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The Future Swiss Electricity Market: Evolution or Revolution?

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Zusammenfassung

Das Elektrizitätssystem ist ein zentrales Element für die erfolgreiche Dekarbonisierung unserer Energieversorgung. Dabei stellen sich aber Herausforderungen wie der Anstieg dezentraler, wetterabhängiger Erzeugung aus erneuerbaren Energien mit niedrigen Grenzkostenstrukturen, der Integration von Wärme und Mobilität in den Stromsektor, der Digitalisierung und dem Auftreten neuer Marktakteure. Diese Herausforderungen erfordern eine bessere Koordination zwischen den Akteuren und möglicherweise neue Marktdesigns, insbesondere für ein kleines Land wie die Schweiz, das stark von Importen und Exporten abhängig ist.

Das Projekt zielt darauf ab, ein Modell zum Vergleich verschiedener Strommarktdesigns zu entwickeln und diese Optionen für die Schweiz zu bewerten. Es wird zwei Szenarien bewerten: einen „evolutionären“ Ansatz, der auf dem aktuellen Marktsystem aufbaut, und einen „revolutionären“ Ansatz, der die Preisgestaltung für Versorgungssicherheit und Energiebezug auf der Verbraucherebene verändert. Die Ziele des Projekts sind:

1. Problem-Mapping: Identifikation der wichtigsten Treiber des Wandels im Elektrizitätssystem und Abschätzung, welche davon für die Schweiz relevant sind und beeinflusst werden können.
2. Modellentwicklung: Erstellung eines Modells zur Simulation und zum Vergleich verschiedener Markt- und Politikstrukturen.
3. Vergleich: Vergleich der Entwicklung des derzeitigen Systems mit einem neuen Marktdesign, bei dem die Versorgungssicherheit im Voraus vertraglich festgelegt wird, und Bewertung der Effizienz dieser Ansätze.

Obwohl das endgültige Modell nicht in der Lage war, alle Elemente und Dimensionen der komplexen Wechselwirkungen im Elektrizitätssektor vollständig zu erfassen, ermöglichte es einen quantitativen Vergleich der beiden Marktansätze und lieferte Erkenntnisse in drei Schlüsselbereichen:

1. Das zukünftige schweizerische und europäische Elektrizitätssystem: Es besteht Konsens darüber, dass die zukünftigen Systeme stark auf wetterabhängige erneuerbare Energiequellen angewiesen sein werden und dass die Sektorkopplung zu einer höheren Stromnachfrage führen wird. Allerdings sind die Details in den verschiedenen untersuchten Studien sehr heterogen und die Meinungen über die Rolle komplementärer Technologien gehen auseinander. Im Rahmen des Projekts wurde festgestellt, dass eine bessere Integration der technisch orientierten Modelle mit Stakeholder-Perspektiven und der Abbildung von Politik- und Marktstrukturen erforderlich ist, um eine bessere Bewertung des Übergangsprozesses zu erreichen.
2. Marktdesign und alternative Ansätze: Das Projekt untersuchte ein „revolutionäres“ Marktdesign, das sich auf Versorgungssicherheit und Verbraucherflexibilität konzentriert, im Gegensatz zu einer klassischen, auf der Nutzungszeit basierenden Tarifstruktur für Haushalte. Theoretisch könnte dieser neue Ansatz zu einem optimierten Systembetrieb und Investitionen führen. Eine Umstellung auf dieses neue Konzept würde jedoch erhebliche Änderungen erfordern, einschließlich neuer Vertragsstrukturen zwischen Verbrauchern und Einzelhändlern/Versorgungsunternehmen sowie mit Erzeugern.
3. Quantitative Bewertung für die Schweiz: Das Modell hat gezeigt, dass der „revolutionäre“ Ansatz zwar die Systemeffizienz leicht verbessern könnte, der Nutzen jedoch begrenzt ist, insbesondere aufgrund der flexiblen Wasserkraftressourcen der Schweiz. Allerdings könnte dieser Ansatz den lokalen Netzbetrieb verbessern. Die Ergebnisse deuten darauf hin, dass weitere Forschung notwendig ist, um die vollen Auswirkungen zu verstehen, insbesondere im Hinblick auf die Investitionsdynamik und die Rolle der Flexibilität der Haushalte.

Das Projekt unterstrich die Bedeutung der Wasserkraft in der Schweiz und den potenziellen Nutzen der Flexibilität der Haushalte für die lokalen Netze. Die Umstellung auf das „revolutionäre" Marktdesign würde jedoch erhebliche Änderungen erfordern, darunter neue allgemeine Tarif- und Vertragsbeziehungen und eine stärkere Beteiligung der Verbraucher. Die Diskussionen stimmen auch mit den europäischen Debatten über das Marktdesign überein, die sich auf den Verbraucherschutz und die Nachfragesteuerung konzentrieren. Weitere Untersuchungen sind erforderlich, um die Investitionsanreize und -risiken in diesen neuen Marktstrukturen zu bewerten.

Résumé

Le système électrique est un élément central pour réussir la décarbonisation de notre approvisionnement énergétique. Cependant, des défis se posent, tels que l'augmentation de la production décentralisée d'énergies renouvelables, dépendante des conditions météorologiques, avec des structures de coûts marginaux faibles, l'intégration de la chaleur et de la mobilité dans le secteur de l'électricité, la numérisation et l'émergence de nouveaux acteurs du marché. Ces défis nécessitent une meilleure coordination entre les acteurs et peut-être de nouveaux designs de marché, en particulier pour un petit pays comme la Suisse, qui dépend fortement des importations et des exportations.

Le projet vise à développer un modèle permettant de comparer différentes conceptions du marché de l'électricité et d'évaluer ces options pour la Suisse. Il évaluera deux scénarios : une approche « évolutive » basée sur le système de marché actuel et une approche « révolutionnaire » qui modifie la tarification de la sécurité d'approvisionnement et de l'achat d'énergie au niveau du consommateur. Les objectifs du projet sont les suivants :

1. Cartographie des problèmes : identification des principaux moteurs du changement dans le système électrique et estimation de ceux qui sont pertinents pour la Suisse et qui peuvent être influencés.
2. Développement d'un modèle : création d'un modèle de simulation et de comparaison de différentes structures de marché et de politique.
3. Comparaison : comparaison de l'évolution du système actuel avec une nouvelle conception du marché dans laquelle la sécurité d'approvisionnement est fixée à l'avance par contrat, et évaluation de l'efficacité de ces approches.

Bien que le modèle final n'ait pas été en mesure d'appréhender pleinement tous les éléments et toutes les dimensions des interactions complexes dans le secteur de l'électricité, il a permis de comparer quantitativement les deux approches du marché et a fourni des enseignements dans trois domaines clés :

1. Le futur système électrique suisse et européen : il existe un consensus sur le fait que les futurs systèmes dépendront fortement des sources d'énergie renouvelables dépendant des conditions météorologiques et que le couplage sectoriel entraînera une augmentation de la demande en électricité. Cependant, les détails sont très hétérogènes dans les différentes études examinées et les avis divergent quant au rôle des technologies complémentaires. Dans le cadre du projet, il a été constaté qu'une meilleure intégration des modèles à orientation technique avec les perspectives des parties prenantes et la représentation des structures politiques et de marché était nécessaire pour parvenir à une meilleure évaluation du processus de transition.
1. Conception du marché et approches alternatives : Le projet a étudié une conception « révolutionnaire » du marché, axée sur la sécurité d'approvisionnement et la flexibilité des consommateurs, par opposition à une structure tarifaire classique pour les ménages, basée sur le temps d'utilisation. En théorie, cette nouvelle approche pourrait permettre d'optimiser le fonctionnement du système et les investissements. Toutefois, le passage à cette nouvelle approche nécessiterait des changements importants, notamment de nouvelles structures

contractuelles entre les consommateurs et les détaillants/distributeurs, ainsi qu'avec les producteurs.

2. Évaluation quantitative pour la Suisse : le modèle a montré que, bien que l'approche « révolutionnaire » puisse légèrement améliorer l'efficacité du système, les avantages sont limités, notamment en raison de la flexibilité des ressources hydroélectriques de la Suisse. Toutefois, cette approche pourrait améliorer l'exploitation du réseau local. Les résultats indiquent que des recherches supplémentaires sont nécessaires pour comprendre l'impact complet, notamment en ce qui concerne la dynamique d'investissement et le rôle de la flexibilité des ménages.

Le projet a souligné l'importance de l'hydroélectricité en Suisse et les avantages potentiels de la flexibilité des ménages pour les réseaux locaux. Toutefois, le passage à une conception « révolutionnaire » du marché nécessiterait des changements importants, notamment de nouvelles relations tarifaires et contractuelles générales et une participation accrue des consommateurs. Ces discussions rejoignent également les débats européens sur la conception du marché, qui se concentrent sur la protection des consommateurs et la gestion de la demande. Des recherches supplémentaires sont nécessaires pour évaluer les incitations et les risques d'investissement dans ces nouvelles structures de marché.

Summary

The electricity system is key to a future carbon free energy provision but faces challenges such as the rise of decentralized intermittent renewable generation with low marginal cost structures, the integration of heating and mobility, digitalization, and the emergence of new actors. These challenges require better coordination among stakeholders and possibly new market designs, especially for a small country like Switzerland, which heavily relies on imports and exports.

The project aims to develop a model to compare different electricity market designs and assess those options for Switzerland. It will evaluate two scenarios: an "evolutionary" approach that builds on the current market system, and a "revolutionary" approach that changes how reliability and quantity are priced at the consumer level. The objectives of the project are:

1. Problem Mapping: Identify key drivers of change in electricity systems and explore how Swiss-specific factors can be influenced.
2. Model Development: Create a model to simulate and compare different market and policy structures.
3. Comparison: Compare the current system's evolution with a new market designs that contracts reliability in advance and assess the efficiency and viability of those approaches.

Although the final model was not able to fully capture all elements and dimensions of the complex electricity interactions it enabled a quantitative comparison of the two market approaches, yielding insights in three key areas:

1. Future Swiss and European Electricity Systems: There is consensus that future systems will rely heavily on weather-dependent renewable energy sources and that sector coupling will lead to higher electricity demand. However, the details across the different reviewed studies are highly heterogeneous and opinions vary on the role of complementary technologies. The project identified a need for better integration of physical systems, stakeholder actions, and policy and market structures to achieve a better evaluation of the transition process.
2. Market Design and Alternative Approaches: The project explored a "revolutionary" market design focused on reliability and consumer flexibility in contrast to a classical time-of-use

based household tariff structure. In theory this new approach could lead to an optimized system operation and investment. However, a shift to this new design would require significant changes, including new contractual structures between consumers and retailers/utilities as well as with generators.

3. Quantitative Assessment for Switzerland: The model showed that while the "revolutionary" approach might slightly improve system efficiency, the benefits are limited, especially due to Switzerland's flexible hydropower resources. However, this approach could enhance local grid operations. The findings suggest that more research is needed to understand the full impact, particularly regarding investment dynamics and the role of household flexibility.

The project highlighted the importance of hydropower in Switzerland and the potential benefits of household flexibility for local grids. However, switching to the "revolutionary" market design would require significant changes, including new overall tariff and contract relations and increased consumer participation. The discussions also align with European debates on market design, focusing on consumer protection and demand-side management. Further research is needed to assess investment incentives and risks in these new market structures.

Main findings

- Most future electricity market assessments are based on technology rich cost-optimization models that only provide a theoretical, technological focused benchmark. A better integration of stakeholder and policy/market design centered assessment with technology oriented electricity models is needed to provide a comprehensive evaluation of the energy transition and direct evaluation of policy and market design options
- The high share of hydropower in Switzerland already provides a high level of flexible generation. Tapping into the flexibility potential on the end-consumer side does only provide modest additional improvements and economic benefits on the overall system level
- The short-term dynamics of end-consumer flexibility (i.e. the hourly demand and injection profile) vary greatly depending on the underlying incentive structure (tariff and overall market design). This is likely relevant for local and regional grid management to address potential congestion and critical system conditions and could alter investment needs.
- The revolutionary design focus on reliably and long term contractual relations can be used as guide for potential tariff adjustments to tap into end-consumer flexibility within the current market design. The main aspect for alternative designs is the need to shift the operation of flexibility assets from the household to market active actors (i.e. retailers, utilities, aggregators, potentially also energy communities)

Contents

1 Introduction

1.1 Background information and current situation

The electricity system will be the central pillar of our future energy provision. However, it will be challenged by several developments (e.g., a high share of intermittent and decentralized generation, low marginal costs structures, coupling with heat and mobility) and accompanied by new opportunities (e.g., demand flexibility, digitalization). The extent of such transitions calls for better coordination of the involved actors and a potential rethinking of market designs for a mostly zero variable cost world. From a Swiss perspective, two more aspects play a crucial role: First, its relatively small size in comparison to its neighbors limits the influence of Swiss decisions on key developments. Second, imports and exports are relatively more important in Switzerland than in larger economies.

These points lead to a central question: How can future electricity market designs help to ensure a secure, sustainable and economical energy provision for Swiss citizens and industries? Is it possible to adjust the current market design to cope with the above challenges, or would a substantially differing design be more suitable to this end?

1.2 Purpose of the project

To address the above sketched research question, this project aims to develop a model tool for the comparison of different electricity market designs and assess a set of design options for the Swiss market. In particular, we will model and compare the performance of two distinct market developments: 1) an ‘evolution’ of the current electricity system design centered on (spot) energy markets with end consumers being steered via pre-defined tariff structures, and 2) a significant adjustment of the market design (termed ‘revolution’) focused on pricing the quality (reliability) as well as quantity (kWh) on the end consumer level leading to an altered relations between utilities, consumers and generators.

1.3 Objectives

The project is expected to provide three main insights that will allow Swiss decision makers to evaluate the ongoing system transformation and identify potential policy, market, and regulatory solutions:

- First, the project will provide a ***problem mapping and structuring***. Based on a comprehensive literature and scenario review, we will identify the main drivers of potential changes in typical electricity systems, assess their scope and importance for the overall system, and map design modification options. Then, we focus on the Swiss case to single out drivers that can be shaped by Swiss decisions.
- Second, a ***schematic electricity-system model*** will be developed based on the mapping. This parsimonious model will provide a representation of the basic system structure covering its main actors and their relations. The model will be calibrated for Switzerland applied to evaluate two design pathways: On the one hand, an 'evolutionary' market setting that supplements the current electricity system with complementary capacity mechanisms. On the other hand, a new ('revolutionary') market design requiring substantial framework changes, which allows retailers, consumers, and generators to contract reliability ex-ante.
- Third, based on the two ***assessments***, we will compare the evolutionary and revolutionary approaches with regard to their efficiency and viability. The comparison will help to identify which setting provides a more robust solution and requires less ongoing interventions to achieve the desired safe, sustainable, and economical energy provision. Given the high uncertainty regarding some of the main development options – especially concerning sector coupling trajectories – the model will also indicate drivers and objectives central for the design choices.

2 Marker Review, Problem Mapping and Structuring

The first project step is a comprehensive mapping of the relevant drivers and resulting challenges and opportunities for future electricity systems. Building upon the extensive literature on electricity markets and policy design and our own expertise, a detailed description and mapping of the problems and relevant solution approaches discussed in the scientific literature and stakeholder is provided. Following we will shortly present the design of the review, the main findings and derived insights. A full description of the review is provided in Darudi and Weigt (2024).

2.1 Procedure and methodology

To provide a guiding framework for the literature review, we transfer the complexity of electricity systems into a simplified three-layer structure, as shown in Figure 1.

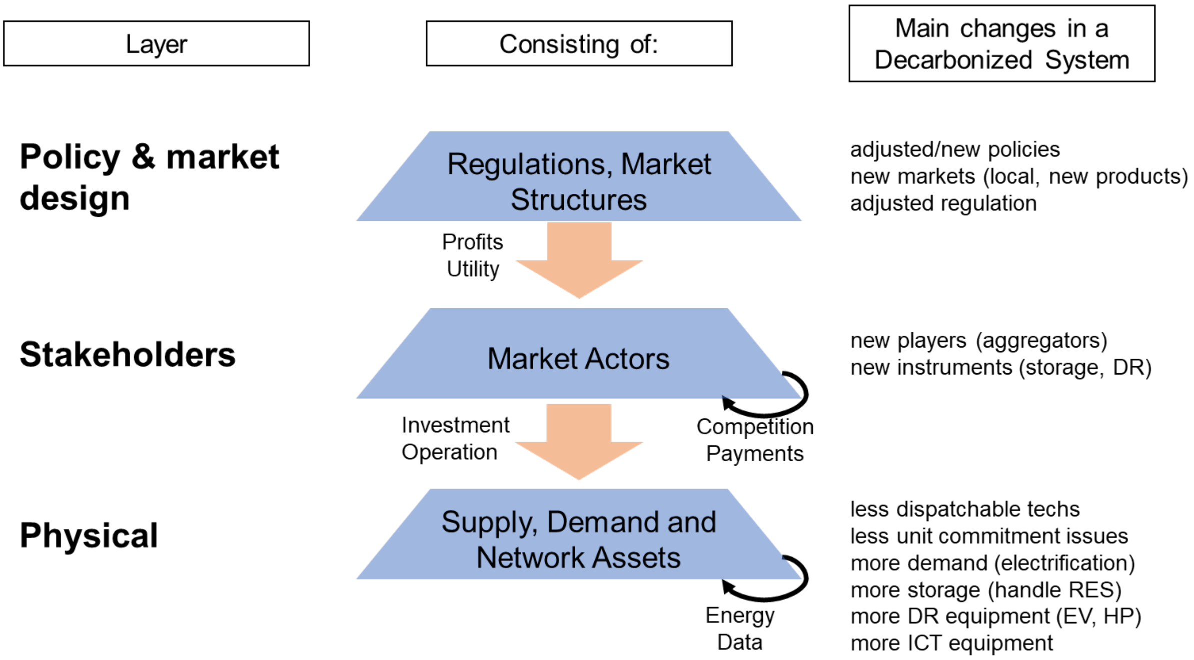

Figure 1 Three-layer representation of the electricity sector

The physical layer includes the technical aspects of electricity systems on the supply, transport and demand side; the stakeholder layer captures the role and relation of the different actors in the system; and finally, the policy and market layer captures the wide range of regulatory, policy and market design concepts and adjustments prevalent in electricity systems. Naturally, the three layers are highly interlinked with policies and markets shaping actor behavior and thereby investment and usage patterns of the underlying technology of the system. Thus, especially the stakeholder and policy layer should normally be interlinked and also include (some) aspects of the physical layer, but usually the main focus lies along one of the three layer aspects.

The purpose of this structure is twofold. On the on hand, it captures the intricate set of interactions within an electricity system and allows to identify how those are expected to change while moving towards a decarbonized future. On the other hand, the structure will shape the review process. By clustering the existing research insights along the layers, we will be able to identity where common insights have already been derived, where diverging viewpoints are prevailing, and where research gaps are still existing.

Physical Electricity System Layer

Physical and engineering aspects play a crucial role in electricity markets as maintaining a balance between supply and demand requires a specific set of physical assets, which are usually categorized into supply side, demand side, and network assets:

- The ***supply side*** consists of a diverse set of power plant technologies which have a significant influence on the systems overall affordability, system adequacy and stability. The plants' characteristics differ greatly across technologies while the transition will have important implications for the way system stability is managed. The altered mix on the supply side will also have significant impacts on the other physical dimensions of the system.
- The ***demand side*** consist of a diverse set of consumers that gain utility from using electricity and pay a price in exchange. With the expected emergence of new electricity demand due to a transfer of mobility and heating demand into the electricity sector, the demand side is assumed to become more flexible and take a more active role within the electricity system.
- Related to this flexibility development on the demand side are ***storage assets***. They represent an emerging technology placed in-between supply and demand. They are similar to flexible shiftable loads in their system effect. However, storage technologies differ from flexible demand (and each other) in their short- and long-term efficiency.
- Finally, ***electricity networks*** in the form of transmission and distribution networks allow transfer of energy from the supply to the demand side. Consequently, they will be impacted by changes on the supply and demand side respectively. In addition, the emerging digitalization (i.e., smart meters and smart grids) could also impact the planning and operation of network assets.

Stakeholder Layer

Stakeholders invest and operate the assets of the physical layer based on their respective individual incentive structures. Stakeholders try to achieve a goal (e.g., maximizing profits or utility) given a set of available instruments (e.g., the supply and flexibility technologies). Thereby they shape the composition of the physical layer while the policy and market layer shapes their incentives space and the interactions between the different actors in the system. Generally speaking, interactions of stakeholders owning the same type of assets (especially in case of supply and demand assets) is usually of a more competitive nature while interactions with other types of assets can be competitive as well as of complementary nature. For example, different renewable generation technologies like wind and solar usually compete for market shares on the supply side while they (may) have complementary relations to demand related flexibility assets like local storage.

