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HYDRO-NUCLEAR OR HYDRO-PV? SWITZERLAND'S DILEMMA

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UNIL | Université de Lausanne

FACULTÉ DES HAUTES ÉTUDES COMMERCIALES

DÉPARTEMENT DES OPÉRATIONS

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THÈSE DE DOCTORAT

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pour l'obtention du grade de
Docteur en Business Analytics

par

Juan Esteban MARTINEZ JARAMILLO

Directrice de thèse
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Jury

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I M P R I M A T U R

Sans se prononcer sur les opinions de l'auteur, la Faculté des Hautes Etudes Commerciales de l'Université de Lausanne autorise l'impression de la thèse de Monsieur Juan Esteban MARTINEZ JARAMILLO, titulaire d'un bachelor en Ingénierie Industrielle de l'Université Nationale de Colombie, titulaire d'un master en Ingénierie-Ingénierie des systèmes de l'Université Nationale de Colombie, en vue de l'obtention du grade de docteur en Business Analytics.

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EXECUTIVE SUMMARY

Over the past decades, climate change mitigation has been one of the main topics in discussing the future evolution of power systems. It is well known that a transition towards green generation is required, as this particular sector is one of the main contributors to global greenhouse emissions. The transition of the electricity system means shifting away from fossil fuel generation and/or nuclear towards renewables. However, there is a lack of existing cases of 100% renewable generation systems, except for Ireland, Norway, and Paraguay. This lack of previous experiences raises concerns about the effects of a transition to renewables. Certain questions need to be answered in the socio-economic, political, and technical fields. One challenge concerning the economic aspect is who will bear the cost of the transition. From a political perspective, policymakers need to know the regulatory mechanisms that enable the transition towards renewables. Finally, in the technical field, one main challenge arises: is it feasible to have a system with 100% renewable generation while guaranteeing energy security and reliability?

We start by analyzing the capacity requirements for a 100% renewable electricity system using Switzerland as a case study. The starting point is the current capacity mix, in which many countries rely strongly on nuclear and/or fossil fuel-based generation. The objective is to achieve an end-state in which the electricity system relies only on renewables. Particularly in our case, Switzerland is dismantling nuclear capacity and aims to replace it with PV. We defined possible end-state scenarios using data analysis. These scenarios use a numerical analysis, considering hydropower (hydro storage and run-of-river), one intermittent renewable technology (PV), and one storage method (pumping). The results show that a system relying on hydro, pumped hydro storage, and PV is theoretically viable. Next, we develop a system dynamics-based model to study the transition process both in the medium and long term in

Switzerland. In the medium term, we study the implications of capacity-based subsidies, of the reduction of the capital cost of PV, and of the speed of the transition process. Our results show that neither the likely continued reduction in capital cost nor a slowing down of the transition process result in a sustainable transition. Thus, subsidies are required to avoid blackouts during the transition. In the long term, we expand the model by exploring three different policies within three climate scenarios: (i) capacity-oriented (capacity auctions), (ii) demand-oriented (demand-side management), and (iii) a combination of both. We conclude that without any intervention blackouts do occur after the start of the transition process under all climate scenarios. With capacity auctions, the system avoids blackouts while making storage profitable. A weakness of this policy is the need for large curtailments. The demand-side management policy is unsatisfactory as it only marginally reduces unmet demand. Finally, the combination of both strategies eliminates blackouts during the transition period and decreases the curtailment slightly compared to the capacity auction scenarios.

Our overall conclusion is that a 100% renewable generation system is technically feasible; however, market-driven investments are not enough to face the transition without the risk of blackouts. Nevertheless, our stylized model provides useful insights for policymakers regarding managing the transition towards renewables. This model is calibrated for the Swiss case, but it can be adapted to other countries or regions. Finally, our modeling process could be used to analyze different energy policies and technologies.

SOMMAIRE EXECUTIF

Au cours des dernières décennies, la limitation du changement climatique a été l'un des principaux sujets de discussion dans le cadre de l'évolution future des systèmes électriques. Il est généralement accepté qu'une transition vers une production verte est nécessaire, car ce secteur est l'un des principaux contributeurs aux émissions mondiales de gaz à effet de serre. La transition du système électrique consiste à abandonner l'utilisation de combustibles fossiles et/ou le nucléaire au profit des énergies renouvelables. Cependant, il n'existe pas de systèmes de production d'électricité 100 % renouvelables, à l'exception de l'Irlande, la Norvège et le Paraguay. Ce manque d'expériences antérieures suscite des inquiétudes quant aux effets d'une transition vers les énergies renouvelables. Certaines questions doivent être résolues dans les domaines socio-économique, politique et technique. L'un des défis concernant l'aspect économique est de savoir qui assumera le coût de la transition. D'un point de vue politique, les décideurs doivent connaître les mécanismes réglementaires qui permettent la transition vers les énergies renouvelables. Enfin, dans le domaine technique, un question essentielle se pose : est-il possible d'avoir un système avec une production 100% renouvelable tout en garantissant la sécurité et la fiabilité de l'énergie ?

Nous commençons par analyser les besoins en capacité pour un système électrique 100% renouvelable en prenant la Suisse comme étude de cas. Le point de départ est la situation actuelle, dans lequel de nombreux pays dépendent fortement de la production nucléaire et/ou à base de combustibles fossiles. L'objectif est de parvenir à un état final dans lequel le système électrique repose uniquement sur des énergies renouvelables. Dans notre cas en particulier, la Suisse a entamé le démantèlement de sa capacité nucléaire et vise à la remplacer par du photovoltaïque. Sur la base d'analyser de donnes nous identifions différents états finaux possibles. Pour chaque scénario nous effectuions une analyse numérique, en considérant l'hydroélectricité (stockage hydraulique et au fil de l'eau), une technologie renouvelable intermittente (PV), et une méthode de stockage (pompage). Les résultats montrent qu'un système reposant sur l'hydroélectricité, le stockage par pompage et le PV est théoriquement viable. Ensuite, nous développons un modèle basé sur la dynamique des systèmes pour étudier le processus de transition à moyen et long terme en Suisse. A moyen terme, nous étudions les implications des subventions basées sur la capacité, de la réduction du coût de panneaux PV, et de la vitesse du processus de transition. Nos résultats montrent que ni la réduction continue probable du coût du PV, ni un ralentissement du processus de transition n'aboutissent à une transition durable. Par conséquent, des subventions sont nécessaires pour éviter une pénurie d'électricité pendant la transition. Sur le long terme, nous étendons le modèle en explorant trois politiques différentes dans le cadre de trois scénarios climatiques : (i) orientées vers la capacité (enchères de capacité), (ii) orientées vers la demande (gestion de la demande), et (iii) une combinaison des deux. Nous concluons que sans aucune intervention, des pénuries se produisent après le début du processus de transition dans tous les scénarios climatiques. Avec les enchères de capacité, le système évite les pénuries tout en rendant le stockage rentable. Une faiblesse de cette politique est le besoin de « curtailment » importantes. La politique de gestion de la demande n'est pas satisfaisante car elle ne réduit que marginalement la demande insatisfaite. Enfin, la combinaison des deux stratégies élimine les pénuries pendant la période de transition et diminue légèrement les « curtailment » par rapport aux scénarios de vente aux enchères de capacité.

Notre conclusion générale est qu'un système de production 100% renouvelable est techniquement réalisable ; cependant, les investissements dictés par le marché ne sont pas suffisants pour faire face à la transition sans risque de pénuries. Néanmoins, notre modèle stylisé fournit des indications utiles aux décideurs politiques concernant la gestion de la

transition vers les énergies renouvelables. Ce modèle est calibré pour le cas suisse, mais il peut être adapté à d'autres pays ou régions. Enfin, notre processus de modélisation pourrait être utilisé pour analyser différentes politiques et technologies énergétiques.

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1. INTRODUCTION

Over the last decades, there has been a growing push to reduce greenhouse gas emissions (GHGs) due to an increasing public consciousness of global warming and its effects in all areas of human life. The energy sector has received particular attention as it is responsible for 29% of global emissions [1]. The worldwide goal is to replace fossil fuel generation with variable renewable energy sources (VRES) to reduce emissions. At the same time, several countries are facing public pressure to scale down or end nuclear generation due to fear of nuclear disasters [2]. These trends have heightened interest in determining whether a 100% renewable energy system is feasible.

An additional element that can threaten the viability of electricity systems based on 100% renewables is climate change. Policymakers need to rethink their strategies to encourage VRES while ensuring future energy security for three main reasons. Firstly, as temperature increases, a change in precipitation is expected in the mid- and long-term (in some regions precipitations may increase, while in others they may decrease). Secondly, with more evaporation, the frequency of cloudy days increases, leading to a reduction in the efficiency of hydro-solar systems [3]. Finally, the seasonal patterns of electricity demand can be altered as more extreme summers and warmer winters are expected [4]. These factors have heightened interest in determining if there is a feasible endpoint and, if yes how we can reach it.

With the continued growth in VRES installed capacity, three main concerns have arisen: (i) a reduction in system flexibility due to the intermittent nature of VRES, which increases the challenge of balancing the market, (ii) VRES capital cost, and (iii) the subsidy-induced distortion of energy pricing [5].

The capital cost of VRES has been decreasing in recent years due to technical developments and economies of scale, leading to countries gradually phasing out subsidies [6]. Thus, while two problems are likely to be eventually resolved by the natural evolution of the technical and economic development of VRES markets, namely capital cost and the need for subsidies, this leaves the question: will this evolution be fast enough? However, the issue of intermittency is far from being solved [7]. As the share of renewables increases, the system's flexibility decreases; consequently, the system is less able to respond to sudden changes in demand and/or supply.

Providing sufficient flexibility may resolve the challenge of generation intermittency. Energy storage, demand-side management, and better control over power dispatch can provide flexibility to the system [8]. Storage is mainly used when supply exceeds demand, and stored energy can be released when needed. Thus, a massive VRES adoption requires sufficient energy storage. Currently, hydro reservoirs are the most widely utilized storage technology, accounting for more than 94% of global installed capacity as it is efficient and provides flexibility to the electricity system. One challenge for hydro-storage is the uncertainty concerning the future evolution of precipitations due to climate change.

Interconnections between regions with complementary generation sources is another way to address intermittency. As an example, the Nordic region is the world leader in regional electricity market coupling. In this market, Denmark uses the interconnections to balance its variable wind power, importing from Norway (hydro generation) and/or Sweden (Nuclear), while exporting excess wind generation. The Nordic interconnection has also proven to increase the security of supply in dry years (when hydro generation is at its lowest point) [9].

Markard [10] highlights how the increasing pace of energy transitions generates new challenges for the regulators. These challenges are (i) the decentralization of the grid that can lead to an increased cost of grid maintenance that is borne by the consumers, (ii) the possibility of death spirals as the grid is not able to recover investments, and (iii) negative prices [11], which can occur when there is a large amount of renewable electricity that cannot be stored or sold. To address these challenges, regulators must accompany the transition towards renewables with well-designed regulations. These should guarantee energy security and attractive prices for investors, but these prices should be low enough to avoid consumers leaving the grid.

Research questions and methodology

The general research question this thesis aims to answer is: How can we achieve the transition to renewable electricity generation under climate change? To answer this question, we ask the following sub-questions: (i) Is an electricity system using 100% renewable sources technically feasible? (ii) Which regulatory mechanisms could enable such a transition? And (iii) Will the proposed regulatory mechanisms still be appropriate if there is an increase in demand and reduction in supply due to climate change?

To answer the first sub-question, we defined possible end-state scenarios using numerical analysis. These scenarios were calibrated for Switzerland and use a stylized analysis, considering hydropower (hydro storage and run-of-river), one intermittent renewable technology (PV), and one storage method (pumping). The results of our analysis allow us to analyze the technical feasibility of 100% renewable electricity generation.

We use a system dynamics approach to answer the second and third sub-questions. This generic model can be calibrated for various areas and technology combinations. We use this model to analyze the transition process in Switzerland, a country with significant hydro and negligible thermal capacity, which has made the political decision to gradually decommission nuclear capacity, replacing it with PV. In addition, we develop different scenarios to test which policy mechanisms enable a smooth transition. Finally, we extend the model by incorporating three different climate scenarios, enabling us to address climate change. These different steps allow us to understand electricity systems that are transitioning towards a high share of renewables while facing the effects of climate change on demand and supply.

This thesis is organized as follows: the next section presents the key elements of electricity markets facing a transition towards renewables. These elements are technical feasibility, policy mechanisms, the role of storage, a review of energy models, and the impact of climate change on electricity markets. Next, we provide a brief description of Switzerland, the case study of this research, followed by a summary of the results. Section three contains a discussion of the results and our conclusions. Finally, the appendix contains the three research papers of this thesis.

2. TRANSITIONS IN ELECTRICITY MARKETS

Transitions of electricity systems are complex, and therefore a broad view should be taken when studying them. Five strands of literature concerning electricity transitions towards a high share of VRES are relevant for this thesis. Section 1.1 presents a brief literature review of the technical feasibility of systems with 100% renewable generation. Policy mechanisms are presented in section 1.2. Section 1.3 discusses energy storage technologies and the role of storage. Next, section 1.4 elaborates on electricity models. Finally, section 1.5 discusses the implications of climate change for electricity systems.

2.1 Technical feasibility

Feasibility derives from “feasible” which means capable of accomplishing a goal or a target. In a broader sense, the technical feasibility of an electricity system is its ability to match demand and supply at all times. Measures used for technical feasibility analysis include system reliability, flexibility, efficiency, and capacity factor, among others.

Except for Iceland, Norway and Paraguay, there is no historical evidence of the technical feasibility of systems with 100% renewable generation. These countries have unique characteristics that make this type of system possible. Iceland possesses geothermal aquifers, a small population, and substantial hydroelectric resources. Norway has huge water resources that can cover more than 90% of the electricity demand. Paraguay has a small population and the second-largest hydroelectric dam in the world, which provides more than 90% of the total electricity demand. These experiences cannot be generalized as the three countries do not rely on intermittent renewables. As a result of these few real experiences and the unique characteristics that these countries have, there is no consensus in the literature concerning the technical potential of electricity systems with a high share of renewable generation.

Four technical requirements should be satisfied to enable the achievement of the proposed end-states: (i) appropriate sizing of operational reserves, (ii) substantial grid development, (iii) system adequacy, and (iv) further analysis of the impact of distributed PV on the distribution network and its implications on the security of supply [12]. Several papers in the literature provide a technical analysis of electricity systems with a high share of renewables for different countries [13]–[16]. These studies argue that 100% renewable generation is feasible. Even though each country has its particular characteristics, three common components appear. Firstly, storage is required to integrate a large percentage of renewables. Secondly, storage is necessary to control the intermittent nature of PV and wind output on an intraday basis to balance demand and supply. Thirdly, long-term storage (inter-seasonal) is profitable and necessary for 100% renewable systems [17].

However, relying only on a technical analysis perspective is not ideal. Primarily all studies analyze a single year (end-state) with ideal conditions and do not account for meteorological outliers [18]. Loftus et al. [19] highlight how these studies do not address in what way the electricity system can reach the end-state; nor do they consider population behavior, the economic viability of the end-states, nor political support [20].

2.2 Needs of policy mechanisms

Electricity markets may suffer from a "missing money problem". This problem happens when the electricity price in a competitive market does not adequately capture the value of the investments that are required for a reliable electricity system. When there is "missing money" in the system, future investments may be compromised. Resolving this problem could result in misallocation of resources. In other words, resolving the missing money problem could result in overcompensating some resources while undercompensating others [21].

A wide variety of policy mechanisms have been deployed around the globe to encourage electricity systems to achieve energy security or to enable transitions towards green generation. The main two strategies used are investment-focused mechanisms (e.g., capacity auctions (CA), tax credits, capacity obligations, reliability options) and generation-based strategies (for instance, Feed-in-Tariffs (FITs), Fixed Premium, contracts for differences) [22]. CA and FITs are respectively the most used investment focus and generation-based strategies.

2.2.1 Capacity auctions

The purpose of CA is to achieve long-term security of supply. There are two forms of CA: for existing units and for new investments. In the first case, each generator submits capacity offers into the auction, and those that clear the capacity market have an obligation to have the capacity available for generation at a given future date. Concerning new units, the offer represents the price at which investors are willing to invest in capacity [23]. Conditions of CA can vary; for instance, in case of new projects, the subsidy is often guaranteed in the long term and can be paid annually, monthly or as a lump sum.

2.2.2 Feed-in-Tariffs

This mechanism has incentivized innovation and investments in initially costly energy technologies, such as VRES. Under FITs, a fixed price per kWh generated, that makes investment profitable, is guaranteed, independently of the market price. Thus, FITs reduce the entry barriers, thereby enabling new agents to enter the market [24]. However, when there is a large share of VRES, FITs can distort the market, inducing overinvestments, thus resulting in large amounts of curtailment. The latter may lead to periods of low prices (even negative) and the bankruptcy of established generators, which in the long run can reduce consumer welfare [25].

2.3 Energy Storage

Electricity is a non-storable energy form at any scale, but it can be transformed into other types of energy that can be stored and used to generate electricity when required. Furthermore, as electricity demand and supply must be matched in real-time, storage provides flexibility to follow both hourly and seasonal demand patterns. The leading technologies used to store energy are mechanical (for instance, pumped hydro storage, flywheel, and compressed air), electrochemical (e.g., batteries), chemical (e.g., hydrogen), electrical (e.g., supercapacitors), and thermal (e.g., hot water tanks). In electricity systems, storage can be used at any point, i.e., water in reservoirs is used at the primary level (generation), batteries at the grid level, and electric car batteries at the level of the final user [26]. Figure 1 presents different storage technologies as well as their size and the discharge time at rated power[1].

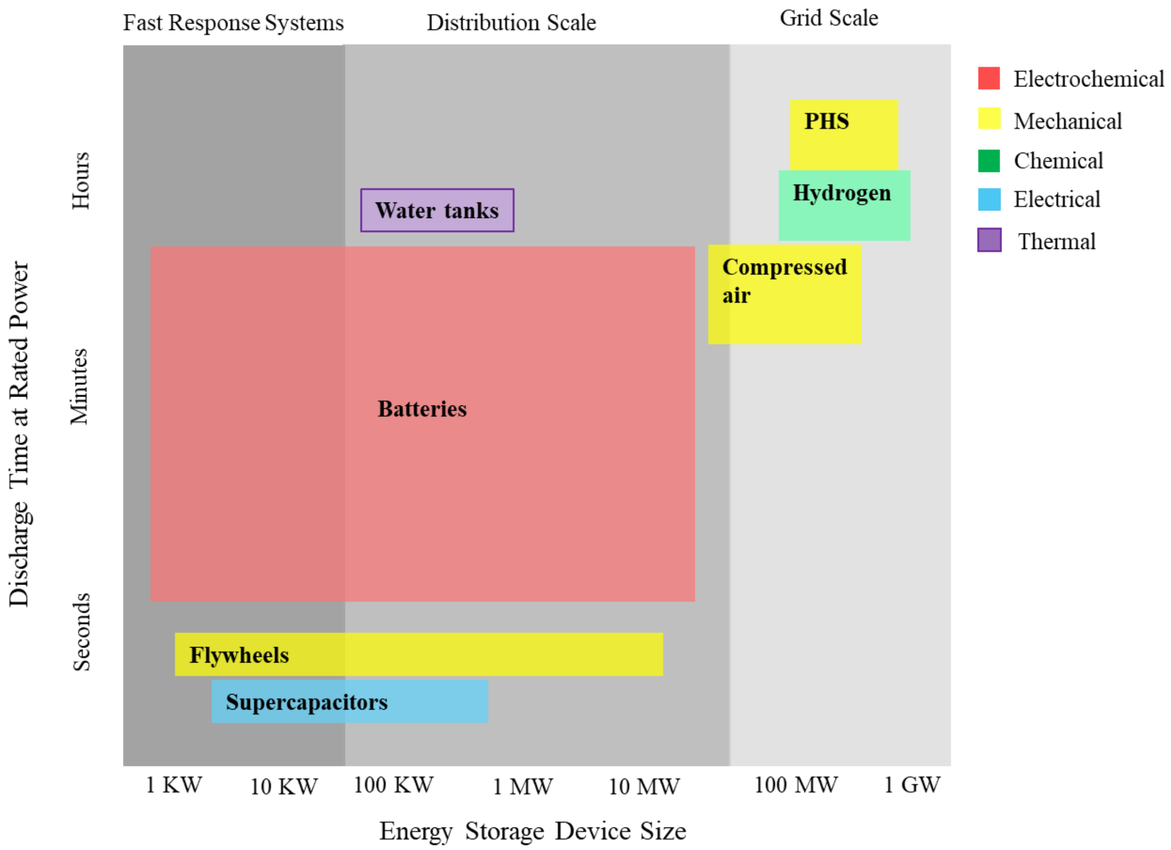


Figure 1. Positioning of Energy Storage Technologies. Adapted from [27]

Energy storage provides the following benefits to the grid: (a) flexibility, (b) reduction in required standby generation, and (c) integration of renewables by shifting excess generation

[1] Discharge time at rated power: Defined as the time required to discharge a device when used at maximum capacity.

towards times when demand exceeds supply. We discuss intra-day storage in section 1.3.1. Next, we elaborate on inter-seasonal storage. Finally, the future perspectives of storage are discussed in section 1.3.3.

2.3.1 Intra-day (short-term) storage

Intra-day storage has been used mainly to ensure power quality and to provide grid support by shifting the load from hours of excess electricity towards moments when generation is tight. Another reason for using intra-day storage is to exploit arbitrage opportunities. The most commonly used storage technologies are batteries, capacitors, flywheels and hydro.

2.3.2 Inter-seasonal (long-term) storage

Inter-seasonal energy storage is commonly used to shift loads between seasons. For example, in Switzerland in 2020, while 55% of consumption took place between October and March (winter), on the supply side the same period accounted for only 28% of annual inflows and 43% of annual hydro generation [28]. In this case, hydro-storage is used to store energy during summer (April to September) to be released in winter. Pumped Hydro Storage (PHS) is currently the most commonly used technology for large-scale storage, representing around 99% of grid electricity storage worldwide [29], [30].

2.3.3 The future of energy storage

The flexibility of electricity systems is threatened as VRES penetration increases. Today the electrical grid cannot handle a large share of VRES without significant supply disruptions. The grid starts to be significantly destabilized if VRES represents more than 20% of the installed capacity. Energy storage becomes the dominant solution, enabling VRES penetration in electricity markets. Storage provides flexibility to the grid, thereby increasing its reliability. New technologies have emerged, such as flow batteries, hydrogen cells, liquid air, stacked blocks, underground compressed air, among others. Table 1 shows the advantages and disadvantages of these technologies.

	Characteristics			
Technology	Geographically constrained	Efficiency	Stage of evolution	Cost
Flow Batteries	No	Low	Market penetration	High
Hydrogen Cells	No	Low	Market penetration	High
Liquid Air	No	Low	Product development	Low
Stacked Blocks	No	High	Concept development	High
Compressed Air	Yes	High	Mature	Low

Table 1. Advantages and disadvantages of future storage technologies [31]

2.4 Energy models

The first energy models were developed in the 1970s to analyze the oil crisis and to study the environmental impact of energy systems [15]. Classification systems include model structure, general and specific purpose, type of data required, methodology, sectoral coverage, mathematical approach, and time horizon [32]. Energy models can also be classified into computational, mathematical, and physical models [33].

Energy modelling, as any modelling, must consider time, space, transparency, and complexity, while capturing the human dimension [34]. Firstly, modelers should consider the timing problem of demand and supply. Secondly to increase the transparency of the modelling process, modelers should publicly release the data and the model to receive feedback. Model transparency also allows for replicability of the model, meaning that an independent third party can reproduce precisely the same results [35]. Concerning complexity, if a model is too detailed, the difficulty of the calculation increases. An overly detailed model can also lead to losing focus of the purpose of the model. However, if the model is too compact, it could miss important real world elements, leading to results that are not consistent with reality. Lastly, modelers should capture soft variables such as the willingness of a population to change, and political will, among others. Decisions based on models which ignore the human dimension could result in undesirable side effects, such as resistance to changes and NIMBY (Not In My BackYard) phenomena, as they do not consider the reaction of the population.

The two primary methodologies used in energy modelling are optimization and simulation [33]. Optimization has traditionally relied on sizeable bottom-up optimization models. Their focus is to build normative scenarios and these models are based on a detailed description of the energy system's technical components. In addition, these models tend to build endpoints/desired points at which the system should arrive to optimize the objective function (e.g., matching demand and supply at the minimum possible cost). While optimization models can provide high-quality analytical solutions (e.g., future energy demand is delivered at the minimum cost), they have several limitations: complex models may not have an analytical solution, optimization models loose effectiveness as more uncertainty is included, and non-linear models are hard to solve.

Simulation models are conceived as white boxes, meaning that the outcomes must be explained by the structure of the system. They can be either stochastic, or deterministic (mainly system dynamics (SD) based models). Stochastic models focuses on making uncertainty explicit. In other words, stochastic modelling provides a range of possible results. These models have as advantages the ability to have a range of practical scenarios and the introduction of uncertainty on the analysis. Disadvantages include the complexity to obtain the data sets that are required to fit the distributions, and the challenge to obtain a high-quality solution, as the results of this method is a range of possibilities. Thus, the modeler needs to analyze and process the outcomes to select the best solution. On the other hand, SD-based models focus on considering possible evolutions of the energy system. These models are built to ask "what if" questions without testing them in the real world [16]. SD has been used extensively to study different aspects of energy markets; examples include regulatory change [36], energy transitions [37], VRES diffusion [38], and investment decisions [39], among others.

2.5 Climate change

We need to distinguish between global warming and climate change. The first one refers to the long-term increase in the average temperature of the globe. Climate change encompasses global warming and the resulting changes in climate conditions such as the increase in sea levels, retreatment of glaciers, ice melting at the poles, extreme flooding, heat waves, hurricanes, and droughts. It is commonly accepted that human activity is the main cause of the increase of GHGs emissions into the atmosphere, which are responsible for global warming [40].

The Intergovernmental Panel on Climate Change (IPCC) forecasts a temperature rise in a range between 1ºC and 5.7º C by the end of the century. The optimistic scenario (an increase of one degree) implies that global human CO_2 emissions are cut to net-zero by 2050. The pessimistic scenario (a rise of 5.7ºC) could occur if emissions double by 2050 compared to 2015 emission levels. The IPCC forecasts that an increase of the average global temperature between 1 and 3 degrees above the temperature registered in 1990 may benefit some regions but endanger others. However, the net annual cost may increase in the long run as global temperature continues to rise [40]. Section 2.5.1 elaborates on the impact of climate change on energy systems, and in section 2.5.2 we discuss the impact of climate change on consumer behavior.

2.5.1 The impact of climate change on energy systems

Climate change affects both the infrastructure and the generation of electricity systems. Extreme events such as hurricanes can lead to more exposure of the electrical infrastructure (e.g., hurricane Maria hitting Puerto Rico in 2017). In this thesis we focus our analysis on two climate change impacts on the generation side. Firstly, potential changes in the mid- and long-term precipitations must be taken into account when hydro represents a substantial share of generation [3]. Secondly, as public awareness about climate change grows, the pressure to intensify the pace of the transition towards green generation increases. Thus, many countries have been developing policies that encourage the transition from fossil fuel generation to renewables to reduce electricity generation emissions [4], [41]. As argued by Li [42], studies related to energy transitions should include the impact of consumer behavior, regulation, the effects of the uncertainty of climate change in energy planning, and the rationality of producers.

2.5.2 Consumer behavior

IPSOS ran a survey in 2019 in 27 countries to understand how consumers modified their behavior due to climate change concerns. The main conclusion of this survey is that climate change awareness seems to be a driver to change consumer behavior, as the results show that 69% of the adults surveyed changed consumption habits regarding products and services because of climate change awareness [43]. In addition, the adoption of electric cars has increased, passing from more than 20,000 in 2010 to 4.8 million at the end of 2019 [44] due to environmental concerns and financial incentives.

On the demand side, five different strategies may change the electricity consumption behavior of households [45]: (i) committing households to reduce consumption through a contract; (ii) setting goals for household energy savings; (iii) providing information about environmental pollution, the importance of saving electricity, and energy-saving tips; (iv) rewarding consumption reduction; and (v) providing feedback to households about their consumption. The two main instruments used by regulators are demand-side management (DSM) and giving a choice to consumers to pay a premium for green electricity [22], [46].

3. SWITZERLAND AS A CASE STUDY

Today Switzerland relies mainly on hydro and nuclear generation. Switzerland's topography and water resources have allowed for an extensive deployment of hydro. Furthermore, Swiss installed capacity and the country's location on the continent allow Switzerland to be an important actor in the European electricity exchange. In 2017, Switzerland decided to gradually replace nuclear with VRES over the next 25 years [6]. In addition, this transition will occur while there is a simultaneous increase in demand and a reduction in water resources due to climate change [47]. This, together with the non-signing of the Institutional Framework Agreement [48], endangers Swiss energy security as replacing nuclear with VRES increases Switzerland's dependency on imports during winter.

3.1 Context

Today the installed generation capacity in Switzerland amounts to 22.4 GW, of which hydro represents 70%, nuclear 13%, solar 13%, and the remaining 4% include cogeneration plants, waste, wind, and biomass [49]. From 2011 to 2020, the average annual electricity generation was 67 TWh. Hydro generation accounts for 57.5%, nuclear for 35.3%, while thermal and renewable plants supply the remaining 7.2% [50]. Over the same period, the average annual demand was 58 TWh and; with grid losses of around 7%, the average annual consumption was 62 TWh. The maximum (minimum) hourly demand registered in 2020 was 9.9 GWh (4.2 GWh) [50], which indicates that as long as there is enough water in the reservoirs, Switzerland can always match its peak demand. Concerning electricity exchanges, the country usually is a net exporter. Between 2011 and 2020, Switzerland has been a net importer in only three years (figure 2a). Imports usually exceed exports during winter (from October until March), while exports reach their maximum in summer (figure 2b). However, future electricity exchanges are jeopardized because Switzerland is not a member of the European power market, and the current political climate is unfavorable, to say the least [51].

a) Annual net exports | b) Monthly net exports

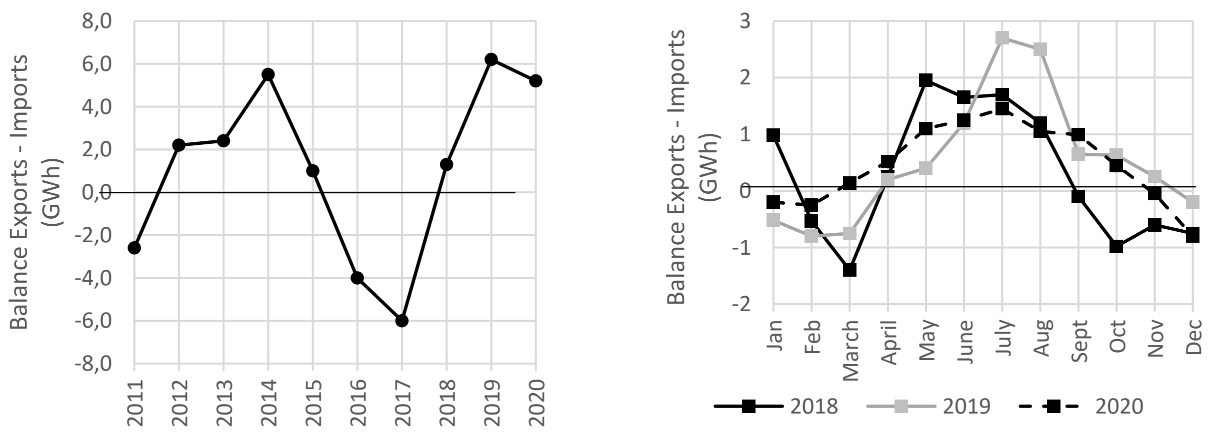


Figure 2. Electricity exchange balance in GWh [28]

With hydro being the principal actor in generation, water resources play a vital role in the system. Reservoirs store excess water in summer to be released in winter [52]. Thus, the lowest reservoir level is typically reached in March (around 10%), while the maximum occurs at the end of September (89%).

With the nuclear phase-out program, the generation mix will change in the medium term. The Federal Council developed the Energy Strategy 2050 that targets a reduction in energy consumption, and increased efficiency, and encourages the deployment of renewables [53]. Furthermore, with the non-signing of the Institutional Framework Agreement, the Federal Council has started a discussion to postpone the nuclear phase-out process by 10 years [48].

Concerning VRES, the government has been encouraging new projects with a FITs mechanism since 2008 [54]. In 2021 PV installed capacity is around 2.8 GW, while wind accounts for 88 MW [49]. PV installed capacity is expected to continue increasing in the coming years, and its potential annual generation is estimated to be of the order of 32 TWh by 2050 [31]. The increase in PV generation worsen the mismatch between generation and demand. Thus, Switzerland must encourage storage, which becomes a strategic measure to resolve the intermittency problem.

3.2 Technical Feasibility of solar-hydro based generation in Switzerland

The first step towards understanding Switzerland's transition process is to analyze the technical feasibility of a 100% green generation system. This question is addressed in the first thesis paper[1]. This paper explores several end-states of the system by considering different combinations of PV capacity, reservoir size, and PHS capacity. The results of this analysis allow us to quantify the capacity requirements that enable Switzerland to achieve security of supply and self-sufficiency while relying on renewables. The following sub-sections summarize the methodology, assumptions, and key results of this paper.

[1] J. E. Martínez-Jaramillo, A. van Ackere, and E. R. Larsen, "Transitioning towards a 100% solar-hydro based generation: A system dynamic approach," Energy, vol. 239, p. 122360, 2022, doi: https://doi.org/10.1016/j.energy.2021.122360. Appendix 1, [67].

