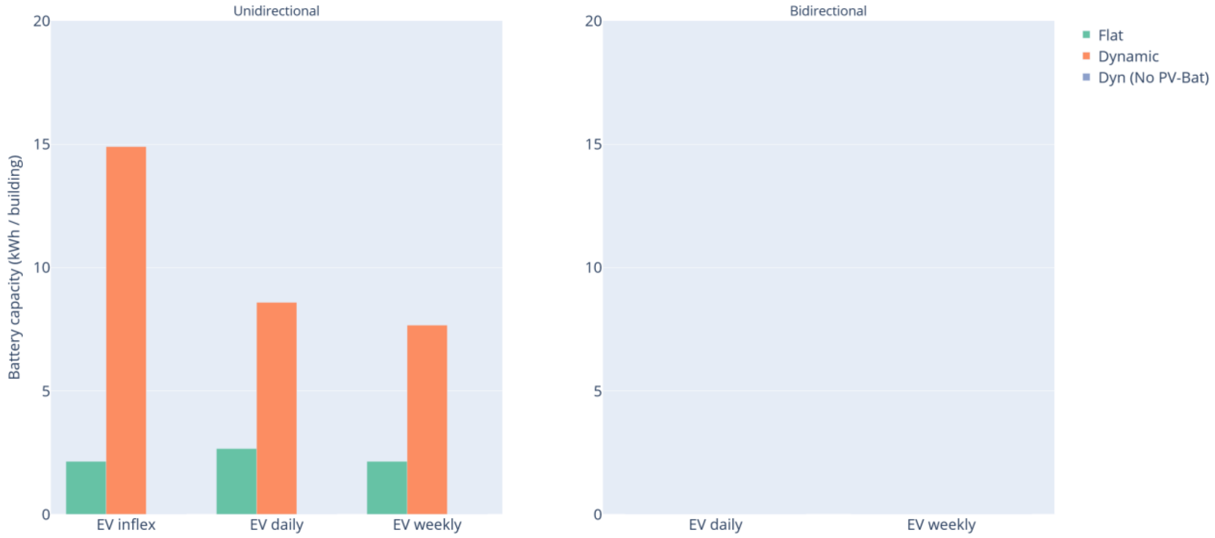


Figure 14: Average battery capacity installed per Swiss single-family household in 2050

Deployment trends for PV and battery technologies are the result of price dynamics. In the *Flat* tariff scenario, the absence of price variation and FiTs results in the system maximizing self-consumption, as the household will only consume electricity from the grid when the price of generating and / or storing electricity (including annualized investment costs) is higher than the retail electricity price. Therefore, the PV and battery capacity deployment in this scenario is the optimal technology mix to maximize self-consumption, given different EV flexibility and heating system scenarios.

### A.3.6 Total annualized costs

Figure 15 shows the variation of annualized electricity costs for Swiss households for different electricity tariff designs and EV flexibility scenarios with unidirectional charging. The annualized costs are from households with a heat pump heating system and include annualized investments (PV and battery capital and operational costs) and electricity costs. Also, the results displayed correspond to the *HP Daily* flexibility scenario for heat pumps.

Adding flexibility in EV charging decreases total annualized costs in average and furthermore, adding flexibility with PV and battery optimal investments lead to the lower overall costs for households, with CHF 1,258 in the *Dynamic – EV weekly* scenario. We also observe that when there is charging inflexibility and dynamic tariffs (*EV inflex-Dyn (No PV-Bat)*), we reach the higher costs (CHF 1,912) because consumers are exposed to price risk without the opportunity to benefit from own-consumption, load-shifting and arbitraging. However, on the *EV weekly* scenario, the cost reduction is such (CHF 1,342), that it is lower that its *Flat* tariff equivalent (CHF 1,365) despite consumers being able to invest in solar PV and batteries for load-shifting.

When comparing the two dynamic price scenarios, the benefits from self-consumption and arbitraging are large enough to justify the investment in PV and battery technology, as consuming exclusively from the grid leads to higher overall costs. Nevertheless, the costs difference is not very large (CHF 84) and could not be enough to justify system-level costs derived from small, distributed generation (e.g., grid defunding, balancing issues, higher capital costs, etc).


Figure 15: Average annual electricity bill for a household with a heat pump heating system and unidirectional EV charging

Figure 16 shows the results of the same analysis but for bidirectional charging. It is very important to clarify that we take as baseline the EV inflex values with unidirectional charging, if by definition, an EV charging inflexibly would not react to wholesale electricity prices to charge and discharge optimally, hence making a bidirectional inflexible charging scenario unrealistic.


Figure 16: Average annual electricity bill for a HH with a heat pump heating system and bidirectional EV charging

In general, for bidirectional charging we observe the same patterns, as flexibility and dynamic pricing reduce the annualized electricity costs for end-consumers. However, two important aspects emerge from the comparison with unidirectional charging. First, the biggest cost reduction occurs when having EV Daily flexibility and increasing the flexibility to weekly reports only marginal additional cost reductions. Second, while the *EV daily* total costs are lower with bidirectional charging compared to unidirectional, the *unidirectional - EV weekly* reached the lower costs among these scenarios.

### A.3.7 Conclusion on demand-side flexibility

In conclusion, our analysis shows that enabling load-shifting flexibility in the Swiss residential sector can significantly reduce household energy costs by 2050. Flexible operation of electric vehicles and heat pumps delivers value to end-consumers, with EV flexibility providing the highest economic gains, particularly under bidirectional charging. Heat pump flexibility also contributes meaningfully to reducing costs, especially when larger daily flexibility windows are allowed. In both cases, exposing households to dynamic electricity tariffs substantially increases the value of flexibility compared to flat pricing structures.

Importantly, the results indicate that dynamic tariffs alone can unlock similar benefits for consumers as those achieved through investments in small-scale PV and battery systems. However, public acceptance of dynamic tariffs remains a potential barrier, which means that well-designed communication and consumer protection strategies are needed.