In the electricity system of the last century the main actors have been energy utilities, regulators, and consumers. With the restructuring and liberalization of electricity market new actors emerged, especially on the supply and retail side (e.g. independent power producers and utility independent retailers) and with the transition towards a decarbonized system new actors are likely to enter the system (e.g. non-hydro storage operators, aggregators for local demand flexibility assets, energy communities) . The resulting interaction of those new stakeholder mix will have significant implications for the overall system. The same physical assets can be operated differently if owned by different stakeholders. Similarly, different operational incentives and profits leads to different investment incentives for different stakeholders and will impact the ownership distribution of assets. Consequently, not only the understanding of the individual role of the respective system actors will be crucial for assessing future electricity systems but also their interaction and the bi-directional relation with the physical layer.

Policy and Market Layer

Policymakers can alter regulations and existing policies as well as introduce new policies to obtain specific political goals and steer (or at least influence) the behavior of stakeholders. In addition, the restructuring introduced a market dynamic that can in theory evolve itself through stakeholder activities (e.g., many wholesale markets in Europe have emerged as private trading platforms). However, policymakers still set the general regulations and standards for market activities and define the conditions for the trade of energy and services.

Similar to the other two layers, there is a high level of interaction between the different elements within the policy and market layer. Given the multitude of political objectives beside a decarbonization, it is likely that electricity system will remain subject to a diverging set of (potentially even conflicting) policies and regulations. As the policy layer defines the manoeuvrable space for stakeholders which as described above defines the composition of the physical layer, the interaction between all three spheres is important to properly assess the overall future system aspects.

2.2 Results

Based on the approach presented above we can identify the following insights for the three layers:

Physical Electricity System Layer

The guiding questions for this part of the review were: What technology mix exists in the future system? What technologies are assumed to enter and leave the system? How is the demand structured? For the relevant literature we mostly focus on (large scale) numerical model scenario studies with a focus on the European region (i.e. EU or Europe as a whole). Those studies are mostly following a cost minimization logic, without markets, without explicitly modeling policies, and without explaining how to achieve this optimal system. A summary of the covered studies is presented in the Appendix.

The investigated studies differ substantially on both modelled technologies and their respective shares in the 2050 system (Figure 2). However, as one common exterminator all decarbonized scenarios rely on a mix of PV and wind on their supply side. Across the investigated studies those two technologies cover on average a share of 70% or more. Nevertheless, the distribution of generation between PV and wind sources can differ drastically from one scenario to the other. Beside PV and wind the scenarios also differ in the remaining technologies of the system, albeit all studies rely on some further technologies beside wind and PV.

Regarding the demand side, the studies also greatly vary in their underlying development assumptions. While there is a general agreement that electrification will play a crucial role, the actual extend for the resulting demand increases vary from 3’000 TWh up to 10’000 TWh (Figure 3), with the majority being in the 4’000 to 6’000 TWh range. In comparison, total net electricity generation/demand in the EU was around 2’800 TWh in 2018; meaning a 50-100% increase is likely to be realized until 2050.

Regarding storage developments most studies assume that the existence of short term storage is a given while the future of seasonal storage and power-to-X technologies is less clear. Studies focusing on a 100% RES system rely on either significant storage capacities or a mix of CSP, biomass, and geothermal technologies to provide back-up.

As most of the large scale scenario models neglect network aspects – and in particular distribution network constraints – no common agreement exists on the role of network developments within the literature. However, those studies that at least include (cross-border) exchange capacity find that those capacities support future systems by linking different demand and generation regions.

Overall, most of the differences between the investigates studies are due to assumptions on costs developments for the different technologies and externally defined constraints (i.e. allowed/non-allowed technologies like nuclear).

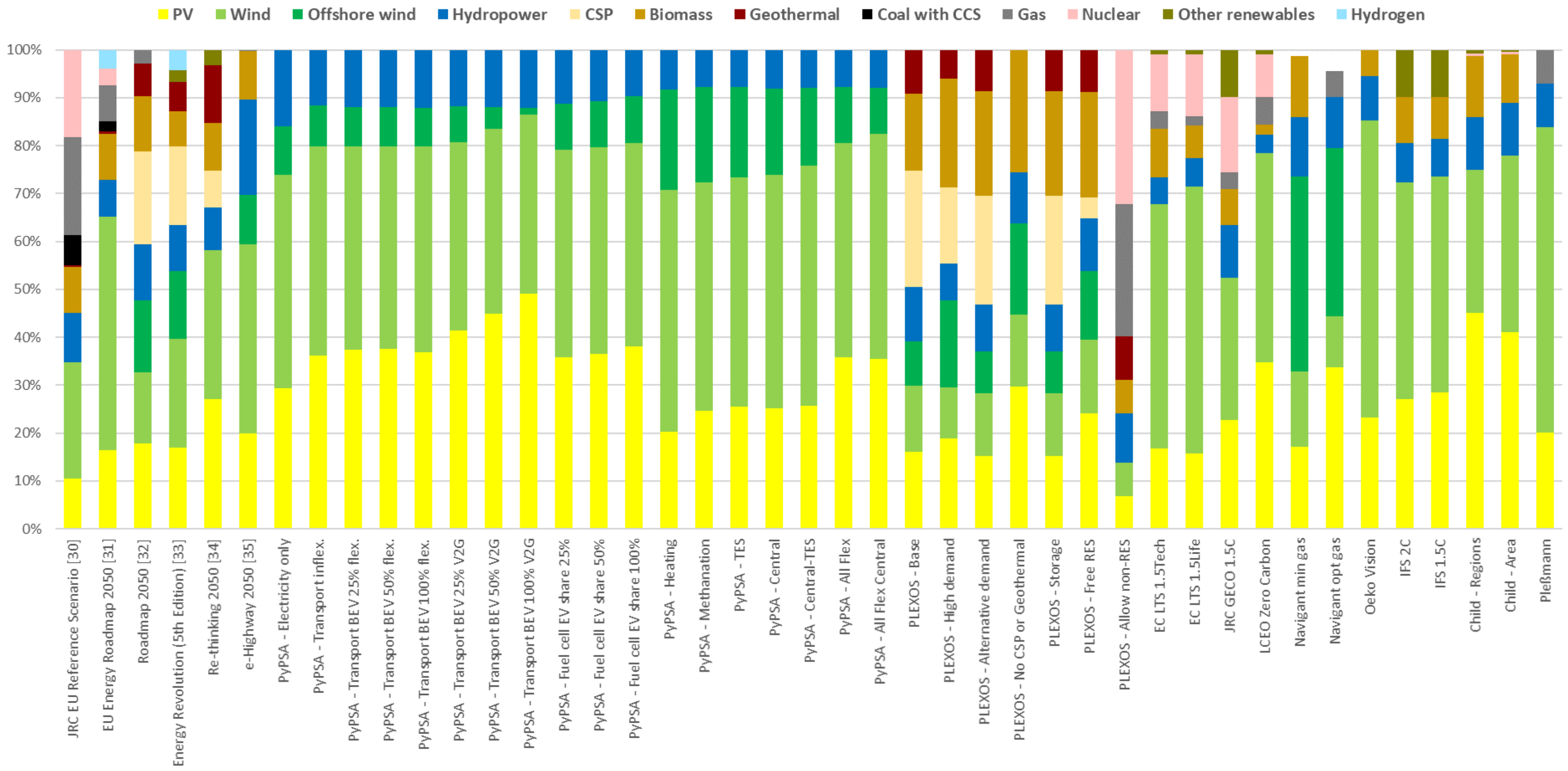

Figure 2: Technology generation shares of the European decarbonization studies (see the Appendix for details)

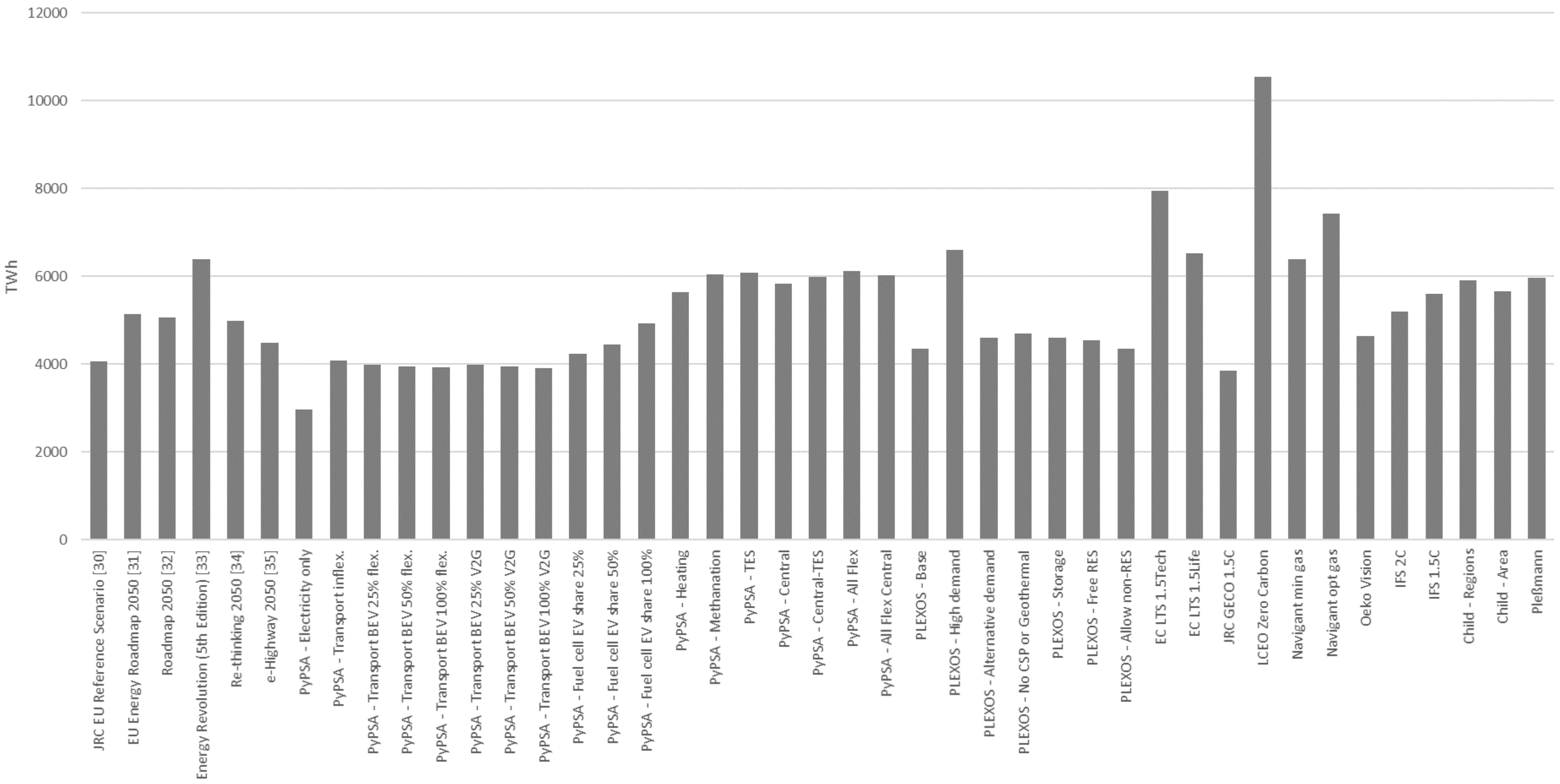

Figure 3: Total generation/demand of the European decarbonization studies (see the Appendix for details)

Stakeholder Layer

The guiding questions for this part of the review were: What actors are investigated? What role do those actors have in the system? How are the actors modeled/defined? For the relevant literature we found a mix of conceptual and small scale model studies that usually investigate only one (or very) few actors. Studies investigating the interaction among different actors are scare.

The literature on the supply side is mostly focused on company behavior; in particular profit maximizing investment assessments (i.e. net present value analyses) as well as handling of risk and uncertainty (i.e. mean-variance approaches). As with the scenario models the underlying technology assumptions are one of the main drivers for the resulting findings. Most investigations focus on a perfect competitive setting and apply optimization, equilibrium and simulation approaches when numerical quantifications are conducted. Studies investigating storage actors follow a similar structure but are relatively scare so far.

On the demand side the development is assumed to be more fluid. Consumers in a decarbonized system are assumed to have a higher degree of freedom in choosing their respective objective, ranging from economic to environmental interests and social concerns. Consequently, also the representation of electricity consumers has become a growing field for researchers. Roughly speaking, future consumers in a decarbonized electricity system can take one of the following roles: i) inflexible consumers (like traditional consumers), ii) flexible consumers, iii) prosumers (owing own generation), or iv) prosumagers (owning generation and storage). In particular, the potential of the demand side to contribute flexibility is widely discussed in the literature and the potential for demand-side flexibility is thought to be significant.

The more active role of consumers calls for a similar perspective as supply-oriented assessment, namely investigating investment and usage decisions. Moreover, instead of maximizing their utility (or minimizing their energy costs), consumers may also seek several objectives when becoming a prosumer or prosumager (e.g. environmental concerns, self-sufficiency etc.). In addition to the individual consumer perspective, also their potential cooperation has become the focus of research and practical implementation. The behavior of both individual and collective actors has been extensively studied in the literature; e.g. based on experiments and model-based assessments and simulations. A particular focus for consumer incentives is the role of tariffs (see also the following part on the policy and market layer).

On the network side, research is focusing on the broader aspects of regulatory economics and incentive regulation with further investigations addressing either i) the interactions between regulated entities (e.g., TSO and DSO) and ii) a regulated entity and a competitive entity (e.g., TSO and generation investor). Regarding the former, the role of future flexibility options is of concern and regarding the latter the literature focuses on the interplay between network investments and market dynamics and the (partial) complementarity of transmission and generation assets. Finally, aggregators are seen as a potential important actor in some studies. However, their actual relevance is still rather unclear. Investigations on aggregators usually follow a classical profit orientation approach.

In general, the reviewed studies focus and investigate only one (or very) few actors. Studies investigating the interaction among different actors are scare.

Policy and Market Layer

The guiding questions for this part of the review were: What policy and market design options are investigated? Is there a common system design? Are there ‘out of the box’ approaches? The relevant literature is similar (and often linked) to literature investigated for the stakeholder part. In addition, there is a body of empirical studies focusing on existing policy and market approaches. Naturally, electricity policies and market design questions are strongly related to the realm of climate policies. However, as a future decarbonized electricity system will by design require a strong climate policy (i.e. a high carbon price) we exclude climate focused studies from the review.

On the supply side most studies either focus on long term dimensions (i.e. investment aspects and supply security) or on short term aspects like spatial and temporal resolutions (i.e. real-time/intraday relations and zonal and nodal market structure). Albeit, assessments of renewable support policies form a large part of the electricity market literature – with both a conceptual and an empirical focus – they are only partially relevant for future market design choices as specific renewable technology support should not be a long-term feature of electricity systems. However, they will likely form an important element of the transition process, with auction based mechanisms taking a more prominent role in recent years. RES support auctions are expected to allow regulators to steer the renewable support policy more effectively because regulators can set the target renewable expansion, and the generation mix ex-ante. However, the success of auctions depends mainly on their design details (i.e. the effects of first price versus second-price auction designs, national versus regional auctions, remuneration choices, prequalification, penalties, and the grace period on realization rates). RES auction could also grow in importance in the form of private, municipal, or community tenders for power purchase agreements (PPAs).

A central theme regarding investment incentives is the role of capacity mechanisms. Investigated capacity remuneration mechanisms differ on the parameter fixed by the procurer (volume vs. price), the nature of the volume being procured (market-wide vs. targeted technologies), and the procurer (centralized procurement vs. bilateral arrangements with load-serving entities). The strategic reserve is the most common mechanism in the EU, in which a central entity procures a pre-determined capacity from plants. The capacity is only utilized in the case of shortages, and they are otherwise prohibited from participating in the energy market. Several studies investigate different specifications for capacity mechanisms and the interplay of high RES shares and capacity markets. However, there is no common agreement on the resulting implications. For example, some studies imply that capacity payments are required to incentivize peak-load investments in a system with high RES shares. As risk perception is central for investment assessments the assumption on risk aversion impacts findings; i.e. while risk aversion may reduce the reliability of an energy only market and the capacity market may lead to higher social welfare shifting investment risks to consumers may reduce incentives to manage and reduce the risk efficiently on the investor side. For Switzerland especially the interplay with the developments in the neighboring European countries is crucial, as planned market design changes in Europe can decrease investments in Switzerland. Albeit storage technologies are expected to play an important role in future systems there is no such common agreement with regard to storage policies. There is limited research on how an actual storage support policy could be designed (which is often linked to a more general demand side policy assessment) and whether such policies are needed.

Demand side oriented policies and regulations can roughly be structured along three lines: i) energy efficiency policies aiming at reducing the overall energy demand, ii) tariff design and the respective incentive structures for consumers as well as the linkage to DSOs and utilities, and iii) flexibility market related polices. The latter also links to the broader relation of the demand side with system and network aspects. The emerging field of consumer cooperation adds to those three fields, but remains limited in its extend so far (and mostly focused on the regulatory settings for cooperation).

While energy efficient policies have a strong focus on building renovations and heating (and thereby to sector coupling), tariff design and flexibility policies are directly electricity related and strongly interrelate with the consumer stakeholder literature, especially the role of prosumers in future electricity systems. One common aspect of the tariff design literatureis the need for a higher time resolution of price signals (either via tariffs or flexibility markets/mechanism) at the consumer level to account for system conditions. However, it is unclear how much is actually needed to induce sufficient incentives. Similar there is an extensive investigation on the role of capacity components in tariffs and the interplay between investment incentives and cost allocation; especially with respect to network tariffs. Finally, the social dimension (often in form of acceptance) and distributional aspects of new market structures is become an increasing area for research.

As flexibility will play a crucial role in future electricity systems policy interventions may be required to build up and maintain this flexibility. For instance, the EU's Clean Energy Package requires DSOs to take advantage of flexible resources by integrating them into both planning and operation tools using market mechanisms to select the most efficient resources. There are several flexibility market initiatives in Europe (e.g., there are already at least 18 flexibility market initiatives such as ENRA, NODES , and GOPACS). However, local procurement of flexibility is still a developing concept with proper TSO-DSO coordination and provision of data networks as important prerequisites of well-functioning flexibility markets.

As identified in the stakeholder part, most of the literature on network related policy choices are embedded in the regulatory economics literature and investigate different incentive regulation approaches or are strongly linked to the above-described tariff design questions and flexibility markets. One particular market aspect of electricity networks is the role of interconnections between different countries/zones and the related import/export aspects.

Finally, policymakers must exercise caution when combining instruments into a policy mix, as overlapping policies or negative synergies may occur. The policies defined directly within the electricity sector interact with each other via several channels due to the complexity of electricity markets. Firstly, policies may affect each other as their goals directly overlap. For instance, policymakers' goals in climate change/environmental policies, energy efficiency improvement policies, and renewable energy support policies have overlapping goals and targets. Secondly, policies that focus on different targets may interact with each other because they target and affect the same stakeholder. When analyzing the effect of a certain policy, a stakeholder that faces only that specific policy may act differently compared to the same stakeholder facing several policies with various restrictions and incentives. Thirdly, policies that target different stakeholders may still affect each other because the targeted stakeholders interact with each other via collaboration or competition. For instance, policies that target RES investors affect policies targeting storage investors as they both participate and compete in the market.
While there is an extensive literature on policy interactions within climate and energy policies, the literature on the interactions between electricity market designs and policies is still limited. Overall, electricity policies and market design questions are strongly related to the realm of climate policies. However, as a future decarbonized electricity system will by design require a strong climate policy (i.e. a high carbon price) we exclude climate focused studies from the investigation.

2.3 Discussion and Insights

The objective of the review was to identify common trends and conclusions already provided by the existing literature and identify needed elements the modeling tool needs to capture, in particular with respect to stakeholders and their interaction. Following we will give a short overview of the main conclusions drawn from the review.

Common drivers and insights

Figure 4 provides a summary of the main commonalities identified in the literature. The three main trends shaping the future electricity system are effects related to the decarbonization of supply, the electrification of heating and transport demand, and the implications a further digitalization will have. As shown especially in the physical layer the decarbonization will be addressed by increasing supply by PV and wind generation with an accompanying residual supply by other carbon free technologies and storage. However, there is no common agreement on the scope of those three aspects. Nevertheless, they clearly indicate the importance of investment incentives for identifying suitable electricity system designs.