3.2.1 Methodology and model conceptualization

Our goal is to focus on the technical feasibility of a system with 100% renewable generation, using a high-level conceptual model. The model does not include uncertainty. Each month is represented by a typical day, allowing us to analyze the balance between demand and supply. The model considers three generation technologies: run-of-river (RoR), PV, and hydro-storage (HS).

Our central assumption is that the electricity system is centrally planned. Thus, the dispatch is optimized from an energy efficiency point of view, i.e., no bids by generators and no market. We also assume that the central planner will dispatch according to the following order: RoR first, PV next, and finally HS. PV is curtailed when necessary to avoid reservoir overflows.

The model computes the required PV, reservoir, and pumping capacity that allows generation to match demand. Given monthly water inflows and sun irradiations, we first calculate the unmet demand after RoR and HS (from natural inflows) generation. Next, using the unmet demand, we calculate the required PV generation (including loss factors due to pumping and PV efficiency). Finally, with the required PV, we can compute the required reservoir size and pumping capacity.

It is essential to distinguish between total generation (G), electricity available for final consumption (referred to as net generation, NG), and potential net generation (PNG). G is the total electricity generated, including both the electricity used for pumping and pumped hydro generation. PNG is the maximum amount of generation that can be made available for final consumption. In an ideal situation, potential net generation is equal to demand. However, the latter is not realistic, as there are curtailments, so NG is the electricity generation available for final consumption. We also have to differentiate between the maximum possible electricity generation from solar ($\overline{PV}$) and the actual electricity generation (PV) given curtailments. Table 2 shows the variables and notations used in the model. Variable names without time subscript refer to annual values; we add a subscript t when considering monthly values.

Variable	Notation
PV generation	PV
PV consumed immediately	$\mathrm{PV^c}$
PV used for pumping	$\mathrm{PV^p}$
PV potential generation	$\overline{PV}$
Run of River generation	RR
Hydro-storage generation from natural inflows	$\mathrm{HS^n}$
Hydro-storage generation from pumping	$\mathrm{HS^p}$
Total generation	G
Potential Generation	PG
Net generation	NG
Potential net generation	PNG
Demand	D
Curtailment	CT

Table 2. Variables and notations used in the model.

Next, we formalize the relationships between these different concepts. We start by defining PV generation. Part of the PV generation (PV) is consumed immediately($\mathrm{PV^c}$), while the remainder is used for pumping, yielding equation 1

$$\mathrm{PV} = \mathrm{PV^c} + \mathrm{PV^p} \qquad (1)$$

Hydro generation (HS) has two components: natural inflows (HS^n) and pumping (HS^p):

$$HS^p = 0.8 * PV^p \quad (2)$$

To quantify the required PV capacity, we first define PNG, which must equal demand.

$$D = PNG = RR + HS^n + HS^p + PV^c \quad (3)$$

D, RR and HS^n are inputs derived from historical data; using equation 2 we can rewrite equation (3) as follows:

$$D - RR - HS^n = 0.8PV^p + PV^c \quad (4)$$

Total generation (G) is defined as the total amount of generation that is actually produced (including electricity used for pumping):

$$G = RR + HS^n + HS^p + PV^c + PV^p. \quad (5)$$

Next, we define monthly potential generation for each month t.

$$PG_t = RR_t + HS_t^n + HS_t^p + PV_t^c + PV_t^p + CT_t, \quad with\ \sum_t HS_t^n = HS^n \quad (6)$$

Monthly RR_t and annual HS^n are given. We develop an algorithm to choose the values of HS_t^n so as to minimize the required PV and storage capacity, as well as curtailment.

3.2.2 Results and discussion

We start by considering an unconstraint scenario (XL) with unlimited storage. Consequently, potential generation equals demand. The results for this scenario show that the current reservoir size would need to double, and that PV installed capacity should increase by a factor of 13 to allow the system to satisfy demand. Next, we analyze the trade-off between PV capacity, pumping capacity, and reservoir size. We thus consider the current scenario (C), which fixes the reservoir at its current size, as well as three intermediate reservoir sizes, small (S), medium (M), and large (L).

Figure 3 visualizes the trade-off between the required reservoir size and PV capacity, as well as the situation in 2018. This illustrates the magnitude of the required investments in both generation and reservoir capacity, to move to 100% renewables. Our results logically show an inverse relationship between reservoir size and PV capacity requirements: the larger the reservoir size, the lower the PV capacity requirements. However, smaller reservoir sizes entail high excesses of potential generation and thus more curtailment. This is the consequence of the inability to store the large excess of PV generation that occurs during summer. If Switzerland were to increase PV capacity to achieve a system with 100% renewables while keeping its current reservoir size, this would entail the most inefficient scenario in terms of curtailment.

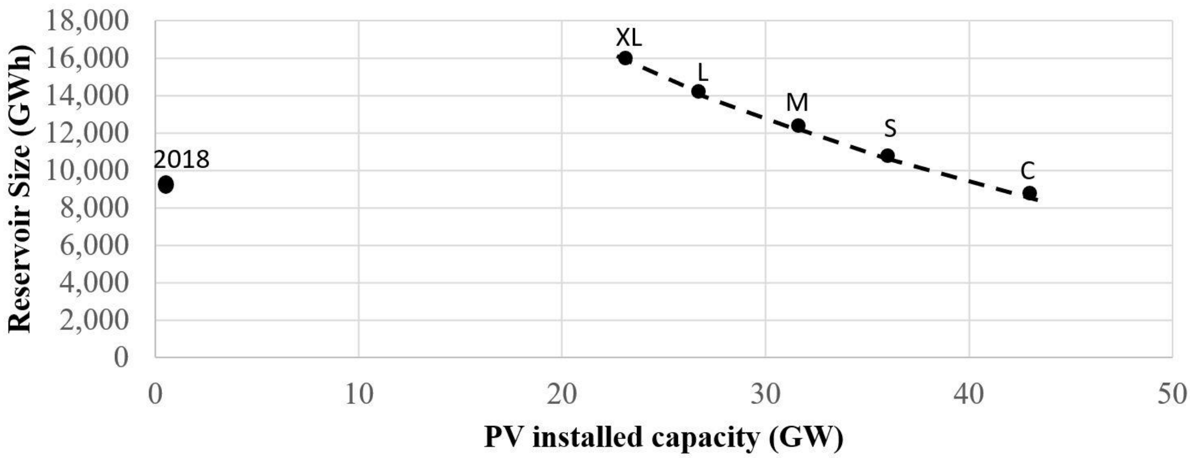
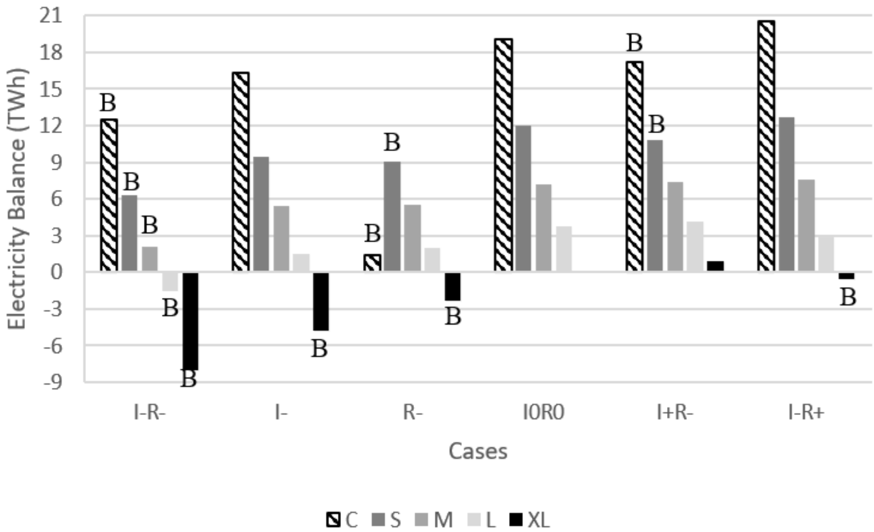


Figure 3. Trade-off between reservoir size and PV installed capacity

We perform a sensitivity analysis to test the impact of a +/- 10% change in inflows and irradiation on unmet demand, resulting in 25 different cases. Figure 3 shows the results of the sensitivity analysis for the electricity balance: while only five cases show an annual shortage, there are 12 cases with blackouts (i.e., there are 7 cases where there is enough energy but at wrong time). This analysis yields two main insights. On the one hand, the system relies more on sun irradiation when the reservoir size is small (C and S scenarios). In fact, a 10% reduction in solar irradiation leads to blackouts, despite a 10% increase in water inflows (I+R- conditions). As shown in the figure, under I+R- scenarios C and S have the annual potential generation to cover demand, however the reservoir size prevents the correct timing, and thus blackouts occur. On the other hand, systems with huge reservoir sizes are more sensitive to changes in water resources (scenario XL with a 10% reduction in inflows). To solve the dependency on natural inflows, the XL scenario must increase pumping during summer, when excess PV generation is expected.



I: inflows, R: Irradiation B: blackout, -: 10% decrease, 0: base case, +: 10% increase,
Figure 4. Sensitivity analysis for the electricity balance (TWh)

Technically, Swiss PV potential is enough for all scenarios, except for the current reservoir size. Technological improvement in PV may resolve the issue for scenario C in the future. Concerning storage capacity, the two smaller reservoir sizes considered are achievable: scenario C by definition has the current size, while for scenario S needs an upgrade in existing damns such as increasing the height and efficiency that are technical and politically feasible. The remaining scenarios are more challenging to achieve due to environmental and political factors that limit the expansion of hydro reservoirs. There are two options to achieve self-sufficiency in the absence of increased reservoir capacity: building additional PV (or another renewable capacity) and/or integrating other interseasonal storage technologies. We can thus conclude that S is the most plausible scenario: the required reservoir size is technically and politically feasible and the required PV capacity is achievable.

Our results show that it is theoretically possible for Switzerland to move to a system based on 100% renewable generation based on hydro and PV. However, our results rely on strong assumptions; thus, they should be seen as a thought experiment. Moreover, our model does not include uncertainty about annual inflows and irradiation, nor the economic, technological, environmental, political, and legal issues that such a system requires. Nonetheless, this study provides a starting point to build a simulation model (subsections 2.4 and 2.5) where the feasibility of policies aimed at implementing this transition can be tested.

3.3 The desirable end-state of the transition towards renewable generation

In the previous section we tested the technical feasibility of an end state with 100% renewable generation. Next, we discuss the impact on the market equilibrium of intermediate states of PV penetration into the electricity system. In this subsection we summarize the principal findings of the working paper *From nuclear to PV and hydro storage. Should we go all the way?*[1]. This paper is not formally part of the thesis; however, we believe its results add insights concerning the impact of different geographical conditions on the requirements of PV and storage capacity, the precision of the results (monthly vs. weekly data) and the desirable share of renewables that makes an electricity system viable.

[1] N. Walker, J. E. Martínez-Jaramillo, and B. Gencer, “From Nuclear to PV and Hydro Storage. Should We Go All the Way?,” USAEE Working Paper No. 21-528, 2021. [Online]. Available: https://ssrn.com/abstract=3980131.,[68]

3.3.1 Results and discussion

We start the analysis with a simplified electricity market. This allows us to study the effects of introducing PV on the market equilibrium of an isolated country. We consider two regions and five stages of the transition from nuclear towards PV. The first is a fictional region (Equator (EQ)), where there is no seasonality and high solar irradiation. This allows us to study the impact of nuclear dismantling on intra-day storage in a controlled environment. The second region (Switzerland (CH)) includes seasonal patterns in demand, and the solar irradiation is lower than in the EQ region. This region allows us to analyze the impact of seasonality on the market equilibrium within the different stages of the transition towards 100% VRES generation. The five stages represent the split of generation between nuclear and PV, starting with 100% nuclear and 0% PV; in each subsequent stage, nuclear capacity is reduced by 25% and compensated with PV. Given the generation mix, the reservoir size is set at the minimum capacity necessary to meet demand. We use Pumped Hydro-Storage (PHS) as the storage technology. PHS allows to shift excess PV to periods when generation is tight.

Figure 4 shows the finance results of the model. The results indicate that systems with a higher share of PV lead to a significant increase in consumer price. This result is not surprising, as the PV bid is higher than nuclear's, because PV needs to include a higher share of capital costs into its price bid, while nuclear's capital cost is generally amortized. The cost of water for PHS is set by the most expensive technology used for pumping. Thus, with an increasing PV penetration, PHS buys more electricity for pumping from PV than from nuclear, resulting in a higher average consumer price. The higher PHS sales price causes the price paid by the consumers to diverge from the market price. The difference increases as more PV enters the generation mix for both regions. For instance, in the 100% PV scenarios, the consumer price is lower than the market price. This is caused by the increased difference between peak and off-peak prices, exacerbated by a higher PV share in the generation, resulting in low-price periods that decrease the average consumer price. With a higher PV share, the low-price periods are longer and more frequently, counter-balancing the high-price periods and thus resulting in a lower average consumer price. Another effect of more PV generation is that nuclear benefits when the price is set by other technologies, while the opportunities to profit from high prices are less for PV.

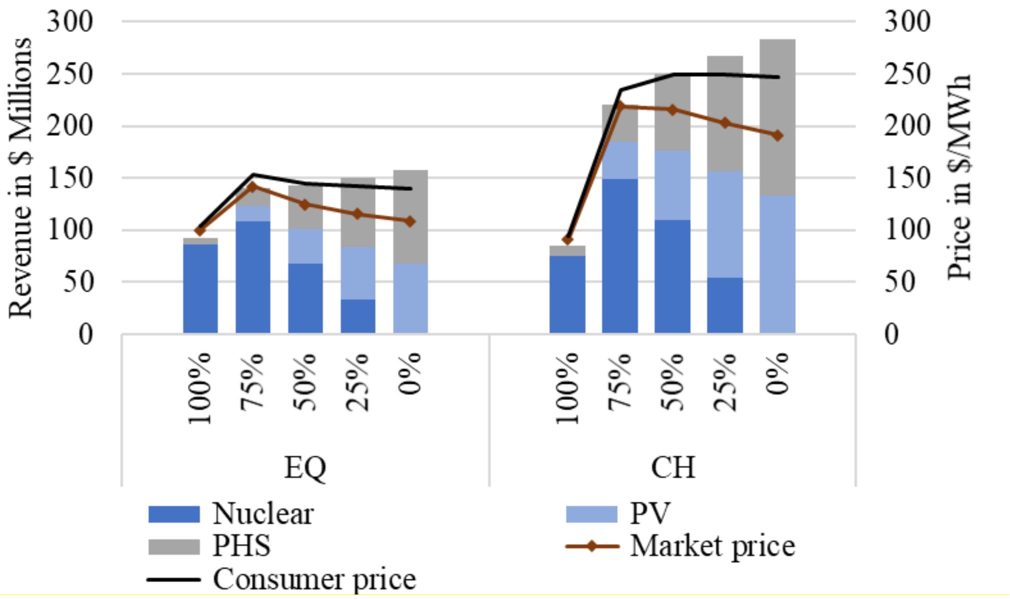


Figure 4. Total sales revenue by technology, market price and consumer price by region and phase-out stage

The results illustrate how seasonality impacts the electricity system in two ways. Firstly, with a higher excess in PV generation, the requirements for storage increases, resulting in a higher PHS consumption. For instance, in CH with 100% PV generation, the PHS consumption represents 25% of the annual consumption. Secondly, prices are higher in the presence of seasonality in systems with a high share of PV. The best option in terms of prices is to let nuclear supply a baseload during off-peak demand while using PV to pump water to the reservoirs. The latter allows the consumer to benefit from lower average prices.

Our results raise two main challenges: how much are consumers willing to pay for green generation? And how to address the higher prices paid by consumers when the system relies only on renewables? Consumers are more likely to pay a premium for green electricity when this generation substitutes conventional energy sources (including nuclear) [55]. The increasing development of PV technology can address the second challenge; as more PV is deployed, an improvement in efficiency and a reduction in PV capital cost is expected as the technology further advances on the learning curve.

This model has several limitations. Firstly, we assume a central planner, which allows all firms to be successful while avoiding market power abuse. Given this assumption we did not deal with investment decisions. Also, we consider these regions as isolated countries: no imports, nor exports. We use this simplification in order to avoid any influence from the electricity exchange on the generation mix decisions and pricing dynamics. However, we think that our analysis provides a helpful tool for policymakers by allowing them to compare alternative end-states. This model may be modified to examine the economic effect of various stages of a transition and the required mix of installed capacity to match demand and supply.

3.4 Transitioning towards 100% solar-hydro based generation

As mentioned before, the Swiss electricity system is transitioning from nuclear-hydro towards PV-hydro based generation. In this section we analyze the transition process in the medium and long term. We address the transition process in the medium term in the second thesis paper[1]. We aim to understand which regulatory mechanisms enable the transition towards

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[1] J. E. Martínez-Jaramillo, A. van Ackere, and E. R. Larsen, "Transitioning towards a 100% solar-hydro based generation: A system dynamic approach," Energy, vol. 239, p. 122360, 2022, doi: https://doi.org/10.1016/j.energy.2021.122360, Appendix 2, [69]

100% renewable generation. We analyze different scenarios to test the transition of Switzerland from nuclear-hydro towards PV-hydro while being self-sufficient. We evaluate two regulation mechanisms (capacity auctions and Feed-in-Tariffs) and the role of storage to enable a smooth transition.

Next, we recognize that climate change is a topic that turns to be a priority when analyzing the viability of such transitions in the long term. Logically, the next question that we aim to answer is: will the regulatory mechanisms still be appropriate if there is an increase in demand and reduction in supply due to climate change? The third thesis paper[1] answers this question. This paper studies the regulation that is required to successfully manage the transition of the Swiss electricity system while facing a simultaneous increase in demand and reduction in water resources due to climate change. This paper considers two policies (capacity auctions and demand-side management) and incorporates climate variability by testing the impact of three climate scenarios on demand and supply. We evaluate the viability of the electricity system in terms of unmet demand and electricity price. The following sub-sections shows the model description, the assumptions, the main results and the model limitations.

3.4.1 Model description

We develop an SD-based model and calibrate it for the Swiss electricity market. Our model takes a high-level view, capturing seasonal and daily patters of demand, precipitations, and sun irradiation using a representative day for each month. We ignore day-to-day variability to focus on medium- and long-term patterns. As discussed in section 2.1, future cross-border exchanges are uncertain; thus, we continue to consider Switzerland as an isolated country.

[1] J. E. Martínez-Jaramillo, A. van Ackere, and E. R. Larsen, Facing climate change: does Switzerland have enough water?, Appendix 3

Advantages and disadvantages of SD

Transitions in energy systems are complex processes involving delays, non-linear interactions between several variables and feedback loops. SD enables to include all these elements, which allows the understanding of the evolution of the energy system by studying its structure. Another advantage of SD is that lets us ask "what if" questions and thus enables us to test different energy policies before implementation. This allows to foresee counterintuitive behaviors. Finally, SD is a useful tool for learning and communicating as this methodology uses graphical tools, which facilitates the comprehension of the structure and hypotheses proposed by the modeler.

SD simulation based models assume that each group of agents (consumers, regulator, generators) is homogenous, and thus these models are not appropriate to capture the individual differences within each group of agents of the electricity system. For instance, SD struggles to integrate individual consumer preferences and the decision rule of each supplier.

Another limitation of SD models is the difficulty to include spatially distributed data. Such data is important when the distribution of resources, generators, infrastructure and consumers are key elements of the electricity system. As mentioned before, SD takes an aggregate view, rather than focusing on individual, micro-level behavior.

Finally, SD is not an optimization method; instead, it is an experimentation tool; the objective is not to find an "optimal" solution but instead to test a range of plausible scenarios. Although SD can incorporate uncertainty, modelers generally make the conscious choice not to include stochastic variables (e.g., day to day variability in an energy system) because the objective is to explain the resulting behavior based on the structure of the system studied, rather than by randomness.

Figure 5 shows an overview of the model. Subsystems and relationships in black are used both in the medium and long-term analysis; the extension for the long term is represented in blue and the dotted lines are the policies tested (i.e., red for both medium and long term, and blue for the long term).

The market operator dispatches RoR and nuclear first, then solar, and finally, a merit-order is used to prioritize PHS and hydro-storage. The bid price of the most expensive dispatched technology sets the electricity price. After market clearing, investors receive information from the operator concerning price and ROI and the generators receive information on the need to curtail/store energy, while the regulator collects information about the current energy margin. The energy margin is the ratio between the yearly energy balance and the annual demand. A positive (negative) energy margin indicates an excess of energy (shortages). Investors decide whether to invest based on the ratio of the expected ROI and their desired ROI. To compute the expected ROI, we run a parallel model that forecasts future capacity, prices, generation by technology, and electricity balance three years ahead (the time required to build PV capacity). Finally, the regulator decides to subsidize PV based on the energy margin (red dashed arrow).

For the long-term analysis we carry out six main changes: (i) we extend the simulation period to capture the long-term effects of climate change on the electricity system, (ii) we introduce three climate scenarios based on the Representative Concentration Pathways (RCPs) developed by IPCC [56], [57], (iii) we introduce trends in demand linked to the climate scenarios, (iv) we consider the evolution of natural inflows and RoR generation by linking them to the climate scenarios, (v) we model the retirement of PV and PHS capacity, and (vi) we consider the electric car penetration (fixed for all scenarios, we assume a 100% electric vehicle fleet by 2100, thus climate independent) and the resulting recharge demand. This last change allows the regulator to introduce a DSM program that focuses on when electric car owners recharge their vehicle.

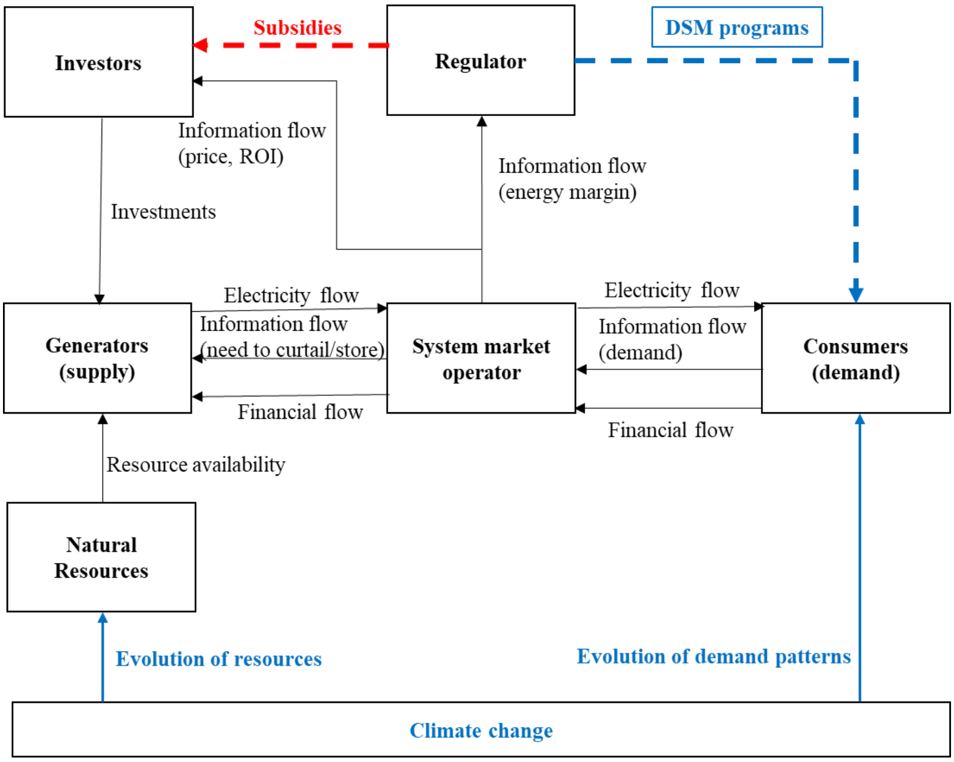

Figure 5. Model overview

We build the simulation model in Vensim DSS 7.3.4. The simulations run from 2020 to 2040 and 2020 to 2100 respectively for the mid- and long-term. The main assumptions of the model are, (i) technology efficiency is fixed, (ii) the government goal is to achieve an energy self-sufficient country, and (iii) the government only subsidize PV, since their goal is to enhance overall generation. Table 3 summarizes the main modeling inputs and assumptions.

Model element	Medium term and Long term	
Marginal and capital costs	Exogenous and constant [58]	
Nuclear capacity	Linear dismantling process, running from 2025 to 2035	
Pumping efficiency	80% [59]	
Cross-border exchange	Excluded	
Model element	**Medium term**	**Long term**
Time horizon	20 years	80 years
Climate change	Not considered	Representative Concentration Pathways (RCP) 2.6, 4.5 and 8.5 developed by the Intergovernmental Panel on Climate Change-IPCC [56], [57].
Demand	Same seasonal pattern over 20 years based on historical data from 2010 to 2019	Trends in demand linked to the climate scenario Inclusion of electric car demand
Natural inflows and RoR generation	Same seasonal pattern over 20 years based on historical data from 2010 to 2019	Evolution of natural inflows and RoR generation linked to the climate scenarios
Retirement of PV and PHS capacity	Not considered	30-year lifetime

Table 3. Model inputs and assumptions. Sources in brackets

Pricing

Marginal cost-based price discovery is often used to determine the spot electricity price, i.e., the price is set by the marginal cost of the generator that allows to clear the market. The marginal cost-based price discovery starts to crumble when the system has a high share of renewables. This happens because renewables have very low marginal costs, which impacts the price setting and increases the electricity price volatility. Moreover, with more renewables (e.g., PV), green generation tends to peak at the same time, resulting in a low price which prevents VRES from achieving enough income to invest in new capacity. Traditionally, governments have encouraged renewable investments via a variety of support mechanisms. However, these can distort the electricity market, thereby creating a vicious cycle in which investments in generation capacity rely more and more on governmental intervention.

Research has shown that long term planning of electricity systems that are transitioning towards renewables requires a change of paradigm. One of these paradigms is the pricing of renewables (Malik and Al-Zubeidi, 2006). These authors argued that bids must capture the economic value of resources required to satisfy future demand, as opposed to only the marginal cost.

Our model considers four generation technologies: RoR, nuclear, PV and hydropower. RoR and Nuclear bids are defined by their LCOE. Our decision of using LCOE is based on the idea that transitions should be studied over the long term and thus bids should capture the full life-cycle costs of each technology.

Hydro bidding

Hydropower has two sources of generation: Hn and PHS. We assumed that Hn and PHS share the generation infrastructure (i.e., generation turbines, reservoir capacity and interconnection to the grid). This shared reservoir capacity implies that PHS storage capacity is dynamic: it is defined at any time as the difference between the total reservoir capacity and the stock of natural inflows. In contrast, Hn storage capacity is considered equal to the total reservoir capacity. Both technologies include in their bids the opportunity cost of generation. This captures the idea that producing at a certain hour diminishes the resources available to produce in the future. On the contrary, saving water for later increases the risk of spillovers. Figure 6 shows the hypothesized opportunity cost, modelled as an impact of the reservoir fill rate on hydro bidding. This impact is used both for Hn and PHS bids and captures the scarcity pricing implemented by hydro when the reservoirs are almost empty, as well as generators' willingness to reduce their price to avoid spillovers. Additionally, the resource for Hn (water) is "free". We thus define the Hn bid as shown in equation 1.

$$\text{Hn bid} = \text{LCOE of Hn} * \text{Impact of Hn fill rate on Hydro bidding} \quad (1)$$

Given this impact, Hn bids range between ten times the LCOE (upper bound, reflecting scarcity pricing) and zero (lower bound) when the reservoir is respectively nearly empty or full.

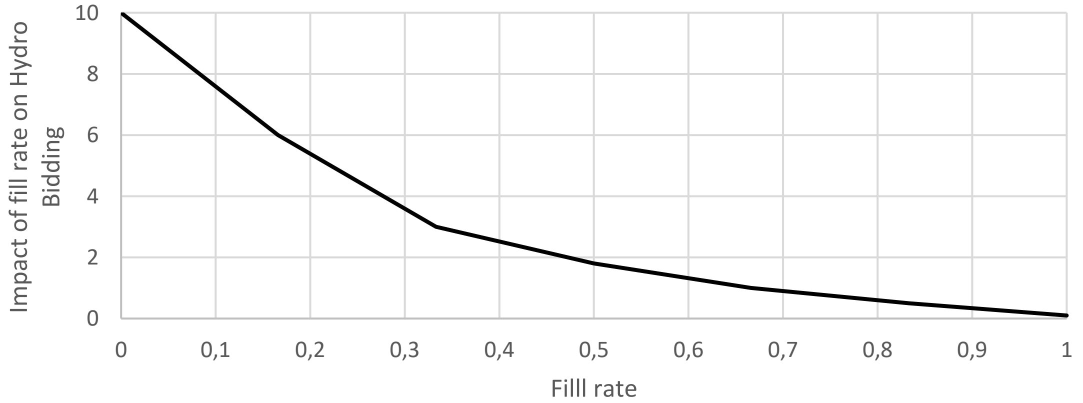

Figure 6. Impact of (Hn or PHS) fill rate on Hydro bidding

In contrast, water is not free for PHS. The cost of water depends on the price at which PHS pumps any excess generation. Another key element is that, as mentioned above, PHS benefits from the existing infrastructure of Hn, pumps being the only required specific investment. This makes the capital expenditure negligible compared to that of traditional hydro. Thus, the PHS bid does not rely on LCOE, but is instead based on the average water cost, adjusted by the impact of its fill rate, as shown in equation 2.

$$\text{PHS bid} = \text{Cost per MWh pumped} * \text{Impact of PHS fill rate on Hydro bidding} \qquad (2)$$

PV bidding

For PV bids, we distinguish two situations. On the one hand, when PV is the marginal producer, PV can bid at its LCOE. On the other hand, when there is excess generation, PV is constrained by PHS' willingness to pay for this excess. PHS' business model relies on arbitrage: storing cheap energy by pumping any excess, mostly in summer, to sell electricity at a higher price when supply is tight. Given Switzerland's geographical and climate conditions, PHS aims for a full reservoir at the end of summer, to be used during winter when generation is tight. Consequently, PHS expects to almost empty its reservoir by the end of winter. This results in a desired fill rate which evolves as shown in Figure 7a. Figure 7b captures PHS's willingness to pay when buying excess PV generation. To determine the price it is willing to pay, PHS calculates the ratio between the desired and current water levels. A ratio higher than one indicates that the PHS reservoir level exceeds the desired level and thus PHS is not interested in pumping. Consequently, if PV aims to get rid of its excess, a decrease in bid is required. On the other hand, when PHS's stock of water is way below the desired level, PHS will be keen to buy, enabling PV to set a higher bid. The resulting bid of PV, thus depends on the presence of excess generation, as well on the PHS reservoir level, as shown in equation 3.

$$\text{PV bid} = \begin{cases} \text{LCOE of PV}, & \text{If EG} = 0 \\ \text{LCOE of PV} * \ \text{PHSWP}, & \text{otherwise} \end{cases} \qquad (3)$$

where EG denotes excess generation and PHSWP captures PHS's willingness to pay when buying excess PV generation (recall figure 7b).

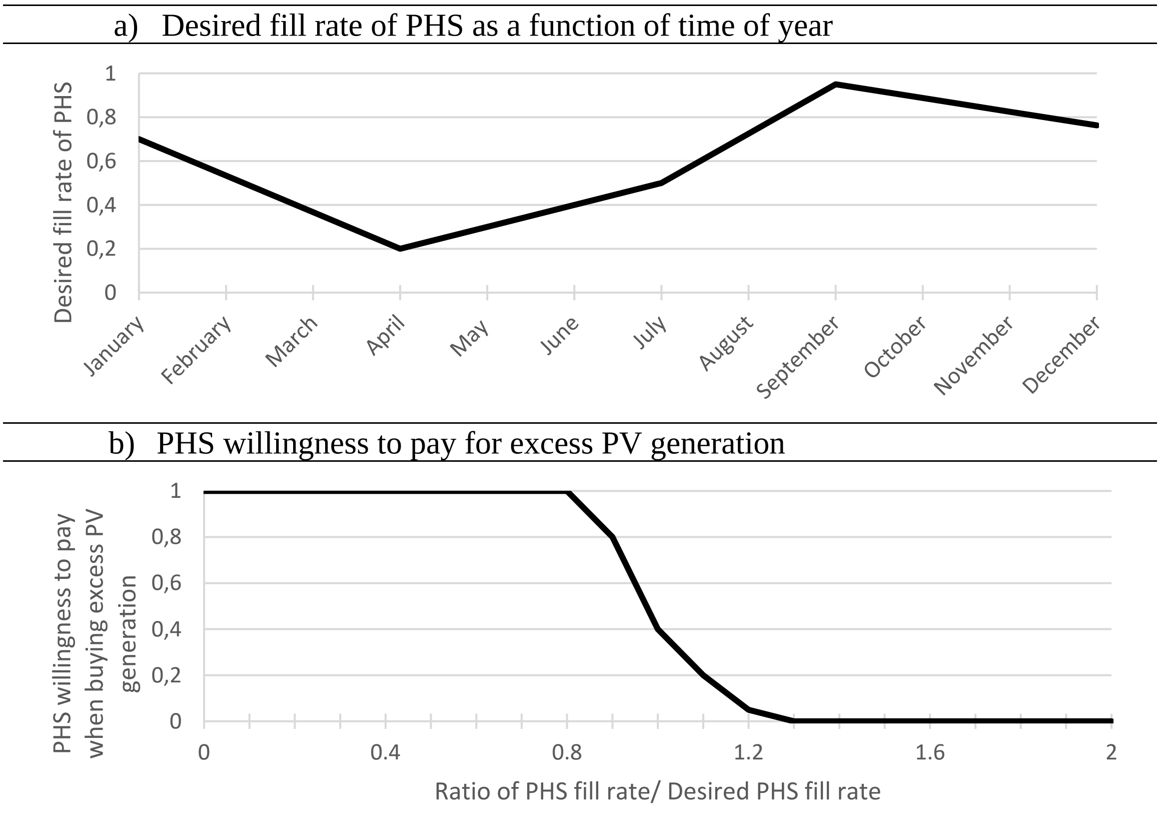

Figure 7. Impacts on PV bid

To summarize, except for PHS, all technologies base their bids on their LCOE. Specifically, RoR and nuclear bid at their LCOE, while PV and Hn apply certain corrections: Hn bids depend on the reservoir level, while PV bids depend on PHS's willingness to pay for the excess generation. Finally, PHS bids account for the average cost of water pumped and the reservoir level.