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# B. Appendix 2: Policy measures to promote electricity flexibility in Switzerland

Considerations in the context of the Mantelerlass legislation

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Version of 1 October 2024, ZHAW Winterthur

**Key messages**

- **Opt-out model**. The Mantelerlass legislation establishes a default right for DSOs to manage existing flexible assets unless customers object. We discuss the implications of the current reforms for the use of flexible demand and potential challenges for their implementation.
- **Ordinance**. The legislation defers some decisions to an ordinance by the Federal Council. Amongst other issues, the ordinance can clarify remuneration of flex and what happens when few flexibilities are used. It is currently under consultation. This paper was prepared before the consultation was published.
- **Three purposes of flexibility.** Flexibility can generally be used for three different purposes.
  (4) Timing of consumption to coincide with **energy** abundance and low prices
  (5) Easing constraints on the **network**
  (6) Providing **balancing**
- **Monopoly for (1) and (2).** The first two flexibility uses can only be exploited by the regional utility, which has a monopoly on the supply of electricity for small customers in Switzerland.
- **Balancing (3) is small.** Private aggregators can only access one revenue stream: balancing. The balancing market is tiny compared to the capacity of new flexible assets.
- **Balancing aggregation is problematic.** Aggregators control assets otherwise served by the monopolist. This is complex. Worse, the current rules ignore that reducing consumption in one hour is likely to lead to higher consumption later, undermining system benefits.
- **Focus on energy and network**. Any regulation fostering greater use of flexibilities should thus focus on uses (1) and (2), i.e. energy and network where the needs are tremendous.
- **Problems of flexibility markets.** Flexibility markets remunerating a deviation from a baseline often yield adverse incentives to increase the problem in the first place (inc-dec gaming).
- **Tariffs**. Dynamic grid and energy tariffs are preferable, as they avoid such incentive problems. Situational short capacity charges are a practical way to prevent peaks from EV charging.
- **Interventions.** We propose five policy measures.
  1. Stronger incentives in regulation for DSOs to use flexibility to avoid grid buildout.
  2. Mandating utilities to offer spot-based energy tariffs as an option to customers.
  3. Mandating DSOs to offer dynamic grid tariffs as an option to customers.
  4. A real-time tariff publication platform. A central point customers' devices can access.
  5. Device specific suppliers: Allow aggregators to fully supply energy to specific devices (heat pumps and electric vehicles), a step towards partial liberalization.

## B.1 Introduction

Switzerland is in the process of reforming its electricity market design as part of the Mantelerlass legislation. Following the entry into force of the Mantelerlass, the Federal Council will revise the Electricity Ordinance. It is currently under consultation. This paper was prepared before the consultation was published.

**DSO's default right to manage flexibilities ("opt-out approach")**. A key point of discussions towards Mantelerlass was whether the grid operator should be able to manage the flexibility potential of electric vehicles (EVs) and heat pumps by default, or whether an explicit choice by the consumer should be required. For existing assets, legislators eventually converged on the "default" approach of grid operators managing flexibility, while leaving an explicit "opt-out" for consumers. For new assets, utilities have to actively recruit flexibilities as by default those are not managed by the utility.

**Implications**. The change to a new default for existing assets will have an impact on other uses of flexibility, such as aggregators that pool flexible assets and commercially monetize their flexibility in electricity markets. Some actors have raised a concern that existing markets for flexibility may be 'dried up', leaving less flexibility available for competitive companies, as the regulation gives control of flexibility to the network operator by default and customers may be reluctant to switch elsewhere for control of their flexible assets. This reduced competition in the market for flexibility may lead to reduced utilization of flexibility potential. In addition, a lack of competition could result in inadequate compensation for the use of flexibility by the incumbent. However, given the provision that for new flexibilities the default approach does not apply, all these concerns are significantly mitigated.

**Flexibility**. In the context of this report, we use the term flexibility to describe actions by any type of asset connected to the electricity system that respond not only to the individual preferences of the user, but also to the needs of the system. By this definition, flexibility can be provided by both demand-side and supply-side assets. Here we focus on the demand side and the management of flexible demand assets (i.e. heat pumps, electric vehicles (EVs), battery storage, distributed PV).

## B.2 Demand flexibility

Before discussing how flexibility can be efficiently used and successfully integrated into the electricity system, we must first have a clear definition of flexibility. We propose a definition in which an asset provides flexibility services only if it adjusts its operation (fully or partially) according to system needs (for example through market or control signals). But why is it important that electricity demand follows these signals?

To answer this question, we can consider the (theoretical) instantaneous value of electricity on a certain connection node. This value of electricity reflects the current cost of production and transmission of electricity, meaning that a high value would signal a situation in which high overall demand drives the operation of costly peaking plants, or congests the distribution network or both. In any of these cases, demand price response, i.e., demand reduction at times of high prices, would be beneficial for the system as it could delay costly expansion of the distribution grid and the installation of additional power generation capacity.

Going back to our flexibility definition, when demand assets calibrate its behavior to the system's needs reflected in such (theoretical) prices, it contributes to increase the system's overall efficiency. For instance, an electric vehicle that charges completely independently from power system signals and prices does not provide flexibility to the system. On the contrary, whenever the electric vehicle adapts its charging behavior to prices or system control signals, it is tapping its flexibility potential.

Following our definition, we can argue that the value of flexibility also has a market design and regulatory dimension. This is the case as the total flexibility potential of a system is not only dependent on the type of devices that are connected to the network, but also on the tariff schemes, regulatory framework and deployment of control technologies. To harness the potential value of flexibility we consider all market segments in which demand assets can provide flexibility services that are useful to the system.

In this context, electricity flexibility can serve three purposes:

- Timing of consumption to coincide with energy abundance and low prices (**energy arbitrage**)
- Avoiding local grid congestion (**network**)
- Balancing the overall power system (**balancing**)

In the following subsections, we discuss these in turn.

### B.2.1 Energy market

Given the large expansion of wind and solar power in the Swiss neighboring countries and Switzerland's own expansion of solar power, the price patterns on wholesale electricity markets will become increasingly dominated by the hourly availability patterns of these technologies. That means in summer, prices will be very low during midday to early afternoon and more expensive in morning and evening hours. Wind will impact prices all year around depending on availability. In hours where renewable supply outstrips demand, prices might even be zero.