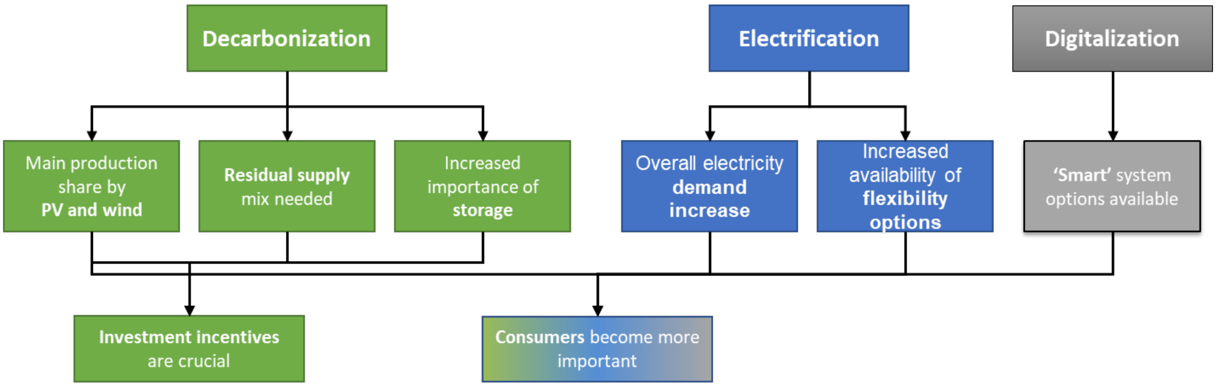

Figure 4: Common drivers, trends and consequences as identified in the literature review

The two other main trends lead to significant alterations on the demand side or at least open up those options. While again the scope of those aspects is not commonly agreed upon in the literature, the insights highlight the importance consumers will play in the future electricity system. Their importance is also shaped by the increase in PV as crucial supply option, as a significant share of this generation is expected to come from rooftop installations.

Identified challenges ahead

While there is no real common conclusion on the scope the different developments will have, there is nevertheless a good understanding of the associated challenges for the future electricity system and the resulting policy and market design challenges. Figure 5 translates the above defined aspects of the future electricity system into respective challenges and resulting system alterations. On the market side the increased role of weather dependent intermittent renewables with high capital but negligible variable costs will have to lead to new price dynamics. Today's price structure is defined by the different variable cost levels of conventional generation and the load level. In the future the interplay between RES surplus and deficit times will shape will not only lead to a different time structure but also to a different price shape. In addition, the expected higher share of storage in the system will make opportunity costs more important for price setting. Those price dynamics will naturally lead to a different investment risk. Together this interplay forms one of the main aspects a market design needs to address and is thereby also a central aspect the model framework will need to capture.

A second important dimensions can be summarized as an increase in decentralization. The availability of local generation and storage options, coupled with an increased participation of consumers and an increased controllability of those new system components also leads to a different relation between local, regional and national markets. This also includes the relation between distribution and transmission system operators, which is often neglected in (techno-)economic electricity system assessments.

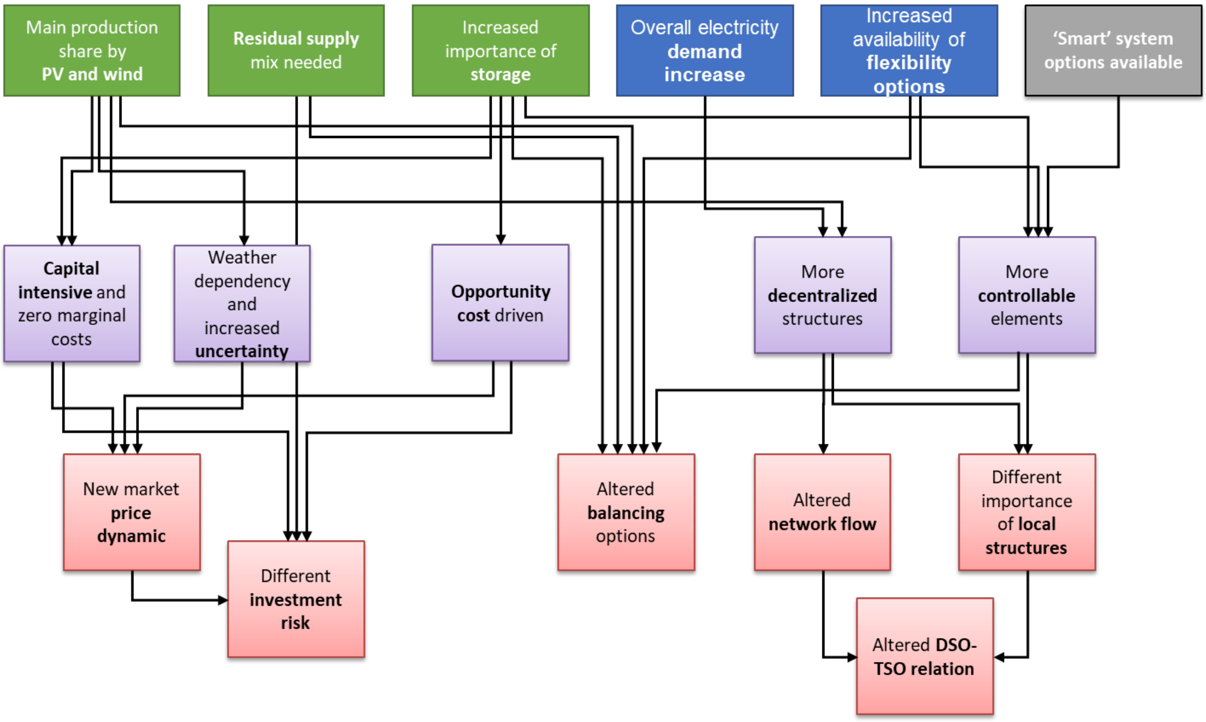

Figure 5: Resulting challenges and system alterations based on the literature review

Research gaps and needed next steps

The review highlights the absence of a comprehensive system assessment approach or a fully accepted future electricity system concept in the literature. There is a gap between large-scale numerical scenario studies and stakeholder/policy-oriented literature, with most future scenarios lacking stakeholder representation or market design perspectives. These studies provide theoretical technical solutions but don't address policy and market designs necessary to achieve such systems. Conversely, many stakeholder and policy studies offer simplified technical representations and overlook critical interactions. A central research challenge is developing a methodology that combines socio-economic aspects of future markets with techno-economic system modeling to compare competing market design concepts effectively.

Another challenge is integrating demand and consumer-centered research with supply-side assessments. The demand side will play a more active role in future electricity systems, but few studies link consumer aspects to the national wholesale level in an integrated manner. Understanding the role of various actors is crucial for shaping the future system, and this requires extending the market design debate to include diverse actors at lower voltage levels and their incentive structures. Furthermore, incorporating storage options into market assessments is also essential, as storage will operate based on opportunity cost logic and could become a pivotal system element.

Network aspects are often simplified or omitted in policy or market research. The increasing interaction between DSOs and TSOs, and the rise in local supply, demand, and storage, necessitate further investigation into the interplay between energy and network aspects. Networks need to be designed for peak capacity usage, which is influenced by demand and supply flexibility. Utilizing local generation and storage could reduce network capacity requirements, but this is complex due to the regulatory environment of network aspects versus the market-oriented nature of energy aspects. Identifying beneficial trade-offs between energy and network assets is a highly complex research effort.

In summary, while current research on future decarbonized electricity systems provides valuable insights, integrating existing approaches across topical and disciplinary boundaries is crucial for a comprehensive assessment.

3 Evolutionary and Revolutionary Market Design

The main objective of the project is the comparison of different market and policy design options. To this end, the review above allows a first clarification of the assumed development of the European electricity market and identification of the needed elements of the model developed in the next project step.

In essence, the two main elements needed to cover the envisioned development structures are 1) a framework of a wholesale based energy market with different investment structures, and 2) tariff based end-consumers making local decisions that are influenced by the wholesale market system layer and in turn influence the system layer.

While this setting provides a first set of requirements for the model design, the objective was to compare this ‘evolution’ of the system with potential significant alterations; called ‘revolution’. Thus, parallel to the market review, the research team of the Environmental Economics group in Basel investigated novel ways for addressing investment and tariff design questions in electricity market design. The objective was to identify an alternative solution to address the challenges of a mostly renewable electricity system that does not follow an energy-and/or-capacity market approach.

Following we will provide a short summary on the basic evolutionary market design aspects, and an overview of the developed revolutionary approach and its main aspects for the envisioned comparison and model design in the next project step. A full presentation of the revolutionary approach is provided in Schäfers et al. (2024).

3.1 Evolutionary market design assumptions

Before investigating the new market approach, we establish our assumption on what an expected adjustment of today’s market design could entail addressing a mostly renewable electricity future. Overall we assume that the future electricity system (both for the evolutionary but also for the revolutionary design) is subject to a strong decarbonization policy (i.e. a carbon price). This should ensure that carbon emitting technologies do not enter the market and the main focus can be on the interaction and incentives for carbon free technologies. Otherwise, additional policy interventions may be needed to compensate for an insufficient climate policy. Furthermore, we postulate that the future electricity market design should not include continued support for specific technologies (i.e. renewables or storage) as a fixed market element. Naturally, such policies could be part of the transition from today’s system into the new design.

The basic premise of today’s market is an energy focused wholesale layer coupled with balancing oriented (short-term) markets for reserve capacities on the supply side and a large base of small scale consumers subject to tariff structures without direct access to the wholesale layer. This basic structure can be complemented by long term capacity oriented elements (e.g. capacity mechanism like strategic reserves).

Starting from this structure, we envision that an evolution of this design maintains its basic structure. The wholesale market will remain energy focused providing the relevant short term operational signals for market participants. We don’t envision a fundamental change in the design of the wholesale layer. The different European markets are likely further interlinked (i.e. flow based market coupling, potentially up to nodal approaches in the long run). Similar the time resolution could further decrease and the intraday markets could increase in importance compared to the day-ahead spot market once large scale thermal units leave the system.

Also the complementary capacity oriented elements are likely subject to further developments. Several European markets already have such mechanisms in place, albeit there is no coordinated nor uniform approach so far. In the long run either national approaches (i.e. strategic reserves) or a more coordinated European approach (i.e. capacity market(s)) can be envisioned.

On the end-consumer side a full transition for all consumers to real-time tariffs with hourly or sub-hourly resolution seems unlikely. Nevertheless, the time resolution of tariffs is likely to increase and the share of fixed and variable components will be adjusted, in particular with respect to network charges. Overall, an adjusted tariff design (both on the energy and grid parts of the tariff) will likely be an important aspect of the future electricity system.

While there are a lot of details on all of those dimensions possible, we will focus on its main structure for our reference 'evolutionary' setting: a) a wholesale energy focused spot market structure that provides the main investment incentives for suppliers, and b) small scale end-consumers being incentivized via end-user tariffs which energy component is linked to the energy market (e.g. via time-of-use price levels). The energy focused wholesale market can be complemented by a capacity market (see Section 4.1 why this part if not modelled).

Thus, we neglect specific developments on the balancing markets and network dimensions. We also neglect large scale consumers, assuming they are active on the wholesale market layer directly.

3.2 Revolutionary market design methodology

As with the generally expected development of the electricity system, any 'revolutionary' approach should address the same underlying challenges; namely it should:

1) Be able to support a high share of RES without promotion policies in the long run.

   Energy only (or energy centered) markets have limits on the refinancing of high shares of RES due to correlated production dynamics ('cannibalization', e.g. see Hirth, 2013)). Thus a supplementary approach (e.g. capacity mechanisms in the evolutionary development) is potentially needed. The alternative market design aims to address this challenge without replicating the 'capacity mechanism – energy market' logic of the evolutionary approach.

2) Be able to tap into the demand-side flexibility potential that opens up with the emergence of new electricity demand.

   As the progress in (smart) technology alters market possibilities by enabling a more direct demand control, it shifts supply security partially towards a private good category. This enables alternative market designs with a stronger focus on private supply security definitions.

As any shift to a new system can be expected to have high transaction costs, such a setting should furthermore be beneficial to all involved parties. Furthermore, a flexible setting in which no actor is 'forced' to participate and regulation is limited to a minimum would be favorable.

Given this backdrop the research team in Basel developed an approach in which consumers choose their level of supply security, leading to electricity supply differentiated by quality and a shift to mainly paying for security of supply instead of paying for energy. The design is an extension of the basic idea of priority service (e.g., Chao & Wilson, 1987) and builds upon the idea of individuals paying for secure capacity, which results in a "capacity market", where the desired capacity level is endogenously determined by consumer preferences for security of supply.

The resulting basic market design is centered around consumer choice and contract design. Consumers chose a supply contract that entails a secure load level and on top a load level which can have a lower supply reliability as well as (if they choose to buy this option) a share of possible surplus electricity delivered at a price of zero (per kWh) in situations, where renewable production exceeds demand.[1] Retailers offer consumers supply contracts that fulfill those reliability contracts by buying from generators a mix of different supply options. Wholesale markets allow retailers to trade excess supply and a

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[1] This option reduces or prevents curtailments and is of interest to consumers that can shift electricity demand over hours or days, e.g. via battery storage, an electrical vehicle, or a heat pump.

regulator is required to ensure that the supply portfolio of retailers fulfills the contractual reliability obligations.

Formally, the approach accounts for three stylized type of actors: consumers, generators, and retailers. Consumers are the only users of electricity. Their electricity demand depends on the price as well as on a random state of nature that describes fluctuations in electricity demand on the individual level. Generators are the only producers of electricity. They invest in generation capacity, which can be a dispatchable technology (production being chosen (within capacity limits) by generators at each point of time) or a variable renewable technology, where production at a given point of time results from a random state of nature.[2] Retailers are intermediaries who buy from generators, sell to consumers, and trade electricity on the spot market.

The state of nature captures natural conditions that affect both supply and demand for renewable energy such as season, time of day, solar radiation, wind, or outdoor temperature, as well as other random effects. All decisions regarding electricity consumption and production of the dispatchable technology are made after the state of nature is known, whereas all investment decisions and all contracts between retailers and consumers as well as retailers and generators are made before the state of nature is known.

Consumers use electricity only for running appliances (i.e., no direct utility) and distinguish two types of appliances: Deliberately used appliances and autonomous appliances. Deliberately used appliances generate utility (u_i) if and only if they use electricity and their use is a deliberate decision. Autonomous appliances render a service and can switch on or off automatically. They capture electricity demand where utility $(\hat{u}_i)$ depends on the average electricity consumption over some time (e.g., 24 hours), the average state of nature during this time span ($\hat{\tau}$, which can for example describe how much warm water a household has used), and the current state of nature (τ). Both utilities are assumed to be independent from each other and additive. Consumers need to pay a price (p) for their portfolio of deliberate (e_i) and autonomous $(\hat{e}_i)$ demand and receive the following net-utility:

$$u_i(e_i,\tau) + \hat{u}_i(\hat{e}_i,\tau,\hat{\tau}) - p(e_i + \hat{e}_i)$$

In each state of nature, the consumer maximizes this net-utility with regard to deliberate electricity consumption and average autonomous consumption resulting in the individually optimal electricity demands.

On the production side, a generator invests in production capacity for the different variable renewable technologies as well as in production capacity for a dispatchable backup technology. For renewable investment costs an increasing cost structure is assumed; i.e. the investment cost per unit of actual production capacity increases with the total investment in that technology, as the better sites are increasingly used up. The output of the renewable technologies depends on the state of nature and has no further operational costs. For the dispatchable backup technology a constant cost level for each unit of production is assumed in addition to the fixed investment costs for the installed capacity.

Retailers buy electricity from the generators and supply it to the consumers. Consumers and retailers agree on a contract for electricity supply where delivery is ensured in all states of nature up to a contracted capacity level and additional supply is subject to availability. The contract specifies prices, capacities, and the reliability of electricity provision ex ante, i.e., before the state of nature realizes.

In addition to this basic setting further assumptions are made to avoid too many case distinctions but keeps the model reasonable for most industrialized countries that have a relatively stable electricity supply and wish to maintain a similar level:

1) The total cost of providing electricity is sufficiently low relative to the highest marginal utility of electricity consumption.

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[2] Note that the model is stylized and does not account for prosumers or prosumagers as individual actors. Both can either be included on the consumer side (i.e. altering the residual electricity demand) or by combining the consumer and generator roles.

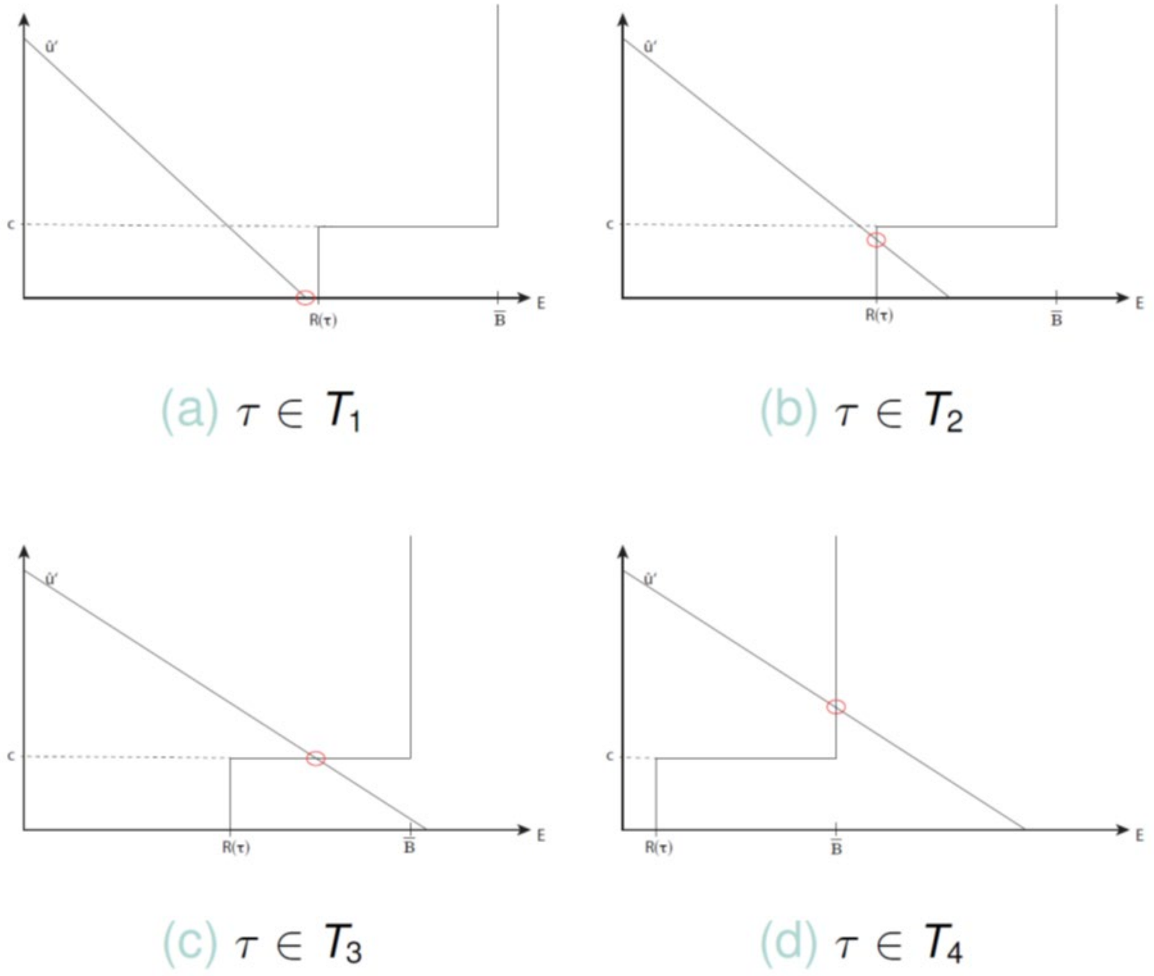
This implies that in a socially optimal equilibrium, consumers will always, i.e., in all states of nature, be supplied with most of the electricity they wish to consume at a price equal to the marginal cost of the dispatchable technology (c). If this is the case, autonomous devices will always get a sufficient amount of electricity to provide a basic level of service, such as keeping room temperature at a level that is at least close to comfort levels or preventing food from spoiling in fridges and freezers.

2) Deliberate energy consumption will generate a strictly higher marginal utility, if it is still below its maximum level, than additional service rendered by autonomous appliances.

   If electricity is scarce (so that a consumer cannot use the amount she would like to use) but the room temperature is at a level that is close to the preferred one, a consumer would most likely not want to use no lights, switch off a TV, or have a cold meal just to bring the room temperature somewhat closer to the preferred level. In other words: When electricity demand at the usual market price is slightly higher than supply, a consumer will offer flexibility by restricting the operation of autonomous devices (by lowering the room or hot water temperature somewhat), and not by deliberately avoiding electricity use, e.g., by sitting in the dark or not preparing a hot meal. This leads to the result that for all electricity prices considered, deliberate electricity consumption always corresponds to the maximum value so that this part of consumption varies only with natural conditions and cannot be affected by prices in the range we consider. However, with their autonomous devices, consumers are willing to provide some degree of flexibility by adjusting the level of service provided by these devices.