3.4.2 Medium term: Results and discussion

We consider two main scenarios: (i) a base case (no subsidies), and (ii) capacity auctions (CA). Table 4 summarizes the main results. The base case shows that relying solely on market-driven investments in PV leads to blackouts. As discussed before, in competitive markets, the electricity price may not adequately capture the value of investments required for a reliable electricity system (the "missing money problem"). Thus, for a viable transition, the electricity price should cover the cost of investments of PV and PHS in order to be profitable. We observed from the CA scenario that a smooth transition is possible while subsidizing only PV investments: subsidizing PV makes energy storage profitable, which was not the case in the base case.

Scenario/Variable	Base case	CA
PV capacity (GW)	9.0	15.7
PHS capacity (GW)	6.7	11.1
Electricity price (CHF/KWh)	0.27	0.18
Unmet demand	Yes	No
Curtailment	Yes	Yes

Table 4. Overview of results

Next, we query if the resulting mix of PV and PHS installed capacity is technically feasible in Switzerland. Starting with PV annual generation, our results suggest that 26 TWh are required, a figure lower than the potential generation of 32 TWh. Secondly, the required storage capacity can be reached by increasing the height of the existing reservoirs by 10%. Finally, regarding pumping, the required expansion of installed capacity is achievable given the geographical conditions.

To assess the robustness of our findings we explore the impact of key parameters such as natural water inflows, reservoir size and PV capital cost and the pace of the nuclear phase-out on the system. Table 4 shows the parameter changes considered for each of the eight sensitivity tests. For instance, a "+/- 10%" means a 10% increase or decrease of the parameter, compared with the base case.

Parameter	**Change**
Natural inflow	+/- 15%
Reservoir size	+/- 10%
PV capital cost	-0.5%/year, -1.25%/year
Nuclear phasing-out period	2025-2040, 2025-2030
Base case: 2025-2035	

Table 5. Sensitivity analysis parameters

In all cases we find that our previous conclusions stand: without subsidies blackouts are expected to occur throughout the transition period. Neither a decrease in PV capital cost (0.5%/year or 1.25%/year), nor a lengthening of the decommissioning process or an increase in reservoir size (15%) will result in sufficient renewable capacity investments to allow the system to meet demand at all times. The sensitivity analysis confirms that the transition towards renewables will lead to higher electricity prices at the end of the transition period. In addition, the welfare of society is threatened by the cost of repeated backouts. In the presence of CA, blackouts are eliminated but the average electricity price at the end of the transition process is 25% higher than the initial price. This is not surprising, considering that replacing nuclear with

PV entails significant investments. However, we find that in presence of CA, the consumer price is lower than the base case despite the cost of CA.

3.4.3 Long term: Results and discussion

We develop 12 scenarios: three climate cases with four different policies. The three climate cases are based on the Representative Concentration Pathways (RCP[1]): 2.6, 4.5, and 8.5 developed by the IPCC [56], [57][2]. The four different policies considered are (i) no subsidies, (ii) capacity auctions for PV investments, (iii) demand-side management focused on the recharge timing of electric car, and (iv) a combination of (ii) and (iii). We assume that the regulators will focus on reducing unmet demand. The results show that if the regulator does not take any action, the system will face blackouts and experience a significant price increase, independently of the climate scenario.

Table 6 summarizes the main results of this research. Our model suggests that capacity auctions can eliminate blackouts and that they increase energy storage profitability in all climate scenarios. However, the side effects of capacity auctions are an increase in curtailments and dependency of the system on PV subsidies. We find that shifting the recharge times of electric cars (the DSM policy) is not enough to eliminate blackouts. Still, this policy shows an improvement in terms of reducing the unmet demand in comparison with not taking any action. It is not a surprise that combining CA and DSM achieves the benefits of both policies: blackouts are eliminated, and curtailment decreases compared to the CA-only policy.

[1] i.e., RCP 2.6 assumes a radiative forcing peak at 2.6 W/m2 before 2100. Radiative forcing: The change in energy in the atmosphere measured in watts per square meter

[2] For more details on the RCPs scenarios, please see Table 2, Appendix 3

Once energy security is provided, consumer price becomes the priority of the regulator. We find that the average consumer price increases across the four policies tested. We can classify the results into two different sets of policies (with and without CA) due to the similarity in the average price within each set. We observe that policies in the set without capacity auctions has a higher electricity price than the ones with CA. In terms of energy balance, the set without CA policies has a high risk of blackouts, for instance, the unmet demand ranges from 1.5% to 15% of annual demand. It is not surprising that the CA policy set will necessarily lead to substantial curtailments. The curtailment in the CA and CA-DSM scenarios (as a % of annual demand) ranges between 6.1% and 15.3%. Within the CA policies set and given the high uncertainty the difference in the average price between the CA-only policy and the combined CA-DSM is negligible (6%). We cannot conclude which policy is the best in terms of consumer price, but we can conclude that the regulator should subsidize PV investments to avoid a huge increase of the average price.

	RCP 2.6				RCP 4.5				RCP 8.5			
	BC	**CA**	**DSM**	**CA-DSM**	**BC**	**CA**	**DSM**	**CA-DSM**	**BC**	**CA**	**DSM**	**CA-DSM**
PV capacity (GW)[2, 3]	14.7	*17.8*	13.3	*17.4*	14.9	*21.0*	14.1	*20.4*	15.2	*22.5*	14.6	*21.6*
PHS capacity (GW) [2, 3]	25.7	*18.6*	20.2	*18.4*	27.7	*21*	23.7	*20.2*	27.8	*22*	24.6	*21.3*
RoR generation (TWh)[2]	13.2	13.2	13.2	13.2	13.1	13.1	13.1	13.1	13.8	13.8	13.8	13.8
PV generation (TWh)[2]	22.1	35.4	21.9	33.8	22.4	42.9	22.3	43.2	22.5	46.9	22.6	47.5
PV consumed (TWh)[2]	19.8	20.9	19.8	21.2	20.7	23	20.7	23.6	20.8	23.7	20.9	24.1
PHS generation (TWh)[2]	1.8	9.6	1.7	8.5	1.4	12.5	1.3	13.3	1.4	14.7	1.3	14.6
Hn generation (TWh)[2]	19.7	17.3	19.6	18	17.8	15.1	17.7	13.5	17	12.7	17	12.3
RoR generation share (%)[2]	23%	17%	23%	18%	24%	16%	24%	16%	25.5%	15.6%	25%	15.6%
PV generation share (%)[2]	39%	47%	39%	46%	41%	51%	41%	52%	41%	53%	41%	54%
PHS generation share (%)[2]	3%	13%	3%	12%	2.5%	15%	2.3%	16%	2.5%	17%	2.4%	16.6%
Hn generation share (%)[2]	35%	23%	35%	24%	32.5%	18%	32.7%	16%	31%	14.4%	31.6%	14%
Unmet demand (TWh)[2]	6.5	-	6.6	-	10.7	-	10.7	-	12	-	11.7	-
Unmet demand (%)[2]	2%	-	1.5%	-	8%	-	7%	-	15%	-	13%	-
Overflow (TWh)[2]	-	2.3	-	1.7	-	2.7	-	4.3	-	4.3	-	4.7
PV curtailed (TWh)[2]	-	2.5	-	2	-	4.3	-	2.9	-	4.8	-	5.2
Curtailment (TWh)[1]	30	348	23	345	32	405	25	369	25	417	22	400
Subsidies (Millions CHF)[1]	-	40,074	-	40,216	-	54,420	-	54,722	-	61,304	-	61,615
Market price (CHF/MWh) [2, 3]	291	*137.2*	284	*131.5*	340	*130.3*	337	*122.2*	345	*123*	341	*114*
Consumer price (CHF/MWh) [2, 3]	291	*143*	284	*137*	340	*138*	337	*130*	345	*132*	341	*124*

[1]Cummulative over the simulation period; [2]Final value; [3]Italics refer to an average over the final cycle

Table 6. Overview of the results

To conclude, while there are trade-offs between the scenarios tested, no regulator will allow a system to have ongoing blackouts. Thus, our results suggest that subsidies are necessary to avoid blackouts; capacity auctions are the most effective action among those tested, and adding DSM will have a useful supplementary impact.

4. RESEARCH LIMITATIONS

We are aware of the limitations of our research; our results rely strongly on the methodology choice and our hypotheses. Concerning the methodology choice, as argued before, we are aware of the limitations of an SD approach, however, the SD model allows us to test different policies, and our analysis provides useful insights.

Regarding the hypotheses, we calculated key variables by averaging historical data, thus the values do not capture possible extreme events. For instance, our research does not consider extreme weather conditions such as long cloudy periods that could reduce PV generation.

Our results rely on the strong hypothesis of a constant population and a stable economy. Historically, population size and economic growth have been considered as drivers of electricity demand. However, over the last decade we have observed how electricity demand is decoupling from population and economic growth. This phenomenon has been explained by the increase in technological efficiency. Thus, we implicitly assume that technology efficiency offsets the impact of future population and economic growth on the increase in demand.

On the opposite side a decline in population is an event that has been forecasted to occur in almost all developed economies during the next 50 years. This phenomenon would have a direct impact on electricity consumption. However, is difficult to forecast future flows of immigration which could offset the low birth rate.

We also ignore the impact of possible economic recessions, unless there is a long-term stagnation, this element should not be considered in long-term models. As an example, the impact of the 2020-2021 pandemic on energy demand was temporary, and we have seen a strong recovery after countries abolished the sanitary measures.

Our research framework is also limited by the omission of possible political and legal changes that a transition towards green generation would require. As an example, one can imagine future global bans on fossil fuel consumption, due to commitments to reduce GHG emissions. A ban on fossil fuels would result in a growth in electricity demand, which will increase the pace of the transition towards renewables. Another example of political issues is the Ukraine-Russia crisis, which has impacted the natural gas and oil prices. This has disrupted the energy markets in the short-term, increasing the electricity price in Europe. One consequence of this increase in price is the discussion among EU members to accelerate the exit fossil fuels and the transition towards renewables. Regarding legal changes, we assume that Switzerland does not reconsider the nuclear phase-out process. Given the current pressure to avoid possible shortages over the next years, the government or the population could call for a vote to review the decommissioning of the nuclear capacity [61].

We assumed that there is no cross-border electricity trade. This modeling choice results from the objective to test the viability of a self-sufficient electricity system with 100% green generation. We are aware that modern economies are strengthening their business ties. However, Switzerland has recently chosen not to sign an agreement with the European Union, which endangers future electrical exchanges between the two parties. This situation is critical as the EU countries give priority to other EU members when trading electricity. In a hypothetical case in which the EU and Swiss electricity supplies are simultaneously tight, Switzerland's electricity security could be endanger, due to the inability of Switzerland to buy electricity from the EU market.

5. CONCLUSIONS

With a growing consciousness of global warming and its effects, and the increased speed of VRES technology development, electricity markets have been moving towards green generation. However, there is still no consensus concerning the viability of such transitions under increasing demand and the uncertainty concerning the availability of natural resources due to climate change. Moreover, many countries are transitioning to a substantial share of PV; this will result in neighboring countries experiencing a surplus of electricity at the same time, making exports unprofitable and also making imports difficult as shortages may concur. Having too much excess might lead to periods of negative prices, a phenomenon that has already occurred [11]. Thus, one should expect that governments will prioritize security of supply by aiming for a high degree of self-sufficiency. In this thesis we have elaborated on the key perspectives of electricity markets that are transitioning towards 100% renewable generation.

The main objective of this thesis was to understand how electricity systems can achieve the transition towards renewable generation under the effects of climate change, both on demand and supply. In this context, we have aimed to answer four questions, using Switzerland as a case study. The first one tackles the technical feasibility of electricity systems with 100% renewable generation. The second question relates to the desirable end-state of the transition process. The third one concerns the regulatory mechanisms that enable a smooth transition towards renewables in the mid-term. The final one concerns the very long-term, i.e., the impact of a simultaneous decrease in supply and increase in demand due to climate change.

Concerning the first question, we find that in terms of technical feasibility, Switzerland's electricity system can rely on a PV-hydro combination. This result should be taken with precaution, given that it only deals with the end-state and not with the feasibility of the transition process. Moreover, we find that in the most plausible scenario, taking into account the political and technical limitations, Switzerland must increase its reservoir capacity by 20% in order to be able to shift the excess PV generation in summer to winter to avoid blackouts. Our results allow us to understand the vital role of storage, which enables the system to deal with seasonality and hourly patterns in demand and supply in systems with a high share of renewables. In our study we consider hydrostorage but this technology could be replace by others (i.e., hydrogen and batteries).

Another solution is the installation of floating panels on high altitude water reservoirs [60], [62]. This combination offers some advantages compared to conventional rooftop PV. The first advantage is a higher generation during winter (snow reflection increase PV generation). Secondly, pumped hydro-storage could pump locally and finally, the current reservoirs already have the required infrastructure (e.g., installed grids). This combination offers a certain potential: a pilot project has proven successful, with a large scale implementation scheduled for 2022 aiming to generate 22 GWh per year [63].

Given the technical feasibility of 100% renewable electricity system, we analyze what mixes of traditional technologies and VRES are most suitable from a social welfare perspective. Our results show that the best option in terms of price in a system with high demand and supply seasonality is to have a reliable base load technology (e.g., nuclear) while storing excess VRES generation to be used at peak time. We also find that a high share of PV generation leads to a significant increase in consumer price. This result is not surprising, as the PV bid is higher than nuclear because PV needs to cover its capital costs, while nuclear's capital cost is generally amortized.

The last challenge of this thesis concerns how to manage this transition both in the medium- and long-term. For both horizons we find that market-driven investments are not enough to avoid blackouts. Thus, the transition process must be accompanied by regulatory mechanisms that encourage investments (e.g., capacity auctions). We also find that subsidizing PV investments makes storage profitable. Indeed, subsidizing renewables (e.g. wind and solar) leads to high excess generation at certain time, resulting in arbitrage opportunities for storage facilities. In the long-term the need for capacity auctions is stronger as the system faces the replacement of reliable generation by intermittent technologies while dealing with the effects of climate change on demand and supply. However, we expect that subsidy requirements could go down over time due to technological progress: PV capital costs should decrease over time, making PV profitable with less, if any, interventions.

Our results show that under current technological conditions the impact of a simultaneous increase in demand and decrease in supply will threaten the viability of such a transition if no subsidies are granted. We assume that the regulator will focus on securing enough installed capacity to meet demand. Regulators must also face the challenge of an increased consumer price that can threaten public support, this is particularly important in countries with a direct democracy, as elaborated upon in the next paragraph. Thus, understanding consumer behavior is essential to design and implement demand-side mechanisms that can result in lower consumer prices compared with supply side-only policies. We can conclude that, among the scenarios tested, the best option is to encourage VRES investments with capacity auctions, and complementing it with a well designed demand-side management mechanism. This combination of policies allows the electricity system to eliminate the blackout risk during the transition process towards renewables, while limiting the need for curtailments.

Switzerland is an interesting case given the power given to people via the ability to call a referendum on any law. This power can be both an advantage and a disadvantage. On the one hand, the population can pressure the government to speed up the required changes. On the other hand, any reform of the system depends on public support. The latter could be a problem as reforming the system depends on the public perception. For instance, energy security could improve transitorily due to more precipitations, but in the long run the precipitations are expected to decrease. The population can perceive that the situation is initially getting better and consequently, voting to postpone critical decisions that are necessary to avoid future blackout risks.

Two recent examples illustrate the power given to people. Firstly, the CO2 act referendum that took place in June 2021. This CO2 act aimed to reduce emissions in Switzerland, but the population voted against it. This referendum faced opposition from two sides. For certain parties the CO2 act went to far, while the environmentalist thought that the proposed measures to be insufficient [64]. Another historical example is the 2017 nuclear power referendum. The population voted against the construction of new nuclear capacity due to the fear of nuclear accidents (recall the Fukushima accident in 2011).

These two elements (CO2 act, no nuclear) and the decision not to sign the Swiss–EU institutional agreement increase the risk of blackouts: a recent study by the Swiss Federal Office of Energy estimates that in 2025 Switzerland could face between 47 and 500 hours of blackouts [65]. To address this problem, politicians have started a discussion on lengthening the nuclear phase-out process and on the installation of 2,000 small gas plants [66].

The transition towards renewables in Switzerland is feasible. However, the country should take several actions in order to successfully achieve such a transition. Firstly, the government should slow down the nuclear phase-out. In parallel to this measure, investments in gas capacity should be contemplated to cover the base load during winter months. While nuclear investments could be considered, this would raise two problems: nuclear is highly controversial and building capacity requires several decades. However, nuclear has the advantage of being a reliable low emission technology. Secondly, the Confederation should introduce aggressive subsidies to encourage a faster increase of PV capacity and, if possible, other renewables (e.g., wind, biomass, geothermal). Finally, Switzerland must encourage new negotiations and pursue an agreement with neighboring countries concerning cross-border electricity exchanges.

The combination tested (PV and PHS) is the most suitable for Switzerland as this country has enough water resources and the right geographical characteristics to make pumping feasible and PV is the renewable technology with the highest potential. Moving forward from the Swiss case, it is important to state that that there is no ideal “one size fits all” energy formula. The results in this thesis should be taken with caution as what is optimal for one country may not be suitable for another due to its differing characteristics. It is crucial to consider the specific renewable resources, and climatic and geographical conditions of a country in order to study its transition towards green generation. For instance, in a region with suitable wind patterns, wind turbines could be chosen as the main renewable technology. In contrast with PV, wind has a less predictable pattern, thus generation can occur at any time, including night hours. The latter should impact the average consumer price as cheap electricity is generated by wind at night, in contrast to our model in which PV is limited to generating only during daylight. With increased uncertainty regarding generation, arbitrage opportunities become more erratic for storage technologies. This may result in lower expected profitability for storage, and thus subsidies may be required to allow the system to develop enough storage capacity.

The more pronounced the seasonal pattern, the stronger the need for long-term storage. PHS is the most used storage technology for three main reasons. Firstly, PHS is a mature technology that has been used since the 1930s. Secondly, it has one of the highest round-trip efficiencies (around 80%). Thirdly, PHS has a lifetime of over 60 years, and a relatively low maintenance cost. However, PHS cannot be deployed everywhere due to geographical, environmental and resource limitations, e.g., insufficient water availability and/or natural features such as mountains.

Other potential long-term storage technologies that have been used are compressed air energy storage (CAES) and hydrogen. Compressed air is a mature technology: the first plant was built in 1978. But this technology requires very large volume storage sites (for instance salt caverns in deep salt formations are preferred) which prevents it from being deployed anywhere (geological constraint). Also, CAES has a lower round-trip efficiency compared to PHS (around 50%). Concerning the environmental aspect, CAES depends on the supply of fuels such as natural gas. In contrast, hydrogen is not geographically constrained, but has several other disadvantages: is not commercially mature, has an even lower round-trip efficiency (between 18%-46%) and high capital costs. To conclude, if CAES or hydrogen are used to store energy instead of PHS, this would entail more energy losses and thus requires increased installed capacity to balance these losses. This would negatively affect, consumer price possible, impacting public support for the transition process.

Some general conclusions can be drawn from our analysis. First, in the presence of intermittent sources, storage is a key element of the transition process. Second, significant excess generation from renewables at certain times is required to make storage profitable. Third, given current capital costs of VRES, market driven investments are not enough, thus intervention is required. Finally, it is important to include the social and political dimensions when analyzing the transformation of an energy system: public support and political will are essential ingredients to successfully achieve any transition.

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APPENDIX: Papers

A.1. J. E. Martínez-Jaramillo, A. van Ackere, and E. R. Larsen, “Transitioning towards a 100% solar-hydro based generation: A system dynamic approach,” Energy, vol. 239, p. 122360, 2022, doi: https://doi.org/10.1016/j.energy.2021.122360

A.2. J. E. Martínez-Jaramillo, A. van Ackere, and E. R. Larsen, “Transitioning towards a 100% solar-hydro based generation: A system dynamic approach,” Energy, vol. 239, p. 122360, 2022, doi: https://doi.org/10.1016/j.energy.2021.122360

A.3. J. E. Martínez-Jaramillo, A. van Ackere, and E. R. Larsen, Facing climate change: does Switzerland have enough water?,

APPENDIX A.1

TOWARDS A SOLAR-HYDRO BASED GENERATION: THE CASE OF SWITZERLAND.

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Abstract

Switzerland has voted for a gradual nuclear phase-out, starting in 2019 with the decommissioning of a first nuclear reactor; however, there is still a debate about how the country will replace nuclear generation. Electricity markets are transitioning towards renewable sources such as hydro, wind and solar. The latter two could produce a mismatch between demand and supply. Combining renewables with storage is one way to address this challenge. This paper analyzes the feasibility of 100% renewable generation in Switzerland. We consider hydro and PV generation, combined with pumped hydro storage, to address the timing problem between demand and PV generation. We explore several combinations of installed solar capacity, reservoir levels and pumping capacity. Our findings indicate that given current technological development, Switzerland would need to double its pumping capacity, increase solar generation capacity by a factor between 13 and 25, while increasing reservoir size up to 100% depending on the installed solar capacity.

Keywords: Swiss electricity market, photovoltaics, sustainability, pumped hydro storage, self-sufficiency

1. Introduction

The last decades have seen an increase in pressure to reduce greenhouse emissions and thereby limit global warming. One sector that has been particularly targeted is electricity generation, with a desire to replace thermal generation by variable renewable energy sources (VRES) to lower emissions. At the same time, following the Fukushima accident, several countries are facing pressure to scale down or end nuclear generation (Ming, et al., 2016). These trends have strengthened the interest in understanding if an electricity system based on 100% renewables can be viable. The main problems of VRES are their intermittent nature (which reduce system flexibility and increase the unpredictability of future electricity generation), their capacity cost and the distortion of electricity prices resulting from subsidies (Ketterer, 2014; Krajačić, Duić, & Carvalho, 2011). Due to technological progress and economies of scale, the capacity cost of VRES has been falling in recent years (Batalla-Bejerano & Trujillo-Baute, 2016; Kaldellis & Zafirakis, 2011). Consequently, a number of countries have started to gradually phase out subsidies (Tabassum, et al., 2014). While this evolution solves two of the problems, capacity cost and subsidies, it makes the remaining issue of intermittency even more central as the transition towards power systems with a high share of renewables seems inevitable (Carley, Baldwin, MacLean, & Brass, 2017; Carley & Lawrence, 2014; Johannsdottir & McInerney, 2016; Riesz & Gilmore Iain MacGill, 2016).

Traditionally electricity has been thought of as non-storable, i.e., demand and supply must match in real time. To enable system operators to balance the market, generation needs to provide sufficient flexibility to follow the hourly and seasonal demand patterns (Papaefthymiou & Dragoon, 2016). While this requirement is well understood and resolved in traditional thermal systems, it poses a new and larger challenge in systems with a high share of VRES. Solutions to generation intermittency include energy storage, demand side flexibility and greater control over electricity dispatch (Barbour & González, 2018; Ecofys, 2014). In particular, storage is used to absorb excess generation at times where demand is below the potential supply; this stored energy can be released when needed.

Energy storage is likely to become a corner stone of VRES penetration in electricity markets. Storage can occur at any point in the system: as a primary energy source such as water in reservoirs, at the grid level (e.g., batteries) and at the level of the final user such as hot water tanks (Papaefthymiou & Dragoon, 2016). While batteries are used in a few electricity systems, such as in Australia (Green & Staffell, 2017), they are still generally considered too expensive (IRENA, 2017). Where geographically possible, power systems have used hydro-storage plants to increase the response to variability in demand and storing excess renewable generation (Hino & Lejeune, 2012). Hydro-storage has the additional benefit of being capable to adjust quickly, thereby providing flexibility to the system. Conventional hydro-storage plants rely on natural water inflows. Adding pumping to a hydro-storage plant mitigates the limitation and variability of natural inflows (Deane, Gallachóir, & McKeogh, 2010).

With a world-wide installed capacity of over 95 GW, pumped hydro storage (PHS) is currently the most widely used technology for large scale storage, representing around 99% of grid-connected electricity storage around the world (Deane et al., 2010; Decourt & Debarre, 2013; Pérez-Díaz, et al., 2015). To be profitable, PHS requires access to the transmission network and water availability (Deane et al., 2010). Switzerland's topography and climate being particularly well suited to PHS, its potential has been exploited for many years, enabling it to become one of the leaders in PHS capacity in Europe.

The aim of this paper is to examine the feasibility of a 100% renewable electricity system by analyzing the case of Switzerland, which needs to replace its nuclear capacity that will be phased-out over the next decades (Pattupara & Kannan, 2016). We consider the combination of solar and hydro generation, with pumping facilities to store energy, and we explore several permutations of installed solar capacity, reservoir levels and pumping capacity.

This paper is structured as follows. In section 2 we review the relevant literature. In section 3 we present the Swiss case. This is followed by a discussion of the data and modelling assumptions in section 4. Section 5 presents the scenarios and results. Finally, section 6 provides a discussion of the results and our conclusions.

2. Literature review

Electricity systems with a high share of VRES have been studied from two main points of view: policy analysis and technical feasibility (Forrester, Zaman, Mathieu, & Johnson, 2017). VRES have been mainly encouraged by tax incentives, subsidies for investors and production incentives. A statistical analysis based on U.S. data concludes that these three policy tools are positively correlated with investment in wind energy generation capacity (Wiser, Bolinger & Barbose, 2007). Subsidies are controversial. It has been argued that subsidies bias the market (e.g., they can lead to investments in inefficient projects) and prevent the development of markets for renewables by creating a mental model among customers that renewables should be free or subsidized (Martinot et al., 2002). Barradale (2010) and Carley et al. (2017) agree that such strategies tend to be temporary, and highly dependent on support from the population. The resulting political uncertainty decreases investors' confidence, reducing the government's ability to secure power investment agreements.

Carley et al. (2017) analyze two specific policy instruments (feed-in tariffs (FITs) and renewable portfolio standards (RPS)) that encourage the adoption of VRES. Both policies aim to develop the markets for renewables by reducing investors' risk. FITs pay producers a preferential price per kWh generated. RPS define a quota of electricity generation or sales from renewables. Using data from 164 countries, the authors provide evidence that FIT and RPS have a statistically significant impact on renewable market growth, as measured by the percentage of energy produced by renewables and the annual incremental renewable energy generation. However, recent developments indicate that the falling capital cost of VRES makes it possible to reduce subsidies; they will most likely be phased out over the next few years (Edenhofer et al., 2013; Held et al., 2018). There already are examples of relatively large wind parks being developed without any subsidies (Tabassum, et al., 2014). While this is not yet the norm, it is expected that an increasing share of projects will be economically viable without subsidies.

Several studies illustrate the technical potential of electricity systems with 80 to 100% generation coming from VRES for different countries. Table 1 summarizes the key findings of selected studies.

Country	Authors	Key points
Ireland	Connolly, Lund, Mathiesen, & Leahy (2011)	The results present a potential 100% renewable energy-system. This study was carried out from a technical and resource perspective, ignoring economic aspects.
Portugal	Krajačić et al. (2011)	The authors develop and model three different scenarios and find that a 100% renewable system needs to rely strongly on hydro, given the current hydro power installed capacity and the potential of this country to rely on pumping to store energy.
United States	Hand (2012)	Current technology is more than adequate to supply 80% of total electricity generation by 2050 from renewable sources; the remainder will be provided by traditional technologies.
Denmark	Lund & Mathiesen (2009)	A 100% renewable system relying mostly on biomass and wind power is possible, but will have to integrate some form of long-term energy storage.

Table 1. *Technical feasibility studies for selected countries*

Most studies conclude that energy storage is key to achieving a 100% renewable system. Schill & Zerrahn (2018) review 33 models, which consider different types of storage. They conclude that, while there is no consensus in this literature, there are some common elements. First, energy storage becomes an economically viable option to integrate high shares of renewables when renewable deployment is between 50 and 70%. Second, for intra-day storage, batteries are useful to smooth the variability of wind and PV. Finally, inter-seasonal power storage (for instance through pumping or hydrogen storage) only becomes economically viable for 100% renewables systems.

3. Switzerland

The Swiss 2017 annual electricity demand was 62.6 TWh, with residential consumption accounting for 33%, industry for 30% and services for 27%. Transport and agriculture accounted for the remaining 10%. In 2017 hourly demand peaked at 8.3 GW (42% of installed capacity) and the lowest hourly demand recorded was 3.7 GW, representing 19% of installed capacity (SFOE, 2017a). With 10.5 GW of hydro-storage generation capacity, Switzerland can always meet peak demand, conditional on enough water being available.

By the end of 2017 the total installed generation capacity in Switzerland was 19.9 GW, of which nuclear represented 17% and hydropower 75%; the remaining 8% include other sources such as cogeneration plants and PV. Hydropower generation capacity consists of 10.5 GW of hydro-storage plants, 2.3 GW of pumped hydro-storage and 4.5 GW of run-of-river plants. Hydropower plants currently under construction will add 1.9 GW to the installed generation capacity by 2020 (OFEN, 2016). PV capacity nearly doubled over the last ten years, reaching an installed capacity of 1.6 GW in 2017 (SFOE, 2016a).

Between 2010 and 2017 the average annual electricity production was 66 TWh, with nuclear representing 36 % of the total generation, hydropower 58% (54% of which produced by hydro-storage plants and the remaining 46% by run-of river) and thermal and renewables 6% (SFOE, 2017a).

Currently, the hydro reservoirs have an aggregate storage capacity of 8.8 TWh, which corresponds to about 15% of annual demand. Figure 1 shows the end-of-month fill rate of the reservoirs from 2008 to 2017. The minimum is reached around the end of March (11%), while the peak generally occurs at the end of September (the maximum level recorded being 89%). Reservoirs are thus used to store excess water during late spring and summer to be used in late fall and winter.

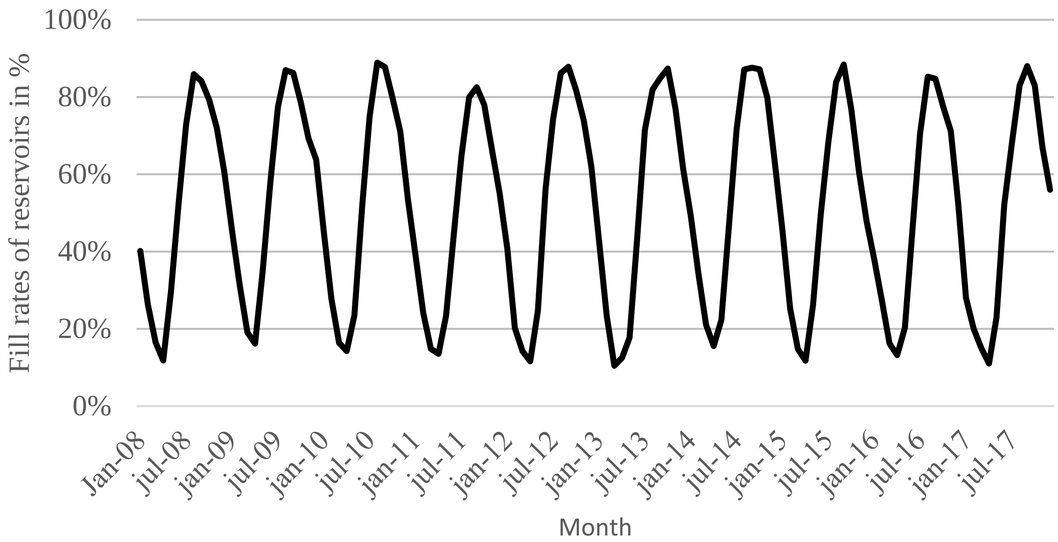


Figure 1. *Fill rate of hydro reservoirs in Switzerland, 2008 -2017* (SFOE, 2017a)

The transition to a 100% renewable generation mix is particularly topical in Switzerland given the decision to dismantle the nuclear plants over the next 25 years (The Swiss Federal Council, 2011), and the opposition from the population (through direct democracy) to the construction of thermal plants (Federal Administration, 2016). This raises the question of how nuclear generation will be replaced. As mentioned above, nuclear energy accounts for 36% of total electricity generation. In recent years there has been a debate about the ability of the Swiss electricity system to meet national demand after 2019, when the first nuclear reactor will be dismantled (The Swiss Federal Council, 2011).

In its Energy Strategy 2050 the Federal council outlines the path the Swiss electric system should follow over the next decades. The aims are to reduce energy consumption, increase energy efficiency and promote the use of renewable energy (SFOE, 2018). To enable the implementation of this strategy, the new electricity law proposes among others to liberalize the market for small consumers, to improve the regulation of the grid (in particular its pricing for consumers), and, a major novelty, the introduction of a storage reserve (The Swiss Federal Council, 2018a). The latter point is particularly interesting, as the government sees this as a way to insure security of supply while minimizing market interference: while most countries develop strategic reserves of generation capacity, the Swiss reserve would consist of stored energy, mainly under the form of water in the hydro-reservoirs.