This offers significant possibilities for flexible loads to reduce their energy costs by timing consumption to the respective hours with cheap and abundant supply and shift away from high-price scarcity hours. Figure 4 shows an example of such load shifting to cheaper hours in the day.

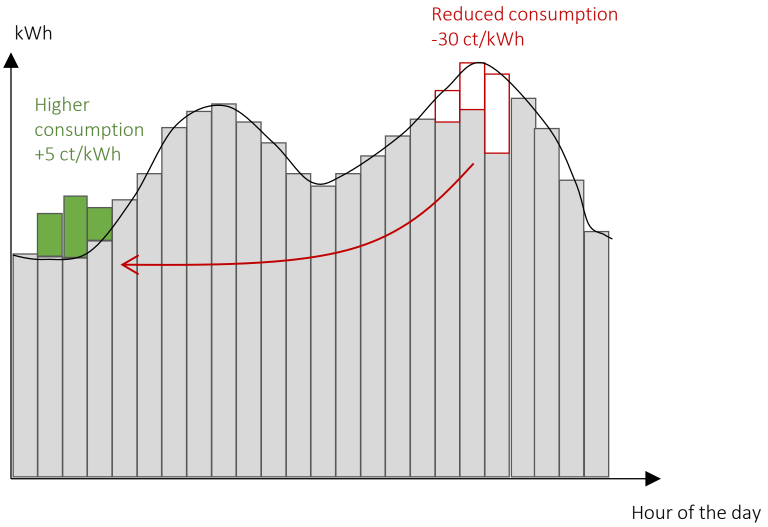



Figure 17: Load shifting to cheaper periods during the day

To make use of such optimized energy procurement, flexible loads must either be exposed to dynamic prices, or be controlled by a central entity such as the energy supplier, to operate according to these signals.

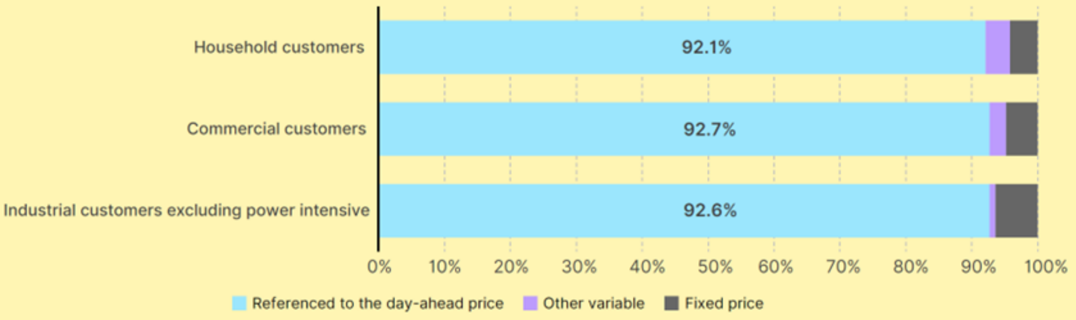
A recent study by Agora Energiewende & FfE (2023) has shown the energy arbitrage potential to be important, but also points out that it must be combined with dynamic network tariffs. Otherwise, dynamic energy tariffs risk causing local grid overloads that lead to an increased need for further grid buildout. This is because most flexible loads might react to the same price signal, and then cause local grid overloads in the hours where electricity is cheapest on the wholesale market. The "energy" side of flexibility should thus be thought of in tandem with the "grid" side of flexibility.

In the process of the electrification of the energy system (including heating and transport), a shift to dynamic electricity tariffs is almost inevitable. This is because the volatility of power prices is likely to increase in a system dominated by variable renewable energies. Especially for electric vehicles, the potential to exploit these hourly price patterns is therefore very high. An example of Norway, a country that is always further ahead than any other European country with respect to electric vehicle deployment, and also has a high penetration rate of heat pumps, Figure X shows that already more than 90% of customers chose energy tariffs which expose them to day-ahead prices.

**How Norwegian customers are exposed to price signals**

In Norway, a country with a high share of electric vehicles and heat pumps, more than 90% of customers have chosen to be exposed to price signals with dynamic electricity price contracts (Figure 18). Customers are metered at an hourly resolution and are directly exposed to the day-ahead prices which enables implicit demand response and can be supported by (out of market) automation.

Level of penetration of different types of retail electricity contracts per type of final customer in Norway – Q2 2023 (%)




*Source: Statistics Norway.*

Figure 18: How Norwegian customers are exposed to price signals. Excerpt from ACER report on barriers to demand response (ACER, 2023).

### B.2.2 Grid constraints

In the coming years, significant amounts of new loads will be connected to distribution grids, in particular heat pumps and electric vehicle charging infrastructure such as wall boxes in private homes. Even if Swiss distribution grids in the past were often over-dimensioned, these loads are likely to require further grid buildout. Furthermore, in the absence of strong incentives for DSOs to efficiently trade-off the alternatives of flexible dispatch versus grid expansion, such over-dimensioning of the grid can be expected to continue.

To reduce the amount and costs of such grid extensions, the flexibility potential in these new load types should be used. In other words, they should be incentivized or controlled in a way to – as a first approximation – minimize the need for grid buildout. In economic terms, instead of minimizing grid buildout, the objective should be an optimization of the trade-off between grid buildout and the loss of utility from load shifting. For such an efficient trade-off to materialize, DSOs must be incentivized respectively. This can, for example, stem from incentive regulation, as we outline in the recommendations below.

The impact on grid buildout is not only about reducing the overall amount of grid expansion needed, but also to optimize its timing. It is generally much cheaper to extend underground powerlines in residential areas synchronously to other street construction works compared to individual construction projects specifically for the power line expansion. Therefore, using flexibility to be able to shift grid expansion projects further into the future might yield significant overall cost savings.

The cost savings achievable from the use of flexibility to reduce grid expansion needs is significant (Agora Energiewende & FfE, 2023, Winzer et al. 2023a) It is thus where the main regulatory focus should be, jointly with optimizing energy procurement timing.