3.3 Results of the Novel Market Approach

The market setting approach described above will lead to four states of the system depending on the state of nature (Figure 6). In state T_1 variable renewable supply suffices to cover the highest possible electricity demand (i.e., electricity demand arising from a zero electricity price); these are for example hours with high renewable injection and low electricity demand leading to a renewable supply surplus. In state T_2 variable renewable supply is insufficient to meet electricity demand at an electricity price of zero, but it is sufficient at a higher electricity price that not yet covers the operating costs of backup technology; those are hours in which renewable generation and demand are equal. In state T_3 the dispatchable backup is required but sufficient to meet the demand that results for a price of electricity that covers the operational costs of the backup technology; those are hours in which renewable generation alone is insufficient but there is sufficient dispatchable capacity to cover demand. Finally, in state T_4 installed capacity does not suffice to cover the demand arising for a price of electricity that covers the operational costs of the backup technology; those are peak hours in which the total available generation is at its limit. Note that these sets are disjoint and that they comprise all possible outcomes, e.g. each state can occur in multiple hours of a year. Depending on investment decisions, some of these sets might be empty.



(a) $\tau \in T_1$ (b) $\tau \in T_2$

(c) $\tau \in T_3$ (d) $\tau \in T_4$

Figure 6: Market Outcomes in the Revolutionary Market Design

Using the basic actor setting and the resulting system states a comparison between:

a) a first best social planner setting,

b) the current market setting in which consumers pay a constant, state-independent, electricity price *p* and in which security of supply is fixed at a maximum level, and

c) the above described novel market design with retailers and consumers entering contracts accounting for a dedicated reliability choice

is conducted.

The comparison (see Schäfers et al. (2024) for details) shows two main results for the functionality of the novel approach compared to the current design. First, the current market design leads to socially suboptimal outcomes, typically implying an overuse of the dispatchable technology compared to the social optimum. These conditions are a close description of a situation in electricity markets without additional renewable support mechanism. Renewable investments have to be refunded on the spot market during those hours where a dispatchable technology is the marginal unit and thus sets the price; in the remaining hours (where renewables set the price), the spot market price will be zero due to the zero marginal costs of renewables. The consumer price is set to cover the average spot market price (which resembles average operational costs) plus the marginal costs of investing in backup capacity. The backup capacity is simply chosen to be sufficiently large for balancing the system under all foreseeable conditions. If investment costs for the dispatchable technology are sufficiently large, the current market setting will also lead to inefficiently low levels of renewable capacity and inefficiently high levels of dispatchable capacity.[3]

Second, the novel market design never achieves strictly lower welfare than the current market design and can reproduce the first best social planner result, if the marginal utility gained from autonomous devices is close to linear. Note that in order to replicate the social planner result in a market setting households would need to face the respective hourly market price (i.e. not the state independent average price). In other words, the social planner benchmark can also be seen as a full real-time tariff approach in which households are subjected to the market dynamics.

Those two findings built the conceptual foundation and showcase that the basic approach is indeed able to provide an improvement compared to tariff designs that neglect reliability (i.e. impose maximum reliability) and use average tariff structures. However, they do not yet answer the question how the novel market design could be implemented in practice.

To this end, one needs to investigate conditions under which consumers, retailers and producers can agree on contracts and how a regulatory authority ensures that the crucial elements of the contracts are enforceable. We consider a contract between customers and retailers that has three main elements. First, there is a range of states of nature in which customers pay a pre-agreed price p for electricity and get as much electricity as they want, up to a pre-agreed capacity maximum. This is identical to the current market design in most countries. However, it now applies not in all but only in some states of nature. Second, customers can pay a fixed fee to get priority for receiving additional electricity (exceeding their defined level of secure energy) for free, if there is a surplus of renewable electricity (states in T_1 and T_2). This is of particular interest to customers who have some way of storing energy, such as battery systems, an electric vehicle or electric warm water supply with a warm water storage. This part of the contract serves to allocate possible surpluses of renewable electricity, which is generated at zero marginal costs. Finally, the contract has a part that allows retailers to reduce delivery of electricity to customers below the demand that would result from the pre-agreed price in states of nature, where there is a shortage of electricity (i.e. T_4). In these cases, customers receive a guaranteed base capacity plus a share of the remaining electricity supply (i.e., total supply minus guaranteed deliveries to all customers). Customers choose their guaranteed capacity (at a fee per unit of capacity) as well as the priority (for another fee) with which they receive additional electricity (i.e., their share of the remaining supply). Together, these choices imply a probability that a customer receives as much electricity as she wants (over all states of nature, i.e., T_1-T_4) as well as a probability of receiving some electricity for free in states, where there would be curtailment otherwise (i.e., states in T_1 and T_2).

In other words, consumers differentiate between a secure capacity level and a less reliable capacity level on top. Thus, customers essentially give retailers the option to cut off a part of their electricity supply as long as the full capacity is still available to them with the contracted probability over all states of nature. By our assumptions on individual utility, customers will only offer flexibility resulting from autonomous electricity use to their retailer. Technically, this implies that customers have two circuits: One for deliberate use and one for autonomous devices that are supposed to offer demand-side flexibility (such as heat pumps, electrical vehicles, fridges and freezers). The first circuit will never be interrupted, the second circuit will receive electricity only with a pre-agreed probability (say, 95%) and thus can be interrupted for a pre-agreed maximum amount of time that ensures that services offered by autonomous devices are not reduced substantially (e.g., a 4 hour interruption will not harm food in fridges or freezers and result only in slightly reduced room and warm water temperatures).

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[3] This is a result of the ex-ante fixed and constant price that consumers pay in the current market design. Due to this constant price, demand-side flexibility cannot be harnessed. Thus, to ensure security of supply, more dispatchable technologies might be required than in the social optimum. This situation arises mainly, if investment costs for dispatchables are high, as demand-side flexibility will be used most strongly in such situations in the social optimum to reduce investment costs.

Retailers buy options for electricity supply from generators to match their obligations to customers. For weather dependent renewable supply this means a fixed price (e.g., payment per year) for all the electricity produced in a given period (e.g., 20 years). For dispatchable generation the retailer buys an option to get electricity up to a certain load at each point of time during the contract period (fixed price per period) and pays an ex-ante agreed price for each unit of electricity that is exercised.

A regulator ensures that each retailer owns a portfolio of such delivery options that ensures that the retailer can provide the secure capacity sold to his customers in all states of nature. Furthermore, the regulator verifies that the portfolio of delivery options allows the retailer to meet the contracted reliabilities for additional capacity as well as the expected free provision of electricity on average over all states of nature.

Given this contractual setting the market structure presented above shows that there is a market clearing equilibrium that reproduced the social planner result. In other words, the socially best outcome under the novel market can be decentralized with fairly simple and intuitive contract design. The resulting payments of all customers are sufficient to cover the costs of procuring the underlying supply portfolio.

3.4 Discussion and Insights for Policy Design, Model Development and Comparison

Albeit the assessment of the novel market design is conducted in a highly stylized conceptual setting, it nonetheless provides important insights for potential policy and tariff design questions.

Firstly, the insight that the current market design leads to suboptimal outcomes and an inefficient mix of intermittent renewable and dispatchable capacities calls for a constant intervention approach. In other words, the base assumption that renewable support at some point in time should end and be fully replaced by a market approach may not hold in the current market design framework. While the framework itself does not lead to insufficient financing for those capacities installed, it leads to a suboptimal capacity mix; meaning that there is insufficient funding for the optimal mix (the 'missing money' problem capacity mechanism aim to adress). Providing sufficient funding for high RES shares will require a transfer approach (i.e. via a capacity mechanisms or a RES auction) financed via a fixed payment or a surcharge (part of the grid tariff).

Second, the capability of the contract based novel market design to replicate a first best system solution provides an alternative approach for tariff design. As the social planner approach is identical to a setting in which price signals vary with the state of the world for all system participants it is identical to a full real time pricing setting. As long as it is unlikely that all consumer will face real time price signals the novel market design provides an alternative market based approach obtaining the same outcome.

Third, the above-specified contracts render investments in variable renewables almost risk-free for generators. The retailer buys all produced electricity at a pre-agreed fee from generators. Generators would be free to either enter such agreements or obtain sufficient financing via short term trading in the energy wholesale market. In principle, an agreement between retailers and generators could cover a period of 15-25 years, so that generators would know whether investing in a given renewable technology will pay off or not before they commit to the investment. In contrast opting for sales on the spot market has the usual market price risks. As the retailers will bear most of the risk they need to refinance those via the respective consumer tariff structure which in turn define the prices they are willing to offer to the generators. This risk allocation is likely to increase investment in renewables, as it reduces financing costs (Wüstenhagen and Menichetti, 2012; Abani et al., 2018).

Finally, in terms of regulatory oversight, the novel market design has some information requirements, which are, however not unrealistic. The regulator has to be able to assess demand and production levels for all renewables over different state of nature. Such demand assessments are already available as a basis for the planning of grid operators. Production profiles for different renewables at different locations are also frequently computed as a tool to check the profitability of the investment (many banks require such profiles for their funding decision). What would be necessary in addition is that these profiles are certified by a third party and that each retailer provides the demand and production profiles to the regulator (which could be mandated). Based on this information, the regulator can easily assess whether the procured production portfolio matches the promises made to customers.

Furthermore, the stylized nature of the conceptual assessment neglects important real world constraints and conditions. Given that we are currently in most liberalized electricity markets in the evolutionary setting with energy markets and some form of RES support and/or capacity mechanisms, altering this structure towards the proposed revolutionary system would incur transaction costs. The basic contract structure between consumers and retailers could likely be implemented via discount based contracts (i.e. offering lower prices if the consumers are willing to offer their flexibility assets/agree to a lower supply security) if smart meter structures are in place and allow a differentiation between different consumer appliances. However, this may require adjustments to legal and regulatory specifications. A potentially more challenging implementation hurdle is the needed regulatory oversight to ensure that both the delivered energy level for consumers fulfills the agreed reliability level and the evaluation of the renewable supply portfolios. The resulting long-term trading structure would be deviation from today's more short term market logic but is basically similar to the ongoing debates about capacity mechanisms that call for a longer term price signal. Finally, the model neglects network related aspects and only focused on energy related decisions. Including transmission and distribution restrictions and different network tariff structures would require a more complicated model formulation and is subject for future research.

In addition to the insights for policy design, the approach also provides important guidelines for the subsequent model design and comparison. Ideally, the setting of the three actors (consumers, retailers, generators) could directly be incorporated into a join model framework using the same data structures for the novel 'revolutionary' approach as for the current 'evolutionary' design. The mathematical specifications of the approach showcase what elements the model will be needing to ensure comparability. However, the conclusion that the novel approach can reproduce the first best social planner result, also opens up the possibility to provide a numerical solution based on a system planning approach for the revolutionary setting which can then be compared to an evolutionary setting. We will discuss and explain those aspects in the following section when explaining the model design process.

4 Model Development and Assessment

Building upon the problem mapping as well as the market design assessment, the second project step is the development, tailoring, and application of a schematic electricity-system model. The aim is to develop a parsimonious model that captures fundamental system dimensions and relevant actors identified by the structure problem mapping stage. Following the insights derived in the mapping stage (Section 2), one central aspect that needs to be captured by the model are the different incentives of the main actors (especially consumers) and their interactions.

Based on this basic structure in the last project step the model will be used to compare the evolutionary and revolutionary market designs (Section 3) to identify which setting is better suited to derive a carbon free Swiss electricity system. To this end, the model will be calibrated to capture the main characteristics of the Swiss electricity system and a scenario set will be derived to investigate different future system conditions.

Following we will shortly present the basic model structure and its development challenges, its data basis and the scenario design, the results of the subsequent scenario simulations as well as basic insights drawn from the results.

4.1 Model methodology and basic structure

The basic model structure was envisioned to be an integrated model chain with several sub modules that represent different elements of the electricity system. In particular, we planned to include sub-modules for different actors on the supply and demand side that interact with each other via market and physical linkages (see Figure 7). Especially the different actors on the demand side (i.e. regional differentiated as well as by consumer type) were seen as a main aspect needed to capture incentive structures of different market designs. Similarly, the role of generators (i.e. large scale investors) is crucial for identifying how additions to the energy only market (i.e. capacity mechanisms) may play out. On the physical side the linkage from local (DSO) to national (TSO) and international (EU imports and exports) structures represents the main setting for all electricity systems. This combination of actors would be simulated using individual objective formulations (i.e. profit/utility maximizing, cost minimizing, regulated objectives) and their relations (i.e. via market prices or contractual relations) would need to be implemented.

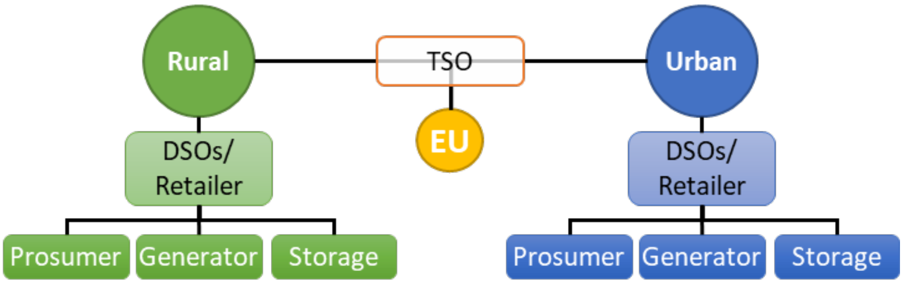

Figure 7 Schematic structure of the original envisioned model structure

Following the main insights from the review, the discussions on the different evolutionary development elements, and the aspects of the novel revolutionary design, the envisioned model structure needed to be adjusted leading to a reduction of the intended complexity of the model. One central aspect of the review for the future system is the increased role of the demand side, in terms of absolute demand needed to satisfy, the amount of decentralised PV supply entering via consumer structures, and especially in terms of flexibility provision for the system. Households are also the main actors within the novel market design and their willingness to pay for reliability drives the contractual design. Thus, a more extensive representation of household behaviour represents the core of the model design as envisioned in the project draft.

On the supply side the main focus lies on investment questions. Especially in the European context the discussion on capacity mechanism, supply security, and refinancing of investments are central points. However, given the envisioned focus of the model on the Swiss setting many of those European developments are external with little room for influence from Swiss decisions. Capturing the interplay of those policy decision with resulting investments into the different generation technologies would require a European wide model. Due to data and computational limitations the model focus was kept on the Swiss context, meaning that many of the investment related policies are not included. The discussion within Switzerland on potential reserve capacities (either the hydro reserve or direct stand-by conventional capacities like Birr) are from a modelling perspective ‘only’ a parameter choice on how much spare capacity is to be kept out of the market structures via regulatory requirements; i.e. outside of the actual model. Beside strategic reserves, a Swiss-only capacity market (i.e. an auction based market in addition to the wholesale energy spot markets) is deemed highly unlikely and European capacity mechanism would need to be captured via assumptions on the total available generation capacities.

On the network side the challenges on the local level as well as the interplay between local and national structures is considered an important aspect of the transition towards a carbon free electricity system. However, we needed to discard those aspects in our model formulation due to data limitations (i.e. missing general DSO grid capacity information) and model limitations (i.e. computational time for a regionalized model).

The adjustments lead to a restructuring of the model as shown in Figure 8. The rural and urban distinction is not directly modelled anymore, but the different consumer types can and are still defined by different local conditions. The demand side is represented by a set of different consumer actors (i.e. classical inflexible demand, flexible demand, and local generation). This demand module is linked to a system module which represent the overall wholesale market dispatch and is linked to a representation of neighbouring markets (i.e. via cross-border exchange). Generators are not explicitly represented as individual actors anymore but part of the system module, thus their dispatch and investment behaviour will always be system-optimal. Therefore, different risk structures and strategic behaviour are neglected.

The linkage between the system and demand layer needs to reflect the relevant physical and economic interrelation. As most consumers are subject to some form of tariff based contract, the incentives on the demand side are governed by those tariffs which in turn are a result of the respective system electricity price derived in the system module. In the other direction, the resulting aggregated demand of all consumer actors defines the total demand level that needs to be satisfied on the system layer. Those consumers that are directly active on the wholesale market can be incorporated as demand in the system module.

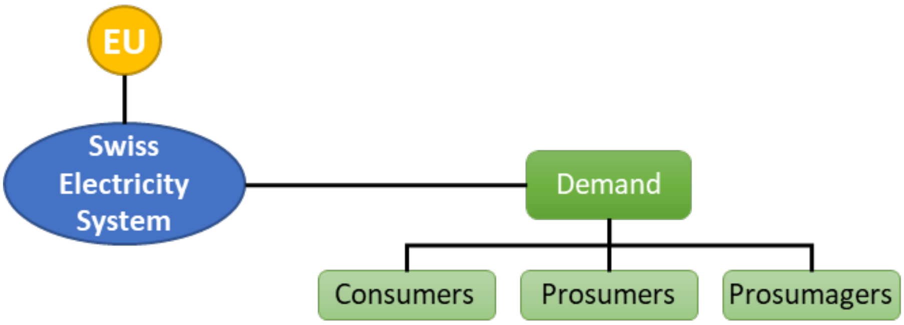

Figure 8 Schematic structure of model design with interplay of consumers, the national system, and international exchange

A related model design discussion was the interplay of short and long run structures. Given the nature of a renewable dominated electricity system the operational time dimension cannot be neglected to address intermittency, storage and flexibility aspects. At the same time the overall system is shaped by the long term investment decision of the different actors. Consequently, the model design needs to capture both time dimensions and the respective decisions made for each.

After test runs with separate modules for operational and investment structures (i.e. in the hourly operational submodule, actors take their assets and further characteristics as given and maximize their profit/utility, while the investment submodule simulates multi-year decisions on asset capacities and policy adjustments) the elements were merged again due to computation challenges and data limitations on the household side. The system module combines investment and operational decision for a yearly time horizon (i.e. is a combined short and long term model) while the demand module only accounts for operational decision (i.e. is a pure short term model). One of the main reasons for abolishing a separate investment module on the demand side is the limited impact of electricity tariffs on two of the main large scale asset decisions: electric mobility and electric based heating. Those choices that are a largely steered by outside constraints like commuting needs, electric car developments or heating policies, and an endogens representation would have required significant extensions and outside assumptions. Consequently, we use a predefined infrastructure set to capture different household types. The same is true for PV and battery installations; i.e. we use predefined PV-battery structures. However, here the tariff design could indeed have impacts on the actual investment decision and also the sizing of the respective assets, especially batteries, which we are not able to capture with the model structure.

Finally, the structure of the novel market design as presented in Section 3 would need to be implementable while still maintaining the capability to also model an evolutionary setting combining wholesale market and tariff structures. As the adjusted model is limited to a consumer and system layer, the actual structure of consumers, retailers and generators with contractual relations is not implementable. Nevertheless, the consumer perspective in terms of deliberate and additional consumption and their respective willingness to forego reliability could still form the basis of the household models. After testing different implementation concepts, we discarded a direct implementation due to missing information on the utility structure. This would be needed to allow a translation of the resulting reliability level in a price discount for the household tariff that the retailer would need to offer.

To still be able to investigate the novel market design we need to rely on the main conceptual finding that the approach achieves the first best social planner optimum. Thus, without modelling the direct contractual implementation, a system planner approach can be used to derive the numerical equivalent of the resulting investment and usage decisions.

Translating all those constraints and adjustments into a mathematical model setting led to the final model structure as specified in Figure 9. In its core form it consists of two main modules:

1) A set of ***household models*** capturing the incentives for electricity usage on the end consumer side for the different consumers based on a direct costs-minimization approach with externally defined tariffs, and
2) a ***wholesale market model*** combining the household demand with the further system parameters to derive the overall cost minimal system dispatch and the resulting market prices and linking the Swiss and European markets.

The two model modules are combined in a looping structure. The household tariffs are based on the energy prices of the wholesale market model (including network charges, taxes and levies on top). The derived household demand profile is in turn provided to the wholesale model as fixed input. The model loop stops when there is either no change between the loops anymore in terms of energy prices and household demand, or the model switches between two states.

This setting allows the direct modelling of evolutionary designs that are based on tariff structures for households and an energy market as main system price signal. The system layer could also be extended to require specific capacity requirements or the investment options could include additional payment elements (i.e. subsidies or technology restrictions) to capture different policy options.

For the revolutionary design the household module can be ignored (i.e. the tariff-discount logic from the revolutionary approach would require a utility based household formulation) and the relevant household information (i.e. available assets and flexibility options) is included in the wholesale system layer. The resulting overall system optimization represents the first best system benchmark, which in turn can be interpreted as the result of a contractual setting with consumers, retailers and generators as presented in Section 3.