The Swiss government has encouraged investment in PV and wind projects with a FITs mechanism (SFOE, 2012). The effect of FITs on the electricity system has been an increase of solar installed capacity from 79 MW in 2009 to 1.6 GW in 2017 and an increase of wind installed capacity from 18 MW to 69 MW over the same period (SFOE, 2017a).

The annual Swiss PV generation potential has been estimated at 15 TWh (Assouline, Mohajeri & Scartezzini, 2015). This potential only considers roof-top PV for a total area of 328 km^2. The authors forecast that by 2050 the potential PV generation could be of the order of 32 TWh, assuming a 90% increase of the performance ratio[1] and an annual increase in cell efficiency[2] of the crystalline silicon wafers of 0.3%. Another option is the installation of floating panels on water reservoirs (Farfan & Breyer, 2018; Ranjbaran, Yousefi, Gharehpetian, & Astaraei, 2019). While this is likely to be highly controversial for reservoirs located in protected areas,

[1] Performance ratio describes the relationship between the actual and theoretical output of a solar panel.
[2] Cell efficiency refers to the proportion of energy that can be converted from sunlight into electricity.

it does offer a certain potential: a pilot project is currently under way, with a large scale implementation scheduled for 2021 if the pilot project proves successful (Romande Energie, 2018). Increasing PV entails an excess of energy during the day, especially in summer, so pumping facilities must provide intra-day and inter-seasonal storage capacity. Pumping is not new in Switzerland. Most of the current pumping facilities started operating in the 1960s. At the end of 2017 the total generation of PHS was of the order of 1.5 TWh, representing 2.3% of the total electricity consumed in Switzerland (SFOE, 2017c).

Switzerland's hydro-generation is limited in winter not by the generation capacity, but by the availability of water, due to the seasonality of inflows and absence of excess PV generation in winter. Increasing reservoir capacity, enabling more inter-seasonal storage, would allow for more hydro-storage based generation in winter. Unfortunately, expansion potential is rather limited for both technical and environmental reasons: the best locations are already in use, and any large new development, implying the flooding of mountain areas, is bound to run into opposition and be blocked by Switzerland's direct democracy system. Gains of the order of 10% could be achieved by heightening existing dams and increasing generation efficiency (i.e., more MWh per m^3 of water). This potential increase is to be put in perspective with the expected loss of storage capacity due to sedimentation in the reservoirs, estimated to be around 7% between now and 2050 (SFOE, 2019).

According to a study from the ETHZ, the retreat of glaciers in the Swiss Alps is creating the potential for seven new hydro-reservoir plants, but these would only add an estimated 853 GWh to the storage capacity, i.e., about a 10% increase. Additionally, while technically possible, these developments would not only be extremely costly, but also run into major opposition as they are partly located in protected areas (ETHZ, 2017).

4. Data analysis and scenarios

We consider the solar-hydro and pump storage combination for two main reasons: firstly, Switzerland's topology and water resources make pumping a feasible storage technology and, secondly, PV is the renewable technology with the highest potential in Switzerland. Solar has nine times the potential of wind and three times the combined potential of biomass and geothermal (SFOE, 2017b). We perform a stylized analysis, considering hydropower (hydro storage and run-of-river), one intermittent renewable technology (PV) and one storage method (pumping).

To address the challenge of moving towards 100% solar-hydro based generation in Switzerland, two main questions must be addressed: (i) can Switzerland be self-sufficient (neither imports nor exports of electricity) with such a system and, if yes, (ii) which combinations of PV, reservoir size and pumping are possible? Studying an isolated country implies that the resulting combination allows meeting the annual demand. We are aware of the increased international collaboration in Europe and the growth in electricity trade across borders (Abrell & Rausch, 2016). Still, for this study we assume that when deciding on energy policy, policymakers might find electricity generation too critical for national security to accept a scenario in which the country is unable to cover national demand. Additionally, capacity margins across Europe have tended to decrease over the last decade (Hary, Rious, & Saguan, 2016). We elaborate on this in the discussion section.

Our analysis takes a high-level view; we consider a monthly approach, using a typical day for each month to analyze demand and supply. This approach allows us to analyze what happens during two extreme intra-day cases: at noon when PV generation peaks and at night when there is no PV generation. Our goal is to focus on the technical feasibility; consequently, we assume a central planning on the system. This assumption reduces uncertainty caused by strategic behavior as it prevents game playing by market participants (e.g., generators withholding capacity to influence price) and, more generally, as uncertainty is positively correlated with the number of market participants (Larsen & Bunn, 1999). One should note that, as this is a conceptual model, we do not consider randomness, but rely on average values.

Taking natural water inflows and average sun radiation per month in Switzerland as given, and initially assuming no constraints on storage and pumping, the required PV is evaluated. To do so, we first calculate the demand that cannot be satisfied by run-of-river and the natural inflows to hydro-storage plants. Next, we compute the required PV to satisfy this unmet demand. We take into account the different loss factors when transforming solar energy into stored energy, and back to electricity. We also quantify the resulting required reservoir size and the pumping. To estimate demand and supply of electricity we use both governmental (Swiss Federal Office of Energy -SFOE-) and other sources. Table 2 summarizes the main inputs and the sources used (please see Appendix 2 for a flowchart providing an overview of the methodology).

Inputs	**Source**
Electricity demand, electricity generation, installed capacity, solar potential, new hydro projects, dam's water level and pumping facilities	SFOE, 2010, 2014, 2016, 2017a, 2017b
Solar irradiation in Switzerland	MeteoSwiss, 2017
Solar cell efficiency	Assouline, Mohajeri, & Scartezzini, 2015
Losses from pumped hydro-storage	Chandel, Nagaraju Naik, & Chandel, 2015

Table 2. Data sources

5. Modelling and results

We consider three sources of generation: run-of-river (RR), PV and hydro-storage (HS). Part of the PV generation (denoted PV) is consumed immediately($\mathrm{PV^c}$), while the remainder is used for pumping ($\mathrm{PV^p} = \mathrm{PV} - \mathrm{PV^c}$). Consequently, the HS is generated from two inflows: natural inflows ($\mathrm{HS^n}$) and pumping ($\mathrm{HS^p}$). The latter is calculated as $\mathrm{HS^p} = 0.8 * \mathrm{PV^p}$ due to losses (Chandel et al., 2015).

To quantify the required PV capacity, we start by calculating the total solar electricity generation needed ($\mathrm{PV} = \mathrm{PV^c} + \mathrm{PV^p}$). Equation (1) describes the relationship between total annual demand (D), RR, $\mathrm{HS^n}$, $\mathrm{PV^c}$ and $\mathrm{HS^p}$.

$$D = RR + HS^n + HS^p + PV^c\ . \tag{1}$$

Recall that D, RR and $\mathrm{HS^n}$ are derived from historical data. Using the fact that $\mathrm{HS^p} = 0.8 * \mathrm{PV^p}$, we can rewrite equation (1) as follows:

$$D - RR - HS^n = 0.8PV^p + PV^c. \tag{2}$$

Next, we calculate the minimum required PV capacity to ensure that the required amounts of $\mathrm{PV^c}$ and $\mathrm{PV^p}$ can be generated so as to meet demand at all times, i.e., taking into account daily and seasonal patterns. We assume a merit order dispatch in which RR is dispatch first, solar next and finally hydro-power, unless this would lead to reservoirs flowing over. In such cases, solar generation is curtailed.

We denote by $\overline{PV}$ the maximum possible electricity generation from solar panels, while PV denotes the actual electricity generation. In the base case we assume unlimited reservoir capacity, implying that there is never a need to curtail PV generation, i.e.,

$$\overline{PV} = PV. \tag{3}$$

It is important to distinguish between on the one hand total generation (which includes electricity used for pumping), and on the other hand electricity available for final consumption, which we refer as net generation (NG). Total generation (G) is defined as the total amount of generation that is actually produced (including electricity used for pumping) and equals:

$$G = RR + HS^n + HS^p + PV^c + PV^p. \quad (4)$$

Potential net generation (PNG) is the amount of electricity that could be generated and made available for final consumption in an ideal situation where generation and demand patterns match:

$$PNG = RR + HS^n + \overline{PV}. \quad (5)$$

In practice this is not the case and net generation (NG) equals:

$$NG = RR + HS^n + HS^p + PV^c . \quad (6)$$

To determine how much should be generated by each technology and any curtailment for each month t. We need to quantifyHS_t^n, PV_t^c, PV_t^c and curtailment denoted (CT_t). Recall that annual RR, monthly RR and annual HS^n are given and that we assume that reservoirs are managed to avoid any water overflows. Potential generation in month t, PG_t is defined as follows.

$$PG_t = RR_t + HS_t^n + HS_t^p + PV_t^c + PV_t^p + CT_t. \quad (7)$$

This equation must satisfy the following constraints; $\sum_t HS_t^n = HS^n$, $\sum_t HS_t^p = 0.8 \sum_t PV_t^p$ and $\overline{PV}_t = PV_t^c + PV_t^p + CT_t$.

In section 5.1 we assume an unconstraint reservoir capacity and thus no need for curtailment. Section 5.2 shows four alternative scenarios illustrating the trade-off between reservoir capacity, PV capacity and pumping facilities. Finally, in section 5.3 we perform a sensitivity analysis of the water inflows and irradiation.

5.1 Unconstraint reservoir capacity

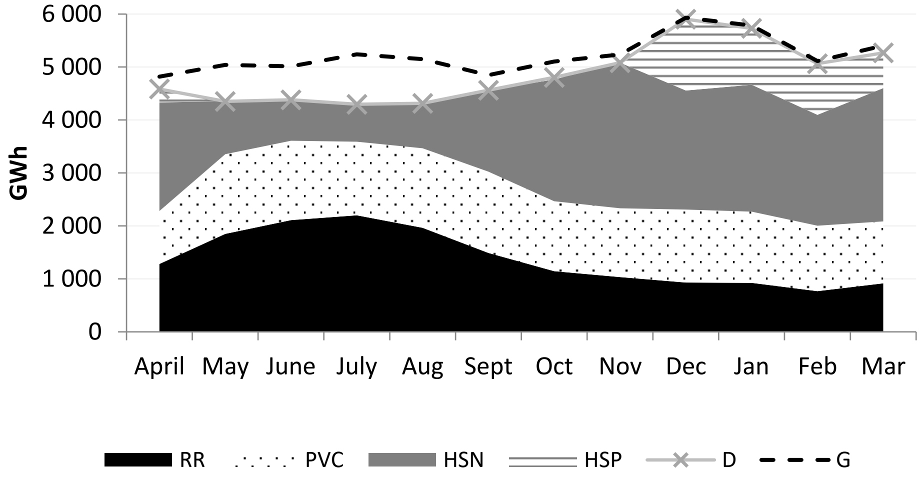
We first consider an "unconstraint" scenario, where the total potential generation enables to cover exactly the annual consumption (including pumping consumption and losses). This scenario captures the extreme case in which storage capacity is non-binding, hence the name extra-large (XL).

In this scenario, PV capacity should increase from the currently installed capacity of 1.6 GW to 23.1 GW, i.e., a factor of more than fourteen; reservoir capacity should almost double from 8,800 GWh to 16,000 GWh, and pumping capacity should increase by 60% from 2.3 GW to 3.9 GW. Figure 2a illustrates the resulting monthly electricity generation by source, as well as total monthly generation and demand.

This figure highlights the mismatch between seasons: from April to November there is a generation surplus (the dotted line exceeds demand), which is stored as water in the reservoirs, to be used from November to March. Note that the immediately consumed PV is remarkably stable over the year, whereas the excess PV generation in summer is used for pumping. There is still some use of hydro from natural inflows in the summer to cover periods without PV. Note that HS^p and HS^n decision are interchangeable with the time constraint that chronologically pumping must occur before HS^p generation.

Figure 2b complements the analysis by showing the end of month reservoir level, as well as the 2018 reservoir size (black horizontal line). The lowest level occurs at the end of March and the peak in August, as is currently the case.

a) Monthly electricity demand and generation



b) Annual pattern of reservoir level

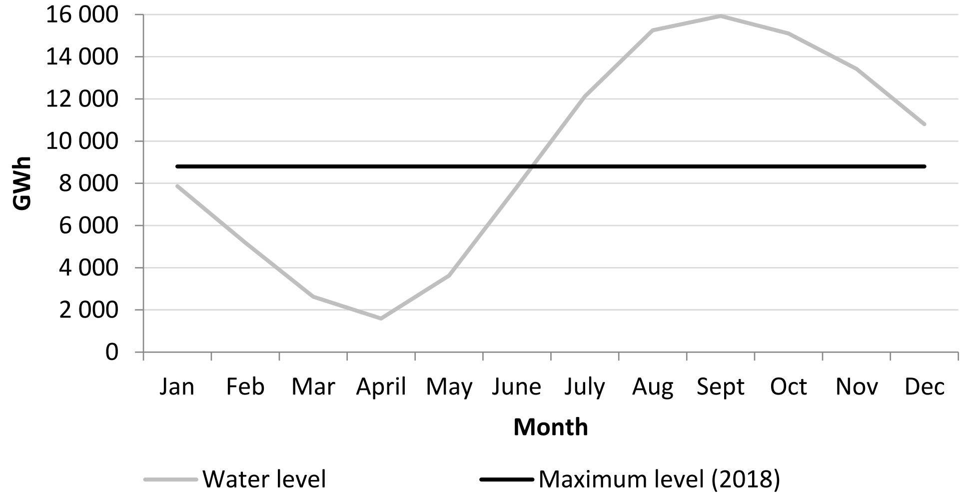


Figure 2. *Electricity demand and generation by month for the XL scenario*

Figure 3 provides further detail by analyzing the representative day for the two extreme months (December and July). Recall that run-of-river is dispatched first, then PV and finally hydro storage. Note that the allocation of hydro-storage generation between HS^n and HS^p within a day is a matter of choice.

December (figure 3a) is characterized by a low PV production (limited sun) and high demand. The resulting gap is filled by generating using water stored from natural inflows or pumped during other seasons (from April to October). Note that even in December some pumping occurs between 12:00 and 13:00, when there is a surplus of solar generation.

Figure 3b shows demand and supply in July. Summer is characterized by a lower demand and more sun compared to winter; consequently, there is a large surplus of electricity generation (generation exceeds demand by 55%) which is stored through pumping.

a) December b) July

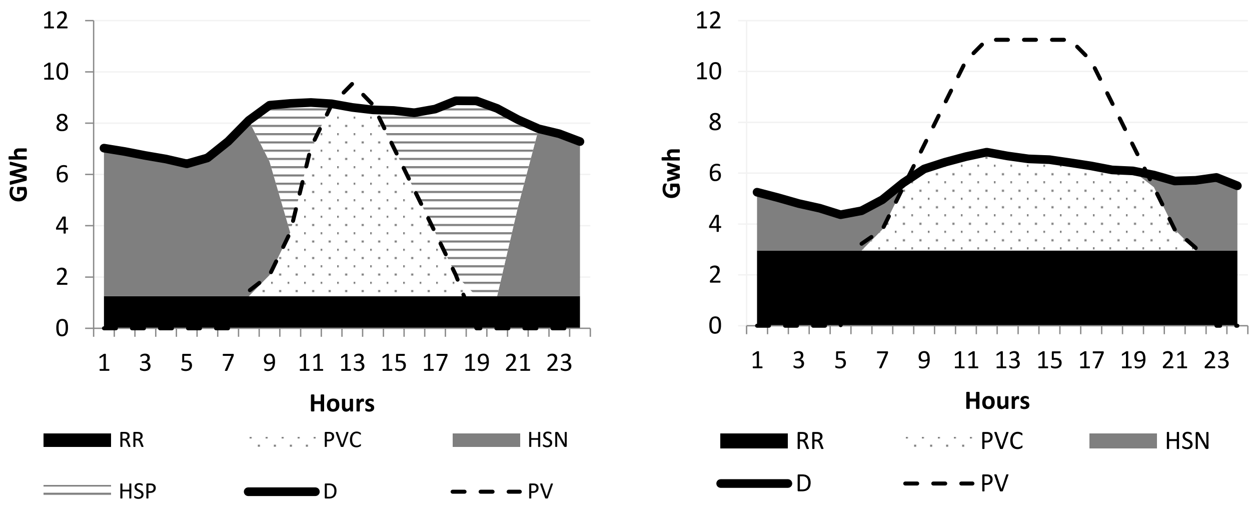


Figure 3. *Demand and Supply for the representative day in December and July*

5.2 Alternative scenarios

While in the XL scenario we assumed unlimited storage capacity, we now turn to analyzing the trade-off between PV capacity and reservoir size, and the resulting required pumping capacity. We consider three intermediate reservoir sizes (**S**mall, **M**edium and **L**arge) as well as the **C**urrent reservoir size (8,800 GWh). Table 3 summarizes the results for all the scenarios. As expected, required reservoir size and PV capacity are inversely related and lower PV capacity leads to less required pumping capacity. The larger the required PV capacity, the larger the excess potential generation, leading to a need for curtailment if this excess cannot be exported.

Scenario	Reservoir size (GWh)	PV capacity (GW)	Pumping capacity (GW)	Required curtailment or exports (GW)
Current (C)	8,800	43.0	16.0	19,078
Small (S)	10,600	36.0	13.0	11,350
Medium (M)	12,400	31.6	9.0	7,203
Large (L)	14,200	26.7	5.0	4,037
Extra Large (XL)	16,000	23.1	3.9	0

Table 3. *Overview of scenarios*

Figure 4 visualizes the trade-off between the required reservoir size and PV capacity, as well as the situation in 2018. This illustrates the magnitude of the required investments, both in generation and reservoir capacity, to move to 100% renewables. Note the non-linear relationship between the reservoir size and PV installed capacity, which results from the 0.8 conversion factor between electricity and water pumped to the reservoirs. With the exception of the XL scenario, potential generation exceeds total consumption (demand plus pumping). There are two possibilities to deal with this surplus: exports or curtailment.

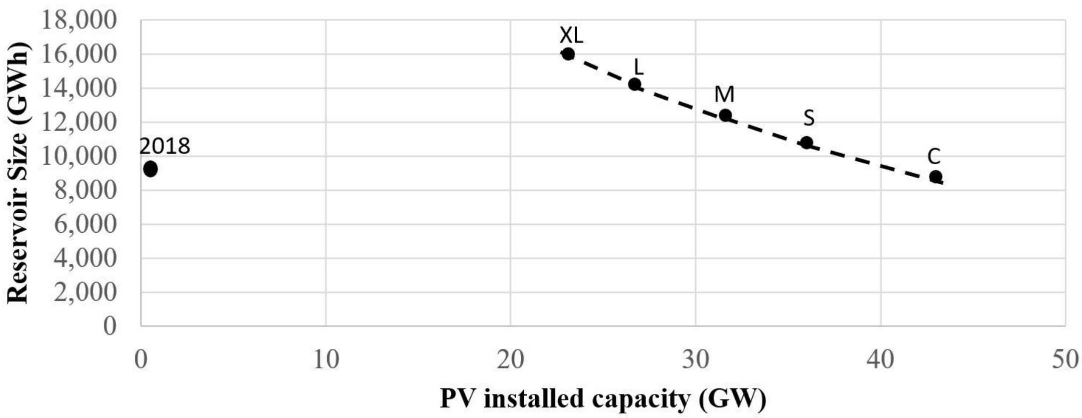
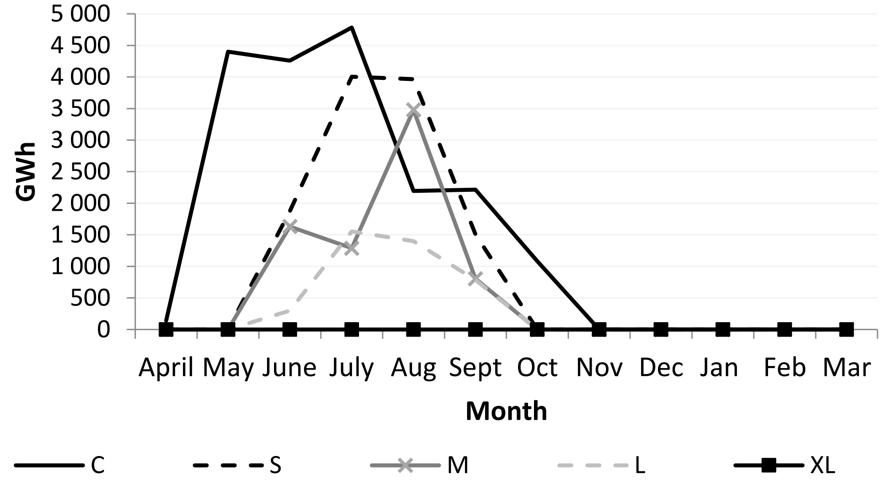


Figure 4. *Trade-off between reservoir size and PV installed capacity*

Figure 5a shows the required curtailment for each scenario. These specific patterns result from the heuristic used to allocate curtailment to the different months in order to avoid reservoir spillovers. The lower the inter-seasonal storage capacity, the more Switzerland would need to invest in generation capacity only required in winter. This leads to curtailment in summer and lower profitability. While in scenario L the excess of potential generation equals 6.9% of annual demand, in scenario C it reaches 32.7%. The latter shows that if Switzerland increases PV, while keeping reservoirs at their current size, this would entail a very high level of excess potential generation. Figure 5b provides a more detailed view by showing the annual evolution of the reservoir level for each scenario. Note that the smaller the reservoir, the longer the period during which it is full.

a) Required curtailment



b) Reservoir level

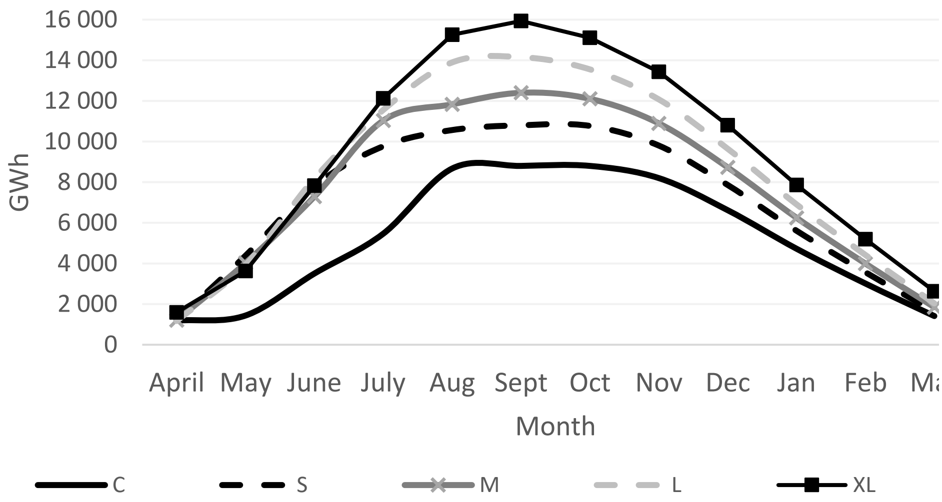


Figure 5. *Required curtailment and reservoir level by scenario*

Figure 6 visualizes the electricity generation by technology (including electricity used for pumping). This figure provides evidence that for larger reservoirs, there is less need for pumping (see scenario L and XL): large reservoirs allow a better water management. For the intermediate reservoir sizes (scenario S and M), as water management is less efficient, there is a higher need for pumping, so demand can be matched. With the current reservoir level, less pumping occurs as the reservoir is simply too small to accommodate significant amount of pumping. As seen in figures 5 and 6, the smaller the reservoir size, the higher the required curtailment, as a direct consequence of the large amount of PV capacity.

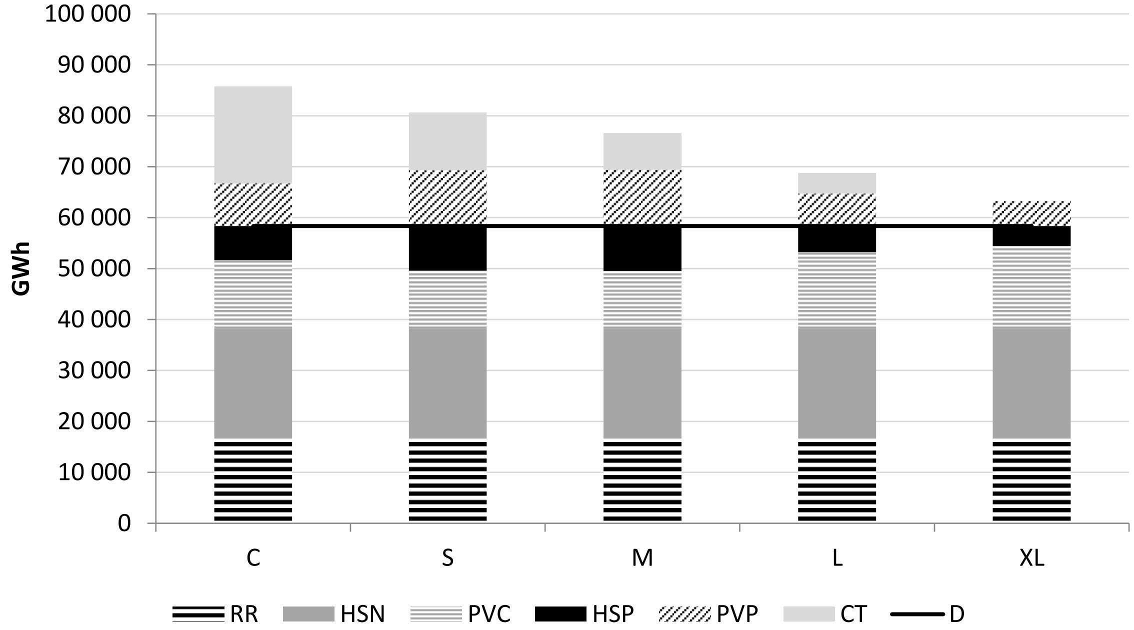


Figure 6. *Yearly* e*lectricity generation by technology*

Figure 7 shows the monthly demand and generation for scenario C. As discussed above, this is the scenario which presents the highest electricity surplus. The figure illustrates the required curtailment, i.e., the difference between the potential generation (PG) and the total generation (G). Notice that even in winter some energy is stored. At noon there is still excess of generation that is used for pumping (see February - March in figure 7).

5.2 Sensitivity analysis

The previous analysis is based on historical average water inflows and sun radiation. We aim to improve our understanding of the results by exploring the impact of less sun radiation and/or less natural inflows (taking into account possible effects of climate change) by keeping the same pattern of water inflows and sun radiation as in base case. We also analyze to what extend a decrease in sun radiation can be compensated by an increase in natural water inflow and vice-versa. Table 4 shows the parameter changes considered for this sensitivity analysis.

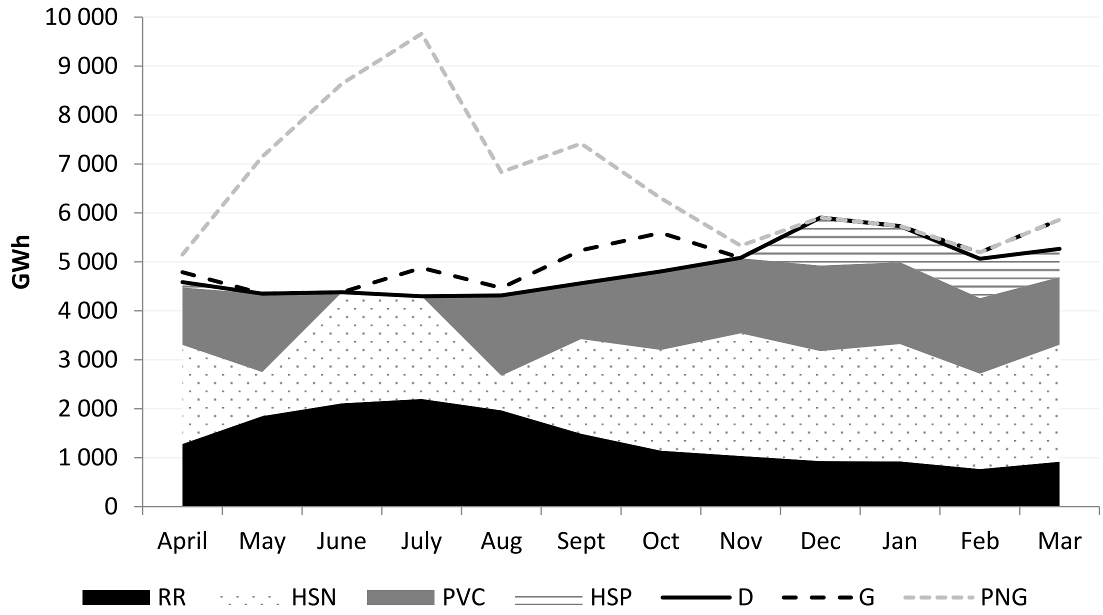


Figure 7. *Monthly electricity demand and generation for scenario C*

Sensitivity Test	Water inflow	Radiation
I^{-}	-10%	-
R^{-}	-	-10%
$I^{-}R^{-}$	-10%	-10%
$I^{+}R^{-}$	+10%	-10%
$I^{-}R^{+}$	-10%	+10%

Table 4. *Sensitivity analysis parameters*

Combining these five sensitivity tests with the 5 scenarios yields 25 combinations. Table 5 illustrates the electricity balance for the sensitivity test. Positive numbers indicate that potential generation exceeds demand, while negative numbers indicate the opposite. The notation I^0R^0 refers to the base-line scenarios of sections 5.1 and 5.2. The bottom line recalls the potential net generation for each scenario in the base case.

	Electricity balance (GWh)				
Case	**C**	**S**	**M**	**L**	**XL**
$I^{-}R^{-}$	12,450	6,291	2,051	-1,500	-8,000
I^{-}	16,300	9,500	5,400	1,494	-4,800
R^{-}	14,300	9,014	5,560	1,980	-2,350
$I^{0}R^{0}$	*19,078*	*12,000*	*7,203*	*3,800*	*0*
$I^{+}R^{-}$	17,215	10,792	7,418	4,200	900
$I^{-}R^{+}$	20,500	12,714	7,561	2,830	-600
PNG $I^{0}R^{0}$	77,420	69,690	65,546	63,380	58,343

Table 5. *Sensitivity analysis results*

Only five cases exhibit a negative annual balance (scenario XL in all cases except $I^{+}R^{-}$ and scenario L under $I^{-}R^{-}$). Recall that the XL scenario was calibrated to ensure that generation exactly matches consumption. Consequently, a reduction in either inflow or radiation, or both, results in an electricity shortage. Furthermore, the results suggest that for large reservoir capacity (i,e,. scenarios L and XL), a change in radiation has less influence on the annual production, given that larger reservoirs correspond to less PV; consequently, water inflows are more important than radiation (see case $I^{+}R^{-}$). The opposite holds for smaller reservoir sizes (Scenarios C and S) which go together with more PV: increasing radiation while decreasing water inflows (case $I^{-}R^{+}$) results in a higher electricity balance than the opposite change (case $I^{+}R^{-}$). Finally, for the intermediate size (scenario M) the electricity balance improves when the radiation increases and water inflows decrease ($I^{-}R^{+}$) and when radiation decreases and water inflows increase ($I^{+}R^{-}$).

In many ways, the results shown in Table 5 paint too positive a picture of the sensitivity analysis: while it is necessary to have enough potential generation to cover the annual demand, it is also important to have the production at the right time, as seen in the previous discussion. Table 6 shows the occurrence of blackouts; B stands for blackout, "+" means that there is a surplus of potential generation, "-" indicates that annual demand exceeds potential generation and "0" signifies that annual demand is equal to potential generation. Whereas there are only five cases with an annual shortage, the analysis shows that blackouts occur in 12 out of 25 cases. In particular, while $I^{-}R^{-}$ only leads to an annual shortfall in the L and XL scenarios, blackouts occur in all scenarios. Furthermore, for scenarios C and S we observe blackouts whenever there is lower radiation ($I^{-}R^{-}, R^{-}, I^{+}R^{-}$), i.e., the system is unable to generate enough excess energy in summer to pump sufficient water to maintain production in winter.

Case	Scenario C	S	M	L	XL
I^-R^-	**B+**	**B+**	**B+**	**B-**	**B-**
I^-	+	+	+	+	**B-**
R^-	**B+**	**B+**	+	+	**B-**
I^0R^0	+	+	+	+	0
I^+R^-	**B+**	**B+**	+	+	+
I^-R^+	+	+	+	+	**B-**

B: blackout, "+": surplus of potential generation, "-": annual demand exceeds potential generation, "0": annual demand is equal to potential generation

Table 6. Sensitivity analysis results for electricity balance for each scenario

These results suggest that radiation is more important when reservoir size is smaller. This is logical, as smaller reservoirs mean more PV, and thus a 10% change in radiation has more impact. Finally, for the larger reservoir size scenario XL the natural inflow has a higher effect than radiation. In the case where we increase the inflow and reduce the radiation (scenario XL, case I^+ R^-) the effect is curtailment, while in the opposite case, the consequence is a blackout.

As discussed before, scenario C, which has the smallest reservoir size and the highest potential generation, presents three cases of blackouts. These occur during March and April and are the consequence of the limitation of the reservoir size, which are empty at the end of winter. As an example, figure 8 illustrates the evolution of the water level in the reservoirs and the required curtailment when radiation is lower. The blackouts occur during night hours in April where there is no PV generation and there is no water left in the reservoirs. One solution is to allow exports and imports. In this scenario electricity could be exported from May to October, while imports would be required between February and April to avoid reservoirs being empty in April.