### B.2.3 Balancing

Lastly, residential demand assets can also be used to provide balancing services to the power grid. Before diving into the possibilities for flexible assets in households to provide balancing, Box 1 provides an overview over the purpose and structure of the balancing market.

**Box 1: Electricity balancing**

ENTSO-E (2018) defines electricity system balancing as "all actions and processes through which Transmission system operators (TSO) continuously ensure the maintenance of system frequency within a predefined stability range, as well as compliance with the amount of reserves needed with respect to the required quality".

In the European Union, the stabilization of the European electricity system is regulated by the Electricity Balancing Guideline (EBGL). This regulation was enacted by the European Commission in 2017 as an effort to enhance the efficiency and integration of European balancing system, which at the time did not have a common operational framework, while fostering competition, non-discrimination and transparency (NEXT, 2023a). Switzerland is not directly part of the EU balancing platforms but participates in the International Grid Control Cooperation (IGCC) for imbalance netting to avoid counter-activating balancing and also participates in joint Frequency Containment Reserve (FCR, historically called primary reserve).

There are three main actors in the balancing market: the TSOs, the Balancing service providers (BSPs) and the Balance responsible parties (BRPs). TSOs oversee the operation of the system and make sure the demand and supply remain balanced. BSPs offer balancing services to the system, they can be generators, demand response assets or storage facilities. BRPs are the legal entities responsible for the imbalances in a certain service region and its portfolio is the balancing group. TSOs can establish their own BRP or can outsource this service to private firms (NEXT, 2023b).

Table 1 shows the four main balancing processes defined in the EBGL for Europe, but due to European harmonization this also broadly applies to Switzerland as well. These processes represent active power reserves that stabilize system frequency after an imbalance occurs. They also become operational at different moments depending on the severity of the frequency disturbance (ENTSO-E, 2018).

| Balancing process | Acronym | Activation | Response time | Also known as |
|---|---|---|---|---|
| Frequency Containment Reserve | FCR | Automatic activation in the entire synchronous area | Max 30 s | Primary Reserve |
| Frequency Restoration Reserves with Automatic Activation | aFRR | Automatic activation within a service region | 30 s to 15 min | Secondary reserve |
| Frequency Restoration Reserves with Manual Activation | mFRR | Semi-automatic or manual activation within a service region | Max 15 min | Tertiary Reserve |
| Replacement reserves | RR | Semi-automatic or manual activation. Replaces activated FRR to be prepared for additional system imbalances | Min 15 min | - |

Figure 19: Balancing processes according to the Electricity Balancing Guideline (EBGL)

Considering the response times of the different balancing processes outlined in *Box 1* above, flexible demand assets like heat pumps or electric vehicles are not suitable to participate in the FCR market, but can provide aFRR, mFRR or RR reserves.

For small assets, in most countries these do not bid directly into balancing markets but are instead pooled by aggregators that jointly bid them into the balancing markets. We discuss the Swiss balancing pools in depth in Section B.3.1 .

## B.3 Flexibility in Switzerland

Existing regulations in Switzerland limit the use of flexible demand resources in the electricity system. Incentivizing the use of flexibility is particularly challenging in the context of the Swiss monopoly in the retail electricity market. While large consumers (over 100 MWh per year) have full access to the wholesale electricity market and can choose their electricity supplier, smaller consumers are tied to regional monopolies.

Therefore, Swiss households are largely reliant on their local utility to offer remuneration for flexibilities. If they instead want to sell their flexibility potential into competitive markets, the current regulation allows Swiss households to sell their flexibility potential in two cases only. Either they are part of an own consumption community (which we do not focus on in this document) or they join a balancing aggregator.

### B.3.1 Balancing pools ("Regelpooling")

Balancing pools allow the provision of balancing energy by distributed assets, thus opening ancillary markets for small consumers, producers or both. Aggregator companies in Switzerland operate under this scheme, remotely controlling the flexible demand assets of several consumers and prosumers in an automated and synchronized manner.

Balancing pools group a number of balancing assets (such as flexible loads, batteries or PV panels) operating together in a coordinated way. The operation of such pools is regulated in Switzerland since 2013 (VSE, 2013). The regulation's goal is to facilitate the participation of groups of smaller balancing assets exclusively in the balancing market. In the context of this report, balancing service providers would be consumers or prosumers owning and operating flexible demand assets.

The operation of aggregated balancing assets is coordinated by a balancing pool operator, a role that has been undertaken both by large energy utilities such as BKW or Alpiq but also by dedicated aggregation companies such as Tiko. All pool operators must be part of a balancing group, which ensures a balanced system within its operation area and represents them towards Swissgrid and other stakeholders.

The balancing market is a relatively small market compared to the overall electricity market. To give an idea on the size of the balancing market, in 2021 its monetary volume was only 2,5% of the value of the bulk electricity valued at wholesale prices for Switzerland (Figure 20). Compared to the volume of flexible demand assets like heat pumps and electric vehicles to come online in the coming years, the balancing market is minuscule. Furthermore, the balancing market is a "correction" market: It deals with left-over imbalances that have not been traded away in earlier market stages from day-ahead to intraday. Because large imbalances in real time can compromise system security, it is a goal of electricity market design to design incentives across all market stages in a way so that the system imbalance in real time remains small – which corresponds also to empirical observations of balancing volumes decreasing despite more renewables in the grid (Ocker & Ehrhart, 2017). Therefore, the balancing market is unlikely to be a large value driver for the use of flexible assets.

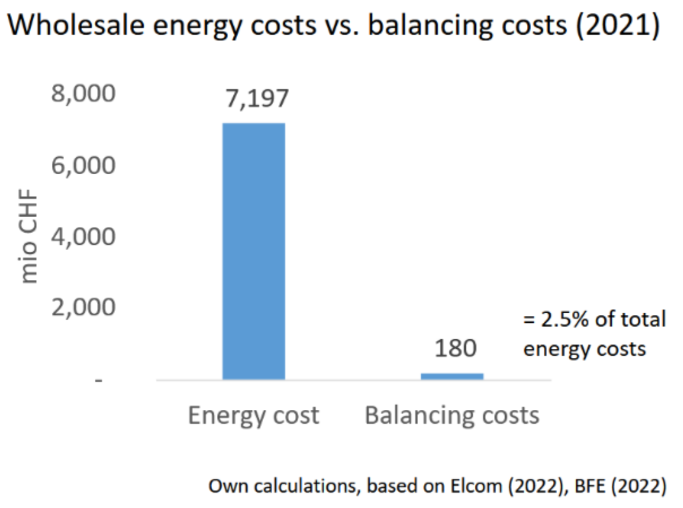



Figure 20: Comparison of energy vs. balancing costs for 2021 in Switzerland, based on spot prices.