Albeit the final model structure only captures parts of what was originally envisioned, the remaining elements still allow a better investigation of incentives structures on the consumer side and its interplay with the overall system than the usual system model approaches. Also, the comparison between this coupled setting with a full system benchmark provides a valuable first indication whether the transition towards a novel market design is worth the potential effort.

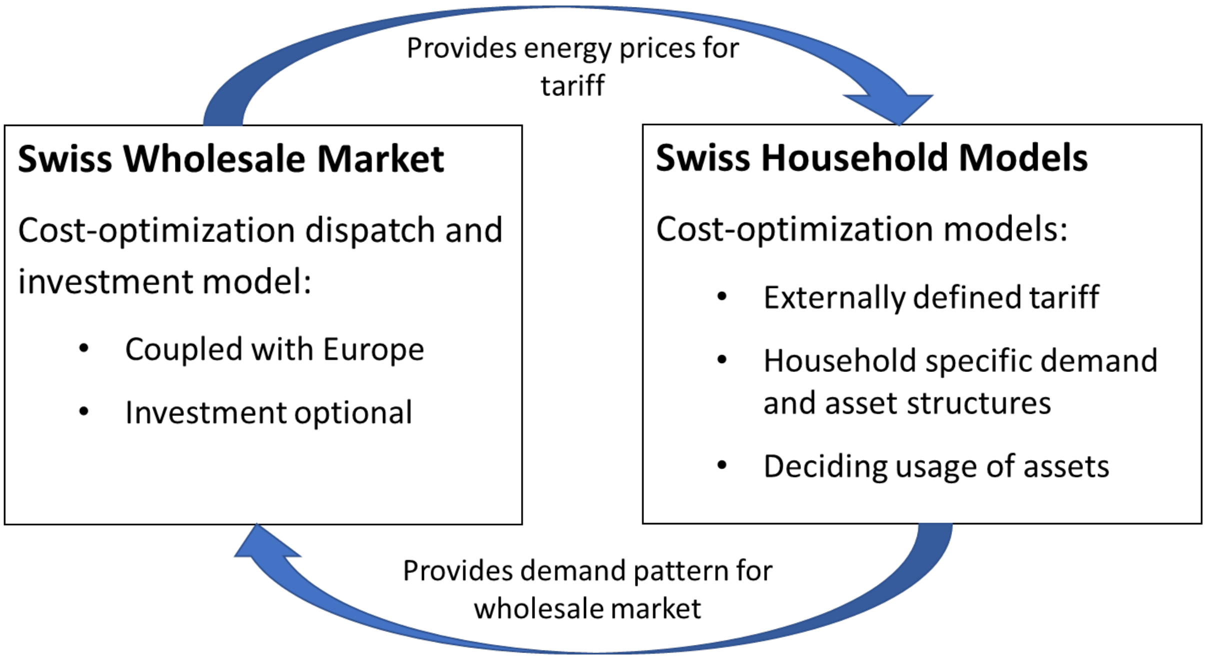

Figure 9 Schematic structure of the final model chain

4.2 Scenario Design and Data structure

The basic model as shown in Figure 9 needs to be mathematically specified and its dataset tailored to the Switzerland as well as the two market design options. To this end we derive a scenario structure enabling the comparison of the different design under different system conditions. In the following we shortly present this basic scenario background before presenting the details of the household and wholesale market modules.

4.2.1 Basic Scenario Setting

The main focus of the comparison is to identify how the two market design settings perform in a renewable dominated system. Therefore, we focus the scenario design on the 2040 system status in Switzerland and Europe, when a significant part of the system transition needs to be achieved. As the model structure is using a one-year reference without a transition between years, we are not able to simulate a transition from today's system to the future structure but derive direct system conditions for the future system.

For the Swiss model aspects, we rely on the Swiss Energy Perspectives 2050+ (CH-EP2050+, Prognos, 2021) as main reference whereas the European data is based on the Ten Year Network Development Plan 2020 (TYNDP 2020, ENTSOE 2020). As both scenario outlets have a set of different underlying scenario pathways we cover the following combinations:

- Swiss scenario pathways: WWB ('Weiter wie bisher' a scenario without additional policy assumtions) and the Zero-Basis reference Scenario with balanced yearly production of the CH-EP 2050+ with a nuclear running time of 60 years
- EU Scenario pathways: National Trends as main pathway, with Global Ambition as sensitivity test

For both setting we use the reference weather year 1984 of the TYNDP 2020 as basis, which represents a rather high winter demand.

For the evolutionary setting we introduce a four-part tariff having a peak and off-peak tariff for summer and winter. The energy price from the wholesale market model will define this energy rate structure and is complemented by network tariffs, taxes and levies as of today (i.e. no further adjustment of network charges to address local network constraints). The model can easily be adjusted to capture other temporal structures for the tariffs. The four periods allow us to capture the main dynamics stemming from time-of-use tariffs for the interplay of flexibility assets and their operation. More differentiated tariffs would alter the actual operation pattern, but not the basic incentive structures (i.e. shifting towards lower priced periods). We will discuss potential implications of more dynamic tariffs in Section 5.

For both settings we run scenarios with and without investments on the wholesale market. In case of investments, only additions of PV and wind are allowed. The investment costs are based on the EP 2050+. As those are not necessarily in line with the underlying costs assumptions of the TYNDP 2020, they should be seen more as an indicative comparison between the two market settings and not as a numerical quantification of the investment needs in Switzerland.

To test the performance of the evolutionary and revolutionary settings further, we implement the following sensitivity tests:

- Winter-Import Limit; imposing a 5 TWh total net-import limit during the winter months. This limit is in line with the envisioned target in the adjusted Electricity Law. However, as none of the input scenarios assume such an import limit, the installed capacities in the EP 2050+ and TYNDP 2020 may not be capable to provide sufficient generation, those sensitivities are also coupled with an investment option.
- Reduced reference RES capacities: As the baseline scenarios are assumed to provide sufficient energy for most settings there is likely no additional investment need. To test how the two

designs differ in their investment behavior we add a setting in which we reduce the installed RES capacities of the Zero-Basis scenario to 70%, freeing up potential space for investments.

4.2.2 Household Model

The household model is designed as a simple cost minimization setting for a full year with an hourly time resolution. For each household demand is structured in a fixed and flexible part. Given the tariff structure the household decides how much of the flexible demand is shifted in time to minimize the tariff payments. The infrastructure of each household is pre-defined; in other words, households only decide about their usage not about their investments.

The basic model structure is the same for each household, while the data for assets, inflexible, and flexible demand varies. The underlying household dataset is derived from the NETFLEX project (see Project Website) and includes 300 representative households from the canton Aargau with their respective asset composition (PV, battery, EV, and heat pump) and PV generation and demand time series.

On the flexibility side the households can have electric vehicles (EVs), a heat pump, and battery storage:

- For EVs a predefined mobility demand is given (based on the NETFLEX data). However, the charging behavior of the EV batteries can be defined to capture different flexibility levels; i.e. fixed charging to refilling the battery whenever connected, flexible charging in a given time window like a day or week, or bi-directional charging. For the scenarios, we only allow charging of cars and provide a weekly time window.
- For heat pumps the heat demand is given for a predefined time window (based on the NETFLEX data), while the electricity consumption to satisfy this demand can be freely chosen within the time window. Detailed thermal or further technical restrictions are neglected and an hourly capacity limit of the heat pump has been derived from the hourly thermal demand curve. For the scenarios, we assume a time window of six hours for heat pump operation flexibility.
- Batteries have no pre-defined usage pattern and are operated within the model to optimize the overall energy usage of the household. We assume a battery efficiency of 81% (90% each way)

On the provision side each household has an unrestricted grid access and can have PV capacity:

- For PV panels a weather dependent hourly injection profile is given that is based on the Aargau dataset (i.e. there are slight variations in orientation and angle between the different households, however, the majority is south facing)
- For electricity consumption from the grid no direct physical limitation is assumed (i.e. the households hourly electricity consumption for appliances and the heat pump will not be limited). However, in case of EV charging a maximum charging capacity of 11kW (on top of the other electricity usages in the household) is assumed. Also, for injection into the grid (i.e. PV surplus) no grid restriction is assumed. Naturally, this approach neglects potential distribution grid bottle necks. Household tariffs are predefined and for the scenarios we use a peak/off-peak structure (i.e. hours between 8 and 20 during weekdays and Saturday are part of the peak period) differentiated for summer and winter.

4.2.3 Wholesale Market Model

The wholesale market model follows a classical least-cost dispatch approach. As with the household model a full year with hourly resolution is modeled. It covers the European system[4] on a one-node per country resolution (i.e. inner country congestion is neglected, except for Italy, Norway, Sweden, and Denmark in which the nodes represent the zones within the country) with cross-border exchange being

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[4] The covered countries are beside Switzerland: Austria, Belgium, Croatia, Czech Republic, Denmark, France, Germany, Hungary, Italy, Luxembourg, Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, and the UK

limited by NTC values (i.e. no flow based representation). Generation capacities are structured in types[5] with a fixed operation cost level per type. The capacity and cost data is taken from CH-EP2050+ and TYNDP 2020.

Hydropower is aggregated via distinct types:

- Run-of-River units are modeled as time series feed-in.
- Pumped-Storage Plants (PSP) units are differentiated in closed (i.e. only the pumped water is available for generation) and open system (i.e. linked to a seasonal storage plant). The open systems are merged with the data for large scale seasonal hydro dams.
- Other seasonal hydro units without PSP are differentiated in medium and small plants.

As the model covers a year, starting and end status of hydro storage is predefined. We assume a starting level of 95% in the seasonal storage and start the model run in October at the end of the storage period. Hydro inflow profiles are based on PECD (Pan-European Climatic Database).

Renewable generation from wind and PV is provided as fixed hourly time series infeed based on Renewables.Ninja. For Switzerland the hourly profiles have been scaled to match the CH-EP2050+ yearly generation values (i.e. the direct Renewables.Ninja profile would lead to a higher yearly generation than is assumed by Prognos for the Swiss scenarios). For biomass the capacities and total yearly generation are based on the CH-EP2050+ values, i.e. the plants are free to be dispatched by the model but their total yearly output cannot exceed the reference values.

Furthermore, the wholesale market model can be extended to allow investments. The type of generation eligible for investments, annuity of investment costs as well as further limitations need to be specified. For a set of the scenarios, we enable investment into Swiss PV and wind capacities. As the model only covers one year, no cross-weather assessments are performed for the investment assessment; in other words, the modeled year is assumed to be repeated indefinitely.

4.2.4 Linkage between Household and Wholesale Market Models

For the evolutionary model runs, the household model defines the demand time series for the wholesale market model. To this end, the 300 household models are run in parallel and the resulting demand time series are aggregated and scaled up to derive a representative Swiss wide household demand time series. The scaling is based on a yearly Swiss reference household demand which is given by the respective CH-EP2050+ scenario. On average each household is scaled up by ca. 8000 to derive an aggregated demand structure that matches the household demand of the Energy Perspectives 2050+. Consequently, the underlying demand dynamic in our model structure is limited in the sense that it only reflects the variability overserved and assumed in Aargau within the NETFLEX project. However, the model structure itself is flexible in the sense that additional household data can easily be incorporated.

Within the wholesale model this household demand is coupled with electricity demand of non-households to derive a total Swiss demand time series, which in turn is assumed to be fixed. Additional flexibility is included via the ‘generation’ types Battery, Demand Side Response, Electrolyzer that represent larger scale flexibility units.

Based on the results of the wholesale market model the hourly electricity price curve for Switzerland is defined and the energy tariffs for the peak/off-peak and summer/winter periods are defined. Those are extended by network charges, levies and taxes and feedback into the household models for the next run. This cycle is repeated until either the differences between each cycle in terms of prices is below a threshold or the model cycles indefinitely between two states.

For the revolutionary model runs, the household models are not simulated. Instead the demand and asset data from the households is transferred to the wholesale market model (using the scaling factors

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[5] The plant types are: Nuclear, Hard coal, Lignite, Natural Gas, Oil, CHP plants, Other, PV, Wind onshore and offshore, Biomass, Hydro, Battery, Demand Side Response, Electrolyzer.

of the evolutionary model).[6] Here the system optimization has full access to the flexibility assets with the same restrictions as in the household model (i.e. heat pumps have a six-hour time window, EVs a weekly charging limit). Thus the revolutionary scenarios are performed in a single model run.

4.3 Scenario results

Using the two model formulations for the evolutionary and revolutionary setting, we conduct a scenario assessment as outlined above. Following we will present and shortly explain the numerical results and derived findings. A broader interpretation of the results from a Swiss policy perspective and comparison with ongoing policy and market design discussion in Europe follows in the next Section.

4.3.1 Overall Scenario Results

Table 1 summarizes the dispatch results for the supply and demand side for the two market design setting for the combinations of 'WWB' and 'Zero-Basis' on the Swiss side and 'National Trends' and Global Ambition on the European side. As the results of the 'Global Ambition' have no significant difference in results, we neglect them for the reminder of the assessment. Note that for those aggregated results, the amount of flexible demand (i.e. heat pumps and EVs) used in the different settings is always identical as this is defined by the heating and mobility demand. However, the usage of those assets differs on an hourly basis and will be investigated further below.

For the WWB setting the main difference between the system optimal revolutionary and time-of-use tariff based evolutionary approach lies with the usage of storage assets. In case of a fully integrative system optimization the need for usage of batteries and pump storage units is reduced by about 0.5 TWh per year respectively. This is a feedback effect from the altered flexible demand usage of the households. As they follow their fixed tariff structure and optimize for their own consumption costs, they use more batteries than is optimal from a pure system perspective. The resulting aggregated demand curve furthermore calls for more usage of pumped-storage assets. The higher charging need for batteries and pumped-storage also leads to a higher generation and import level.

Table 1: Swiss System Dispatch Results [yearly values in TWh]

CH Scenario	**WWB**						**Zero-Basis**		
EU Scenario	**National Trends**			**Global Ambition**			**National Trends**		
Market Design	**Rev.**	**Evo.**	**Delta**	**Rev.**	**Evo.**	**Delta**	**Rev.**	**Evo.**	**Delta**
RES-Supply	8.55	8.55		8.55	8.55		23.25	23.25	
Hydro	36.79	37.17	0.38	36.75	37.13	0.38	37.61	38.08	0.47
Other	12.34	12.60	0.26	12.19	12.60	0.41	12.22	12.22	-0.00
Net-Imports	10.76	11.26	0.50	10.79	11.24	0.46	-3.17	-2.85	0.32
Fixed-Demand	55.24	55.24		55.24	55.24		55.01	55.01	
Flex-Demand	11.11	11.11		11.11	11.11		11.11	11.11	
Batteries/DSR	0.66	1.29	0.63	0.55	1.29	0.74	1.27	1.40	0.13
Pump-Demand	1.43	1.94	0.51	1.38	1.88	0.50	2.52	3.13	0.62

Note: 'Delta' is defined as the evolutionary value minus the revolutionary value. 'RES' supply includes wind and solar. 'Other' includes nuclear, fossil and all non-wind, PV or hydro generation. 'Fixed demand' is the sum of all predefined hourly electricity demand that cannot be shifted. 'Flex-Demand' incorporates heat pump and EV charging demand. 'Batteries/DSR' represents battery charging and further demand side related flexibility options.

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[6] For computational reasons the individual household batteries were merged into one large battery for the revolutionary model run as otherwise the model would take too long to solve.

For the Global Ambition as well as the Zero-Basis setting the same principal behavior is observable, albeit the numerical levels differ. Overall, a system operator can utilize flexibility assets more efficient than if they are steered by tariff based households, leading to less need for energy provision and imports (0.3 to 0.5 TWh per year); or in the case of a net export setting a higher potential for exports.[7]

As the total yearly demand of the flexible heat and mobility is fixed Table 1 does not capture the differences in their usage structure over time. Figure 10 shows the operation of heat pumps, EV charging and battery charging and discharging. The pattern of heat pump and electric vehicle charging shows a stronger peak structure and more block like nature in case of the system optimization approach in the revolutionary setting, in which the system manager can decide about when and how much to use the assets. Contrary, if the household is purely incentivized by its time-of-use tariff structure in the evolutionary setting it follows the repeating daily pattern. This results in a more ‘steady’ usage with lower peaks; i.e. for the presented month in Figure 10 heat pumps (EV charging) show peaks of ca. 2.5 GW (3.5 GW) in the evolutionary setting while the revolutionary setting has peaks up to 5 GW (7 GW).

For batteries the two cases showcase a completely diverging yearly pattern. The revolutionary system optimization shows a mix of strong peak injections and withdrawals scattered around the year, with more usage in the spring and summer months (left hand side of the graph). The evolutionary tariff-based approach however shows nearly no storage usage during the winter half and a repeating charge-discharge pattern in the summer half. Here tariff level (i.e. filling up the storage during low price periods) and technical characteristics (i.e. losses for charging) can decide the usage structure, if there is an arbitrage possibility between low and high tariff periods. But also the interplay with PV generation shapes the battery usage. During winter there is little surplus energy as energy demand is high and any PV surplus can easily be accommodated by the heat pump by shifting the pumps demand to those hours with PV generation.[8] During summer months he heat pump flexibility option is gone as there is no space heating needed and any surplus of the PV production needs to be stored in the battery to maximize its benefit. As during summer time, the PV output is significantly higher than during winter months the overall surplus that needs to be shifted is also higher. This household incentive structure is not coupled to the overall system conditions. For example, the household will shift its PV surplus to nighttime and use it for its own demand while the system’s residual demand may peak during different times and would call for an earlier or later release of stored energy. Transferring the household’s flexible assets to the system level enables them to be used more in line with system surplus and deficit times enabling a better system optimization.

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[7] Please note that the renewable production profile used for Switzerland and Europe in our model deviates from the CH EP2050+ profile and can lead to subsequent differences in the Swiss trading position compared to the Zero-Basis results of the CH EP2050+ (see also alternative weather realization in Section 4.3.4)

[8] Note that we assume a six-hour time window for heat pump optimization. Given the lower sun hours during winter, this time window is more than sufficient to capture any surplus situation via heat pumps.

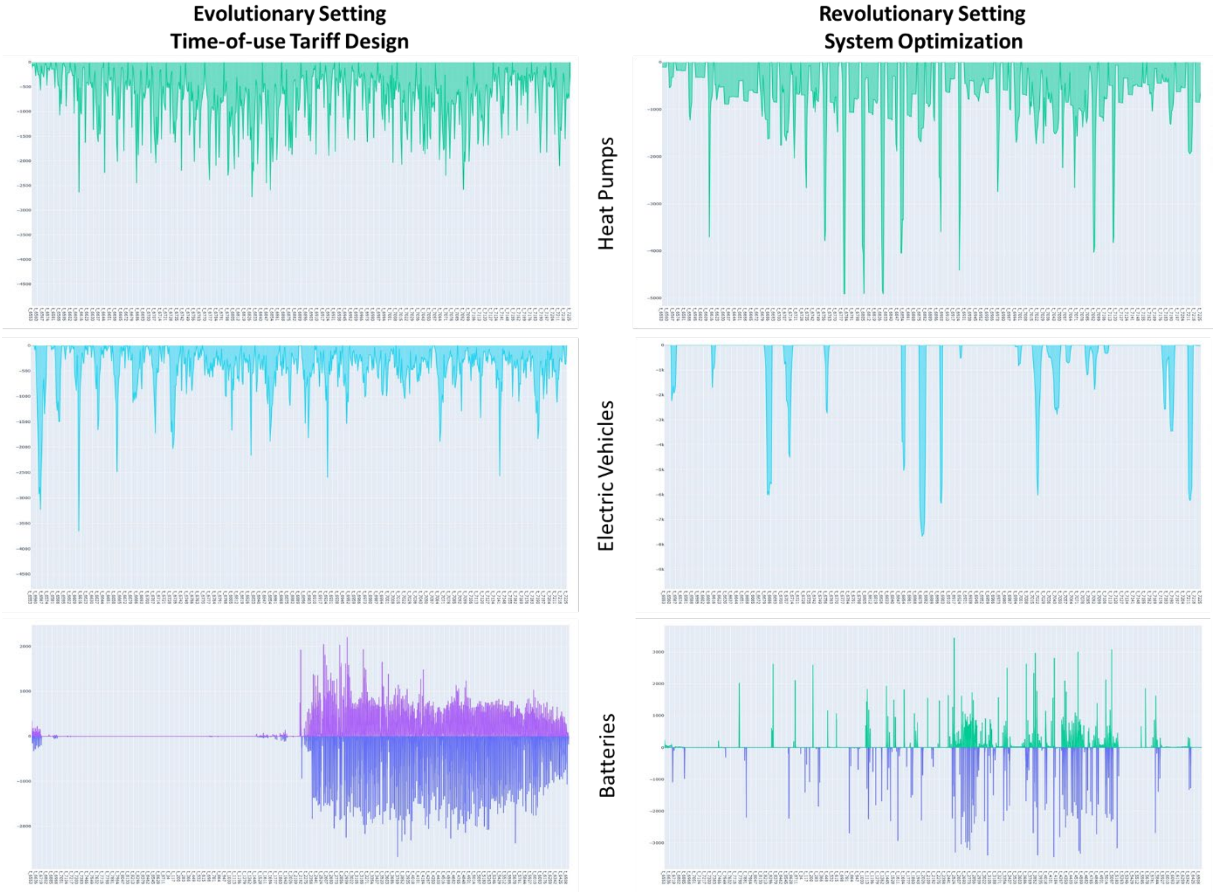

Figure 10 Usage pattern of heat-pumps (first month), charging of electric vehicles (first month), and batteries (full year) for the WWB-National Trends scenario

The direct relation between the system conditions and the usage of heat pumps and EV charging in the system optimization approach is also highlighted in the exemplary snapshot presented in Figure 11. Whenever Swiss market prices are low, either due to cheap imports or renewable surplus, the demand of flexible assets peaks. Those peaks are higher (i.e. normally in the range of 5 to 10 GW, but can reach up to 18GW) and less frequent than the peaks of a tariff-based system (i.e. usually in the range of 3 to 5 GW, with the higher end reaching 7GW). This behavior is to be expected from a system optimized usage. While the model accounts for overall system conditions and generation as well as NTC constraints with neighboring electricity systems, it neglects local system constraints like distribution grid and transformer limits. However, as the basic idea of the revolutionary approach is to transfer the operation of flexibility assets to utilities this also opens up the possibility that those operators account for the distribution related constraints directly. Thus, while including those constraints in the optimization may lead to a shift in the peak pattern, it would by design not put the local system in critical conditions (see also Section 4.3.5).