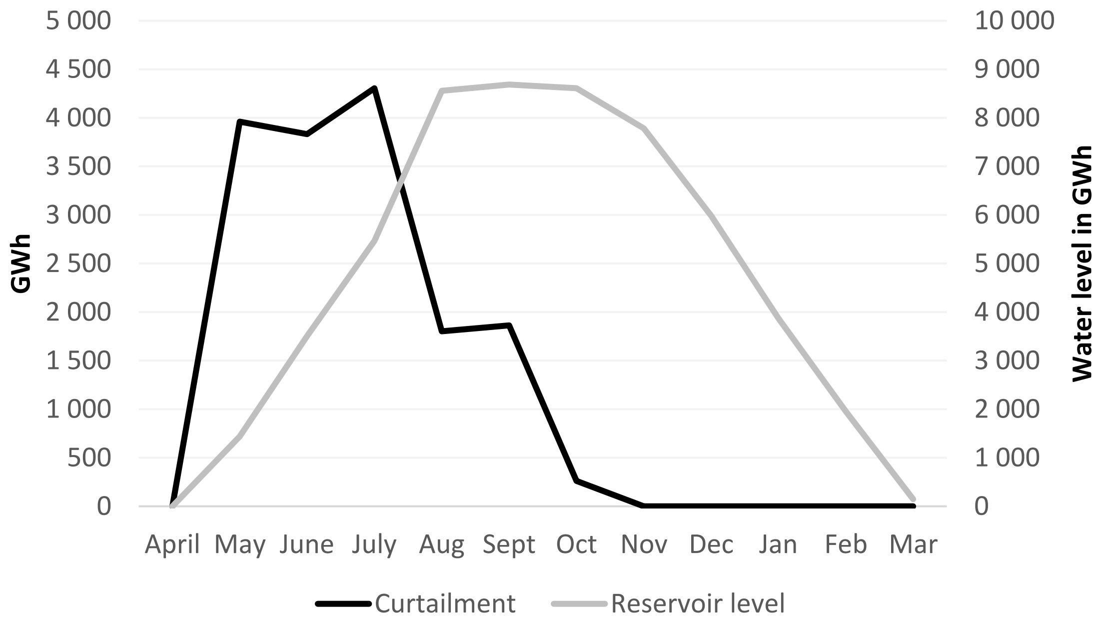


Figure 8. *Water level in reservoirs (scenario C, case R^-)*

6 Conclusion and Policy implications

In this paper, we have examined the capacity requirements for a 100% renewable electricity system in Switzerland, considering only a hydro-solar combination, with pumping facilities to store energy. The analysis explores five different combinations of PV capacity and reservoir size. The XL scenario, where the potential generation equals demand, requires twice the current size, while the installed PV capacity should increase by a factor of 13. The other scenarios illustrate the trade-off between PV generation capacity and reservoir size. The C scenario explores the extreme case in which the reservoir remains at its current size. Limitations on reservoir size lead to higher PV capacity requirements. In the C scenario, PV capacity must increase by a factor of 25. Based on current technologies, Switzerland's potential PV capacity (estimated at 36 GW) is sufficient for all but one of the scenarios we consider: Scenario C would require an additional 6.5 GW, not an unsurmountable challenge given the pace at which technology evolves. Increasing storage capacity is more of a challenge: Scenario C assumes the current storage capacity, and Scenario S could be achieved with the existing technologies through the upgrading of existing plants (heightening certain dams and increasing the efficiency of the generators).

We find that the smaller the reservoir size, the larger the need for curtailment. While in scenario L the need for curtailment is only 6.9% of annual demand, in scenario C it reaches 32.7%. The latter shows that if Switzerland increases PV, while keeping reservoirs at their current size, this would entail high levels of excess potential generation. The excess energy is the consequence of the PV needed in winter to complement the energy available in the reservoirs. However, in summer this large amount of PV capacity leads to excess electricity, as the reservoirs are too small to accommodate the water that could be pumped up.

The sensitivity analysis with respect to inflows and irradiation indicates that even though only five cases show an annual shortage, there are 12 cases with blackouts. The reason is that even if there is enough generation on an annual basis, it cannot be delivered at the right time. At a general level, and in line with expectations, the analysis shows that the smaller the reservoir size, and thus the higher the PV capacity, the more sensitive the system is to changes in solar radiation. While a system with a larger reservoir size is more sensitive to changes in water inflows, the reduction in inflow can partly be compensated by pumping the excess energy generated by PV in summer.

The sensitivity calculation highlights a number of security of supply issues. In the three scenarios with the smaller reservoirs (C, S, M), a 10% decrease in radiation (even assuming increased precipitations) leads to blackouts despite the total amount of potential generation being sufficient to cover demand. These three scenarios are already characterized by very high levels of PV.

These stylized calculations show that it is theoretically possible for Switzerland to move to a system based on 100% renewable generation based on hydro and PV. However, it should be noted that our calculations have many limitations and should only be seen as a thought experiment for the consequences of such a scenario. We have not dealt with the large number of economic, technological, environmental, political and legal issues that such a change would require. It is clear that the exact mix of generation technologies will depend on the Capex and Opex of the different technologies. Nevertheless, we believe that our analysis has provided valid insights.

In the analysis, we do not consider exports and imports, as the aim was to understand the requirements assuming that Switzerland wanted to maintain electricity self-sufficiency. It is also likely that Switzerland's neighbors will move towards a significant, if not 100%, share of VRES. While the mix of technologies is bound to differ across countries, including for instance a large share of wind in Germany, which has excellent conditions for this technology, all countries are expected to have a significant share of solar. This would make it difficult for Switzerland to export during the PV peak, as at such times a European-wide excess is expected, which might lead to, possibly extended, periods of negative prices, a phenomenon already observed today (Paraschiv, Erni, & Pietsch, 2014). This will make the choice of keeping Switzerland self-sufficient expensive, as the excess energy in summer could at best be sold at a low price, at worse being curtailed. However, if Switzerland is willing to accept that it is not self-sufficient, it may be able to buy enough energy in the critical period in the winter, or in the autumn to top-up its reservoirs, making it likely that the overall cost could be significantly lower. In other words, if the regional technology mix has more variety and Switzerland is willing to forgo the self-sufficiency criteria, it could play a stabilizing role at the regional level. Indeed, while wind also suffers from intermittency, its pattern differs from PV and Swiss PHS could act as a buffer. However, regulators in neighboring countries have raised concerns in their recent annual reports about the possibility of capacity shortages at certain times (e.g., in France (RTE, 2019)) and there already are occasional shortages in the South of Germany (Consentec & R2b, 2015). This implies that it would be risky for Switzerland to rely on import from these countries. Indeed, the convergence of generation technologies observed across Europe in recent years increases the likelihood of countries facing shortages at the same time; this problem cannot be resolved through interconnections.

While Switzerland's potential to expand its hydro reservoirs is limited by environmental and political factors, the current reservoirs already provide a large amount of storage capacity. Combined with strengthened cross-border transmission capacity this could make Switzerland “the battery” of Europe. However, even more reservoir capacity may be needed to take full advantage of this situation. With sufficient pumping, reservoir and transmission capacity, and a well-functioning market, Switzerland could take advantage of the periods of low electricity prices, not only when PV is generating excess energy, but also at other times when there is excess energy due to wind generation, which has less strong intra-day and seasonal patterns. While in the past Switzerland used cheap nuclear energy from France and Germany to pump at night, selling its hydro generation at high prices at noon to Italy, in the future it could purchase excess PV and wind energy whenever these occur, and produce profitably at times when there is little or no PV and wind generation.

The best hydro-storage sites are already developed, and there is strong environmental opposition to increasing reservoir size by heightening dams, let alone create new reservoirs by flooding valleys. Thus, if Switzerland is keen to achieve self-sufficiency, in the absence of increased storage capacity, this can only be achieved by building additional PV (or other renewable capacity) to displace the use of the stored hydro to periods where renewables are not available. This is a costly approach, as a large share of the potential generation will be wasted. This issue should be taken into consideration in a transition to a sustainable system. While expanding reservoir capacity will encounter resistance, it may the most desirable option until other storage technologies become viable. However, reservoir constructions are ambitious, long-term projects: they are capital intensive, they represent a long-term commitment given their long lifetime and it takes decades to obtain planning permission, resolve oppositions (with possible referendums), and build. Consequently, considerations on hydro-storage and pumping should receive attention early-on in the transition process. The need for this is enhanced by the government's intention to create a storage reserve, thereby forcing dam-owners to keep water in reserve, which de facto reduces the storage capacity for every-day generation decisions (The Swiss Federal Council, 2018b).

Another solution to deal with the excess of energy may be storing it in other sectors such as transportation or in the residential sector. Options include encouraging the use of electric cars in the transportation sector and heath pumps in the residential sector. Both solutions are focused on the short term (intra-day) and cannot store energy across seasons.

Our analysis provides useful information for Swiss policy makers. As Switzerland aims to transform its energy system, this study provides one option to achieve 100% renewable nuclear-free electricity. Also, this study provides the basis to build a simulation model where the feasibility of policies aimed at implementing this transition can be tested, while lifting a number of the limitations of the analysis in this paper.

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Appendix 1

Acronyms	**Definition**
B	Blackout
C	Current scenario
CT	Curtailment
D	Demand
FITs	Feed-in tariffs
G	Generation
HS	Hydro-storage
HS^n	Hydro-storage generation from natural inflows
HSP	Hydro-storage generation from pumping
I^-	-10% natural water inflow
I^+	+10% natural water inflow
I^0R^0	No change in sun radiation and natural water inflow
L	Large scenario
M	Medium scenario
NG	Net generation
PHS	Pumped hydro storage

PNG	Potential net generation
PV	Photovoltaic
PV^C	Photovoltaic consumed immediately upon generation
PV^P	Photovoltaic used for pumping
R^-	-10% sun radiation
R^+	+10% sun radiation
RPS	Renewable portfolio standards
RR	Run-of-river
S	Small scenario
VRES	Variable renewable energy sources, i.e., PV and wind energy
XL	Extra-large scenario
$\overline{PV}$	Maximum possible electricity generation from photovoltaic

Table A1. List of acronyms

Appendix 2

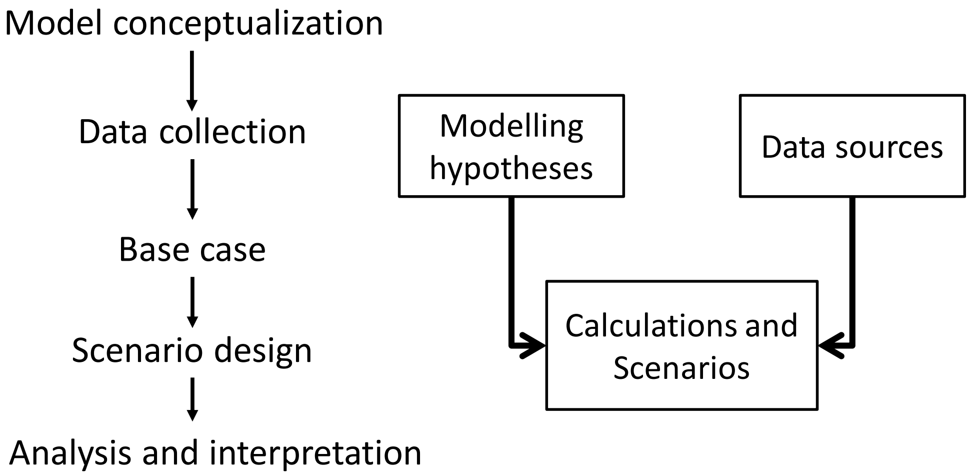

Figure A1. Flowchart illustrating the methodology

APPENDIX A.2

TRANSITIONING TOWARDS A 100% SOLAR-HYDRO BASED GENERATION: A SYSTEM DYNAMIC APPROACH.

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Abstract

Many countries have targeted a gradual transition towards 100% green generation; however, there is uncertainty concerning the economic and social consequences of such a transition. The main technologies that have been implemented are hydro, wind and solar. The latter two could cause an increase in electricity prices due to a mismatch between demand and supply. This paper uses a system dynamics approach to analyze the transition process of Switzerland, which is gradually moving from nuclear towards solar and hydro base generation. We consider hydro-pumped storage to address the timing problem between supply and demand. We developed different scenarios to test the viability of such a system. Our findings indicate that leaving the system to a free market will entail shortages during the transition, as well as a doubling of the electricity price. To mitigate this effect, we propose a capacity auction mechanism to smooth the transition process. We find that subsidizing PV indirectly encourages storage, thereby eliminating shortages, and mitigating the increase in the electricity price during the transition.

Keywords: energy transition, pumped hydro-storage, system dynamics, energy policy, renewables

1. Introduction

Electricity systems across the globe are facing the challenge of transitioning towards low-carbon electricity generation [1–3]. Thus, many countries are considering policies that encourage the use of Variable Renewable Energy Sources (VRES), such as sun and wind. VRES has increased sharply over the last decade due to technological progress, government incentives and economies of scale [4,5]. While in 2009 the total renewable installed capacity was of the order of 1,150 GW, at the end of 2018 it had reached 2,378 GW [6].

A high share of VRES in the electricity mix reduces flexibility and security of supply [1,7], making it challenging to balance the market at all times. To solve the mismatch between the seasonal and daily patterns of demand and supply, energy storage has been used [8,9]. Today the most used energy storage technology is hydro storage. Conventional hydro storage plants rely on natural water inflows; adding pumping mitigates the limitation and variability of natural inflows [10].

Any transformation of the electricity system must be accompanied by efficiently designed policies that drive the desired transition smoothly. The challenge that arises is how to achieve the desired transition while considering factors such as electricity security and costs. Traditionally researchers have focused their studies of sustainable transition on the supply angle. Markard (2018) draws attention to the acceleration of energy transitions, which creates challenges (for instance, the decline of established business and decentralization of the electricity system) that require new approaches from policy makers and researchers. From the demand point of view, studies have focused on demand side response, demand reduction, and distributed energy, among others [12].

The aim of this paper is to explore different pathways for a transition towards 100% green generation. We develop a stylized simulation model of an electricity system which consists of a base load (e.g., run-of-river), a technology that is being phasing-out (e.g., nuclear), an intermittent technology introduced to replace the phased-out technology (e.g., PV) and an energy storage technology (e.g., pumped hydro-storage).

Our objective is to gain understanding of the feasibility of a transition towards a 100% renewable electricity system. We focus on the long-term consequences of such a transition, exploring the impact on blackouts, electricity price and required capacity. More specifically, we aim to understand whether a market-driven transition is possible, or whether governmental intervention (e.g., through subsidising of capacity investments) is required to achieve a smooth transition. We conclude that such a transition is technically feasible, but government intervention is essential to insure sufficient investments. A key insight of our model is that, while a smooth transition requires investment in both PV and pumped hydro-storage (PHS) to be profitable, this can be achieved by subsidising only PV. Indeed, the build-up of a large PV capacity creates a profitable environment for investments in PHS.

This generic model can be calibrated for different regions and technology mixes. Our goal is to develop a model to test the appropriateness of different energy policies that target a smooth transition towards renewables. In this paper, we calibrate the model using the Swiss context to identify the challenges and potential solutions, with one important caveat: we assume that the jurisdiction aims at being self-sufficient with respect to generation, i.e., there is no reliance on an integrated regional market, nor imports, to satisfy demand. This assumption, which is a limitation to the generality of our analysis, could be relaxed by including imports and exports as respectively additional generation capacity and demand. Given the objectives of our analysis, i.e., understanding the transition, this would not affect the main insights of our work, unless we explicitly modelled a regional market. We assume, as stated above, that jurisdictions have a political desire to be self-sufficient should a regional market be unable to deliver the agreed amount of electricity. The COVID-19 pandemic has recently illustrated the risks of relying on imports in a very different, but equally crucial setting: medical care. Indeed, the sharing of supplies of personal protective equipment at the start of the pandemic [13], and more recently of vaccines [14], among European countries has been all but smooth.

This paper is structured as follows. In section 2 we review the relevant literature. In section 3 we present the Swiss context. This is followed by a discussion of the methodology and the model description in section 4. Section 5 presents the simulation results and scenarios. Finally, section 6 provides conclusions and policy recommendations.

2. Literature review

Three strands of literature concerning electricity transitions towards a high share of RES are relevant for our work: policy mechanisms, energy storage and electricity models [15].

There are different types of policies that encourages investments in VRES and they can be classified in two main groups: direct (DP) and indirect instruments (IP). DP target an immediate stimulation of investment in VRES, while IP aim to improve the long-term context, so VRES expands gradually [16]. DP can be subdivided into two groups: price or quantity driven. The most commonly used strategies are investment focused (e,g,. investment subsidies) and generation-based strategies (for instance, Feed-in Tariffs (FITs) or a fixed price premium). Besides regulatory mechanisms, there are also voluntary actions to promote VRES which rely on the willingness of consumers to pay a fee for green electricity [16].

VRES have been encouraged by tax incentives, investment subsidies and production incentives. A statistical analysis based on U.S. data concludes that these three policy tools are positively correlated with investment in wind energy generation capacity [15]. However, subsidies are controversial. It has been argued that they bias the market (e.g., they can lead to investments in inefficient projects) and prevent the development of markets for renewables by creating a mental model that renewables should be subsidized or even free [16]. Barradale (2010) and Carley et al. (2017) agree that such subsidies tend to be temporary, and dependent on public support. The resulting political uncertainty decreases investors' confidence, thereby reducing the government's ability to secure power investment agreements.

FITs have been the most commonly used tool in Europe to promote the expansion of VRES and are a well-established policy that has been used to limit the risk for investors [20]. They induce innovation in initially costly energy technologies, such as solar power [21]. Nicolli and Vona (2019) suggest that FITs enable new agents to enter the electricity market, thus limiting the power of incumbents, which reduces entry barriers. On the negative side, FITs can lead to investors not responding to price signals from the market, thus distorting the market (e.g., over investments) and reducing the consumer welfare [23].

Capacity auctions for VRES are a policy mechanism where the regulator defines the capacity or the generation that must be available at a certain moment in time. Under this mechanism, companies submit a bid with a price (required subsidy) per unit of capacity or per unit of generation at which they are willing to install new capacity [20]. Lucas, Ferroukhi and Hawila (2013) argue that the main advantage of auctions is to guarantee a known fixed subsidy per unit of installed capacity. Another advantage is to increase competition, thereby revealing the true market price; capacity auctions also improve the predictability of renewable generation. The disadvantages discussed in the literature are: high administrative costs, underbidding, collusion between agents, and increasing entry barriers for medium and small agents [20,23,24].

There has recently been a shift from the previously predominant model of feed-in-tariffs (FiT) towards capacity auctions, which are considered to be a more competitive or market-based way to subsidize renewable energy. This evolution has been observed, among others, in Germany, where pressure from the EU and industry has changed the way renewables are subsidized [25]. However, FiT schemes have the advantage of also being suitable to encourage smaller installations, e.g., households and communities, whereas capacity auction are more appropriate for large installations [26].

Energy storage becomes necessary for electricity markets that aim to have a high share of VRES. Although balancing supply and demand is done largely at a primary energy input level (e.g., hydro reservoir when geographically possible), storage can occur at the grid level (e.g., batteries) and at the level of the consumer [27]. The main technology currently used is hydro storage, which can quickly adjust generation, thereby providing flexibility to the system. Adding pumping to a hydro-storage plant mitigates the limitation and variability of natural inflows [10].

Schill & Zerrahn (2018) review 33 models which consider different types of storage. They conclude that, while there is no consensus in this literature, some insights do emerge. First, energy storage becomes an economically viable option to integrate high shares of renewables when renewable deployment reaches between 50 and 70%. Second, for intra-day storage, batteries are useful to smooth the variability of wind and PV. Finally, inter-seasonal power storage (for instance through pumping or hydrogen storage) only becomes economically viable for 100% renewables systems.

Many studies have shown that energy system transitions have to take into account not only technical feasibility, but also how the interaction between regulation, markets and strategies of different actors shape the transition [29]. Li, et al., (2015) propose the concept of socio-technical energy transition (STET) models. STET models extend quantitative models with elements of socio-technical transitions such as policies, agent behavior and technological evolution. STET models must capture the interaction between demand, supply, investment decisions, regulation and delays [30].

3. The Swiss context

We choose Switzerland for two reasons: the dismantling of nuclear plants over the next 25 years [31], and the opposition to the construction of thermal plants [32]. The dismantling of nuclear capacity over the next decades raises the question of how this generation will be replaced: how will the Swiss electricity system meet national demand after 2019, when the first nuclear reactor will be dismantled and how much will this transition cost [31]?

To answer these questions the Federal Council has developed the Energy Strategy 2050, which draws the path the electric system should follow. This strategy aims to increase efficiency, decrease energy consumption and incentivize the use of VRES [33]. The main measures being proposed to enable the implementation of this strategy are the liberalization of the electricity market for small consumers, which should lower the consumer price, and the introduction of a storage reserve which will increase the security of supply [34].

Currently, the total installed generation capacity in Switzerland is 20.2 GW. Hydropower represents 75%, nuclear 15% and the remaining 10% include cogeneration plants and PV [35]. The average annual electricity production over the last decade was 67 TWh, with hydropower accounting for 58%, nuclear for 36% and thermal and renewable plants for the remaining 6 % [36]. The average annual demand over the same period was 61.9 TWh, indicating that Switzerland is a net exporter: the average annual exports (imports) were 33 TWh, (31 TWh) [37]. The maximum hourly demand registered was 9.9 GW and the lowest 4.2 GW [38]. Consequently, as the hydro generation installed capacity is twice the hourly peak demand, as long as there is water available, Switzerland can always meet the peak demand. With hydropower being the main generation technology, water in the reservoirs becomes a strategic resource. The minimum fill rate is typically reached at the end of March, while the maximum occurs at the end of September. Reservoirs are thus used to store excess water during late spring and summer, to be used in late fall and winter [39]. As mentioned in the introduction, we deviate in one important dimension from the Swiss case, in that we do not consider imports and exports, i.e., we assume that there is a desire to be self-sufficient. This hypothesis could be relaxed by treating imports and exports as additional demand or generation capacity.

The Swiss government has been encouraging wind farms and PV projects with Feed-in Tariff mechanisms since march 2008 [40]; installed capacity has increased by 2.3 GW while wind installed capacity increased by only 51 MW [33]. PV installed capacity is expected to continue increasing in the coming years.

The increasing PV entails an excess of energy during the day, especially in summer. This disequilibrium between generation and demand can be resolved by curtailment, exports or storage. Storing the excess has become a priority in systems which are transitioning to a high share of renewables. Pumping is not new in Switzerland and has been used to provide intra-day and inter-seasonal storage capacity. In 2019 the total generation of pumped hydro-storage was of the order of 4.3 TWh, representing 6.7% of the total electricity consumed in Switzerland [37]. Assouline, Mohajeri & Scartezzini (2017) evaluate the potential of PV generation to be of the order of 32 TWh by 2050. Technological evolution, including the installation of floating panels on water reservoirs, could push this figure even higher [42].

Hydro-generation is limited not by the generation capacity, but by water availability. Increasing reservoir capacity would facilitate dealing with the seasonality of inflows, thereby increasing hydro-generation in winter. By increasing the height of current reservoir dams, a 10% storage capacity increase could be achieved [43].

4. Methodology and model description

Electricity markets are complex as they involve many factors and actors that interact, creating feedbacks in the presence of delays. We therefore model the system's structure explicitly. This kind of modelling provides understanding of the dynamics of the industry, which is particularly important for policymakers during periods of transition. We propose a System Dynamics (SD) based model. SD is useful to incorporate feedbacks and delays into the model [44,45], which allows understanding the behavior of the system by studying its structure.

SD based simulation models have been used extensively to study the impact of energy policies [46]. They provide the possibility to explore the possible outcomes of changes to the underlying system before these are implemented. This methodology has been used to study regulatory changes. SD has been used to analyzed the impact of introducing a high share of renewables [47,48]. Castaneda, et al. (2017) explore the effect of introducing a high share of rooftop solar generation (prosumers); they find that, in the long-run, rooftop solar can generate death spirals in electricity markets.

Energy transitions have also been discussed in the SD literature. For instance, Bunn et al. (1998) discuss how SD is useful to improve the understanding of systems facing a transition. Olsina, Garces, and Haubrich (2006) propose a model to evaluate the long-term dynamics of deregulated electricity markets. They show that regulatory mechanisms need to be implemented as early as possible so that the required capacity is available, and prices remain stable. Finally, SD has also been used as a decision support tool to study investment decisions. Ochoa (2007) build a SD model to study investment dynamics for Switzerland, while Kilanc and Or (2008) developed a decision support tool to study investments, pricing, and regulation in a decentralized electricity market.

Model formulation

This model was developed to explore different pathways for a transition towards 100% green generation. We aim to study the appropriateness of capacity auctions. Our goal is to test if this policy allows to manage the transition from a system with a significant share of nuclear generation to a system based only on PV and hydro. In this section we provide an overview of the model, focusing on the intuition behind the model. To provide this overview we use a causal loop or feedback diagram (Figure 1), which shows the main concepts of the model and visually illustrates how they are interrelated [42]. The appendix provides a full documentation of the model, including all equations, parameter values and a graphical representation of the non-linear relationships.

Causal look diagrams use a “+” or “-” next to an arrowhead to indicate the causal relationship between two variables. A “+” sign indicates that if the cause variable increases, the effect variable increases as well, while a “-” sign indicates that if the cause variable increases, the effect variable decreases [44]. The two parallel lines on an arrow indicate a lag. The clockwise arrow indicates a feedback loop. A “B” indicates a balancing or negative loop: an increase in one variable, traced around the loop, will lead to a further decrease of that variable, generating a balancing behavior.

The key (state) variables (installed capacity of PV and pumps) are represented by the two rectangles. The model has three balancing loops, which we describe in turn. The first feedback loop (B1) represents investments in PV capacity. An increase in PV capacity will increase the generation of electricity from PV, which, due to the low OPEX, will lead to lower electricity prices. This in turn reduces the forecast of future electricity prices, resulting in a lowering the return of investment (ROI) compared to the desired ROI; this will reduce investments in PV, thereby slowing down, or even halting new PV capacity coming on-line, as current projects are gradually completed.

The second loop (B2) captures the dynamics of PHS pumping capacity in a similar way: an increase in pumping capacity allows for more water storage, leading to lower electricity prices and thus lower profitability and eventually fewer investments in pumping capacity. Note that this loop is characterized by significantly longer time-lags, as the construction time for PHS is significantly exceeds that for PV, with two consequences. First, once the price is sufficiently attractive to encourage PHS investments, it will take a considerable time for this new capacity to come online, compared to investments in PV capacity. Second, even though, following capacity coming online, the electricity price falls below that required for investment, capacity will continue to increase as projects under construction continue to come online; indeed, it is unlikely these will be cancelled once launched.

The third loop B3 captures the interaction between PV and pumping. An increase in PV installed capacity leads to more electricity being available for pumping and thus more water in the reservoirs. The higher the water level, the lower the electricity price and hence the lower the PV and PHS profitability, which discourages investments, as discussed in the two previous loops.

The final element of the model represented in Figure 1 is the determination of the amounts of subsidies needed to ensure enough capacity to satisfy demand, with an appropriate energy margin**.** Note that we do not use the capacity margin due to the high share of hydropower; instead, we use the concept of energy margin [53]. The energy margin gap represents the deficit of energy required to satisfy the annual forecasted electricity demand, i.e., the difference between expected demand and supply. This gap is influenced by the desired energy margin, which itself depends on the share of PV. Indeed, in the presence of a large share of intermittent generation (PV in our model) a more important energy margin is required to achieve the same level of security of supply. This increases the requirements for new capacity which trigger the necessity of subsidies.

As outlined above, both B1 and B2 show that investment decisions depend on the comparison between the desired ROI and the ROI forecast. To calculate the latter, we run a second version of the model in parallel, a shadow model which forecasts generation and electricity prices three years ahead (i.e., the time required to build capacity), assuming that demand and water inflows remain unchanged. This shadow model is used to calculate the future expected price and generation by technology, yielding the ROI forecast.

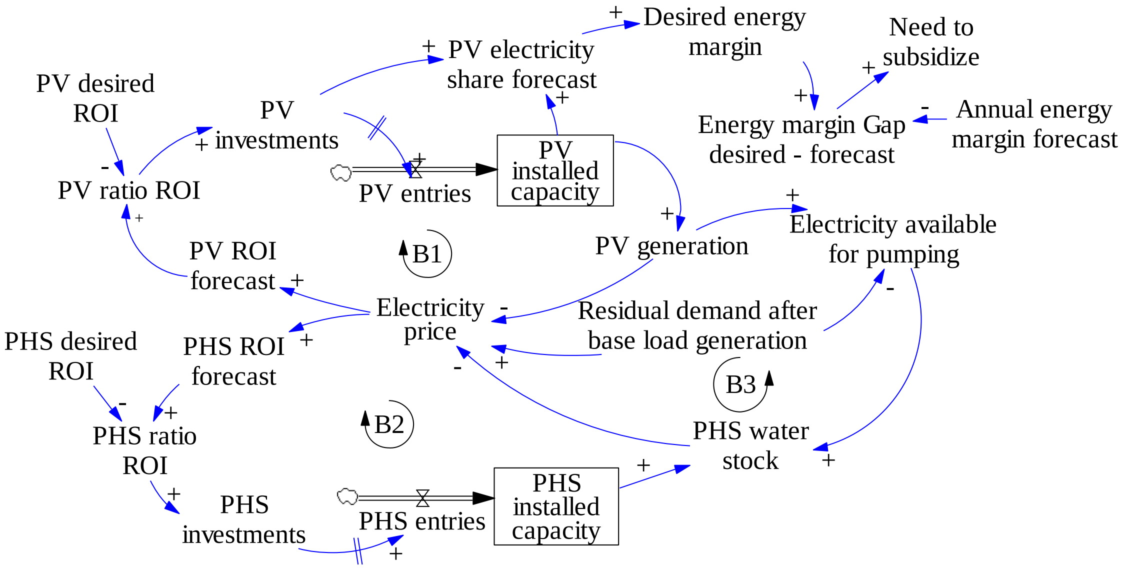

Figure 1. Main variables and relationships of the proposed model

The annual excess energy is calculated as the difference between the total hydro-storage availability (natural hydro and pumping) and the annual unmet demand after base-load, nuclear and PV. A negative energy margin indicates a shortage, while a positive energy margin indicates an excess of energy. The regulators compare the forecasted energy margin with the desired energy margin. The latter depends on the share of PV generation: the higher the PV share, the higher the desired margin. The regulator will subsidize PV when the forecasted energy margin is lower than the desired one: we calculate the subsidy per MW of capacity that makes the investment in PV attractive, capturing the idea of a capacity auction.

We use a typical day to represent each month and capture seasonal and daily patterns of sun irradiation, demand and supply. This simplification implies that we ignore day-to-day variability. Recall that our objective is to analyze a long-term transition towards 100% renewable electricity generation. Consequently, our focus is on long-term patterns, as opposed to short-term operational behavior. While daily variations play an important role in the latter case, they do not affect our long-term conclusions. Seasons are defined as follows: winter

(December - February), spring (March - May), summer (June - August) and fall (September - November).

For non-hydro technologies, the bids are calibrated so as to achieve an economically viable system, i.e., they are based on the levelized cost, so as to cover both the fixed and variable costs. The hydro-storage bid price additionally depends on the water level in the reservoir, and the PHS bid price is further influenced by the purchase price of water. We assume that run-of-river and nuclear are dispatched first, followed by solar, and finally hydro-power: a merit-order dispatched is used to prioritize PHS and hydro-storage. The electricity price is set by the bid price of the most expensive dispatched technology. The levelized costs (parameters) are given on the table in Appendix A.1.2.2.

We focus on investments in pumping capacity (not generation capacity) because generation capacity is used jointly by PHS and hydro-storage, and Switzerland already has enough hydro-storage generation capacity to match peak demand. We initially assume a linear nuclear capacity dismantling process to focus our analysis on the transition process, rather than on how a system reacts to sudden changes in capacity.

We assume no cross-border exchange of electricity. The Absence of exports leads to excess generation at the start of the simulation. While we are aware of the increased international collaboration in Europe and the growth in cross-border electricity trade [54], our aim is to understand what is needed for a country such as Switzerland to achieve a transition towards self-sufficient green generation. Indeed, Switzerland's neighbors will also move towards a high share of VRES, including a significant share of solar. This will entail European-wide electricity excesses and shortages at certain times.

The simulation model was developed in Vensim DSS 7.3.4. The simulations run from 2020 to 2040. Table 1 summarizes the data sources used to calibrate the model and the main assumptions. We perform the traditional tests to validate SD models [55], which include a link-by link validation of the model, checking the dimensional consistency of each equation and carrying out extreme condition tests to ensure model robustness. The model has successfully passed these tests and also respects basic physics laws such as mass and energy balance. Moreover, we perform an extensive sensitivity analysis, which is summarized in section 5.1. The model is calibrated using secondary data bases, presented in table 1, which are mainly based on current Swiss conditions. Recall that we study the transition for a country aiming to be self-sufficient, i.e., we do not consider imports and exports. As Switzerland currently imports significant volumes in winter, and exports similar volumes in summer our simulation results not be validated against historical data.