The control sequence for balancing pools works as follows. Swissgrid centrally monitors the provision and delivery of balancing power and balancing energy for the overall power system. When a system imbalance occurs, Swissgrid forwards the call for balancing energy to the pool operator, which in turn operates its aggregated provision units by varying generation or flexible demand assets under its control, according to the system's needs. Finally, Swissgrid processes the balancing energy measurements ex-post and issues the pertinent bills.

It is important to keep in mind that the operation of balancing pools takes place in a hybrid market environment in which regional monopolies are still supplying small consumers' electricity demand, while the control pool operator manipulates the consumer's flexible demand assets when participating on the balancing market.

Having multiple concurrent suppliers can be problematic since the state of an asset at a given time affects its interactions with several markets and stakeholders, meaning that suppliers may adversely impact each other in managing one asset. One issue aggregators in this context have mentioned to us in interviews is that the number of DSOs in Switzerland makes it difficult to aggregate small assets, because it means interacting with each single one of the DSOs if problems occur.

Another clear example of the problems that can arise from having concurrent suppliers is what we call "catch-up consumption". Catch-up consumption occurs when the demand reduction triggered by aggregators of flexible demand assets (such as heat pumps or electric vehicles) causes additional consumption in subsequent market time units, outside of the balancing call-up period. This happens because the demand reduction from the first period will be needed later in time (e.g., a consumer would still want to charge their EV at, say, 100% of its capacity after interrupting its charging or providing balancing energy).

The problem with such catch-up consumption is that it leads to new imbalances in the subsequent market time units, which are not compensated for in the current operational framework for balancing provision. Additionally, since there is no information exchange in real time between the independent aggregator and the TSO or BRP, the latter would not be able to anticipate this catch-up consumption and therefore, a similar amount of system imbalance could be realized in the second period.

Figure 21 shows a schematic depiction of the catch-up consumption problem. Here, the projected demand from the TSO or BRP is represented in green and the realized demand in red. We see that after a positive call (i.e., demand exceeds supply), the control pool operator reduces demand in (1) by managing the flexible demand assets under its control. Later, when the delayed demand is consumed in (3), it creates a disbalance of similar magnitude in (2) but in the other direction.

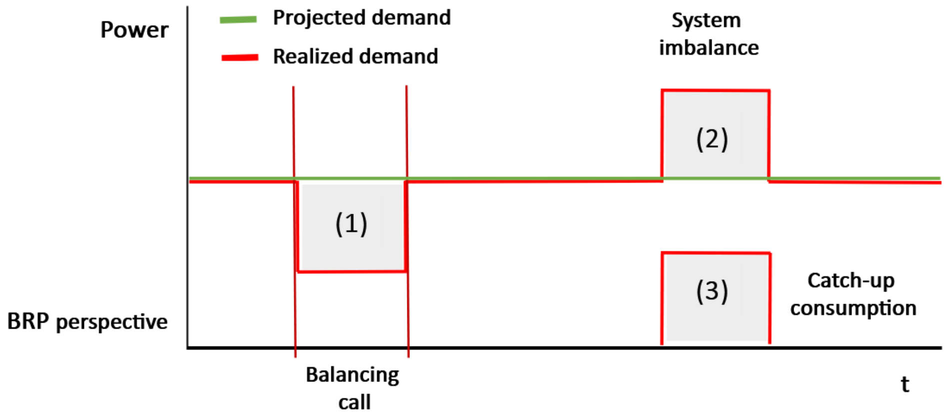



Figure 21: Catch-up consumption due to concurrent suppliers of energy and balancing services from the BRP's perspective

In short, instead of improving the balancing market's efficiency with the inclusion of smaller agents, the current regulation for balancing pools and aggregators, in which concurrent suppliers coexist, could create further balancing issues in the system. While this effect is clearly existing from a theoretical point of view, it would be worthwhile to analyze it also empirically, especially if we consider that the growing capacity of flexible demand assets in the system could make this problem more significant in the future.

### B.3.2 Mantelerlass on flexibility

The Swiss federal law on a Secure Electricity Supply with Renewable Energies (Mantelerlass) has passed both Swiss parliamentary chambers in fall 2023 and modifies the Energy Act (Energiegesetz/EnG) and the Electricity Supply Act (Stromversorgungsgesetz/StromVG). In this section we present our understanding of the Mantelerlass sections concerning flexible electricity demand assets. As we are not lawyers, we cannot exclude errors or misunderstandings.

The DSO's default right to manage flexibility is defined in Article 17 of the revised StromVG. In summary, we understand the proposed reforms as follows:

- Access to flexibility requires a contract. (StromVG Art. 17c1 and 17c2)
- The DSO is allowed to operate flexible demand resources if the resource owners do not explicitly object. (StromVG Art. 17c3)
- It is the responsibility of the Federal Council to determine the way in which DSOs inform the owners about the use of their flexibility and how they can object. (StromVG Art. 17c3)
- The DSO is allowed to operate flexible demand resources against the will of the resource owners if this is required to guarantee safe operation of the grid (StromVG Art. 17c4 and c5)
- The Federal Council is empowered to take measures to improve the use of flexible demand if it is established that this regulation leaves significant flexibility potential unused. Such measures may be to the detriment of the DSOs and can consist of exemptions from Article 17b3 or the introduction of new flexibility market measures. (StromVG Art. 17c3)

## B.4 Remuneration of flexibilities

An important topic is how the flexibilities used by utilities should be remunerated.