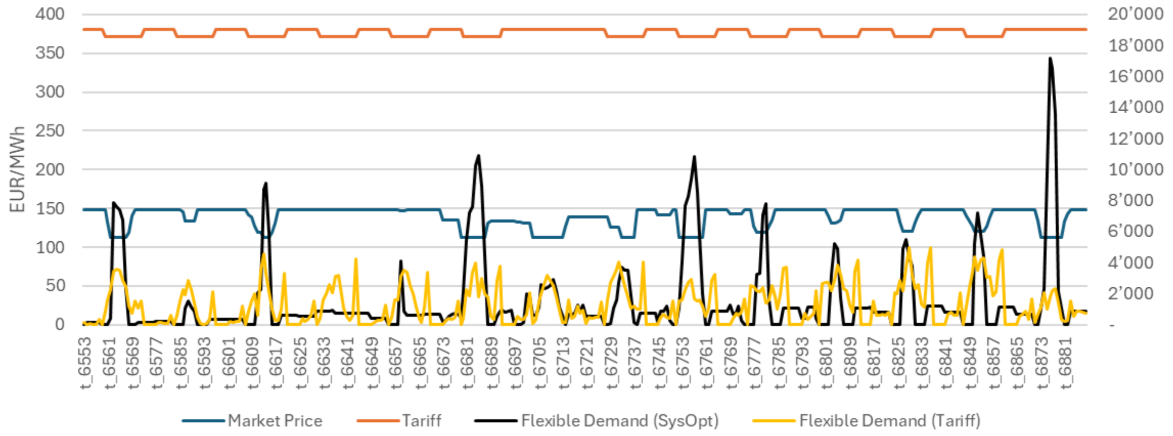

Figure 11: Swiss flexible demand under tariff and optimized system conditons

Beside the base scenario combinations, we also tested a limited winter import case to identify whether the different market designs also provide different results in coping with scarcity situations. To this end, we limit the allowed total import during the winter half year to 5TWh. The model is still free to import and export during winter within its NTC limits as long as the net position does not exceed the imposed energy limit. Table 2 summarizes the main dispatch numbers for the winter cases and provides comparisons with the unrestricted setting as well as between the two market design settings. For the WWB cases we firstly observe that the winter limitation significantly reduces the net-import position and leads to a shortfall of energy in both market designs. In the tariff based setting the battery usage by households is not really impacted. This is mainly due to battery usage being limited to the summer half year anyway. Pumped-storage usage is lower than in the unrestricted setting but still higher than in the system optimal market design. Overall, the differences between the two market settings are similar to the base setting without limited winter imports. Thus, the basic dynamics between both cases seem not to be impacted by the presence of shortage situations.

Table 2: Swiss System Dispatch Results for limited winter import cases [yearly values in TWh]

	WWB							Zero-Basis						
	Free		5TWh Winter			Win.-Free		Free		5TWh Winter			Win.-Free	
	Rev.	Evo.	Rev.	Evo.	Delta	Rev.-Delta	Evo.-Delta	Rev.	Evo.	Rev.	Evo.	Delta	Rev.-Delta	Evo.-Delta
RES	8.55	8.55	8.55	8.55				23.25	23.25	23.25	23.25			
Hydro	36.79	37.17	36.67	36.87	0.20	-0.13	-0.30	37.61	38.08	37.61	38.08	0.46	0.00	-0.00
Other	12.34	12.60	12.37	12.90	0.53	0.03	0.30	12.22	12.22	12.22	12.22	-0.00	-0.00	0.00
Imports	10.76	11.26	8.52	8.78	0.26	-2.24	-2.48	-3.17	-2.85	-3.17	-2.83	0.34	-0.00	0.01
Fixed	55.24	55.24	55.24	55.24				55.01	55.01	55.01	55.01			
Flex	11.11	11.11	11.11	11.11				11.11	11.11	11.11	11.11			
Bat/DSR	0.66	1.29	0.56	1.29	0.72	-0.09	-0.00	1.27	1.40	1.27	1.40	0.13	-0.00	0.00
Pump	1.43	1.94	1.26	1.53	0.27	-0.17	-0.40	2.52	3.13	2.52	3.13	0.61	0.00	-0.01

Note: 'Win.-Free' represents the difference between the scenario with a 5TWh import limitation during winter and the unrestrictive free import setting of the base scenario. 'Delta' is defined as the evolutionary value minus the revolutionary value. 'RES' supply includes wind and solar. 'Other' includes nuclear, fossil and all non-wind, PV or hydro generation. 'Fixed demand' is the sum of all predefined hourly electricity demand that cannot be shifted. 'Flex-Demand' incorporates heat pump and EV charging demand. 'Batteries/DSR' represents battery charging and further demand side related flexibility options.

For the Zero-Basis settings we do not observe any differences between the restricted and unrestricted winter setting. Also, the differences between the tariff based and system optimal approach remain in the same in both settings. In other words, the increased renewable generation assumed in the Zero-Basis setting is sufficient to maintain the import limit without the need for alterations.

4.3.2 Investment Results

The base scenarios did not allow any investments in the wholesale market module. Thus, the results were fully driven by the externally defined generation capacities for Switzerland (based on the CH-EP2050+) and the European countries (based on the TYNDP 2020). As showcased in Section 3 the novel market design should lead to an optimized capacity investment. To test the impact of the two approaches on generator investments we run a set of further sensitivities in which we allow investments in the wholesale market module for PV and wind capacities. In a first sensitivity we simply allow investments on top of the base capacity numbers. As those are sufficient to cover demand the need for additional capacities is likely small. To allow for larger investment incentives we run a second sensitivity in which we reduce the installed PV and wind capacities to 70% of the Zero-Basis levels.

In case of allowed investment in the base setting, we don’t observe any investment in our model. In other words, the externally defined capacities lead to a price level that is insufficient to incentives further capacity additions. However, for the restricted winter setting we observe investment activity in the WWB setting to counter the energy shortage. For the Zero-Basis setting we still do not observe further capacity additions. Table 3 presents the dispatch results for the different WWB cases in the settings with a 5TWH winter restriction. In both market design settings additional RES investments are implemented and in both cases those are fully focused on wind capacities. Given the higher availability of wind during the critical winter months they provide a better cost-benefit structure in our model setting. The system optimal novel market setting allows a slightly lower investment volume to obtain a cost optimal supply structure. The increased availability of RES generation also increases the amount of stored energy in both market settings. Compared to the no-investment setting about 0.3 TWh in the system optimal setting and 0.7 TWh in the tariff setting are stored in addition. As with the base winter comparison, the battery usage of households in the tariff setting is not altered between the different simulations, as they are still simply operating their batteries in summer months to optimize their PV surplus transfer between tariff time windows.

Table 3: Swiss System Dispatch Results for investment cases with winter restriction, WWB [yearly values in TWh]

	WWB, 5TWh Winter Limitation						
	No Investment		Investment			Inv-NoInv	
	Rev.	Evo.	Rev.	Evo.	Delta	Rev.-Delta	Evo.-Delta
RES-Supply	8.55	8.55	12.19	12.37	0.19	3.64	3.82
Hydro	36.67	36.87	36.81	37.40	0.58	0.15	0.53
Other	12.37	12.90	12.45	12.85	0.41	0.08	-0.05
Net-Imports	8.52	8.78	7.06	7.26	0.20	-1.46	-1.52
Fixed-Demand	55.24	55.24	55.24	55.24			
Flex-Demand	11.11	11.11	11.11	11.11			
Batteries/DSR	0.56	1.29	0.69	1.29	0.59	0.13	0.00
Pump-Demand	1.26	1.53	1.46	2.23	0.77	0.20	0.70

Note: ‘Inv-NoInv’ represents the difference between the investment case and the no investment setting of the base scenario. ‘Delta’ is defined as the evolutionary value minus the revolutionary value. ‘RES’ supply includes wind and solar. ‘Other’ includes nuclear, fossil and all non-wind, PV or hydro generation. ‘Fixed demand’ is the sum of all predefined hourly electricity demand that cannot be shifted. ‘Flex-Demand’ incorporates heat pump and EV charging demand. ‘Batteries/DSR’ represents battery charging and further demand side related flexibility options.

Turning to the adjusted Zero-Basis settings we don’t observe any additional capacity installations even with a 70% capacity level.[9] Given that the investment costs are based on the CH-EP2050+ levels, which are not necessarily in harmonization with the underlying assumptions of the TYNDP 2020 settings defining the overall European electricity prices in our model, this indicates that RES capacities in Switzerland beyond the assumed 70% level of the Zero-Basis settings are not beneficial if sufficient imports from Europe can be obtained. However, given the highly simplified nature of the model and the non-harmonized price and investment costs settings, those results are to not to be taken as an indication that RES investments in Switzerland are unnecessary.

Table 4: Swiss System Dispatch Results for investment cases with and without reduced CH-EP2050+ RES capacities [yearly values in TWh]

	Zero Basis, no winter restriction							
	100% EP2050+			**70% EP2050+**			**Difference**	
	Rev.	**Evo.**	**Delta**	**Rev.**	**Evo.**	**Delta**	**Delta**	**Delta**
RES	23.25	23.25		16.34	16.34	-0.00	-6.91	-6.91
Hydro	37.61	38.08	0.47	37.24	37.62	0.38	-0.38	-0.46
Other	12.22	12.22	-0.00	12.28	12.42	0.14	0.05	0.20
Imports	-3.17	-2.85	0.32	3.36	3.70	0.34	6.53	6.54
Fixed	55.01	55.01		55.01	55.01			
Flex	11.11	11.11		11.11	11.11			
Bat/DSR	1.27	1.40	0.13	1.06	1.40	0.34	-0.20	-0.00
Pump	2.52	3.13	0.62	2.02	2.53	0.51	-0.50	-0.61

Note: ‘100% EP2050+’ represents the base case setting with the Zero Basis capacities. ‘70% EP2050+’ represents the case in which the Zero Basis wind and PV capacities are reduced to 70%. ‘Difference’ is the difference between the 100% and 70% case. ‘Delta’ is defined as the evolutionary value minus the revolutionary value. ‘RES’ supply includes wind and solar. ‘Other’ includes nuclear, fossil and all non-wind, PV or hydro generation. ‘Fixed demand’ is the sum of all predefined hourly electricity demand that cannot be shifted. ‘Flex-Demand’ incorporates heat pump and EV charging demand. ‘Batteries/DSR’ represents battery charging and further demand side related flexibility options.

Table 4 summarizes the difference between the two market design settings for the two capacity cases. Comparing the differenced in the setting with reduced RES capacities with the base setting differences showcases rather similar dynamics. In general, battery and pumped-storage usage is reduced in the system optimal setting. As the base setting has a slight net-export structure the system optimal setting leads to higher exports, whereas it leads to lower net-import in the reduced capacity setting. Comparing the differences of the respective market design in the two capacity settings shows that firstly the total reduction in renewable production is the same for both. For the tariff based design there is no change in battery usage, as they are fully driven by the local conditions (i.e. PV surplus and the time structure of the tariff). As those don’t change between the two capacity settings, also the incentives are not altered. However, the larger system usage (i.e. pumped-storage usage) and resulting import needs are altered due to the significant change in overall RES availability.

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[9] In preliminary version of the scenarios with a higher renewable availability we did observe some investments into wind energy but not additions to PV capacities.

4.3.3 Tariff Model Aspects

The evolutionary tariff design is using a loop between the household models and the wholesale model layer. For all conducted scenarios the model cuts off after five loops as it is circling between two stable solution states; i.e. the solutions of the two layers are not converging but remain in a repeated back and forth. While the two resulting states differ in their concrete numerical solution their aggregated results are closely in line. In other words, the above described basic differences between the tariff based solution and system optimal model are nearly independent from the actual tariff case selected. Note that this only refers to the modelled four-part time-of-use- tariff structure. For a discussion on the general role of tariff structure and potential impacts of other design settings please refer to Section 4.3.5.

The reason for the back and forth between two price/tariff states is the decoupling of the tariff setting from the final market price realisation. While this is of course a model based necessity (i.e. having a direct market to tariff feedback requires a joint modelling of the household and system layer in one singular model) it also reflects real world time-of-use tariff structures. The retailers need to fix the tariffs some time before the actual realization of demand. For rather stable tariffs with only a few time periods this fixation usually happens in rather long time steps (i.e. yearly). A direct feedback from market prices to tariffs would be akin to real-time tariffs. Subjecting all households to the real time market price is model wise similar to a full system optimization, as long as the price impact of the households' decisions would be accounted for. If real-time pricing is just a (very) short-term fixing of the tariffs for households, the basic decoupling still occurs; i.e. a household become the ex-ante signal that at hour X prices are low and subsequently adjusts its flexible assets to increase demand in that hour which in turn increases the final market prices in hour X.

As households optimize their asset usage based on those fixed tariffs they shift their flexible demand into low tariff periods if possible. This demand shift in turn alters the overall system demand curve, making the demand level in those periods higher. While this the intended effect the tariffs are supposed to initiate the feedback of the demand shift to market prices would need to be perfectly anticipated and incorporated into the tariffs upfront. Within the model we use a simple average energy price during the tariff time windows as basis. This in turn does not anticipate the change of demand. Consequently, with a given tariff structure the households reallocate their flexible demand which in turn increases demand in the low tariff periods. This higher demand leads to higher prices in the wholesale market model which in turn alters the tariff structure for the next loop. This leads to the switching behaviour in our model.

Figure 12 and Figure 13 highlight this dynamic for two exemplary tariff realizations, both for the usage of heat pumps and for EV charging. The two tariff states (Tariff A and B) are not only different with respect to their tariff level but also with regard to which period is the high and which is the low prices period. Albeit only exemplary, this still highlights that a fixed tariff structure can lead to significant alterations of flexibility incentives in relation to the real system status.

For the heat pump usage, the assumed flexibility window of six hours is smaller than the time window for each tariff period. Thus, the model aims to maximize the electricity consumption for heat pumps just before the switch to the higher tariff period and then just adds enough further consumption to satisfy the thermal demand in the tariff window. In the following low tariff period, the model can then use the heat pump more less in direct consumption mode (i.e. transferring electricity into heat whenever heat is needed) until the very last hour where it charges as much as possible again. In consequence the tariff only leads to a partial shift of heat demand. A shorter tariff structure could potentially lead to a further improvement in altering the demand pattern.

For EV charging the total mobility pattern is usually not so restrictive that it leads to the need for charging during high tariff periods or when no PV surplus is available. This is especially pronounced in Tariff B where charging during the high tariff period is rather minor. For Tariff A the differences between the two tariff levels is rather small leading to a significant higher charging also during the 'high' tariff period. The timing of charging during a tariff window can not be steered by the tariff anymore, as the costs for charging are similar through the respective period. Thus, we don't observe a clear peak to time relation as in the heat pump usage.

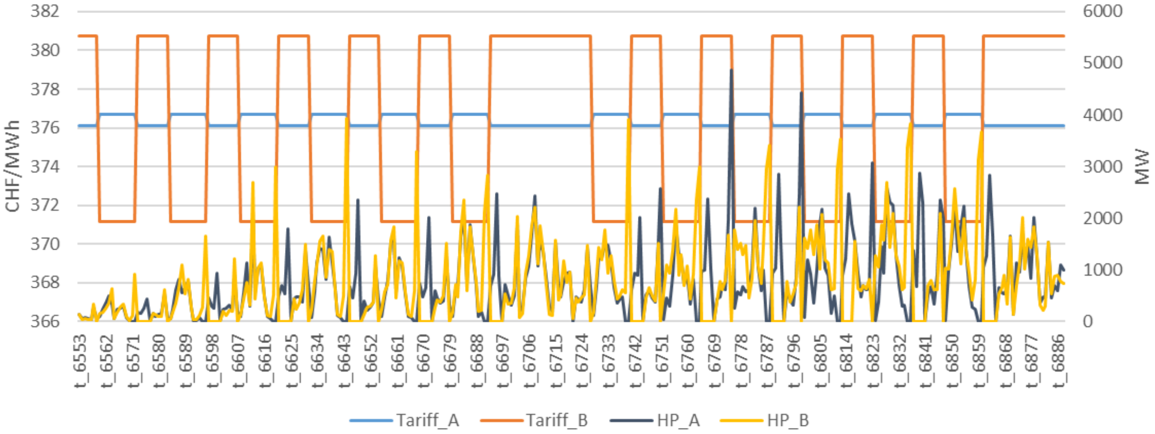

Figure 12 Hourly tariff structure and heat pump demand for two tariff settings

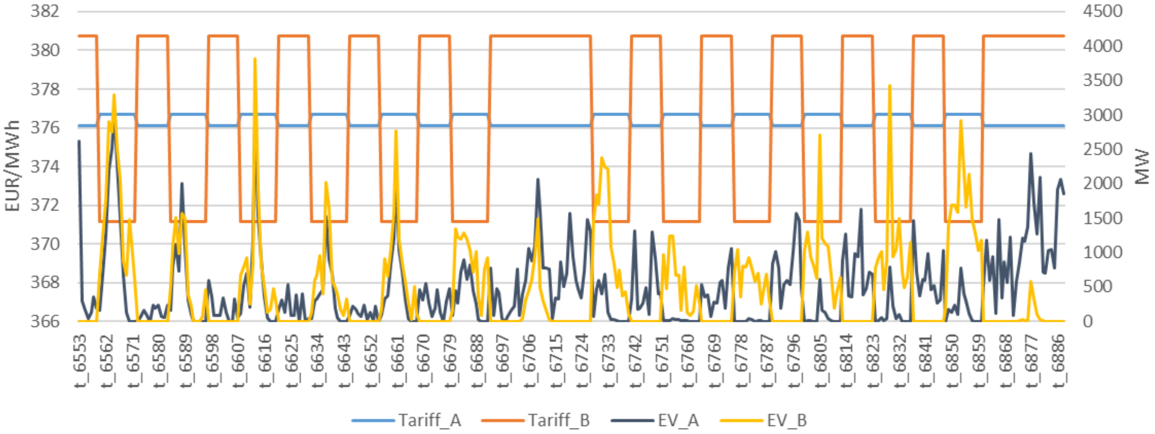

Figure 13 Hourly tariff structure and EV charging for two tariff settings

4.3.4 Economic Assessment

So far the result presentation has showcased the dispatch differences on an aggregated level as well as the implications for short term dynamics. A central question of the model comparison is to identify which design provides a better economic performance. To this end we can compare the costs and benefits of the different settings.

Table 5 showcases the expanses for covering the Swiss energy demand on the wholesale level as well as the income Swiss supply generates on the market. As the overall price dynamic of the model is highly simplified the numerical values should be interpreted as indications and not as benchmark for real world cost comparison. For the unrestricted setting we can observe that the novel market design ensuring a system optimal usage of flexibility assets provides a slight reduction in overall costs for covering the Swiss electricity demand. The consumer costs are about 0.5 to 1.3% lower in the revolutionary setting compared to the tariff case, which translates to 50 to 120 mn Euro per year in our cost structure. The only exception is the WWB winter restricted case which is characterized by an energy shortage. In this model run the overall system costs are slightly lower in case of the flexible system optimal setting.