Input	Source	Data and hypotheses
Electricity demand, electricity generation, installed capacity, dam's water level and pumping facilities	OFEN, 2018; SFOE, 2010, 2014, 2016, 2017a, 2017b, 2020b	Historical data from 2010 to 2019
Solar irradiation	MeteoSwiss, 2017	We build an hourly curve for a representative day per month.
Solar cell efficiency	Assouline, Mohajeri, & Scartezzini, 2015	We assume 20% efficiency.
Losses from PHS	Chandel, Nagaraju Naik, & Chandel, 2015	We assume 80% efficiency.
Marginal and capital costs	IEA, 2018	Costs are exogenous and constant.
Nuclear capacity		Nuclear capacity is being dismantled linearly over the period 2025-2040.
Hydro-storage and run-of-river turbine generating capacity; Hydro-storage and reservoir size.	SFOE, 2020b	We assume an exogenous and constant installed generating capacity, i.e., no dismantling of, nor investments in capacity. The same hypothesis is made for the size of the hydro-storage reservoirs.
Planning and construction process for PV and PHS	Gevorkian, 2012 Manwaring, Mursch, & Tilford, 2012	We assume a total investment time (project planning, obtaining the permits, and construction) of 3 years for PV and 2 years for PHS (only pumping capacity, storage capacity is assumed to remain constant).

Table 1. Data sources and assumptions

5. Simulation results

We consider a base case scenario in which there are no subsidies, i.e., investment in PV generation and pumping capacity is driven by the market. Figure 2a shows the PV, nuclear and pumping capacity over the simulation period. Recall that nuclear capacity dismantling is exogenous. The rapid increase in pumping capacity during the first years results from the excess of electricity generation at night (see figure 2b): the availability of inexpensive electricity increases the ROI of PHS, encouraging investments. PV increases in anticipation of future nuclear dismantling. Figure 2b also shows that the investments in PV and pumping capacity are not enough to avoid shortages (and thus blackouts) in winter from the middle of the simulation period onwards.

c) Installed capacity d) Electricity balance

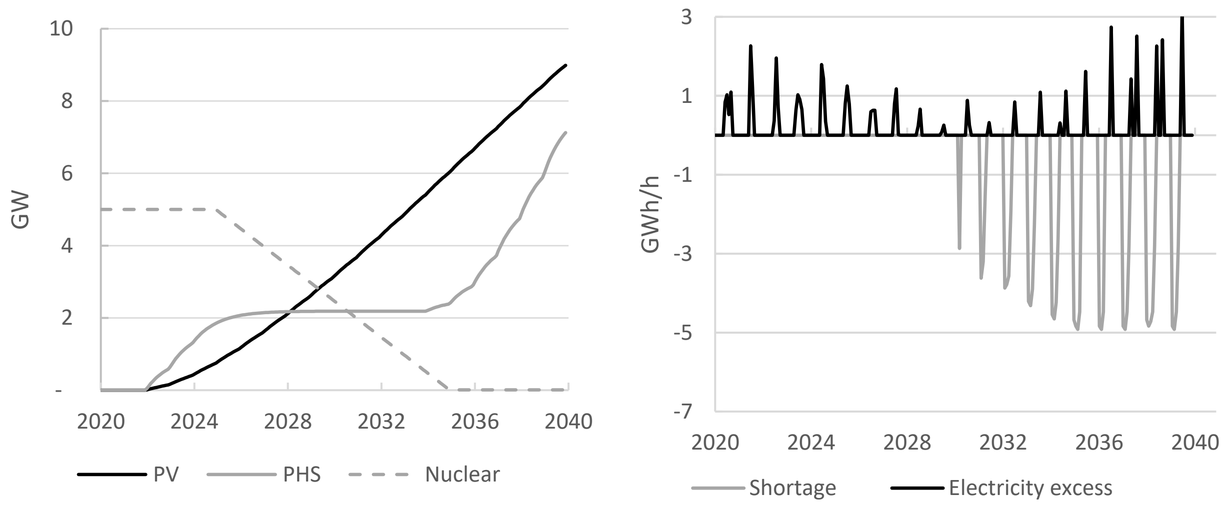

Figure 2. Installed capacity and electricity balance in the base case scenario

Shortages lead to an increase of the electricity price. Figure 3 shows the evolution of the electricity price and the reservoir fill rate, which are inversely correlated. As the reservoir fill rate decreases, the electricity price increases.

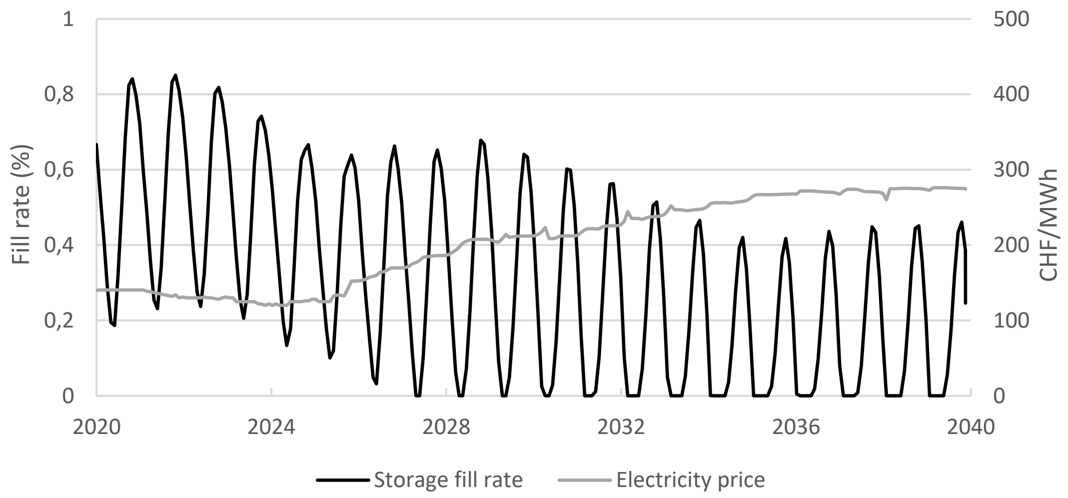

Figure 3. Reservoir fill rate and electricity price in the base case scenario

5.1 Sensitivity analysis

We assume that the parameter values presented in Table 1. remain constant over the simulation horizon. In reality these are likely to change. We therefore aim to test the robustness of these insights by exploring the impact of key parameters such as natural water inflows, reservoir size and PV capital cost, as well as the speed of the nuclear dismantling process. PV capital cost and natural inflows are conditions that are not controlled by the regulator. The first one depends on the development of the technology, while the second one depends on climate variations. The regulator can influence the length of the nuclear dismantling period and the size of the reservoirs.

Table 2 shows the parameter changes considered for each of the eight sensitivity tests. For instance, “+/- 15%” means that this parameter is increased/decreased by 15% compared with the base case.

Parameter	Name	Change
Natural inflow	I^{+}, I^{-}	+/- 15%
Reservoir size	R^{+}, R^{-}	+/- 10%
PV capital cost	$C^{-0.1}, C^{-0.25}$	-0.5%/year, -1.25%/year
Length of the phasing-out period	N^{+}, N^{-}	2025-2040, 2025-2030

Table 2. Sensitivity analysis parameters

All sensitivity scenarios show shortages. We consider two measures to evaluate their extend: the severity of shortages when they do occur (measured as the % of unsatisfied hourly demand during the hour with the worst shortage) and the frequency of shortages (measured as the % of hours per year with a shortage). In almost all cases, the worst shortage occurs in 2035. The only exceptions are the scenarios N^{+} and N^{-}, in which the worst year is 2030 and 2040, respectively.

Table 3 summarizes the results of the sensitivity analysis and compares these to the original scenario (denoted B^{0}). These results show that the water inflows and the length of the nuclear dismantling process have a significant impact on the frequency of shortages. All parameters tested have a negligible impact on the maximum unmet demand (measured as a % of hourly demand). The maximum hourly shortage always occurs in February. As shown in table 3, this shortage takes place in 2036-2040, except for the scenarios N^{-} and N^{+}: decreasing (increasing) the length of the nuclear dismantling shifts the year with the maximum shortage to 2040 (N^{-}) and 2031-2040 (N^{+}) respectively.

Case	Years with blackout	Maximum number of hours with a shortage		Maximum hourly unmet demand	
		%	**Year**	**%**	**Years**
B^0	2030-2040	36%	2036	71%	2036-2040
N^+	2033-2040	24%	2040	69%	2040
N^-	2028-2040	45%	2030	71%	2031-2040
$C^{-0.1}$	2030-2040	35%	2036	71%	2036-2040
$C^{-0.25}$	2030-2040	34%	2036	71%	2036-2040
R^+	2031-2040	36%	2036	71%	2036-2040
R^-	2028-2040	36%	2036	71%	2036-2040
I^+	2032-2040	26%	2036	68%	2036-2040
I^-	2028-2040	43%	2036	74%	2036-2040

Table 3. Sensitivity analysis results for shortages - base case

Next, we consider the impact on price. To facilitate interpretation, we consider the ratio between the electricity price of each scenario and the base case price, as shown in figure 4. A ratio above (below) one means that that scenario has a higher (lower) price than the base case. Figure 4 shows how four scenarios have prices lower than B^0 (N^+, I^+, $C^{-0.1}$ and $C^{-0.25}$). N^+ and I^+ imply more generation, respectively due to more nuclear installed capacity (N^+) and has an increase in the natural inflows (I^+). Both $C^{-0.1}$ and $C^{-0.25}$ have a lower capital cost, leading to a lower bid and thus a lower price than the base case. These four scenarios reduce blackouts leading to a price ratio lower than 1. In N^-, nuclear capacity decreases faster, while in I^- the natural inflows are lower; both scenarios lead to more blackouts due to lower resources, and thus to higher prices. The remaining scenarios (R^+ and R^-) exhibit a more complex pattern. A smaller reservoir size (R^-) results in a higher fill rate of the reservoir and thus the price at which hydro bids initially decreases (2021). After one year the smaller reservoir size leads to an inability to store enough water to avoid blackouts during the winter, and thus the electricity price increases. This increase in price incentives PHS investments, so after 2028 the price ratio drops below 1. R^+ exhibits an opposite pattern compared to R^-. At the start, R^+ has a lower water fill rate which, leads a decrease in the price ratio after 2020. After 2021 as the reservoirs can store more excess electricity, the electricity price stays low until 2030: having the ability to store more energy discourages PHS investments, so when the dismantling process reaches a point where the supply is unable to match demand, the price ratio goes above 1.

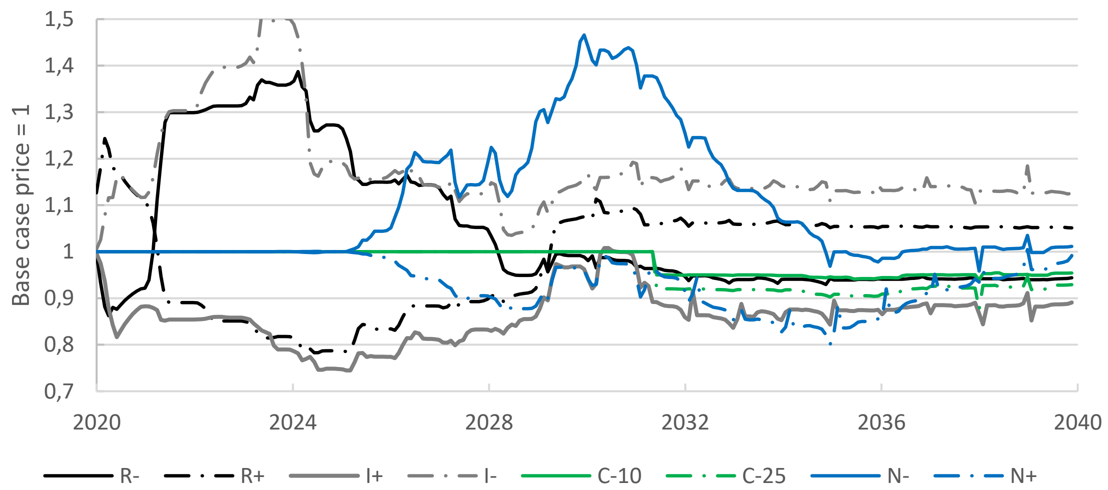

Figure 4. Electricity price ratios (base case =1)

We also tested the impact of the linear nuclear phase-out hypothesis, replacing it with a more realistic step function: we divide the phasing-out process into three equal-sized discrete steps. Figure 5 shows the results for the main variables of the model. Figure 5a shows that the electricity price increases significantly at each step. In figure 5b we observe the energy margin forecast decreases three years before the step, as expected this triggers chunky investments; as a consequence, the energy margin increases in anticipation of each step, and decreases at the time of the step. Figure 5c shows the energy balance. While the excess is similar for both scenarios, this is not the case for the shortages. In the linear case shortages start around 2029 (the year where the energy margin turns negative, see figure 5b), while for the step case shortages already start around 2026, just after the first chunk of nuclear capacity is retired. After 2026 the shortages decrease until the next step, when the shortages increase again. Figure 5d shows no major differences between a linear function and step function for the installed capacity and the electricity balance. These results allow us to conclude that our model is robust with the pattern of the nuclear dismantling process.

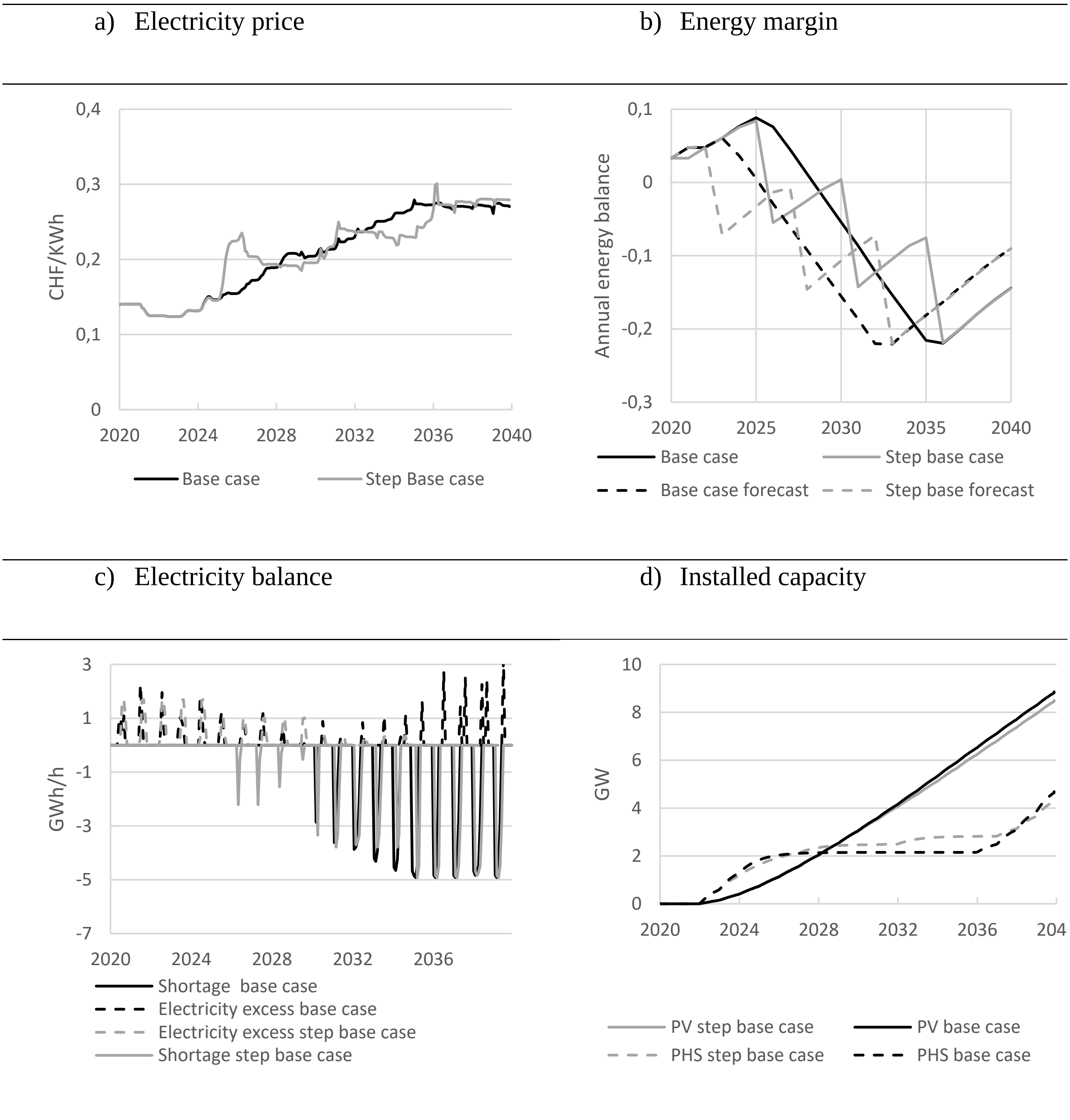

Figure 5. Nuclear dismantling (step vs linear function)

5.2 Capacity auctions

The previous analysis points to insufficient investments in PV and PHS capacity to avoid blackouts. Figure 6 shows the evolution of the annual energy margin for the base case. This figure shows an initial increase due to the excess of energy, followed by a linear reduction, along the pattern of nuclear dismantling.

Figure 6a shows the evolution of the energy margin and figure 6b shows the forecasted energy margin (i.e., the value shown for 2023 is the value that was forecasted in 2020). A negative forecasted energy margin predicts insufficient energy to meet demand (see figure 6b after 2028). This is a signal for the regulator that there is need for action, and that an intervention is required to avoid blackouts. We consider one policy mechanisms to encourage investments, capacity auctions (CA), which triggers investments, leading to more installed capacity, and thus a higher energy margin (see figure 6a after 2026).

a) Energy margin b) Forecasted energy margin

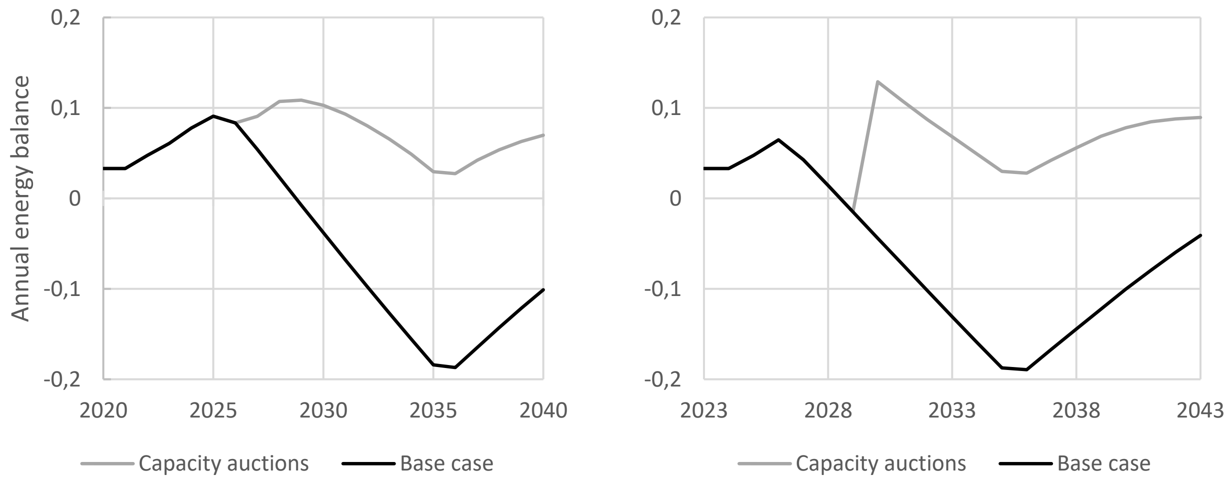

Figure 6. Annual energy margin and forecasted annual energy margin

Figure 7 captures the evolution of PHS and PV installed capacity. We see that CA have the expected effect on the system: PV installed capacity grows rapidly due to an increase of PV ROI. At the end of the simulation, PV installed capacity is 66% higher than in the base case. We also observe that the pumping capacity increases by 34% compared to the base case. When CA is implemented, blackouts are eliminated, and the total annual excess electricity equals 9% at the end of the simulation.

c) PHS installed capacity

d) PV installed capacity

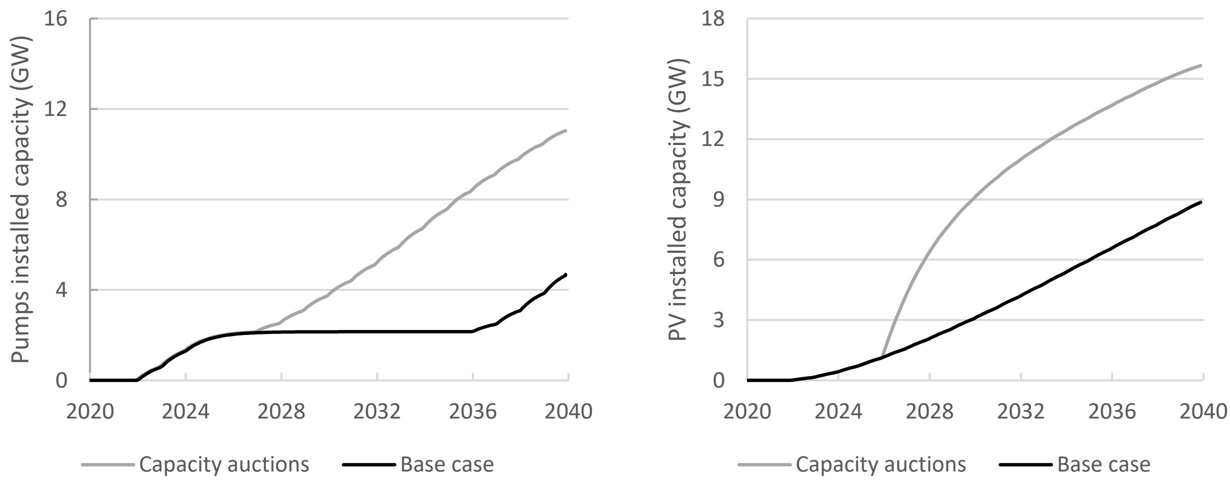

Figure 7. Installed capacity of PV and pumps by scenario

Figure 8 shows the evolution of the electricity price. During the first year we observe a constant price, but over the next four years price decreases due to the introduction of PV capacity in anticipation of the nuclear dismantling process. Next, in 2025, as nuclear capacity is being dismantled, the electricity price starts to increase for both scenarios. In the base case the electricity price continues to increase until the end of the nuclear dismantling process (2035). This increase responds to shortages (recall figure 2), as the hydro bid depends on the reservoir level: when there are shortages, the reservoir is almost empty, so the hydro bid is at its maximum, which increases the electricity price. In the CA scenario, the regulator incentivizes investments in PV to avoid shortages. The increase in both PV and pumping capacity (recall figure 7) leads to a reduction in the electricity price between 2025 and 2030. The higher the PV capacity, the higher the excess of cheap electricity that can be pumped.

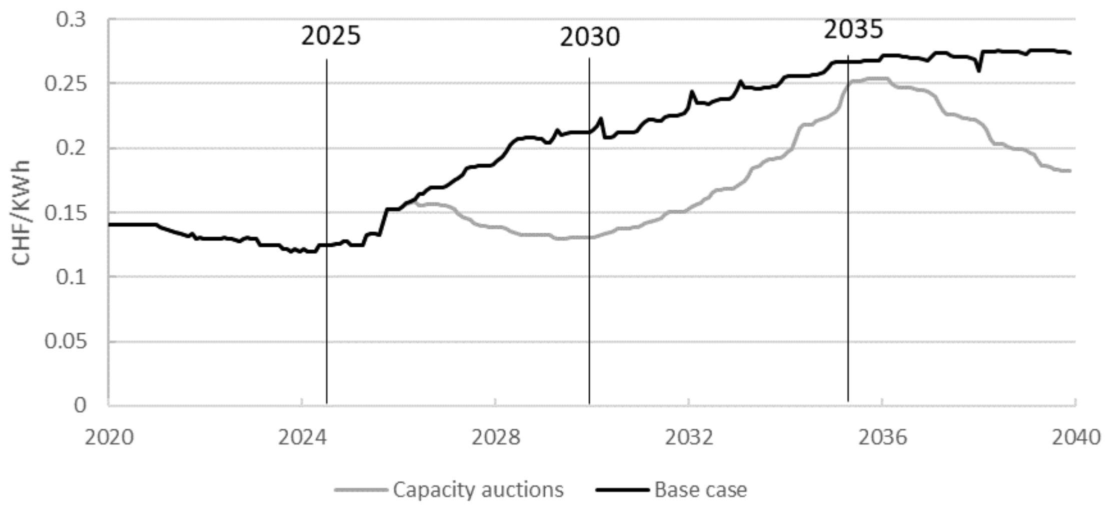

Figure 8. Electricity price

Figure 9 illustrates the interdependency between the evolution of PV installed capacity and the ROI of PHS. The base case illustrates how PHS is unprofitable when PV capacity is low; this technology only turns profitable once there is enough PV installed capacity (in 2036, when PV installed capacity reaches 7 GW and PV generation represents 26% of total generation). To be profitable, PHS needs to maximize the difference between the prices at the time of pumping and of generation. Figure 9 also illustrates how subsidizing PV indirectly encourages investments in pumping capacity: the increasing PV installed capacity leads to inexpensive excess electricity, which increases PHS's ROI.

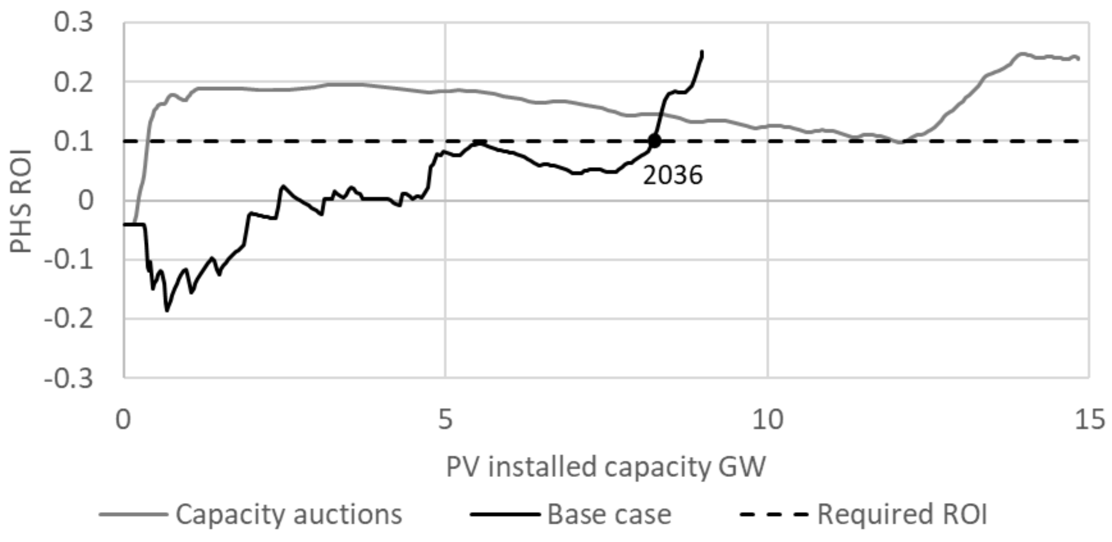

Figure 9. PV installed capacity versus PHS ROI

PHS profit also depends on its utilization rate, the evolution of which is shown in figure 10a. We can observe that after 2024 the utilization rate is higher with CA than in the base case, as there is more electricity available for pumping, therefore subsidizing PV indirectly encourages PHS. Figure 10b shows how subsidies maintain the fraction of hours per year the pumps operate above 30%, while in the base case, this fraction falls after 2024, reaching a minimum of 8% of the total hours of the year in 2034. Note that CA results in more PHS installed capacity, a higher utilization rate and more active hours per year.

a) Utilization rate

b) Fraction hours/year

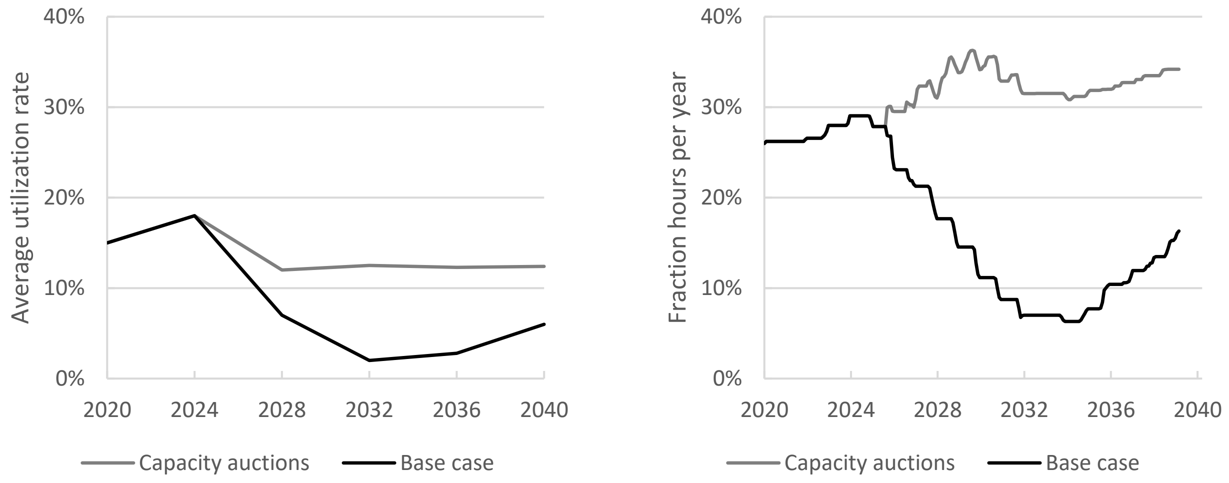

Figure 10. PHS utilization rate

We also performed a sensitivity analysis for CA. Considering that this scenario does not have blackouts, we only focus on the conditions that deteriorate the base case (I^-, R^-, R^+ and N^+). The results show that shortages only occur in the CA scenario when there is a 10% reduction of the reservoir size (case R^-). Replacing the linear nuclear dismantling process by a step function has no significant impact on investments nor on other key variables such as the electricity price.

6. Conclusions and Policy Implications

In this paper, we developed an SD based model to analyze the requirements for a country such as Switzerland to drive a transition towards a 100% renewable electricity system, considering only a hydro-solar combination, with PHS to store energy. In the base case scenario, the system is unable to meet the annual demand after the start of the dismantling process. No single measure, whether slowing down the nuclear dismantling process, modifying the reservoir size, or improving technology allows the system to pass through the transition without creating significant blackouts over several years, disruptions that no society can accept. In other words, neither the likely continued fall of the capital cost for PV, nor the two regulatory options of delaying the nuclear dismantling or increasing the reservoirs results in a sustainable transition. Consequently, subsidies are required to minimize the risk of a blackout during the transition period. Furthermore, subsidizing PV makes energy storage profitable, which was not the case in the simulations without subsidies.

All the scenarios, with or without subsidies lead to higher electricity prices. For instance, we observed that in the base case the price almost doubles during the transition. This is without taking into account the cost of years of continued significant blackouts, which would create a considerable economic cost for society as a whole [67]. Introducing capacity auctions leads to lower prices compared to the base case: after a peak around 2035 prices start to decrease towards the end of the simulation ending at a level approximately 25% above the initial price. The increase in cost should not be a surprise as old, at least partly written off nuclear plants are replaced with PV capacity, which requires significant capital expenditure.

Our stylized model shows that without subsidizing PV, blackouts are inevitable. For a smooth transition, investments in both PV and PHS need to be profitable. Our simulations show that this can be achieved while subsidizing only PV capacity. Indeed, in the presence of a sufficient amount of PV capacity, PHS turns profitable. Next, let us consider the practical feasibility of the proposed transition. With an annual electricity demand of 62 TWh and annual hydro-generation of 39 TWh, only 23 TWh of net additional generation are required. Assuming that 60% of PV generation is pumped, and a 20% loss factor, this implies that around 26 TWh of PV generation is required, a figure well below the estimated potential of 32 TWh by 2050 [41]. The required storage capacity can be achieved by increasing the height of current reservoir dams by 10%, which is technically possible. Regarding the need for pumping, currently there are 14 PHS plants running in Switzerland with an estimated potential pumping capacity of 369 GWh. Given Switzerland's geographical conditions, this could be doubled over the next decade by increasing the capacity of current plants and using new locations [66]. We can thus conclude that the nuclear dismantling process can be implemented without disruptions to supply by relying on a PHS and PV combination.

This stylized model has a number of limitations. In the analysis we do not consider exports and imports; as argued before, relying on cross-border trade to cover shortages or sell excess generation could be a risky strategy for governments. Recall that many countries are moving towards a significant share of PV; this will result in neighboring countries simultaneously facing an excess of electricity, making exports unprofitable, if not impossible. This may lead to extended periods of low, or even negative prices, a phenomenon that is not new in European countries such as Germany [68]. Furthermore, there are no historical examples of what would happen if several countries faced shortages at the same time. However, the recent experience among European countries within the health area is not encouraging [13].

While the model only considers capacity auctions for subsidizing capacity investment, we have also tested FITs as an alternative mechanism. However, we have not reported these results as in our model they are very similar to those of capacity auctions. One of the main differences between these two mechanisms lies in who carries the risk. In capacity auctions the regulator (and thus the final consumers) knows the cost of subsidizing a certain increase in capacity upfront and the companies carry the risk of future not developing as expected. On the contrary, with FITs the regulator bears the risk, as the generators are guaranteed a minimum price. Our model does not incorporate this risk aspect, which explains why the results of both mechanisms are similar. Furthermore, as discussed in the introduction, capacity auctions are becoming the predominant way to subsidies new investments in renewable generation across Europe.