**Monopsony**. When procuring flexibilities from customers, the DSO holds a near-monopsony position. A monopsony is the equivalent of a monopoly, but on the demand side. Here, it is the grid operator that demands flexibility provision from many customers, so the DSO acts as the only demand entity in the market for flexibilities who can make use of the flexibilities for grid purposes. There might be other demand for flexibilities, e.g. from aggregators who use the flexible resources for system balancing. However, these compete on an unequal footing, as the usage for grid purposes are often of higher value than the use of flexibilities for system balancing, depending on local grid loading situation. The DSO's monopsony position puts the DSO into a more powerful position compared to the customers. This is because the DSO might be able to choose from many customers but the customers can only make contracts with one entity, the DSO, when it comes to using flexibilities for the grid. In such settings, regulation on pricing can be helpful. This is also done in other settings where a monopoly arises, such as network regulation more generally.

**OPEX incentives**. A problem with the current regulatory setting for DSOs in Switzerland is that the revenue of grid operator increases with the amount of grid buildout, so that there is an incentive for grid buildout rather than using the existing grid as efficient as possible or using flexible assets to minimize the need for grid buildout. In the regulation, this is counterbalanced by the NOVA principle (Netzoptimierung vor Netzverstärkung vor Netzausbau) which stipulates that grid optimization must take precedence before grid reinforcement, which again must take precedence before grid buildout. However, in situations where economic incentives are misaligned with regulatory provisions, suboptimal compliance is likely. Therefore, a lever to incentivize adequate payment of flexibilities is also to address the underlying incentive problem. Once grid operators have incentives to reduce overall grid costs (e.g. through incentive regulation), it would be in their own interest to procure (efficient) flexible assets to reduce grid buildout and also to pay customers an adequate amount so that they voluntarily accept usage of their flexible resources.

**Distributional effects**. The remuneration of flexibilities also has distributional consequences between poor and rich, or between house-owning and apartment renting grid customers. As single family home owners are more likely to possess flexible loads such as EVs or heat pumps, too generous remuneration of flexibilities that exceeds the asset's benefit to grid cost reduction would benefit them at the expense of the remaining network tariff payers. Thus, for the public perspective, it is important to pay the adequately high remuneration to optimize grid buildout vis-à-vis the use of flexibilities while neither paying more nor less than the optimal amount.

**Variation of benefit**. The benefit of using flexibilities greatly varies between grid areas and even between individual assets and locations within a single distribution grid. For example, if a particular DSO grid is already larger than necessary for all connected loads, flexibilities might not have any positive value for grid cost reduction. If, however, a DSO grid is near capacity already, than any new connected load might trigger then need for grid buildout unless it can be incentivized to shift consumption to underutilized hours. Even within a single DSO area, individual branches of the network might be near capacity and others might have plenty of headroom. To account for such variation, the remuneration of flexibilities should also be allowed to vary along with the benefit they bring. Such variation should not be considered discriminatory, as long as it can be objectively justified.

**Targeting**. Such variation in remuneration can also be considered as targeting: Targeting the highest remuneration where the benefit is highest. If no variation of offered remuneration to flexibilities was allowed, then this would risk diluting the benefits of flexibility procurement. A lot of money might be paid out to flexibilities, many of which do not actually bring any system benefit. Therefore, allowing DSOs to approach customers directly which are (objectively) of high value to avoid grid buildout seems a useful approach. A prerequisite to such targeting is transparent data availability about the grid and the likeliness of necessary grid reinforcements in case of new loads, so that customers can understand why one of them gets an offer for flexibility remuneration while another one doesn't.

**Voluntary vs. involuntary flex.** Two cases of flexibility provision can be differentiated. The remuneration for voluntarily provided flexibility (regardless of whether this is opt-out or opt-in) and the remuneration for involuntarily provided flexibility as part of the emergency clause (Artikel 17c Absatz 4 StromVG), which is currently foreseen to be for free.

**Inter-dependence**. Remuneration in the two regimes is inter-dependent. If emergency use is for free, then it is less attractive for DSOs to contract voluntary flexibilities, because in any case it can rely on the fallback emergency mechanism and doesn't need to pay anything in case in a year ex post flexibilities turn out not to have been needed.

**Structure of remuneration**. A crucial aspect regarding remuneration is the structure of remuneration. Remuneration can either be capacity-based, or call-up based, or a combination of capacity and callup-based. Remuneration creates incentives. If payment of flexibilities is done through callup-based payments, a problem is that the payment itself might make the problems worse which the flexible loads are supposed to cure. This is the inc-dec gaming problem which we describe in section B.5.1 .

**Inc-dec incentives**. Consider the following remuneration scheme: Whenever the grid is fully loaded, grid operators would send reduction commands to electric vehicles and reimburse each EV that was charging before the command for reduction came (or express a willingness to charge while the command for reduction was active) with a high reimbursement payment. Then it would become attractive for electric vehicles to deliberately consume electricity (or express the willingness to charge) exactly at the worst moments just to be called up and earn the remuneration. As charging time optimization of EVs would likely be done by automatic control algorithms, the users wouldn't even have to do this themselves but aggregators or algorithms would do it for them.

**Avoiding call-up payments**. Due to these inc-dec gaming incentives, call-up payments should be avoided. That means, the remuneration of flexibilities should not depend on how often they are used by the grid operator. Better options instead would be to pay them a fixed charge based on e.g. last year's consumption of the asset. Capacity payments (per kW) would also avoid inc-dec incentives but would provide incentives to inflate connection capacities just to get paid higher fixed charges.

**Rebated tariffs as remuneration**. Therefore, payments based on actual consumption (e.g. of the previous year) or rebating current consumption makes more sense. The rebate should ideally be calculated based on how often a certain asset type (such as EV or heat pump) is likely to be helpful to relieve grid constraints, i.e. how often such assets consume in the critical hours when load curtailment is necessary. Say, heat pumps often consume during the critical hours, but EVs would not (just, as an assumption). Then the rebate should be higher for heat pumps because they are likely to be more helpful in grid relief. Evidently, such differentiation only works if the utility has sufficient data to make the differentiation. It is important that the strength of the rebate does not depend on the usefulness of the specific asset, but only of the asset class more generally. Basing the strength of the rebate on the specific asset would, again, induce incentives to increase consumption specifically in critical hours, which is not desirable.