However, the demand expanses as well as the overall energy not served level is smaller in the tariff-based setting (see below).

Looking at the income side, the lower column of Table 5 shows the total value of all generation within a year in terms of Swiss wholesale prices. Here the direction depends on the Swiss system scenario. In case of WWB the actual income is higher in the tariff-based setting whereas in the Zero-Basis the income is higher in the system optimal setting. As the income is a combination of hourly generation and hourly prices it is both impacted by the total quantity (being higher in the tariff based setting due to more storage output) and the utilization of price dynamics (being usually better in the system optimized setting).

Due to the net import position during the WWB cases, the total income is lower than the total consumption expanses. Whereas in the Zero-Basis case the chosen weather year leads to a slight net export position which in turn leads to an overall higher value of the sale volume compared to the buying volume. Thus in total, the two differences are rather similar for the WWB scenario if no winter restriction applied. However, in the Zero-Basis scenario the lower demand leads to cost savings while at the same time the lower overall supply output still produces a higher income. Thus, the system oriented operation of flexibility assets has a clear advantage for consumers and producers in Switzerland under this scenario.

The WWB winter limited case is heavily characterized by the energy not served levels. For those hours a virtual 'lost load' with a high cost level (1000€/MWh) is assumed which leads to the observed high cost and income level. In those cases, the evolutionary setting led to lower consumer cost but also slightly lower generators income as the revolutionary setting. However, as the model is optimizing the whole European system, transferring the Swiss flexibility assets to the system level may alter their usage to manage some foreign system structures. Overall the system costs are lower in the revolutionary setting than in the tariff-based evolutionary setting despite the slightly higher level of ENS. Given the artificial nature of the lost load management the economic results should be interpreted with caution. We do not consider the model results to provide any conclusive insight whether tariff based household behaviour is worse or better than a centrally operated system for our case with ENS. While it is reasonable to assume that in a purely Swiss oriented setting a transfer of flexibility to the Swiss system planner should never decrease and in most cases improve supply security, the model does not capture such a Swiss-only setting and the interference with the larger European model components can lead to results that are not necessarily optimal from a single country perspective.

Table 5: Swiss consumer costs and generation income for base scenarios [bn € per year]

	No Winter Limit						**5TWh Winter Limit**					
	WWB			**ZeroBasis**			**WWB**			**ZeroBasis**		
	Rev.	**Evo.**	**Delta**	**Rev.**	**Evo.**	**Delta**	**Rev.**	**Evo.**	**Delta**	**Rev.**	**Evo.**	**Delta**
Demand Costs	9.66	9.71	0.05	9.12	9.23	0.12	38.24	38.15	-0.09	9.12	9.23	0.12
Generation Income	8.41	8.45	-0.03	9.86	9.84	0.03	30.90	30.87	-0.03	9.86	9.83	0.03

Note: 'Delta' is defined as the evolutionary value minus the revolutionary value.

Another question is how much a more time differentiated tariff structure can achieve in terms of system benefits compared to a fully flat tariff structure still common for many households in Switzerland. This has been tested by using the tariff-based model setting and fixing the tariff to a yearly average. Table 6 showcases this test case in comparison with the basic time-of-use tariff and system optimal model results. In aggregate the time-of-use setting does improve the overall system costs slightly[10] and shows a bit less storage and import usage. But overall the results are close to each other. The main shift happens with the optimal system operation.

Table 6: Comparison of market design results with a flat tariff structure for the Zero-Basis setting. [yearly values in TWh]

Market Design	**Flat**	**T-o-U**	**Rev.**
RES-Supply	23.25	23.25	23.25
Hydro	38.09	38.08	37.61
Other	12.29	12.22	12.22
Net-Imports	-2.83	-2.85	-3.17
Fixed-Demand	55.01	55.01	55.01
Flex-Demand	11.11	11.11	11.11
Batteries/DSR	1.48	1.40	1.27
Pump-Demand	3.15	3.13	2.52
Total System Costs[bn€]	122.33	122.32	122.11
Cost Savings[mn€]		-6.08	-214.19

Note: ‘Flat’ represents the case in which the household have a yearly average tariff. ‘T-o-U’ represents the base case of the evolutionary scenario with a four part time-of-use tariff. ‘RES’ supply includes wind and solar. ‘Other’ includes nuclear, fossil and all non-wind, PV or hydro generation. ‘Fixed demand’ is the sum of all predefined hourly electricity demand that cannot be shifted. ‘Flex-Demand’ incorporates heat pump and EV charging demand. ‘Batteries/DSR’ represents battery charging and further demand side related flexibility options.

Looking at the hourly dynamic (Figure 14) the differences between the two settings showcases that the flexible assets are shifted away from the direct usage pattern (flat tariff) towards more favourable time windows in the time-of-use setting. But since the flexibility of the heat pumps is assumed to be six hours the absolute shifting potential is limited. For EV charging the demand shifts fully to the low tariff periods, but as a lot of EV charging at home happens during low price periods already (i.e. nigh time) there is only a small overall reallocation. Thus, the tariffs do have the intended shifting incentive and lead to more pronounced demand peaks. However, as the actual shifted energy from heat pumps and EVs is rather minor, the overall system impact is not pronounced. For battery usage the flat tariff has no change in the overall yearly usage structure; during winter times the battery is not used and in summer times a daily charging pattern in line with the PV production surplus occurs which is not impacted by the actual tariff structure. Thus, while there are potential system benefits to be reaped by using a higher granularity tariff structure, they are rather small given the technical structure of the flexibility assets at the household level if not direct linkage to overall system conditions is achieved (i.e. the main aspects highlighted in Section 4.3.3. remain and make the system oriented operation of flexibility assets more beneficial than an ex-ante fixed tariff structure).

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[10] Please note that the total system costs represent the whole European model set. As the changes are mostly impacting Switzerland one can assume that a majority of the differences is materializing in Switzerland.

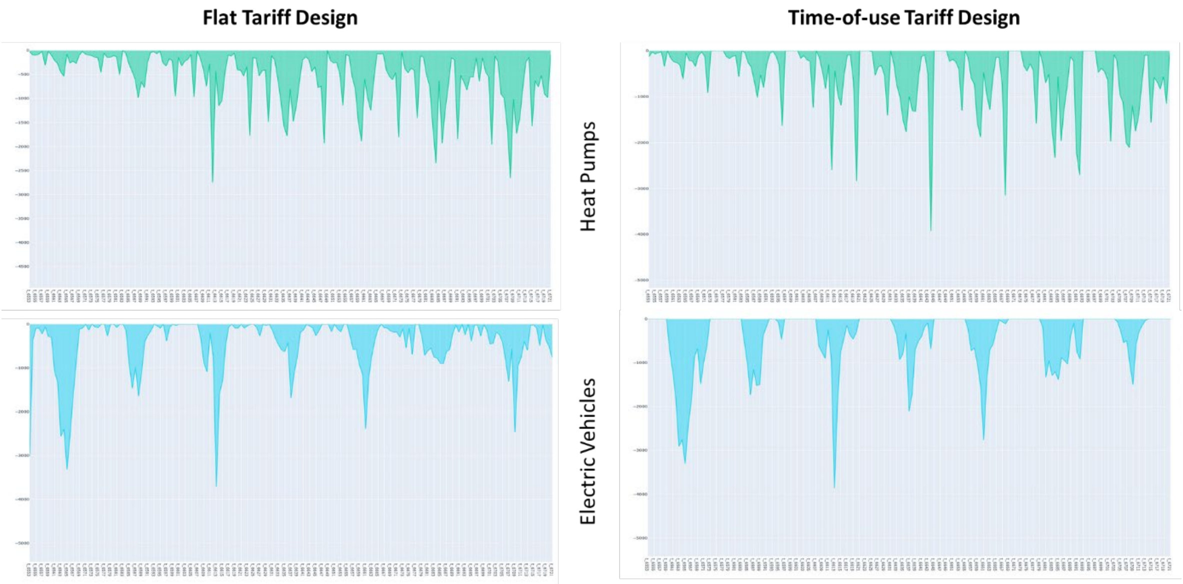

Figure 14 Usage pattern of heat-pumps and charging of electric vehicles in the flat and time-of-use tariff structure for the first modelled week

Finally, another challenge of the predefined tariff setting is that with increasing weather influence the short term price picture can greatly fluctuate over days, weeks and years. To get a rough quantification how those dynamics impact the system operation in a tariff-based setting we simulate an additional test case. Using the Zero-Basis case and the tariff setting of our base weather year 1984 we let the model run with a different weather realization (i.e., weather year 2007, both the demand and renewable time series are adjusted accordingly). Thus, the household has the ‘wrong’ tariff signal as the structure is based on the 1984 dynamic, whereas transferring the operation of flexible assets to the system operator should lead to an optimal usage regardless of the realized weather structure.

Table 7: Comparison of weather impact on Swiss system dispatch

Market Design	**Evolution**			**Revolution**		
Weather Year	**1984**	**2007**	**Delta**	**1984**	**2007**	**Delta**
RES-Supply	23.25	23.86	0.61	23.25	23.86	0.61
Hydro	38.08	38.48	0.41	37.61	38.24	0.63
Other	12.22	11.12	-1.10	12.22	11.55	-0.67
Net-Imports	-2.85	0.72	3.56	-3.17	0.55	3.72
Fixed-Demand	55.01	55.00		55.01	55.00	
Flex-Demand	11.11	11.11		11.11	11.11	
Batteries/DSR	1.40	1.41	0.00	1.27	1.89	0.62
Pump-Demand	3.13	6.50	3.36	2.52	6.18	3.66
Total System Costs [bn€]	122.32	114.59	-7.73	122.11	114.31	-7.80

Note: ‘1984’ represents the base case with the 1984 demand and weather time series. ‘2007’ represents the case in which the 1984 energy prices are used for the tariff levels but the 2007 demand and weather time series is used for the hourly modeling. ‘Delta’ is defined as the 2007 value minus the 1984 value. ‘RES’ supply includes wind and solar. ‘Other’ includes nuclear, fossil and all non-wind, PV or hydro generation. ‘Fixed demand’ is the sum of all predefined hourly electricity demand that cannot be shifted. ‘Flex-Demand’ incorporates heat pump and EV charging demand. ‘Batteries/DSR’ represents battery charging and further demand side related flexibility options.

2007 is characterized by a slightly higher RES generation in Switzerland but also by an accordingly altered RES profile in Europe leading to lower overall market prices (ca. 14%). This altered market condition makes utilization of Swiss storage assets more profitable. Consequently, pumped-storage is significantly increased in this weather realization for both market design. However, as batteries are operated by households in the tariff case, their usage is not really impacted by the changed market condition. Thus, whereas in the system optimal setting battery charging demand increases by ca 0.6TWh it remains unaltered in the tariff setting. The associated system and income benefits consequently can also not be realized in the tariff setting. While both cases have a ca. 8 bn € per year total system cost reduction, the optimal usage of Swiss flexibility assets saves another 70 mn € per year.

4.3.5 Model Limitations

As with all model-based assessments our scenario comparison is subject to simplifications, model limitations and assumption structures that impact the results and the potential conclusions one can draw. Following we will shortly highlight the most important limitations and their implications.

On the modelling side the analysis is subject to typical simplifications of Swiss electricity dispatch simulations. We assume a fully deterministic structure, meaning that the full years' realization of renewable and demand time series is known. The model results therefore represent a perfect foresight benchmark. Given that household flexibility assets can provide valuable short term up- and downward ramping of electricity, they can also be used to manage short term uncertainty and unforeseen deviations. Our model neglects such settings and therefore underestimates the potential overall benefit of gaining access to the household assets either via direct control or smart tariff incentives.

Both the system dispatch model as well as the household models are pure cost optimization formulations. For the households this means that behavioural aspects or non-monetary incentive structures are not included. However, how such elements could alter the operation of flexibility assets is not straightforward. Thus, whether this leads to a potential over or undervaluation of their value is unclear. On the system layer we optimize the overall electricity system, meaning the full (simplified) European system and not only the Swiss part of it. Consequently, all available assets in Switzerland (i.e. hydro and in case of the revolutionary approach also the households' flexibility assets) are used to minimize the overall European system costs. This in turn can lead to benefits that materialize outside of Switzerland (i.e. addressing peak conditions in neighbouring countries) and can lead to an under-evaluation of potential benefits within Switzerland if those assets would be operated with a more national focus. Furthermore, the system structure (i.e. power plant types instead of individual units, not locational details) and exchange between countries is highly simplified (i.e. NTC trading instead of a full flow-based system model). This usually leads to a flatter price dynamic compared to real world price patterns, which in turn leads to a lower benefit from flexibility and storage.

Finally, the optimization structure is also used for runs with investments, meaning that investments in Switzerland could occur that actually benefit neighbouring countries (i.e. providing an additional cheap exports) and are not needed for Swiss electricity demand. Limiting such system optimal investments would require a decoupled European and Swiss model structure. As no additional investment materialize in our scenarios and also in the cases with only 70% of the PV and wind extensions projected in the Zero-Basis scenario, the underlying costs/price structure of the model is not favourable for investments in Switzerland. We did not make test runs without any additional capacity investments to determine the total amount of investments our model would derive compared to the Zero-Basis scenario. As long as import possibilities are not restricted and Swiss investment costs are higher than European investments our model is likely to show smaller total investments than the Zero-Basis case, as we don't impose a yearly energy balance constraint.

Furthermore, we only use one year instead of a set of different years with varying weather and demand realizations. As our base year is the weather realisation of 1984 – a year with a rather high winter demand – this should potentially incentivize more investments than a fully average year. However, accounting for variability over years can lead both to more or less investments depending on how this would be incorporated. If the different years are all run individually, the most challenging system conditions should define the investment maximum. If the years are accounted for together and weighted (i.e. akin to a distribution function) it would be possible that no investments are carried out to address rare system conditions (i.e. highly infrequent events). Again, as our model runs don't show any investments, a different approach would likely not alter this result. Generally, the inclusion of a more detailed risk perception on the investor side would be needed to obtain a better understanding of the different incentive structures and compare the resulting capacity additions to the objectives of the new electricity law (see also below).

Next to the model structure there are also limitations on the data side that impact the results. Firstly, the household data is based on the NETFLEX project and represent a snapshot of Aargau consumers. Whether they are indeed representative of the whole Swiss consumer structure is unclear. Also, the household asset endowment is defined externally. While this is a reasonable approach for heat pump and EV investments, this may not be true for PV and battery investments. The different tariff and market design approaches can potentially alter the desired size of both elements. This would be especially important if additional RES or storage support policies are to be investigated. In our scenarios, investments are only accounted for on the system layer and the results show that with our given cost/price structure we don't experience significant investment incentives. Thus, it is likely that also the pre-defined PV/battery capacities would not materialize if we would have endogenized their representation.

A second data limitation is the representation of the neighbouring European countries. Not only are they highly aggregated in their representation, we also only have a small set of European development cases covered. Given that European developments are central for Switzerland's electricity system a larger variety of European settings may alter the resulting benefits the different approaches can materialize. Especially with regard to the interplay of investment incentives and import/export dynamics a fully endogenized European-Swiss model would be preferable, that has a consistent data structure. However, such a model was out of scope for the project.

Beside the model-based constraints there are also limitations stemming from neglected aspects that were not incorporated into the model structure in the first place. Among them the missing representation of distribution grid aspects is likely a central aspect that can significantly alter the results and the derived insights. As shown above a system optimal operation of flexibility assets leads to a stronger peak pattern for both heat pump usage and EV charging, amounting to several GW of more load in some hours. While the transmission system is likely sufficiently interconnected to manage those demand spikes the same may not be true for all distribution grids. Given a high heterogeneity of distribution grid structures and missing local grid data, we were not able to include a proper representation of grid and transformer related capacity constraints. Both constraints can likely limit how much demand of flexibility assets can peak in any given grid area, thus the presented demand shifts are likely overestimating the actual shifts that would happen. However, the main idea of the revolutionary approach is to shift the operation of the assets to aggregators (i.e. retailers/utilities). As long as those also account for the local grid constraints they would include those in their operational decisions. If they are not part of the retailers' operation space, they would call for additional grid based tariff structures on top of the energy aspects. Similar, in case of the tariff based household optimization in the evolutionary setting, accounting for grid constraints would call for a representation of different grid charging approaches. In the assumed 'per energy' approach used for the model, grid constraints are fully neglected and even the lower peaks of the tariff based scenario runs may breach local grid constraints.

Another originally planned but finally neglected model aspect are different investment characteristics on the generator side; i.e. accounting for different risk and investment incentive structures. This is especially relevant for the evaluation of the revolutionary approach, as the second feature of this approach is a more long-term oriented investment logic. We were not able to include this into the model structure. Thus, the results do not provide a full picture on the investment side. Our simple system optimal investment runs only highlight the usual nature of investments in Switzerland: assuming sufficient exchange capacities it is likely that imports are cheaper than investments in Switzerland. Here a more detailed representation of different investor structures may change the derived insights as a fully spot market driven investment setting bears higher risks than a long term price structure. While for risk neutral investors a sport market setting would be similar to a long term setting as long as the expected average price is equal, a risk averse investor would likely have a higher incentive to invest in a long term structure. The relevance of long term price signals is also central to the capacity market debate (see Cramton et al. (2013), Duggan (2020), Holmberg and Tangerås (2023), and Shu and Mays (2023) for an overview on capacity market and investment asepcts). In addition, risk aspects have a significant impact on the financing costs of energy generation a lower risk level could also alter the preferences for specific technologies (see also Dukan and Steffen, 2024).

On the tariff side we only investigated a four-part tariff with a winter and summer structure. The basic shifting dynamics on the household side are well represented with this logic. Further granulation on the time structure would alter the numerical results but not the basic logic of the shifts: limited flexible demand like heat pumps are shifted to the lowest price period within their flexibility range and charged before moving into higher price periods if possible while more flexibly units like our assumed EVs are mostly shifted to the low price period. Adding more tariff periods just means that in between tariff levels will be left out from shifts if sufficient flexibility is available and be used for those assets that have higher time constraints in their flexibility. However, those alterations do not change the fundamental difference between the evolutionary tariff-based structure and a system optimal asset usage, as long as those tariffs are defined ex-ante. They simply cannot correctly represent current system conditions. Only a fully responsive real time pricing tariff logic would account for such a feedback. However, what we did not capture are other tariff concepts, especially also on the grid charges, that try to set incentives in relation to system peak conditions (i.e. critical peak tariffs). Such approaches aim to translate system conditions into tariff signals and should provide better incentives for households to align their asset operation with system conditions without the need to shift the operation to a utility. Nevertheless, also those approaches would require to link the tariff signal to real system conditions and not simply average structures to ensure a consistency between the final household incentives and current system needs.

5 Conclusions and Policy Insights

Within the project the main objectives were to 1) identify upcoming electricity market challenges and relate them to both modeling and assessment capabilities as well as to ongoing policy discussion, 2) to develop a model tool capable to investigate different market and policy settings, and 3) to use the model to compare different future market approaches. Albeit the final model tool did not capture all the envisioned actor and market elements it allowed a quantitative comparison of two alternative market approaches.

The main findings of our project can be summarized along three main trajectories:

1. With regard to the future Swiss and European electricity system:

There is a general agreement on the trend of the development of the overall system (i.e. a system dominated by weather dependent wind and solar generation and a higher electricity demand) but a lot of differences on the details. Which role different complementary technologies (i.e. wind, biomass, hydrogen, storage) will play depends on the underlying scenario and model assumptions, but there is a common agreement on the need for those complements. Some of the main challenges systems are facing along the transition are strongly linked to the consumer side. Due to electrification of space heating and mobility, household demand will become more important. Furthermore, due to owning heat pumps, EVs with batteries and (possibly) batteries in PV installations, households will own a substantial share of the assets that can provide flexibility in the electricity system. This implies that the interplay of the demand side with the other actors and components of the electricity system becomes increasingly relevant. Apart from the practical implications for the design and functioning of the electricity system and electricity markets, this also calls for a stronger focus on households, their decisions and household heterogeneity in modeling and quantitative research. Who invests in the different technology options and how they are actually used can make a huge difference both in terms of achieving specific political targets and in terms of required adjustments to the overall system design. Scientific analysis has to be able to investigate this and this requires moving beyond system-level models.

Overall, the review and mapping conducted at the beginning of the project has shown that there are ample technology centered scenario assessments of potential future system configurations. What is missing are economic and policy focused models. Most models neglect direct actor, market or policy representations, and in turn stakeholder or policy oriented assessments are usually not complemented with technology-rich electricity system models. A better integration along the three layers (physical, stakeholders, policies/markets) and the inclusion of socio-economic dimensions into technological focused system modeling is needed to provide a better understanding of how to achieve the desired transition goals.