Our results are limited by the model boundaries. We have not dealt with environmental, political, and legal changes that such a transition would require. Our results should be seen as an experiment to test different policies. It is clear that technological or political changes could affect the validity of our results. Nevertheless, we believe that our analysis has provide valid insights.

Finally, our modelling process provides a useful tool not only for Swiss policy makers, but also for other countries. This model could be adapted to study the feasibility of different energy policies for other regions or countries with a different mix facing a transition in their energy system.

ACKNOWLEDGEMENT

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APPENDIX

Appendix A.1 lists the model equations. Appendix A.2 provides a graphical representation of the nonlinear relationships. The equations of the parallel model used for investment decisions (recall section 4) are identical and thus not included here.

A.1.1 List of variable names and abbreviation

Name	***Abbreviation***
Annual_demand	*AD*
Annual_energy_margin	*AEM*
Annual_energy_margin forecast	*AEMF*
Annual_Natural_Inflows	*ANI*
Annual_PHS_revenue	*APR*
Annual_pumped	*AP*
Annual_unmet_demand_after PV	*AUDAPV*
Available_electricity_for pumping	*AEP*
Base Hn price	*BHnP*
Base_LCOE_base load	*BLCOEBL*
Base_LCOE_nuclear	*BLCOEN*
Base_LCOE_solar	*BLCOES*
Base_load_price	*BLP*
Base_load_technology generation_per_hour	*BLTGH*
Base_load_technology installed_capacity	*BLTIC*
Change_in_average_Price	*CAP*
Cost_per_MWh_pumped	*CMWhP*
Current_price(t-year)	*CP*
Desired_energy_margin	*DEM*
Desired_fill_rate_of_the reservoir_as_a_function_of time_of_year	*m(DFRR)*
Dmnl	*Dimensionless*
Dummy_base_load	*DBL*
Dummy_Hn	*DHn*
Dummy_intermittent	*DI*
Dummy_nuclear	*DN*
Dummy_PHS	*DPHS*
Dummy_potential_pumping	*DPP*
Electricity_demand_per_hour	*EDH*
Electricity_demand_per_hour (t+year)	*EDHY*
Electricity_price_without excess_correction	*EPWEC*
Electricity_used_for pumping	*EUP*
Energy_margin_Gap_desired-forecast	*EMG*
Excess_after_base_load	*EABL*
Excess_after_PV	*EAPV*
Gap_base_load_generation-Demand	*GBLG*
Hn_generation_capacity	*HnGC*
Hn_generation_if_Hn_first	*HnHnF*
Hn_generation_if_PHS_first	*HnPHSF*
Hn_price	*HnP*
Hn_reservoir_installed capacity	*HnRIC*
Hn_stock	*HnS*
Hn_total_generation	*HnTG*
Hn_water_release	*HnWR*
Hourly_and_monthly variation_of_solar_radiation	*v(SESR)*
Hourly_and_seasonal_demand factors	*v(HSEF)*
Hourly_average_demand	*HAD*
Hourly_PHS_revenue	*HPR*
Hourly_PHS_revenue(t+year)	*HPRY*
Hydro_availability	*HA*
Hydro_price	*HP*
Impact_of_an_increasing share_of_PV_capacity_on_the desired_energy_margin	*n(PVSCDEM)*
Impact_of_the_ratio_between current_and_the_desired_ROI on_PHS_investment_decision	*h(PHSRROI)*
Impact_of_the_ratio_between current_and_the_desired_ROI on_PV_investment_decision	*h(PVRROI)*
Impact_of_the_reservoir_fill rate_on_overflows	*f(RFR)*
Impact_of_the_reservoir_fill rate on_pumping	*g(RFR)*

Impact_of_the_reservoir fill_rate_on_the_price	*i(RFR)*	PHS_pumping_ROI	*PHSPROI*
Indicator_Hn_generation_first	*IHnGf*	PHS_Ratio_ROI	*PHSRROI*
Initial_energy_margin	*IEM*	PHS_release(t+year)	*PHSRY*
LCOE_base_load	*LCOEBL*	PHS_released_cost	*PHSRC*
LCOE_Hn	*LCOEHn*	PHS_reservoir_capacity	*PHSRC*
LCOE_nuclear	*LCOEN*	PHS_storage_fill_rate	*PHSSFR*
LCOE_PHS	*LCOEPHS*	PHS_total_generation	*PHSTG*
LCOE_solar	*LCOES*	PHS_utilization_rate	*PHSUR*
Market_price	*MP*	PHS_water_cost	*PHSWC*
Monthly_impact_on_natural inflows	*v(MINI)*	PHS_water_pumped	*PHSWP*
Monthly_impact_on_Run-of-rivers_generation	*v(MIRoR)*	PHS_water_pumped(t+year)	*PHSWPY*
Natural_inflow	*NI*	PHS_water_release	*PHSWR*
Natural_inflows(t+year)	*NIY*	PHS_water_stock	*PHSWS*
Need_to_subsidize_PV	*NSPV*	PHS_yearly_pumping investment	*PHSYPI*
Normal_inflow	*NoI*	Price_per_MWh_PHS	*PMWhPHS*
Nuclear_availability_and efficiency	*NAE*	Pumping_active	*PA*
Nuclear_generation_per_hour	*NGH*	Pumping_active(t+year)	*PAY*
Nuclear_installed_capacity	*NIC*	Pumps_project_lifetime	*PPL*
Overflow	*O*	PV_active	*PVA*
Phasing-out_technology dismantle	*PTD*	PV_active(t+year)	*PVAY*
PHS_annual_generation	*PHSAG*	PV_annual_generation	*PVAG*
PHS_annual_income	*PHSAI*	PV_annual_income	*PVAIn*
PHS_annual_net_revenue	*PHSANR*	PV_annual_income_with capacity_auction_forecast	*PVAICAF*
PHS_annual_total_cost	*PHSATC*	PV_annual_income_with_FITs forecast	*PVAIFITF*
PHS_annual_total_hours	*PHSATH*	PV_annual_investment	*PVAI*
PHS_capital_cost	*PHSCC*	PV_annual_net_revenue	*PVANR*
PHS_cost_of_water	*PHSCW*	PV_annual_net_revenue_with capacity_auctions_forecast	*PVANRCAF*
PHS_default_investment_size	*PHSDIS*	PV_annual_net_revenue_with FITs_forecast	*PVANRFITF*
PHS_desired_fill_rate	*PHSDFR*	PV_annual_total_cost_per_MW	*PVATCMW*
PHS_desired_ROI	*PHSDROI*	PV_annual_total_cost_per_MW with_subsidies_forecast	*PVATCMWSF*
PHS_entries	*PHSE*	PV_annual_total_hours	*PVATH*
PHS_generation_capacity	*PHSGC*	PV_average_utilization_factor	*PVAUF*
PHS_generation_if_Hn_first	*PHSGHnF*	PV_capacity_auction_subsidy forecast	*PVCASF*
PHS_generation_if_PHS_first	*PHSgPHSF*	PV_capacity_forecast	*PVCF*
PHS_investment_in_pumping	*PHSIP*	PV_capacity_under construction	*PVCUC*
PHS_potential_generation	*PHSPG*	PV_capital_cost	*PVCC*
PHS_price	*PHSP*	PV_capital_cost_with_subsidies forecast	*PVCCSF*
PHS_pumping_capacity	*PHSPC*	PV_change_in utilization_factor (t+year)	*PVCUFY*
PHS_pumping_capacity_under construction	*PHSPCUC*	PV_construction_time	*PVCT*
PHS_pumping_dismantle	*PHSPD*		
PHS_pumping_efficiency	*PHSPE*		

PV_consumed	*PVC*
PV_cumulative_utilization factor	*PCCUF*
PV_current_utilization_factor	*PVCuUF*
PV default investment size	*PFDIS*
PV_desired_ROI	*PVDROI*
PV_dismantle	*PVD*
PV_efficiency	*PVEf*
PV_entries	*PVE*
PV_generation	*PVG*
PV_generation(t+year)	*PVGY*
PV_hourly_revenue	*PVHR*
PV_hourly_revenue(t+year)	*PVHRY*
PV_installed_capacity	*PVIC*
PV_investment_in_new intermittent	*PVINI*
PV_lifetime	*PVL*
PV_no_subsidies_yearly revenue	*PVnSYR*
PV_O&M_expenses_per_MW per year	*PVOME*
PV_price	*PVP*
PV_price_per_MWh	*PVPMWh*
PV_project_lifetime	*PVPL*
PV_Ratio_ROI	*PVRROI*
PV_ROI_no_subsidies	*PVROInS*
PV_ROI_with_capacity_auction forecast	*PVROICAF*
PV_ROI_with_subsidies forecast	*PVROISF*
PV_utilization_factor	*PVUF*

Ratio_Hp_fill_rate/desired fill rate	*RHpFRDFR*
Ratio_required_PV_investment forecast	*RRPVIF*
Required_additional_PV capacity	*RAPVC*
Required_FIT	*RFIT*
Required_PV_annual_income forecast	*RPVAIF*
Required_PV_annual_net_profit forecast	*RPVAnPF*
Required_PV_capital_cost forecast	*RPVCCF*
Required_PV_price_per_MWh forecast	*RPVPMWhF*
Required_PV_ratio_ROI_to satisfy_PV_investment requirement	*RPVRROISPV*
Required_PV_ROI_forecast	*RPVROIF*
Reservoir_fill_rate	*RFR*
Shortage_after_base-load generation	*SABLG*
Shortage_after_Hn	*SAHn*
Shortage_after_hydro generation	*SAHG*
Shortage_after_PHS	*SAPHS*
Shortage_after_PV_generation	*SAPVG*
Shortage_after_PV_generation (t+year)	*SAPVGY*
Storage_fill_rate	*SFR*
System_hourly_electricity_price	*SHWP*
Time_to_build_pumps	*TBP*
Total_water_capacity	*TWC*
Total_water_in_reservoirs	*TWR*

A.1.2 Equations

Variables with a superscript (*) are nonlinear functions and are shown in Appendix 2.

A.1.2.1 Capacity and demand

This subsection provides the equations concerning capacity and generation for each technology, as well as for electricity demand.

A.1.2.1.1 PV capacity

Name /Equation		***Unit***
	Parameter value	
PVCT	26,280	Hour
PVDIS	500	MW/hour
PVDROI	0.1	Dmnl
PVL	262,800	hour
	State and associated variables	
$\frac{d(PVCUC)}{dt} = PVINI - PVE$	$(PVCUC(0) = 0)$	MW
$\text{PVINI}(t) = \text{PVAI}(t)$		MW/hour
$\text{PVE}(t) = \frac{\text{PVCUC}(t)}{PVCT(t)}$		MW/hour
$\frac{d(PVIC)}{dt} = PVE - PVD$	$(PVIC(0) = 1)$	MW
$\text{PVD}(t) = \frac{\text{PVIC}(t)}{PVL(t)}$		MW/hour
	Other Variables	
$\text{PVAI}(t)$=PVDIS* h(PVRROI)*(Figure A2.3)		MW/hour
$\text{PVCF}(t) = \text{PVCUC}(t) + \text{PVIC}(t)$		MW
$PVRROI(t) = \begin{cases} \frac{PVROISF(t)}{PVDROI(t)}, & \text{NSPV}(t) > 0 \\ \frac{PVROInSF(t)}{PVDROI(t)}, & otherwise \end{cases}$		Dmnl
PVROISF(t)= (PVROICAF(t)*Switch capacity auction)+(PVROIFITF(t)*(1-Switch))		Dmnl

A.1.2.1.2 PHS and hydro-storage capacity

Name/Equation		***Unit***
	Parameter value	
PHSDIS	300	MW/hour
PHSDROI	0.1	Dmnl
PHSGC	10,000	MWh
HnGC	10,000	MWh
HnRIC	8,800	GWh
NoI	3,500	MWh/hour
TBP	8,760	Hour
TWC	262,800	Hour

State and associated variables	
$\frac{d(PHSPCUC)}{dt} = PHSIP - PHSE \qquad (PHSPCUC(0) = 0)$	MW
$\mathrm{PHSIP}(t)=\mathrm{PHSYPI}(t)$	MW/hour
$\mathrm{PHSE}(t) = \frac{\mathrm{PHSPCUC}(t)}{\mathrm{TBP}}$	MW/hour
$\frac{d(PHSPC)}{dt} = PHSE - PHSD$ $PHSPC(0) = 1$	MW
$\mathrm{PHSPD}(t) = \frac{\mathrm{PHSPC}(t)}{PL(t)}$	MW/hour
$\frac{d(PHSWS)}{dt} = PHSWP - PHSWR \qquad (PHSWS(0) = 880{,}000)$	MWh
$\mathrm{PHSWP}(t)=\mathrm{EUP}(t)*\mathrm{PHSPE}$	MWh/hour
$\mathrm{PHSWR}(t)=\mathrm{PHSTG}(t)$	MWh
$\frac{d(HnS)}{dt} = NI - Overflow \qquad (HnS(0) = 8{,}800{,}000)$	MWh
$\mathrm{NI}(t)=\mathrm{NoI}*\mathrm{V(MINI)}^{*}$(Figure A2.9)	MWh/hour
$\mathrm{HnWR}(t) = \mathrm{HnTG}(t)$	MWh/hour
$\mathrm{Overflow}(t) = \mathrm{NI}(t)*\mathrm{f(RFR)}^{*}$(Figure A2.1)	MWh/hour
Other variables	
$\mathrm{PHSRROI}(t) = \frac{\mathrm{PHSROIF}(t)}{PHSDROI(t)}$	Dmnl
$\mathrm{PHSRC}(t)=\mathrm{TWC}-\mathrm{HnS}(t)$	MWh
$\mathrm{PHSYPI}(t)=\mathrm{PHSDIS}*\ \mathrm{h(PHSRROI)}^{*}$(Figure A2.3)	MWh/hour
$\mathrm{RFR}(t) = \frac{HnS(t) + WS(t)}{TWC(t)}$	MWh
$\mathrm{TWR}(t)=\mathrm{HnS}(t)+\mathrm{PHSWS}(t)$	MWh

A.1.2.1.3 Nuclear and RoR capacity

Name / equation		***Unit***
Parameter value		
BLTIC	3,500	MW
State and associated variables		

$\frac{d(NIC)}{dt} = -PTD \qquad (NIC(0) = 5{,}000)$	MW
$PTD(t) = \begin{cases} 0.057, & 43{,}800 \le t \le 131{,}400 \\ 0, & otherwise \end{cases}$	MW/hour

A.1.2.1.4 Market clearance (demand and supply)

Name / equation		***Unit***
	Parameter value	
BLTIC	3,500	MW
NAE	0.68	Dmnl
PVEf	0.2	Dmnl
PHSPE	0.8	Dmnl
HA	0.9	Dmnl
HAD	6,500	MWh/hour
	Other variables	
GBLG(t)=BLTGH(t)+NGH(t)-EDH(t)		MWh/hour
AEP(t)=EABL(t)+EAPV(t)		MWh/hour
BLTGH(t)=BLTIC* v(MIRoR)*(Figure A2.9)		MWh/hour
EDH(t)=HAD*v(HSEF)*(Figure A2.7)		MWh/hour
EUP(t)=min(AEP(t), min($\frac{\mathrm{PHSRC}(t)}{PHSE(t)}$,PHSPC($t$)))*i(RFR)*(Figure A2.4)		MWh/hour
$EABL(t) = \begin{cases} GBLG(t), & GBLG(t) < 0 \\ 0, & otherwise \end{cases}$		MWh/hour
$EAPV(t) = \begin{cases} 0, & PVG(t) < SABLG(t) \\ PVG(t) - SABLG(t), & otherwise \end{cases}$		MWh/hour
$\mathrm{HnHnF}(t) = \min(\text{Potential generation from Hn}(t), \mathrm{SAPVG}(t)) * \mathrm{IHnGf}(t)$		MWh/Hour
$\mathrm{HnPHSF}(t) = \min(\mathrm{PGHn}(t), \mathrm{SAPHS}(t)) * (1 - \mathrm{IHnGF}(t))$		MWh/Hour
HnTG(t)=HnHnf(t)+HnPHSF(t)		MWh/Hour
$IHnGf(t) = \begin{cases} 1, & HnP(t) \le PHSP(t) \\ 0, & otherwise \end{cases}$		Dmnl
NGH(t)=NIC(t)*NAE		MWh/hour
$\mathrm{PHSGHnf}(t) = \min(\mathrm{PHSPG}(t), \mathrm{SAHn}(t)) * \mathrm{IHnGF}(t)$		MWh/Hour
$\mathrm{PHSgPHSF}(t) = \min(\mathrm{PHSPAPVG}(t), \mathrm{SAPVG}(t)) * (1 - \mathrm{IHnGF}(t))$		MWh/Hour
$\mathrm{PHSPG}(t) = \min(\mathrm{PHSGC}, \mathrm{PHSWS}(t))$		MWh/hour

PHSTG(t)=PHSgPHSF(t)+PHSGHnF(t)	MWh/Hour
$\mathrm{PVC(t)} = \min(\mathrm{PVG}(t), \mathrm{SABLG}(t))$	MWh/hour
PVG(t)=PVEf*PVIC(t)* v(SESR)*(Figure A2.8)	MWh/hour
$SABLG(t) = \begin{cases} -GBLG(t), & \mathrm{GBLG}(t) < 0 \\ 0, & otherwise \end{cases}$	MWh/hour
SAHn(t)=SAPVG(t)-HnHnl(t)	
$\mathrm{SAHG}(t) = \max(\mathrm{SAPVG}(t) - \mathrm{HnWR}(t) - \mathrm{PHSWR}(t), 0)$	MWh/hour
SAPHS(t)=SAPVG(t)-PHSgPHSF(t)	MWh/Hour
SAPVG(t)=SABLG(t)-PVC(t)	MWh/hour

A.1.2.2 Bid by technology and market price

This subsection provides the parameters and equations used to calculate the bid for each technology, as well as the electricity market price.

Name / equation		***Unit***
	Parameter value	
BHnP	50	CHF/MWh
BLCOEBL	74	CHF/MWh
BLCOEN	70	CHF/MWh
BLCOES	120	CHF/MWh
PHSCC	500,000	CHF/MW
PPL	25	Year
PVCC	992,000	CHF/MW
PVOME	15,000	CHF/MW/Year
PVPL	30	Year

Data from IRENA (2017), Fu, Feldman and Margolis (2018) and Renew Economy (2017)

A.1.2.2.1 PV Bid

Name / equation	***Unit***
State variables	
PVA(t)=DI(t)	Dmnl/hour
PVAY(t)=PVA(t-8760)	Dmnl/hour

$\frac{d(PVAG)}{dt} = PVG - PVGY$	$(PVAG(0) = 0)$	MWh
$\frac{d(PVATH)}{dt} = PVA - PVAY$	$(PVATH(0) = 0)$	Dmnl
PVCUFY(t)=PVCuUF(t-8760)		Dmnl/hour
$\frac{d(PCCUF)}{dt} = PVCuUF - PVCUFY$	$(PCCUF(0) = 0)$	Dmnl
PVCuUF(t)=v(SESR)*(Figure A2.8)		Dmnl/hour
PVGY(t)=PVG(t-8760)		MWh/hour
PVHR(t)=SHEP(t)*PVC(t)		CHF/hour
PVHRY(t)= PVHR(t-8760)		CHF/hour
$\frac{d(PVnSYR)}{dt} = PVHR - PVHRY$	$(PVnSYR(0) = 0)$	CHF
Other Variables		
$DI(t) = \begin{cases} 1, & PVG(t) > 0 \\ 0, & otherwise \end{cases}$		Dmnl
LCOES(t)=BLCOES*DI(t)		CHF/MWh
PVAIn(t) =PVPMWh(t)*PVATH(t)*PVAUF(t)*PVEf		CHF/Year
$PVAUF(t) = \begin{cases} 0, & \text{PVATH}(t) = 0 \\ \frac{PCCUF(t)}{PVATH(t)}, & otherwise \end{cases}$		Dmnl
PVANR(t) =PVAI(t)-PVATCMW(t)		CHF/MW/Year
$\text{PVATCMW}(t) = \frac{PVCC(t)}{PVPL(t)} + PVOME(t)$		CHF/MW/Year
$PVPMWh(t) = \begin{cases} 0, & \text{PVAG}(t) = 0 \\ \frac{PVnYR(t)}{PVAG(t)}, & otherwise \end{cases}$		CHF/MWh
$\text{PVROInS}(t) = \frac{PVANR(t)}{\text{PVCC}}$		Dmnl

A.1.2.2.2 PHS Bid

Name / equation		***Unit***
State and associated variables		
$\frac{d(APR)}{dt} = HPR - HPRY$	$(APR(0) = 0)$	CHF
HPR(t)=SHEP(t)*PHSTG(t)		CHF/hour

HPRY(t) = HPR(t-8760)	CHF/hour
$\frac{d(PHSAG)}{dt} = PHSWR - PHSRY \quad (PHSAG(0) = 0)$	MWh
$\frac{d(PHSATH)}{dt} = PA - PAY \quad (HSATH(0) = 8{,}800{,}000)$	Hours/year
$\frac{d(PHSCW)}{dt} = PHSWC - PHSRC \quad (PHSCW(0) = 140{,}800{,}000)$	CHF
PHSRY(t)=PHSWR(t-8760)	MWh/hour
$\mathrm{PHSRC}(t)=\mathrm{CMWhP}(t)*\mathrm{PHSWR}(t)$	CHF/hour
$\mathrm{PHSWC}(t)=\mathrm{PVP}(t)*\frac{\mathrm{PHSWP}(t)}{\mathrm{PHSE}(t)}$	CHF/hour
$\mathrm{PA}(t)=\mathrm{DP}(t)$	hours
PAY(t)=PA(t-8760)	Hours
Other Variables	
$CMMWhP(t) = \begin{cases} \frac{PHSCW(t)}{PHSWS(t)}, & \mathrm{PHSWS}(t) > 0 \\ 0, & otherwise \end{cases}$	CHF/MWh
$DPHS(t) = \begin{cases} 1, & \mathrm{PHSWR}(t) > 0 \\ 0, & otherwise \end{cases}$	Dmnl
$DPP(t) = \begin{cases} 1, & \mathrm{EUP}(t) > 0 \\ 0, & otherwise \end{cases}$	Dmnl
$\mathrm{LCOEPHS}(t)=\mathrm{PHSP}(t)*\mathrm{DPHS}(t)$	CHF/MWh
$\mathrm{PHSAI}(t)=\mathrm{PHSUR}(t)*\mathrm{PMWhPHS}(t)*\mathrm{PHSE}(t)*\mathrm{PHSATH}(t)$	CHF/MW/year
$\mathrm{PHSANR}(t)=\mathrm{PHSAI}(t)-\mathrm{PHSATC}(t)$	CHF/MW/year
$\mathrm{PHSATC}(t) = \frac{PHSCC(t)}{PPL(t)} + \mathrm{CMWhP}(t) * \mathrm{PHSATH}(t) * \mathrm{PHSE}(t) * \mathrm{PHSUR}(t)$	CHF/MW/year
$\mathrm{PHSDFR}(t)$= m(DFRR)* (Figure A2.5)	Dmnl
$\mathrm{PHSPROI}(t) = \frac{PHSANR(t)}{PHSCC(t)}$	Dmnl
$\mathrm{PHSSFR}(t) = \frac{PHSWS(t)}{PHSRC(t)}$	Dmnl
$\mathrm{PHSUR}(t) = \frac{PHSWP(t)}{PHSPC(t)*PHSE(t)}$	Dmnl

$PMWhPHS(t) = \begin{cases} 0, & \text{PHSAG}(t) \leq 0 \\ \frac{APHSR(t)}{PHSAG(t)}, & otherwise \end{cases}$	CHF/MWh
$\text{RHpFRDFR}(t) = \frac{PHSSFR(t)}{PHSDFR(t)}$	Dmnl
$\text{SFR}(t) = \frac{HnS(t)}{TWC(t)}$	Dmnl

A.1.2.2.3 Hydro-storage, RoR and Nuclear Bid

Name / equation	***Unit***
Other variables	
$DBL(t) = \begin{cases} 1, & \text{BLTGH}(t) > 0 \\ 0, & otherwise \end{cases}$	Dmnl
$DHn(t) = \begin{cases} 1, & \text{HnWR}(t) > 0 \\ 0, & otherwise \end{cases}$	Dmnl
$DN(t) = \begin{cases} 1, & NGH(t) > 0 \\ 0, & otherwise \end{cases}$	Dmnl
LCOEBL(t)=BLCOEBL*DBL(t)	CHF/MWh
LCOEHn(t)=HnP(t)*DHn(t)	CHF/MWh
LCOEN(t)=BLCOEN*DN(t)	CHF/MWh

A.1.2.2.4 Market price

Stocks and associated variables	
Name / equation	**Unit**
CAP(t)=SHEP(t)	CHF/MWh/hour
CP(t)=CPY(t-8760)	CHF/MWh/hour
$\frac{d(MP)}{dt} = CAP - CP \qquad (MP(0) = 70)$	CHF/MWh
Other variables	
$\text{BLP}(t) = max(LCOEN(t), LCOWBL(t))$	CHF/MWh
$\text{EPWEC}(t) = max(max(BLP(t), PVP(t)), HP(t))$	CHF/MWh
HnP(t)=BHnP*g(RFR)*(Figure A2.2)	CHF/MWh
$HP(t) = max(LCOEHn(t), LCOEPHS(t))$	CHF/MWh
PHSP(t)=CMWhP(t)* g(RFR)*(Figure A2.2)	CHF/MWh

PVP(t) =LCOES(t)*(DPP*(1- i(RFR)*(Figure A2.4)))	CHF/MWh

A.1.2.3 Subsidies

This subsection provides the parameters and equations used to calculate the subsidies for PV.

Name / equation		***Unit***
	Parameter value	
IEM	0.033	CHF/MWh
	State and associated variables	
Equation		**Unit**
$\frac{d(AD)}{dt} = EDH - EDHY \qquad (AD(0) = 0)$		MWh
EDHY(t)=EDH(t-8760)		MWh/hour
$\frac{d(ANI)}{dt} = NI - NIY \qquad (ANI(0) = 0)$		MWh
NIY(t)=NI(t-8760)		MWh/hour
$\frac{d(AP)}{dt} = PHSWP - PHSWPY \qquad (AP(0) = 0)$		MWh
PHSWPY(t)=PHSWP(t-8760)		MWh/hour
$\frac{d(AUDAPV)}{dt} = SAPVG - SAPVGY \quad (AUDAPV(0) = 0)$		MWh
SAPVGY(t)=SAPVG(t-8760)		MWh/hour
	Other Variables	
$AEM(t) = \begin{cases} \frac{ANI(t) + AP(t) - AUDAPV(t)}{AD(t)}, & t > 8760 \\ IEM, & otherwise \end{cases}$		Dmnl
$AEMF(t) = \begin{cases} \frac{ANI(t) + APF(t) - AUDAPVF(t)}{AD(t)}, & t > 8760 \\ IEM, & otherwise \end{cases}$		Dmnl
DEM(t)= n(PVSCDEM)*(Figure A2.6)		Dmnl
EMG(t)=DEM(t)-AEMF(t)		Dmnl
$NSPV(t) = \begin{cases} 0, & \mathrm{EMGF}(t) > 0 \\ 1, & otherwise \end{cases}$		Dmnl
PVAICAF(t)=PVPMWhF(t)*PVATH(t)*PVAUF(t)*PVEf		CHF/MW/year
PVAIFITF(t)=NSPV(t)*(RFIT(t)+PVPMWhF(t))*PVATH(t)*PVAUF(t)*PVEf		CHF/MW/year

$\mathrm{PVANRCAF}(t)=\mathrm{PVAICAF}(t)-\mathrm{PVATCMWSF}(t)$	CHF/MW/year
$\mathrm{PVANRFITF}(t)=\mathrm{PVAIFITF}(t)-\mathrm{PVATCMW}(t)$	CHF/MW/year
$\mathrm{PVATCMWSF}(t)=\frac{PVCCSF(t)}{PVPL(t)+PVOME(t)}$	CHF/MW/year
$\mathrm{PVCASF}(t)=(\mathrm{PVCC}-\mathrm{RPVCCF}(t))*\mathrm{NSPV}(t)$	CHF/MW
$\mathrm{PVCCSF}(t)=\mathrm{PVCC}-\mathrm{PVCASF}(t)$	CHF/MW
$\mathrm{PVROICAF}(t)=\frac{PVANRCAF(t)}{PVCCSF(t)}$	Dmnl
$\mathrm{RRPVIF}(t)=\frac{RAPVC(t)}{PVDIS(t)}$	Dmnl
$RAPVC(t)=\begin{cases}\frac{AUDAPV(t)}{PVE(t)*PVAUF(t)*PVATH(t)}, & \mathrm{t}>8760\ \wedge\ \mathrm{AEMF}(t)<0\\ 0, & otherwise\end{cases}$	MW
$\mathrm{RFIT}(t)=\mathrm{RPVPMWhF}(t)-\mathrm{PVPMWhF}(t)$	CHF/MWh
$RPVAIF(t)=\begin{cases}\mathrm{PVATCMW}(t)+\mathrm{RPVANPF}(t), & \mathrm{PVATCMW}(t)+\mathrm{RPVANPF}(t)>0\\ 0, & otherwise\end{cases}$	CHF/MW/year
$\mathrm{RPVANPF}(t)=\mathrm{RPVROIF}(t)*\mathrm{PVCC}$	CHF/MW/year
$RPVCCF(t)=\begin{cases}PVCC(t), & \mathrm{RPVROIF}(t)<0\\ \frac{\mathrm{PVAICAF}(t)+\mathrm{PVOME}}{\mathrm{RPVROIF}(t)+\frac{1}{PVPL(t)}}, & otherwise\end{cases}$	CHF/MW
$\mathrm{RPVPMWhF}(t)=\begin{cases}0, & \mathrm{t}<8760\\ \frac{\mathrm{RAIF}(t)}{\mathrm{PVATH}(t)*\mathrm{PVAUF}(t)*\mathrm{PVEf}}, & otherwise\end{cases}$	CHF/MWh
$\mathrm{RPVRROISPV}(t)=\mathrm{h}^{-1}(\mathrm{PVRROI})^{*}$(Figure A2.3)	Dmnl
$\mathrm{RPVROIF}(t)=\mathrm{RPVRROISPV}(t)*\mathrm{PVDROI}$	Dmnl

A.2 Graphical representation of nonlinear functional relationships

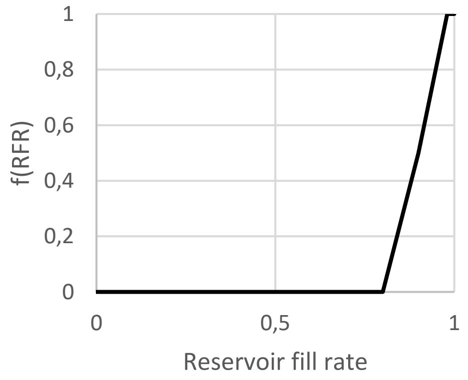


Figure A2.1 Impact of the reservoir fill rate on overflows f(RFR)

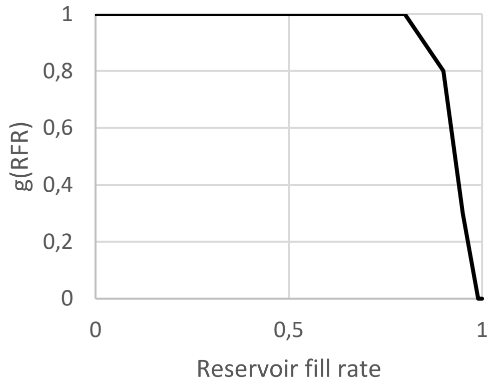
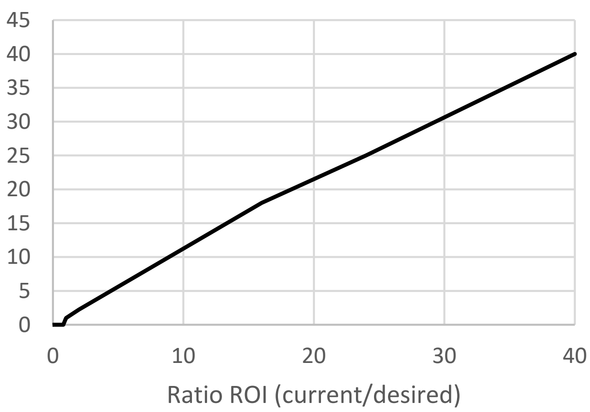


Figure A2.2 Impact of the reservoir fill rate on pumping g(RFR)



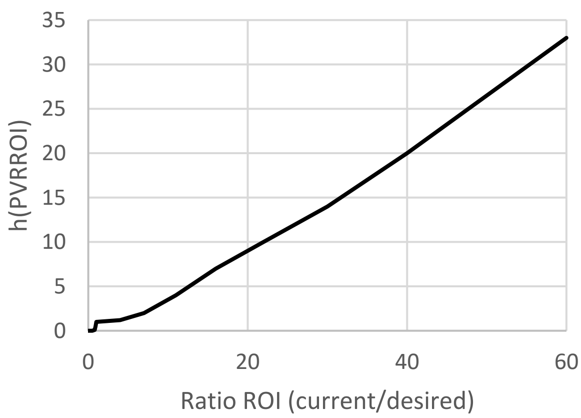


Figure A2.3 Impact of the ratio between current and the desired ROI on investment decision, i.e., h(PHSRROI) and h(PVRROI)