**High level principle**. Grid operators should have some freedom in designing remuneration schemes. However, it might make sense to define an additional higher-level principle apart from non-discrimination. An additional principle that would be advisable would be refraining from call-up payments, because of the detrimental effects.

## B.5 Markets vs. tariffs for grid flexibility

In the past years, flexibility markets were often discussed as a solution for DSOs to dispatch flexibility for the purpose of grid congestion relief. Flexibility markets are local electricity markets where the DSO may request upward or downward flexibility from distributed resources and pays for the up or down activation. However, such markets suffer from a fundamental incentive problem. Local flexibility markets which remunerate flexibility providers for grid relief provide perverse incentives to first increase grid congestion to subsequently get paid to relieve grid congestion again. This problem is called increase-decrease gaming and has gained significant attention in recent years (see e.g. Hirth & Schlecht, 2020). [4]

In the following, we first recapitulate the problem of increase-decrease gaming. Second, we outline a solution to the increase-decrease problem in the form of dynamic grid tariffs. They do not suffer from the problem of increase-decrease gaming while achieving time-variant dispatch of local flexibilities and are thus preferable over a flexibility market.

### B.5.1 The problem of increase-decrease gaming

As we showed in previous work (Hirth & Schlecht, 2020), a two-stage electricity market where the two stages have a different geographical granularity offers arbitrage opportunities and incentives for strategic bidding behavior. In scarcity situations and regions, producers will anticipate that higher profits can be generated by selling their production on the redispatch market rather than the zonal market. They therefore offer higher prices on the zonal market to price themselves out of the market. Conversely, producers in surplus situations and regions will anticipate profits from being downward-redispatched. To achieve this, they place low bids on the zonal market to push themselves into the market. On the redispatch market, they buy the energy back at a price below the zonal price and thus meet their delivery obligation. One can understand these strategies as an optimization between two markets or as arbitrage trading. They are also known as increase-decrease (inc-dec) gaming.

Such strategic bidding has problematic side effects: it exacerbates congestion, creates windfall profits, and gives rise to perverse investment incentives. The problem is not limited to large-scale redispatch on transmission grid level but the same incentives apply in local distribution grids when flexibility markets are used which pay distributed energy resources for grid relief.

For simplicity, in the following we provide an example. We assume a case where the local DSO needs load-reduction flexibility at 19:00 of a particular day to avoid transformer overload, as that is a time when load on distribution grids is high. We further assume an electric vehicle (EV) arrives home at 15:00 and would – from own preferences – start to charge directly when coming home. The problem of increase decrease gaming in flexibility markets now is the following: If the EV owner anticipates that the DSO needs downward flexibility at 19:00 and is willing to pay for that downward flexibility, then there is an incentive for the EV owner to pretend postponing to charge its EV to exactly 19:00, so that it is available when the DSO asks for and is willing to pay for load reduction. However, by doing so, the EV owner had

[4] Section B.5 on grid flexibility is based on work in the PATHFNDR project by Christian Winzer and Ingmar Schlecht.

made the problem worse, namely it has increased congestion at 19:00 – just to relieve the caused congestion afterwards at a payment from the DSO to the EV owner.

More recently, Ehrhart et al. (2022a) have analyzed multiple ways that are often claimed could mitigate inc-dec gaming, however, they find that the problem is fundamental and none of the potential mitigation mechanisms could solve the fundamental problem of increase-decrease gaming in redispatch markets.

Empirical evidence also underlines the significance of inc-dec gaming. An analysis of the Italian redispatch market by researchers from Stanford (Graf, Quaglia and Wolak, 2021) found generators made congestions significantly worse in responding to incentives from redispatch markets – a finding that is echoed by market participants from Italy in private conversations. Inc-dec gaming also played a role in the California energy crisis of 2021. Lastly, a form of inc-dec gaming was also found by the British regulator Ofgem to be used by energy firms from 2018 to 2022. According to a Bloomberg analysis, they "received £525m in extra revenue from using the 'off-on manoeuvre' between 2018 and 2022" (The Guardian, 2023). This underlines that market parties respond to incentives.

The problem of inc-dec gaming is also relevant for small household customers, because they are likely to be managed by professional aggregation firms or household energy management systems which are also likely to respond to incentives in the best interest of their customers. Given the detrimental incentives arising from flexibility markets, also small household assets like EVs or heat pumps would then likely to make critical situations worse.

### B.5.2 Dynamic grid tariffs as a solution

Given the problems of market-based flexibility procurement, alternatives are necessary. Dynamic grid tariffs can be a solution to the problem and are thus preferable over a flexibility market. This is because grid tariffs are charged on the actual metered consumption, and not on the load reduction compared to hypothetical load levels a customer requests before. Hence, dynamic grid tariffs do not discriminate between those units who provide grid relief and those who do not and thereby avoid the perverse incentives of flexibility markets to increase congestion before solving it.

Dynamic tariffs can provide an incentive to shift flexible loads from periods with high prices to periods with lower prices. In contrast to flexibility markets, the level of grid tariffs is specified by the grid operator and not by the market. Another difference to flexibility markets is that the grid tariffs affect all units in the grid area and not only the ones who actively help solve the grid congestion – this is the main reason why grid tariffs do not suffer from the inc-dec problem. By contrast to direct load control by a single network operator, control via dynamic prices can simultaneously take into account congestion in different network levels and markets by over-laying the corresponding price signals.

For more details on dynamic grid tariffs, see the work by Winzer et al. 2023a and an upcoming policy brief on electricity retail rate design in Winzer et al. (2024).

### B.5.3 Situational short capacity charges as a practical solution

Highly dynamic grid tariffs that react to hourly or even quarter-hourly grid load changes and forecasts are not easy to implement and need live grid data transmission.