2. With regard to basic electricity market design discussion and alternative design approaches:

The motivation behind the developed ‘revolutionary’ market design was to combine two of the main challenges of renewable dominated electricity system: investment aspects for renewable technologies and the need for complementary backup technologies on the supply side and consumer driven dynamics and flexibility provision via tariffs on the demand side. In principle, this approach follows a similar logic as the discussed adjustments to the existing electricity system – i.e. the ‘evolutionary’ adjustment – in form of capacity mechanisms or new tariffs, but it focuses on a different relation between the supply and demand side with retailers as the main link. Consumers can choose their desired reliability level and whether they provide flexibility to the retailer which in turn secures sufficient diversified supply via long term contracts on the supply side.

The conceptual assessment has shown that this alternative approach can reproduce a first best social optimal benchmark. Using today’s market structure such a setting could only be achieved by providing consumers with real time tariffs that are directly linked to spot markets; i.e. subjecting them to the same price incentives as the supply side. Thus, in theory, the long-term tariff logic and focus on reliability as central element provides an alternative to today’s adjustments debates. The model implementation was unable to fully capture all these aspects, but it was able to obtain a first evaluation on the differences between such an optimal system structure and a conventional system design via time-of-use tariff incentivized households.

The results show that for the Swiss case the aggregated differences are small. There are substantial differences in how and when individual assets, and thus flexibility options, such as heat pumps, stationary batteries or EV charging, are used (see. e.g., Fig. 10). Thus, the model clearly captures the different incentives on the individual level. But on the aggregated level, the resulting differences in usage decisions are not of much relevance. Thus, our analysis clearly shows that for solving system-level problems, an evolutionary approach is providing almost all the benefits of the revolutionary approach but with much less required change to the design of electricity markets.

However, two points are important to note in this context. First, we covered only the aggregate level, there might be benefits on smaller scales (e.g. local grid operation) that are not captured by our results (see also next point and Section 5.1). Second, the evolutionary approach is still based on substantial changes to the current system design; there are day/night and summer/winter differences in consumer prices that are based on averaged supply/demand conditions in winter/summer as well as night/day. Thus, our results do not indicate that the electricity market design should not be changed, but only that modest changes could already achieve much.

Furthermore, switching from today's system to a new approach would require an alteration of current market structures. The energy market centered design (spot-market with forward and intraday elements) would need to be complemented by a long term contractual design that provides the main incentives for investments while the short term spot/intraday markets are mostly for operational purposes. In addition, the revolutionary approach requires a separation of inflexible and flexible demand (i.e. smart meters; shifting control to the retailer/utilities for flexibility) at the household level. This technical requirement could likely be provided via the planned smart meter rollout, however not all smart meter designs allow a separation of provision within one household. Overall, the revolutionary approach is coming with transaction costs that are hard to quantify.

3. With regard to the quantitative assessment of the different market designs for Switzerland

The developed model has a focus on household operational incentives and system interplay and thereby allows the comparison across different approaches along those lines. The results show the limits an ex-ante defined tariff based approach has in tapping into the flexibility potential on the household side: while such tariffs will lead to adjustments of the operation of those assets to match the respective tariff structure the decoupling of current system conditions from the tariff levels (i.e. the tariffs are fixed for a longer time frame in advance) will automatically lead to suboptimal asset usage from an overall system perspective. Albeit the result show that for Switzerland the benefit of a fully system optimized flexibly usage is small (i.e. about 0.5 – 1 TWh differences in aggregated flexibility usage and about 200mn € in total yearly system costs) a shift to 'system steered' usage of flexible assets does alter the hourly demand profile. This in turn can have important implications for other system components, especially the local grid. However, the model does not capture those dimensions, so we cannot make an assessment whether they would significantly alter the cost-benefit evaluation.

Overall the modeled impact of the revolutionary system optimal approaches compared to the evolutionary tariff oriented setting does not directly seem to justify potential transaction costs of such a major shift. Nevertheless, the basic premise of the approach (focus on reliability as choice on the consumer side and the operation of household asserts in a system optimal way) could potentially be included in ongoing tariff design debates to achieve the system optimized asset usage. The central challenge is the shift of asset operation from the asset owner (i.e. the households) to market active actors (i.e. retailers, utilities, aggregators, potentially also energy communities). There are a number of options that could provide approaches that fall in between the evolutionary and the revolutionary approach. For instance, incentives could be provided to consumers to transfer partial control of their assets to a local grid operator; e.g., in 2024 Germany has implemented a change where all new heat pumps can be set (by the local grid operator) to a reduced level of operation (4.2 kW) in exchange for either a flat reimbursement per year or a reduced electricity price. Similar approaches could be used for EV charging, so that a part of a consumer's flexible assets can basically be operated by a central actor, if system conditions require this.

But for such solutions, further research is needed to provide a quantification of the neglected system components.

Finally, the investment side of the novel approach as well as the existing market structure could not be properly captured with the develop model. Thus, whether and how the different design impact potentially risk averse investors and how this could impact the overall transition towards a renewable dominated system could not be quantified.

5.1 Insights for Swiss Electricity Policy Discussion

The numerical results show a rather low overall impact of the two different design (as well as rather minor gains from moving from a single to a four-period tariff). The main reason for this is likely the high share of flexibly hydro generation in the Swiss electricity system. From a model perspective the main difference between the household operated flexibility assets and the system optimal ones is that in the former case the household demand profile is fixed in the system mode stage. This means, that all other system assets have to handle whatever the demand profile requires. Given the high inherent flexibility of Swiss hydropower the alterations can easily be handled by increasing and decreasing hydro generation over the hours. As the overall demand does not change (the yearly total need for heat pumps and EV charging is fixed) between the two settings, the alterations are simply shifts in time. Whether a more conventional system with higher fossil shares would lead to a higher benefit of the revolutionary approach would need to be tested with another base market as reference (i.e. Germany). Furthermore, as all countries are interlinked in an optimal system way, the changes in Switzerland are rather minor compared to the total system size. Thus, if all household demand within the modeled countries would be accounted, the impact may also be more pronounced. Nevertheless, the results again highlight the important advantage Switzerland has along the transition pathway thanks to its high share of hydropower.

With regard to the envisioned increase of local Swiss renewable generation the role of PV and in this regard especially rooftop PV generation is expected to increase. This in turn increases the need for an improved coordination of local PV generation and battery/ local system storage usage. As the model does not capture the local grid conditions, the result do not provide a direct quantification of this dimension. But the scenarios allow some conclusions on the impacts of different tariff structures; namely that an ex-ante defined time-of-use tariff structure does set incentives for in-household asset optimization but this does not necessarily lead to system optimal behaviour. Our results show stark differences in the use of assets between the system-optimized (revolutionary) and individually-optimized (evolutionary) approach. If consumer prices do not reflect current scarcity (as in the evolutionary approach or the current market design in Switzerland), what is good for the individual can deviate strongly from what is good for the system.

To solve this, it is either possible to provide consumers (or at least those with flexible assets) with prices that capture current scarcities or to shift the decision how to use flexible assets to an actor that decides based on overall system conditions. The proposed new revolutionary tariff approach could achieve the latter, but also other tariff designs in the current market structure that enable utilities access to those assets (as the in between option described above) would address this issue.

A central question of the ongoing electricity debates in Switzerland is how to achieve the targeted renewable expansions. Within the revision of the electricity law, a sliding market premium is planned as well as a requirement for a local renewable share as part of the end-consumer tariffs. The final project model does not provide quantifications for investment structures beyond a system optimization perspective and thus cannot provide a proper comparison to the premium and share requirement. However, the conceptual assessment of the revolutionary approach shows that the setting can provide an alternative investment logic which would be stemming from consumer preferences and ensure a long run financing. Further research on quantifying the investment dynamic of the new approach would be needed.

The revised electricity law also includes provision in terms data availability and management, flexibility, and smart meter rollout. Those provisions are required for the revolutionary approach to enable utilities to manage household assets as well as for other tariff designs aiming to utilize the assets outside of pure household optimization. However, the lack of full end-consumer liberalization may pose a challenge in tapping into those solutions. New market actors and competitive pressure could provide a mutliplicator in developing creative tariff solutions. Within the prevailing partial liberalization if would need regulatory specifications to include new tariff approaches for households. The new law includes new possibilities with regard to dynamic network tariffs as well as specifications on virtual energy consumers and local electricity communities. Both aspects could provide new approaches to address the challenge of an improved flexibility usage.

Another open question is how much household flexibility will be needed to reap most of the potential benefits. The numerical results show the importance and benefits of the large hydropower share in Switzerland and the relative little impact household flexibility assets have on the overall system. The changes in hourly dynamics showcase more potential, but they likely are more important on the local grid level. Thus, tapping into household flexibility could be an important element for local utilities. Given that secure electricity supply is an important concern, providing a flexible tariff setting with a ‘safe’ option that ensure full reliability is likely important for a larger acceptance and as security for households without own flexibility options. The revolutionary approach has such a backup integrated by design, as consumers are free to choose a 100% reliability level. Being able to tap into this potential could also be important for distribution grid investments. Local congestion can be relieved by additional grid or transformer capacity or potentially by altered operation of household assets. Which option is more economic and how much households would need to participate is likely greatly diverging from grid area to grid area. Thus a flexible regulatory structure allowing for the implementation of such tariff options could be a valid approach.

5.2 Relation to European Electricity Market Discussion

Albeit the assessment and model focus lie on Switzerland, the larger European dimension could not be neglected and the overall market design question is also relevant for the ongoing discussion in Europe. The new electricity market design rules in the EU (Directive EU/2024/1711 and the amending Regulation EU/2024/1747) aim to boost renewables, better protect consumers and enhance industrial competitiveness. In particular, the proposed approaches want to make consumers and companies more independent form short term market fluctuations via long term structures. In this regard the revolutionary approach follows a similar base structure, by transferring the consumer preferences into a long-term contractual relation with the retailer. The same is true for the generators in this model who will obtain a clear long term price signal in relation to their production portfolio. The EU structure foresees power purchase agreements (PPAs) and two-way contracts for difference (CfDs) as important long-term options and has a general strong focus on the role of the state as supporter for those instruments. In contrast the revolutionary setting relies on consumer preferences as main driver and uses market-based contract relations as main instrument. The state would enter as regulatory control of the underlying reliability and risk levels. The model in its current form is not able to provide a comparison of those different approaches. Thus, whether the European mechanisms or a shift towards a more contract-oriented structure would be more efficient is subject for future research.

The European market design debate also includes concerns about short term market dynamics (i.e. peak shaving products) which are related to the question if tapping into household flexibility opens up new options for short term operational management. The project results show that if those assets are to provide benefits, they need to be managed close to short term market structures, either via a respective entity being active on those markets (i.e. a utility or retailer) or via respective contract design (i.e. real time pricing). As addressed above the technical requirements for managing household assets remote need to be in place to be able to tap into the potential. Being focused on just Swiss households the results don’t show sufficient benefit on the larger European market stage. Whether this would be different if large shares of European household assets would be added to operational flexibility pool would need to be tested in a proper European model setting.

Finally, the proposed adjustments to the European market designs and the related discussions have a strong focus on consumer side aspects. One the one hand, in terms of protecting vulnerable consumers from the larger market dynamics as discussed above, and on the other hand, in terms of the increasing importance of demand side related decisions for the development of the future electricity system. The developed model is addressing the latter aspect by putting more emphasis on a representation of household behavior and link this back to the overall system layer. The integration of heating and mobility into the electricity system will alter the overall system dynamic and increase overall energy demand. Beside the needed increase in energy supply (as highlighted by the review of European scenarios) the model results highlight the potential differences in short-term capacity dynamics. For the Swiss demand data, the differences are few GW of capacity difference in the hourly profile; which in turn can be accommodated in the Swiss system due to the high hydropower share. If a similar scale would occur in Europe, the alteration of demand dynamics could easily shift the needed generation capacity in specific hours tremendously (i.e. 2 GW in Switzerland are about 20% of peak load). Depending on how this demand dynamic is incentivized this can lead to significant investment and operational challenges. Thus, a better understanding of the demand side in electricity systems is also crucial for European system developments.

Overall, the discussions in Europe and Switzerland address similar issues and have a lot in common. While the final project model version takes up some of the demand side related challenges a further integration of other marker dimensions, especially investment incentives and risk, will be needed to provide a comprehensive assessment of future developments and respective market and policy choices.

6 Outlook and next steps

The main next step is the further development of the model to account for the missing dimensions and improve its usability for policy assessment. Dr. Darudi will continue this work as part of the research he carries out in SWEET EDGE focusing on renewable support policies.

The basic conceptual evaluation of the revolutionary market design needs to be prepared for publication to obtain further feedback on the design idea.

7 National and international cooperation

No direct joint research work has been carried out with other research teams in Switzerland or abroad for the project beyond the usual exchange at workshops, conferences and via bilateral discussion.

Given the Covid situation in the first project year, participation at workshops and conferences has been limited and subsequently the review results have not been presented at scientific conferences or stakeholder events. Starting in the second year the main focus was on model design. Exchange on model questions has been conducted using our internal network (i.e. experts at the University Basel and ZHAW). The further development of the model is part of the ongoing research of SWEET EDGE and will built upon the cooperation within the consortia. The conceptual evaluation of the revolutionary approach has been discussed at internal outlets at the University Basel and at workshops by Sebastian Schäfers (i.e. SCCER CREST research seminar and EEA Virtual Congress 2020).

8 Publications

Darudi, A., and Weigt, H. (2024). *Review and Assessment of Decarbonized Future Electricity Markets*.
Faculty of Business and Economics - University of Basel, Working papers 2024/06
submitted to *Energies*

Schäfers, S., Dato P., and Krysiak F. (2023). *Contract design for energy markets with intermittent technologies*
published in Schäfers, S. (2023). *Four essays on the design and regulation of environmental markets.*
PhD thesis at Faculty of Business and Economics - University of Basel

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The model data is based on:

ENTSO-E (2020). TYNDP 2020 – Scenario Report. Link: https://2020.entsos-tyndp-scenarios.eu/

ENTSO-E Pan-European Climatic Database (PECD 2021.3). Link: https://www.entsoe.eu/outlooks/eraa/2021/eraa-downloads/; see also https://zenodo.org/records/5780185

NETFLEX (2022). NETFLEX – Effiziente Netzentgelte für flexible Verbraucher. Link: https://www.aramis.admin.ch/Grunddaten/?ProjectID=44252&Sprache=en-US

Prognos (2021). Energieperspektiven 2050+. Technischer Bericht Gesamtdokumentation der Arbeiten. Link: https://www.bfe.admin.ch/bfe/en/home/policy/energy-perspectives-2050-plus.html/

Renewables.Ninja (2023). Data on hourly Wind and PV injection. Link: https://www.renewables.ninja/

The final model formulation will be shared via the SWEET CROSS Catalog.

A full model description will be provided as a publication of the scenario runs via the WWZ Working Paper series.

10 Appendix

Table 8: Studies analyzing the feasibility of at least 95% reduction of CO2 emissions in Europe by 2050

		Generation mix [TWh]									Flexibility [GW]				Demand [TWh]			
Model	Scenarios	PV + CSP	Wind (on)	Wind (off)	Hydro	Fossil	Nuclear	other RES	Hydrogen	Total	PHS	Battery+CAES	Power-2-X	Other	Total	Transport	Heating	Network
PRIMES	JRC EU Reference Scenario	429	980	0	421	1088	737	405	0	4060	0	0	0	0	3574	0	0	
PRIMES	EU Energy Roadmap 2050	843	2504	0	396	494	180	525	200	5142	0	0	0	0	3377	0	0	
Undisclosed	Roadmap 2050	1880	758	758	591	144	0	930	0	5061	AT	0	0	0	4385	0	0	
MESAP/Planet	Energy Revolution	1510	1450	901	620	0	0	1017	267	5765	0	0	0	0	3889	0	0	
Undisclosed	Re-thinking 2050	1732	1552	0	448	0	0	1255	0	4987	0	0	0	0	4987	0	0	
Antares	e-Highway 100% RES	892	1774	464	890	13	0	454	0	4488	114	0	0	0	4298	0	0	
PyPSA	Electricity only	871	1326	305	474	0	0	0	0	2976	47	57	107	-	2960	-	-	NTC
	Transport inflex.	1478	1779	352	474	0	0	0	0	4083	47	169	178	Y	3952	1102	-	NTC
	Transport BEV 25% flex.	1488	1691	327	474	0	0	0	0	3979	47	495	101	Y	3952	1102	-	NTC
	Transport BEV 50% flex.	1489	1668	325	473	0	0	0	0	3955	47	560	93	Y	3952	1102	-	NTC
	Transport BEV 100% flex.	1451	1688	317	474	0	0	0	0	3952	47	641	96	Y	3952	1102	-	NTC
	Transport BEV 25% V2G	1654	1570	298	473	0	0	0	0	3995	47	863	93	Y	3952	1102	-	NTC
	Transport BEV 50% V2G	1771	1531	175	474	0	0	0	0	3952	47	834	53	Y	3952	1102	-	NTC
	Transport BEV 100% V2G	1920	1464	56	474	0	0	0	0	3952	47	878	2	Y	3952	1102	-	NTC
	Fuel cell EV share 25%	1515	1835	409	474	0	0	0	0	4233	47	121	245	Y	4131	1102	-	NTC
	Fuel cell EV share 50%	1627	1920	431	474	0	0	0	0	4452	47	88	349	Y	4311	1102	-	NTC
	Fuel cell EV share 100%	1879	2090	488	474	0	0	0	0	4930	47	15	486	Y	4670	1102	-	NTC
	Heating	1145	2853	1176	471	0	0	0	0	5645	47	91	382	Y	-	1102	3585	NTC
	Methanation	1491	2890	1196	474	0	0	0	0	6050	47	141	404	Y	-	1102	3585	NTC
	TES	1548	2920	1145	473	0	0	0	0	6087	47	113	416	Y	-	1102	3585	NTC
	Central	1472	2839	1055	474	0	0	0	0	5839	47	99	305	Y	-	1102	3585	NTC
	Central-TES	1538	2997	975	474	0	0	0	0	5983	47	88	258	Y	-	1102	3585	NTC
	All Flex	2190	2735	720	473	0	0	0	0	6117	47	1304	236	Y	-	1102	3585	NTC
	All Flex Central	2136	2825	583	474	0	0	0	0	6017	47	1153	99	Y	-	1102	3585	NTC
PLEXOS	Base	1830	620	400	480	1055	0	350	0	4735	56	0	X		4409	800	500	C en

	High demand	2300	620	1280	480	1455	0	420	0	6555	56	0	X	16 GW shedding	6020	800	500	
	Alternative demand	1840	520	510	480	898	0	400	0	4648	56	0	X		4409	800	500	
	No CSP or Geothermal	1390	720	900	480	1210	0	0	0	4700	56	0	X		4409	800	500	
	Storage	1834	580	416	480	1005	0	420	0	4735	56	80	X	82GW load shifting	4409	800	500	
	Free RES	1684	700	296	480	1061	0	410	0	4631	56	0	X		4409	800	500	
	Allow non-RES	290	390	0	480	1836	1127	387	0	4509	56	0	X		4409	800	500	
PRIMES	EC LTS 1.5Tech	1333	4060	0	439	298	941	878	0	7948	51	69	511	0	-	0	0	
	EC LTS 1.5Life	1029	3629	0	386	129	836	515	0	6524	53	54	403	0	-	0	0	
POLES	JRC GECO 1.5C	877	1144	0	419	137	602	671	0	3851	NR	0	NR	0	-	0	0	
EU-TIMES	JRC LCEO Zero Carbon	3663	4604	0	419	607	942	314	0	10548	NR	0	NR	0	-	0	0	
Navigant Energy System Model	Navigant min gas	1100	1000	2600	800	0	0	809	0	6309	NR/AT	0	NR	Y	5513	853	390	
	Navigant opt gas	2500	800	2600	800	400	0	0	0	7100	NR/AT	0	NR	Y	4461	772	399	
NR	Oeko Vision	1079	2878	0	432	0	0	252	0	4641	0	0	0	0	0	0	0	
interaction of seven models	IFS 2C	1405	2359	0	420	0	0	1015	0	5199	NR	NR	NR	0	0	0	0	NTC
	IFS 1.5C	1593	2526	0	439	0	0	1044	0	5602	NR	NR	NR	0	0	0	0	
LUT Energy System Transition	Regions	2655	1770	0	649	0	25	801	0	5900	AT	NR	37	-	5259	-	-	NTC
	Area	2317	2091	0	622	0	25	597	0	5650	AT	NR	4	-	5259	-	-	NTC
elesplan-m	Decarbonization pathway EU	1199	3805	0	539	426	0	0	0	5968	43	22	367	-	4448	-	-	CoG