An easier to implement interim solution is the introduction of situational short capacity charges (German: "situative kurze Leistungspreise", see also Winzer et al., 2024, and Neon, 2024). They are *situational* (i.e. active only when a highly loaded grid can broadly be foreseen, such as only in winter evenings) and they are *short* (i.e. they look at the peak capacity only during a short time-period such as a multi-hour period and are charged for the single multi-hour period). This sets them apart from yearly peak capacity charges.

The problem with yearly peak capacity charges is that they put an extremely high penalty on increasing ones own yearly peak – even if in the time period where one's own demand peak occurs the grid is only mildly loaded and there is no grid-related need at all to incentivize demand reduction.

Such situational short capacity charges incentivize to load electric vehicles more slowly during potential peak hours, while not affecting charging behavior outside of potential peak hours. Also, they do not need real-time information if the time windows are known in advance, and they can be calculated based on measurement timeseries ex post. Thereby, they are easier to implement than highly dynamic tariff structures that require real-time information.

### B.5.4 Forward markets for dynamic tariffs

An alternative, and from an economic perspective even more efficient – but more complicated and challenging to implement – way to deal with distribution grid peaks is to complement dynamic tariffs with a kind of “forward market” for grid fees. This is a concept we are currently looking into in latest research.

To prevent rebound peaks in case of large volumes of automatic load control, dynamic per kWh grid charges will need to be fixed ex-post, based on the actual measured grid load (Winzer and Ludwig, 2022). While ex-post grid charges provide the right load-shifting incentives, they are hard to anticipate and create significant price risks for consumers. To avoid this, grid operators could offer the possibility to fix the grid tariffs for scheduled injections and withdrawals ex-ante, in a local forward market on the dynamic grid tariff. Grid operators could forecast bottlenecks and the resulting dynamic grid charges based on scheduled injections and withdrawals, while grid-customers could lock-in the price forecast of the grid operator for scheduled injections and withdrawals and would only pay deviations from their schedule at dynamic ex-post grid charges.

## B.6 Recommendations: Interventions for promoting flexibility

We recommend refraining from flexibility markets, due to the adverse incentives (inc-dec gaming) outlined above. We also see the balancing aggregation model as problematic in its current setup, see no easy fixes and regard the balancing market in general to be too limited in size to justify integrating small-scale assets with complicated regulations and split responsibilities with the potential of adverse incentives.

We recommend four interventions to improve the use of flexible demand assets.

1. Incentives for DSOs
2. Spot-based energy tariffs
3. Dynamic grid tariffs
4. A real-time tariff publication platform
5. Device-specific suppliers

**Incentives for DSOs**. The regulatory framework for DSOs should include stronger incentives for DSOs to efficiently trade-off the usage of grid flexibility and further grid buildout. While the current NOVA principle, which stipulates that optimization of grid use is to be prioritized over grid reinforcement and grid buildout, is a good step in that direction, it remains hard to monitor for the regulatory agency ElCom. Regulation should be changed so it is in the self-interest of DSOs to make this trade-off efficiently. This requires changing from a cost-plus regulation to an incentive regulation (see the extensive literature on the subject, e.g. Joskow, 2014) and choosing the parameters of such regulation to incentivize the use of flexibilities.

**Spot-based energy tariffs**. We recommend mandating energy suppliers to offer spot-based energy tariffs. With spot-based we mean tariffs that are defined close to real-time, for example one day before delivery, so they can incorporate the structure (but not necessarily the level) of day ahead spot power prices. In Winzer et al. (2023b) we outline how profile tariffs enable such spot-based incentives for flexibility provision while protecting customers from changes in the level of prices and thus ensuring stable electricity bills for customers.

**Dynamic grid tariffs**. Grid congestions in the DSO grid are likely to be the most pressing reason why residential electricity flexibility will be urgently needed in the coming years. This is due to the foreseeable fast deployment of electric vehicles and heat pumps. While direct load control by DSOs presents a valid solution especially as a last-resort measure, it comes at the downside of being unable to take short-term preferences of customers into account adequately and balance the (time-variant) disutility of customers from such load control with the system need for them. Dynamic grid tariffs, that would be set in a similarly short-term manner as spot-based energy tariffs, for example day ahead, can do that. Customers facing such tariffs remain in control and are thus able to prioritize e.g. fast-charging when needed. An example of a highly dynamic grid tariff is Group-E's Vario tariff (Groupe-E, 2023). We recommend mandating DSOs to introduce dynamic grid tariffs to foster demand flexibility.

**Situational short capacity charges**. An easier to implement interim solution is the introduction of situational short capacity charges (German: "situative kurze Leistungspreise", see also Winzer et al., 2024, and Neon, 2024). They are capacity charges, so that they charge on a peak demand. They are *situational* (i.e. active only when a highly loaded grid can broadly be foreseen, such as only in winter evenings) and they are *short* (i.e. they look at the peak capacity only during a short time-period such as a multi-hour period and are charged for the single multi-hour period). This sets them apart from yearly peak capacity charges.

**Platform publishing real-time tariffs**. Digitalization and automation will play a vital role in the dissemination of dynamic tariff schemes, as constant monitoring of the electricity market and remote operation of flexible demand assets will be essential to its successful implementation. Therefore, a unified online platform where all stakeholders can have access to hourly tariffs and other important information can contribute to enhance the reach of these schemes and its transparency towards consumers. Especially, household energy management systems (EMS) are likely to access such a platform to optimize the consumer's flexibility dispatch.

**Device-specific suppliers**. We also believe it is worth investigating the option of allowing aggregators to fully supply energy to specific devices (heat pumps and electric vehicles), as a step towards partial liberalization. The advantage of such device specific suppliers is that they can manage the full value potential of flexible assets, from energy procurement to balancing provision, without a problematic split of responsibilities. Device-specific suppliers also have the advantage of being able to reap economies of scale when specializing in managing a specific type of demand asset which they manage in all of Switzerland or even internationally and can thus consider the full set of restrictions of such specific assets, like the charging properties of a specific car type or of a specific heat pump with thermal storage. To enable device-specific suppliers, careful regulation is needed that avoids consumers cherry-picking over time, by switching to the competitive market in times of low wholesale electricity prices and reverting to the main supplier in times of high wholesale prices. In ongoing work, we are advancing this idea.

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