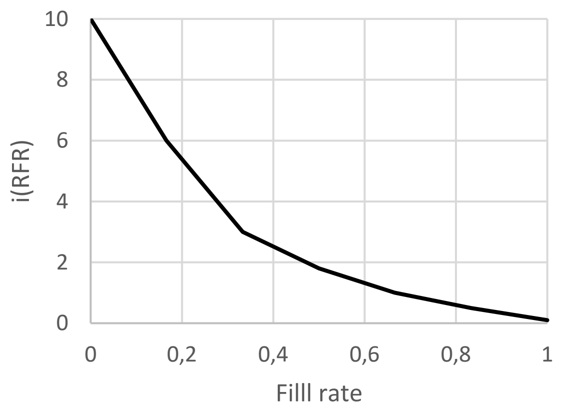


Figure A2.4 Impact of the reservoir fill rate on the price i(RFR)

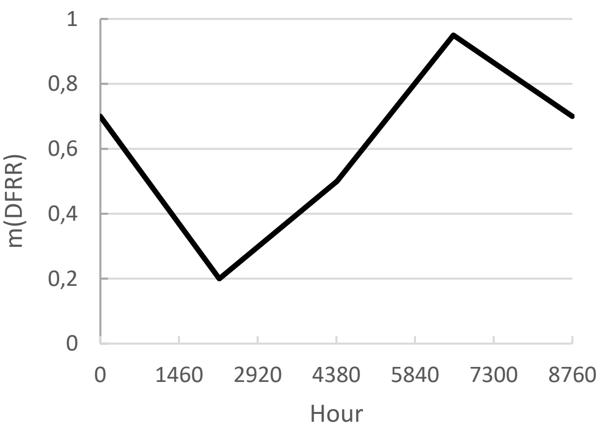


Figure A2.5 Desired fill rate of the reservoir as a function of time of year m(DFRR)

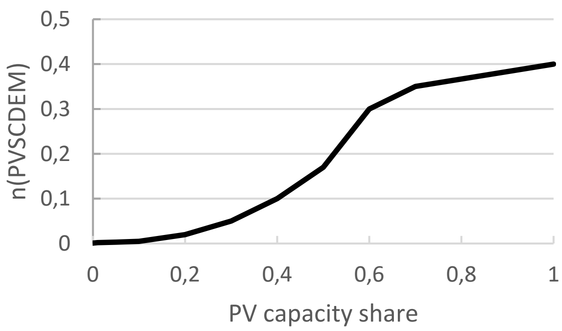


Figure A2.6 Impact of an increasing share of PV capacity on the desired energy margin n(PVSCDEM)

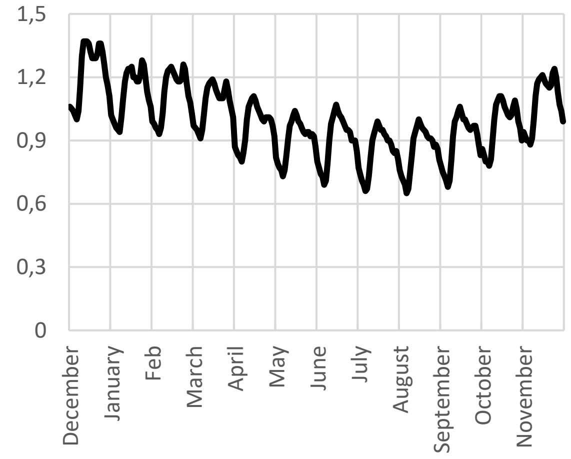


Figure A2.7 Hourly and seasonal demand factors v(HSEF)

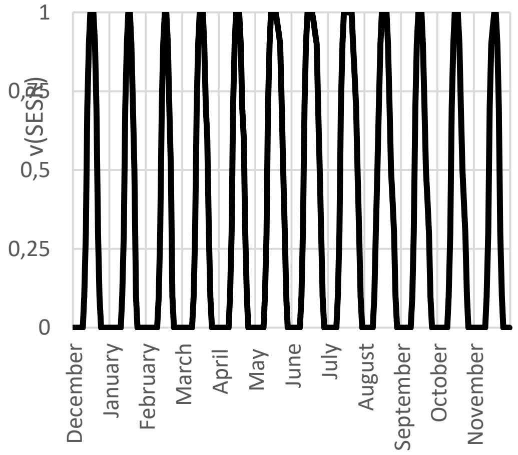


Figure A.2.8 Hourly and monthly variation of solar radiation v(SESR)

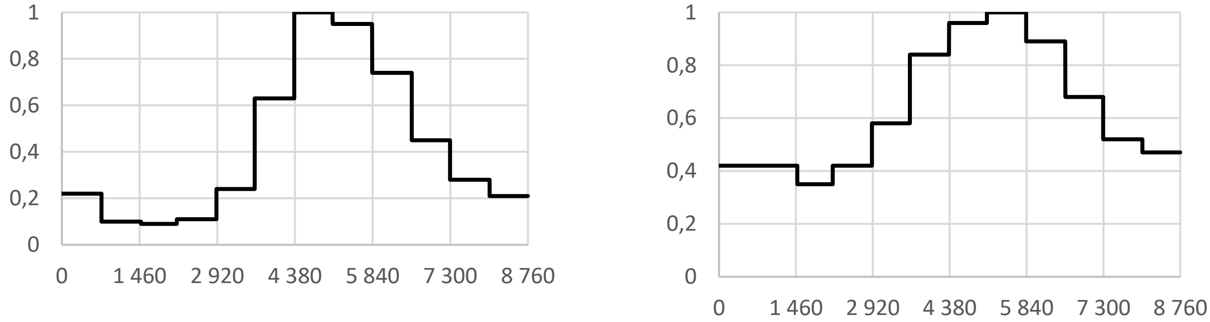


Figure A2.9. Monthly impact on natural inflows and RoR generation, i.e., V(MIRoR) and V(MINI)

APPENDIX A.3

FACING CLIMATE CHANGE: DOES SWITZERLAND HAVE ENOUGH WATER?

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Abstract

Energy transitions towards green energy are taking place worldwide, motivated by climate change concerns. As the most used renewable technologies (i.e., wind, solar and hydro) have an unpredictable output, managing this variability is challenging. This paper uses a system dynamics approach to understand what type of regulation is required to successfully manage the simultaneous increase in demand and reduction in water resources in the Swiss electricity system, which is gradually replacing nuclear by solar generation. We address climate variability by running three climate scenarios while considering both demand side management and capacity auctions. Our findings indicate that, without government intervention, shortages occur and prices are higher. Subsidizing PV eliminates blackouts, decreases the electricity price and indirectly encourages Pumped Hydro-Storage investments.

Keywords: energy modelling, climate change, renewables, energy policy

1. Introduction

The effects of temperature increases caused by climate change impact the viability of electricity systems in at least two ways. Firstly, where a significant part of generation is based on hydro, policymakers need to rethink these in the mid- and long-term in the light of changes in precipitation (Bruckner et al., 2014). Secondly, many countries have been developing policies that encourage the transition from fossil fuel generation towards renewables to mitigate the greenhouse gas emission (GHG) footprint while ensuring future energy security (Carley et al., 2017; Connolly et al., 2011; Pattupara & Kannan, 2016).

Deployment of Variable Renewable Energy Sources (VRES) has been on the agenda of governments around the world. The increase in VRES capacity has been driven mainly by governmental interventions, leading to economies of scale and technological improvement (Batalla-Bejerano & Trujillo-Baute, 2016; Kaldellis & Zafirakis, 2011). Global VRES capacity has more than doubled over the past decade, increasing from 1.3 TW in 2011 to approximately 2.8 TW at the end of 2020 (IRENA, 2021). However, to achieve the goals of the Paris Agreement, i.e., reducing the emissions of the energy sector by 14% by the end of 2050, a further 7.7 TW of VRES capacity is required (IRENA, 2019).

Due to its intermittent nature, increased VRES capacity creates a challenge for electricity markets, as demand and supply must be balanced at all times. This can be achieved either through significant flexibility of the system (Carley et al., 2017; Clerjon & Perdu, 2019) or through storage (Kondziella & Bruckner, 2016). Hydro-storage is by far the most efficient and most used storage technology, accounting for over 94% of worldwide installed storage capacity (IRENA, 2020). There are two main types of hydroelectric storage: conventional and pumped hydropower storage (PHS). While conventional hydro-storage does increase the flexibility of the electricity system, it is heavily dependent on natural water inflows, which are influenced by climate conditions and seasonality. Adding pumps to hydro-storage is a way to mitigate these limitations (Deane et al., 2010).

We focus on Switzerland to illustrate the impact of climate change in a country which relies heavily on hydro-generation. Currently, the total installed generation capacity allows Switzerland to meet demand and be a net exporter in most years (SFOE, 2020). In 2020 hydropower represented 58% of the total generation, nuclear accounted for 36% and the remaining 6% came from thermal and renewables (SFOE, 2020). However, Switzerland is facing a transition towards 100% renewable generation following a referendum against the construction of new fossil plants and the decision by the Federal Council to dismantle the nuclear plants over the next 25 years (The Swiss Federal Council, 2011), two decisions which endanger the future Swiss energy security as dismantling nuclear would make Switzerland import dependent in winter[1]. Furthermore, studies suggest that climate change will affect hydro resources. Run of river generation (RoR) is expected to increase by 2% by 2050, before decreasing to 0.5% above current levels by 2070 (Finger et al., 2012). Over the same period reservoirs are expected to receive less water in summer and more during fall. Gaudard et al. (2014) conclude that, while by 2050 hydro-storage plants should increase their generation by 0.2%, by 2070 their generation is expected to be 10.1% below the current level, increasing the challenge of replacing nuclear.

[1] However, as future electricity imports from the EU are uncertain due to the non-signing of the Institutional Framework Agreement, the Confederation is currently discussing a 10-year extension of the nuclear phase-out process (RTS, 2021)

The Swiss Federal council has developed an energy strategy, covering the period up to 2050, to anticipate the consequences of both climate change and the transition towards renewables on energy security. This strategy targets three objectives: a reduction in energy consumption, increased energy efficiency and the promotion of renewable energy (SFOE, 2018). One of the key proposals of this strategy is the implementation of a storage reserve which seeks to insure security of supply by imposing a 10% reserve level in the reservoirs (The Swiss Federal Council, 2018).

The objective of our research is to understand what type of regulation is required to successfully manage the expected increase in demand and reduction in precipitations (both of which are subject to a high degree of uncertainty due to climate change) while simultaneously decommissioning the nuclear plants. We adapt the simulation model presented in Martínez-Jaramillo et al. (2021), which analyzes the transition of the Swiss electricity system towards 100% renewables, by considering three different climate scenarios and including changes in both the demand and supply sides. The model is calibrated using Swiss data and considers the nuclear phase-out, a renewable technology (PV), RoR and hydro-storage (HS), as well as PHS as storage technology. Demand will be affected by climate change, which is expected to generate hotter summers and milder winters. This may increase electricity consumption for air conditioning during summer and decrease demand for electricity in winter. The scenarios incorporate Panos et al. (2019)'s estimates for electric vehicle adoption up to 2050, and we assume 100% adoption by 2100, leading to a substantial growth in demand over the simulation period. On the supply side we include the effects of climate change on natural resources, i.e., less water resources in the system, and thus lower hydro-generation, as temperature increases. We use the model to test different actions to mitigate the impact of climate conditions on the electricity system.

An important modeling choice is our decision to consider Switzerland as an isolated country. This represents a future in which Switzerland may find it difficult to trade electricity in the common European market. While extreme, this scenario is not impossible for at least two reasons. Firstly, as more countries are transitioning towards renewables, the convergence of generation technologies creates a correlation between periods of surplus and shortage across countries. Secondly, Switzerland is not integrated in the European electricity market, and the current political situation does not bode well (RTS, 2021).

This paper is structured as follows. In section 2 we review the relevant literature. In section 3 we discuss the methodology and present the model description. Section 4 presents the simulation results. Finally, section 5 provides conclusions and policy recommendations.

2. Literature review

The model builds on three strands of literature: energy transitions, energy storage and consumer behavior. The literature on energy transitions focusses either on technical feasibility or takes a broader approach. On the technical side, several studies illustrate the potential of electricity systems with 80 to 100% generation coming from VRES for countries such as Ireland, Portugal, the United States and Denmark (Connolly et al., 2011; Hand, 2012; Krajačić et al., 2011; Lund & Mathiesen, 2009). Although results differ from country to country, all authors agree that energy storage becomes necessary for electricity markets that aim for a high share of renewables. Energy storage has been used traditionally to balance supply and demand at the primary level (e.g., hydro reservoirs) but in recent years storage has been introduced both at the grid level and at the final consumer level (e.g., batteries) (Papaefthymiou & Dragoon, 2016). The most used technology is hydro-storage, which is highly dependent on climatic conditions, including seasonality; adding pumping mitigates the variability of natural inflows (Deane et al., 2010).

The broader approach focusses not only on technical feasibility, but aims to include consumer behavior, the role of regulation and, more generally, the impact on different agents in the electricity system (Edwards, 2011). However, while energy transitions are proposed as strategies to mitigate climate change, these studies rarely include the long term effects of climate change (Schaeffer et al., 2012). The main reason for this lies in the challenge of developing plausible scenarios that capture the uncertainty resulting from extreme events caused by climate change (Li et al., 2015).

Renewable generation has been encouraged through subsidies, via investment focused mechanisms (e.g., Capacity auctions (CA)), and pricing-based strategies (e.g., Feed-in Tariffs (FITs)) (Haas et al., 2011). FITs are a well-established policy that has been used to encourage investments in renewables for decades. They generally guarantee a minimum price for the electricity produced for a given number of years. While this guarantees a return for the investors, it does transfer the financial risk to the consumers (Atalay et al., 2017). Under CA, investors submit a bid at which they are willing to build the required new capacity (Atalay et al., 2017). These bids will, in most cases, be negative: they represent the size of the subsidy an investor requires to build new capacity. The bidder who asks for the lowest subsidy obtains the right (and obligation) to build. The main advantage of CA is to determine the total amount of subsidies upfront, thereby shifting the financial risk from the consumers to the investor (Lucas et al., 2013). Furthermore, CA reveal the true market price by increasing competition. FITs and CA both induce innovation in initially costly technologies and reduce entry barriers (Atalay et al., 2017; Nicolli & Vona, 2019).

While subsidies encourage investment in VRES, they can cause investors to ignore price signals from the market: investors might choose to wait in the expectation of more generous subsidies that will further limit the riskiness of the investments (Martinot et al., 2002), thereby reducing consumer welfare as prices and / or subsidies increase (Passey et al., 2014). Another criticism is that the temporary nature of subsidies decreases investors' confidence as they are subject to regulatory change. For instance, the level and length of FITs have been observed to vary from year to year, making it difficult to plan (Barradale, 2010; Carley et al., 2017).

On the demand side, there are direct and indirect mechanisms to incentivize investments in renewables and improve consumption efficiency. The main direct instrument used by regulators is Demand Side Management programs (DSM). Such programs have two main goals: shifting consumption away from periods of tight supply and/or reducing total consumption by increasing the energy efficiency (Broberg et al., 2021). Broberg et al. (2021) conducted a survey among Swedish households to elicit their preferences concerning a DSM program aiming to control the load during winter peak hours. The authors concluded that households are not likely to change their consumption patterns without a sufficient compensation to cover the cost of inconvenience (e.g., not cooking dinner at the usual time). The authors quantify that the compensation required to change habits represents 13% to almost 25% of the yearly electricity bill of an average household. An example of an indirect strategy is to provide consumers with the possibility to pay a premium for green electricity, thereby lowering the subsidy required for VRES (Haas et al., 2011).

Guo et al. (2018) provide an overview of five different intervention strategies that aim to change the consumption patterns of households. These are: (i) committing households to reduce consumption via a contract; (ii) setting a goal on energy savings by households; (iii) providing information about environmental pollution, the crucial role of saving electricity and tips for saving energy; (iv) rewarding reduction in consumption through social and economic incentives; and (v) providing feedback to households about their electricity consumption, together with energy saving tips.

3. Methodology and model description

We develop a System Dynamics (SD) based simulation model. This methodology allows the modeler to capture the complexity of the interrelationships between different elements of the real system by explicitly focusing on feedback and delays in the system, and thereby provide a holistic perspective (Sterman, 2000). SD has been used extensively to study electricity markets to address different challenges such as VRES diffusion (Aslani et al., 2014), capacity adequacy (Petitet et al., 2017), regulation (Wang et al., 2017) and investment dynamics (Liu & Zeng, 2017), among others.

Model description

We extend the model presented in Martínez-Jaramillo et al. (2021) to study what type of regulation is required to successfully manage the simultaneous increase in demand and long-term reduction in precipitations resulting from climate change, being aware that both of these are subject to a high degree of uncertainty. The model takes a high-level view, using a representative day for each month to capture seasonal and daily patterns of demand and supply. Figure 1 provides an overview of the model. This diagram shows the main subsystems and their interrelationships. The market operator decides which technology to dispatch based on bids from the generators and demand from consumers. The dispatch order is as follows: RoR, nuclear, solar and finally hydro-power (HS and PHS). In this process the electricity price is set by the highest bid among dispatched technologies. After clearing the market, the operator sends information to the investors (electricity price and ROI), the generators (the need to curtail/store energy) and to the regulator (energy margin).

Investors receive ROI information from the market. Their investment decision depends on the ratio between the desired ROI and the forecasted ROI. To calculate the latter, we run a parallel model which calculates expectations of future capacities, price, generation by technology and the electricity balance three years ahead (the time required to build PV generation capacity). The investors' decisions impact the installed PV and PHS capacity of the generators. HS and RoR capacities are assumed fixed during the simulation period, while nuclear capacity decreases due to the phasing-out process. Generators depend on the availability of water and sun radiation. As mentioned in the introduction, Switzerland may face barriers to trade electricity with the common European market. We therefore assume that the government's aim is for the country to be self-sufficient with respect to generation, i.e., we consider neither electricity imports nor exports.

The assumptions concerning demand include the changing penetration of electric cars in Switzerland: while representing barely 1 % of the total vehicle fleet in 2019, this number is expected to increase to 65% by 2050 (Panos et al., 2019). We further assume that Switzerland will reach a 100% electric car fleet by 2100.

Finally, the regulator receives information about market performance. The principal measure used in the model is the annual energy margin, i.e., the ratio between the yearly energy balance and the annual demand. A positive energy margin indicates an excess of energy, while a negative margin implies shortages. The desired energy margin increases as more renewables are introduced into the system because these generation sources reduce the flexibility of the system. The regulator then compares the desired energy margin with the expected energy margin. If the desired energy margin is higher than the expected one, PV capacity will be required to match future demand. The dotted arrows in the diagram represent the actions of the regulator when shortages are expected. The regulator can either implement a capacity auction mechanism (subsidies) or promote a demand-side management program, or both.

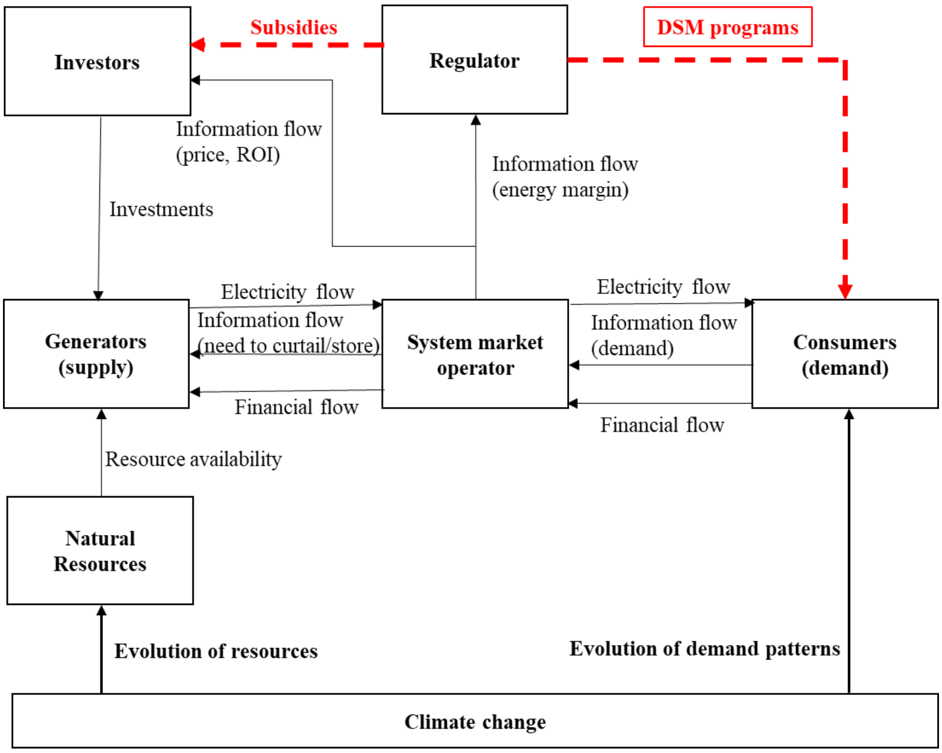


Figure 1. Model overview

Table 1 provides an overview of the model modifications compared to the model used in Martínez-Jaramillo et al. (2021). The main modification is to explicitly incorporate climate change: we consider three possible climate scenarios which influence the trend in demand, water availability and generation. In particular, electric car penetration is included because of its impact on demand. Consequently, we extend the simulation period until 2100 to enable analyzing the long-term effects of climate change on the electricity system. The model passes the traditional tests to validate SD models (Barlas, 1996). These include extreme condition tests that ensure model robustness and checking that all equations respect physics laws such as conservation of mass and energy, as well as the dimensional consistency of each equation. The model is developed in Vensim DSS 7.3.4.

Model element	(Martínez-Jaramillo et al., 2021)	Current model
Time horizon	20 years	80 years
Climate change	Not considered	Included based on the Representative Concentration Pathways (RCP) 2.6, 4.5 and 8.5 developed by the Intergovernmental Panel on Climate Change-IPCC (Riahi et al., 2011; Thomson et al., 2011); (see table 2 for details).
Demand	Same seasonal pattern over 20 years	Trends in demand linked to the climate scenario. Inclusion of electric car demand (see subsection 5.2 for details)
Natural inflows and RoR generation	Same seasonal pattern over 20 years	Evolution of natural inflows and RoR generation linked to the climate scenarios (see table 2 for details).
Retirement of PV and PHS capacity	Not considered	30-year lifetime.

Table 1. Overview of model modifications compared to the model presented in Martínez-Jaramillo et al. (2021)

4. Simulation results

We first consider a base case scenario in which there are no subsidies, i.e., investments in PV generation and pumping capacity are driven by the market. Given the high degree of uncertainty concerning climate change and its consequences, we considered three climate scenarios, named Representative Concentration Pathways (RCP): 2.6, 4.5 and 8.5. These scenarios were developed by the IPCC (Riahi et al., 2011; Thomson et al., 2011) to forecast possible greenhouse gas concentration trajectories until 2100. Emission trajectories describe different climate scenarios, and the ensuing impact on outputs such as the change in average temperature. We use previous studies to model the impact of the increase of temperature on both demand (Moon et al., 2018) and supply (Finger et al., 2012). Table 2 provides the hypothesized impact of each RCP scenario on key model inputs.

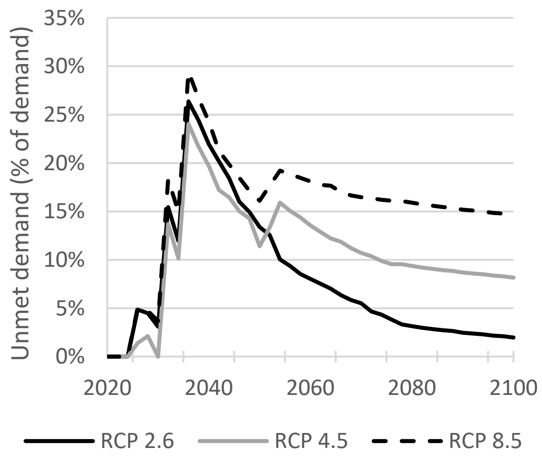
Variable	Years	RCP 2.6	RCP 4.5	RCP 8.5	Source
Temperature	2030-2050	+1 ºC	+1.4 ºC	+2 ºC	Riahi et al., 2011;
	2070-2090	+1.4 ºC	+1.8 ºC	+3.7 ºC	Thomson et al., 2011
RoR generation	2030-2050	+0.5%	+2%	+3%	Finger et al., 2012
	2070-2090	+2%	+1.5%	+5%	
Natural inflows	2030-2050	+1%	+0.5%	+3%	Finger et al., 2012
	2070-2090	-9%	+1%	-14%	
Demand	2030-2050	-3%	-0.5%	+2.5%	Moon et al., 2018
	2070-2090	+2%	-3%	+5%	

Table 2. Overview of the climate change scenarios

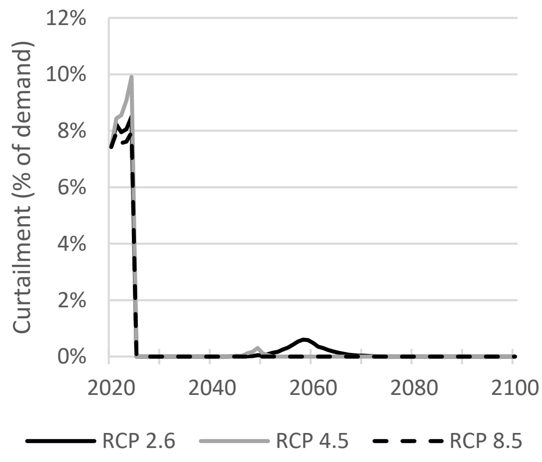
Without any governmental intervention all three cases exhibit unmet demand (figure 2a) which implies that the system will face blackouts in the future. There are three distinctive spikes of unmet demand before 2036, which correspond to the three stages of the nuclear dismantling process. In 2036 unmet demand reaches its highest value, ranging from 24% of the annual demand in RCP 4.5 to around 29% in RCP 8.5. Figure 2b illustrates how a system can face blackouts and curtailments in the same year. The curtailments at the beginning of the simulation period represent the electricity that would be exported from Switzerland. Recall that we consider a system without imports and exports. Around 2060 we observe that the annual curtailment accounts for almost 1% of annual demand in RCP 2.6, while the unmet demand is of the order of 8%. This curtailment results from precipitations that cannot be stored in the reservoirs during summer illustrating that the system is unable to store all the excess energy (mainly in summer) to deliver it when required (in winter).

The increase in the ROI of PHS after the highest peak in unmet demand changes the trend in installed capacity (figure 2c). Figure 2d shows the ratio between expected and desired ROI for PV and PHS, which captures the willingness to invest: investments are profitable when the ratio is above one. So, after 2040 the increase in PHS capacity continues until the end of the simulation period as PHS is benefiting from high prices, which drives its ROI. Indeed, recall that there are blackouts: at such times the reservoir level is low, so the PHS bid increases due to scarcity pricing. PV does not benefit much from scarcity pricing as this occurs mainly when there is little or no PV generation. Also, when PV generation peaks, price is usually low, so PV investors barely recover their investments. Consequently, PV capacity increases at a slower pace than PHS. In the three scenarios market driven investments in PV and PHS are insufficient to avoid blackouts. In the discussion that follows we focus initially on scenario RCP 4.5. Then, to explore the effects of governmental interventions on both the supply and demand sides. Next, in section 5.4 we briefly discuss the robustness of our results with respect to the climate change scenarios.

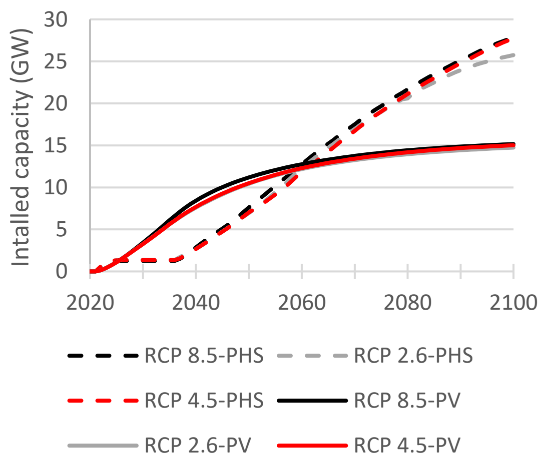
e) Annual unmet demand (% of annual demand)



f) Annual curtailment (% of annual demand)



g) Installed capacity (GW)



h) ROI/ Desired ROI

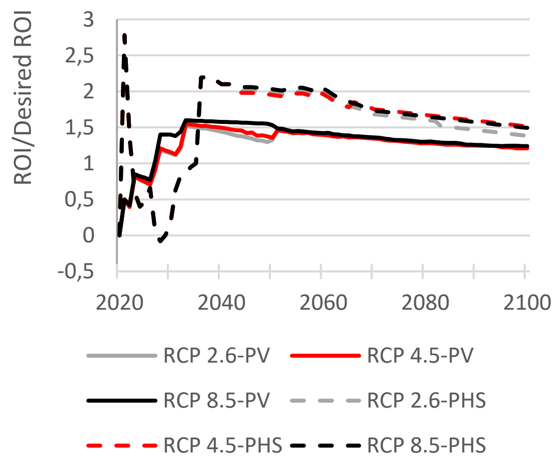


Figure 2. Unmet demand, curtailment, installed capacity and ROI for the three climate change scenarios

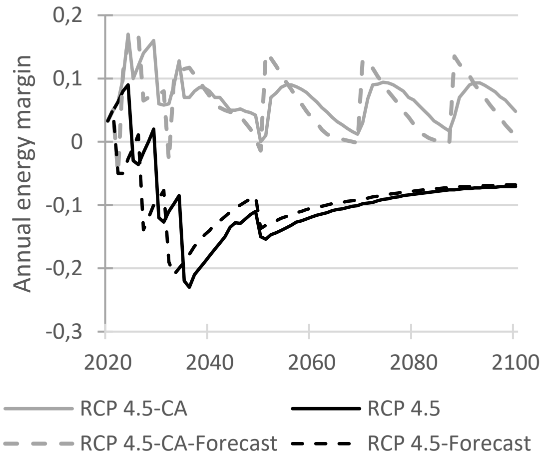
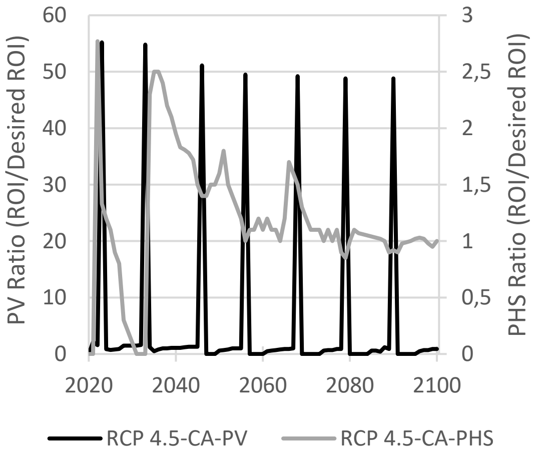
4.1 Capacity Auctions

We consider capacity auctions, a policy mechanism to encourage investments. Specifically, we assume that regulators intervene whenever they expect a negative energy margin to occur within a 3-year horizon. We assume that regulators only subsidize PV as their objective is to increase total generation: PHS only enables storage, i.e., shifting excess generation towards moments where demand exceeds supply. Figure 3a shows the evolution of the energy margin, as well as its three-year forecast. Logically the latter decreases three years before each step of the nuclear dismantling process. When a negative energy margin is expected, the regulator subsidizes PV, causing its ROI to spike (figure 3b); this leads to an increase of PV capacity (figure 3c) and the energy margin (figure 3a). Unlike RCP 4.5, RCP 4.5-CA never faces a negative energy margin. This indicates that using the energy margin as a signal to trigger the CA policy is useful to anticipate capacity shortages, thereby successfully avoiding blackouts.

Figure 3d shows the evolution of the electricity price. In RCP 4.5-CA the price initially decreases due to the introduction of PV capacity in anticipation of the nuclear dismantling process. Consequently, there is more energy available in the system (recall figure 3a). This excess of energy decreases hydro's bid price and thus the average market price. In the RCP 4.5 scenario the electricity price exhibits an increasing trend as the energy margin is negative and blackouts occur from 2025 onwards (recall figure 2a).

Figure 3c captures the evolution of PHS and PV installed capacity. We observe that in the CA scenario PV shows a cyclical pattern. As discussed in Bunn & Larsen (1992), electricity prices might fluctuate due to the simultaneous timing of investments in generation. Consequently, when there is overcapacity, price is low, resulting in little incentive for investments. Thus, the cyclical pattern in PV capacity is related to the evolution of the electricity price and the associated investments in generation: the spikes in PV investments result from the subsidies given by the regulator when a blackout is expected, and the ensuing gradual decrease results from the PV lifetime. In contrast to the base case, PHS capacity grows at a declining rate, matching its decreasing ROI. At the end of the simulation, PV installed capacity is 56% higher than in the base case, while PHS capacity is 31% lower, and there are no blackouts.

So far, our discussion has ignored the cost of subsidies. In the CA scenario subsidies total around CHF 54,420 million. This may seem like a huge amount, but it amounts to less than CHF 80 ($75) per person per year. Figure 3d shows the evolution of the consumer price, which is calculated by adding a surcharge to the market price to cover the annualized subsidy. The average annualized subsidy during the simulation period is approximately CHF 10 per MWh, which represents 6.4% of the market price at the end of the simulation. Concerning the evolution of the electricity price, in the base case we observe that at the end of the simulation the price is 2.4 times higher than the initial price, while in the CA scenario, as the price oscillates, in a range between 10% and 60% above the initial price. We can thus conclude that CA allows the system to anticipate and avoid blackouts, while achieving a much lower price, even after covering the cost of subsidies.

a) Annual energy margin	b) ROI/ Desired ROI
	
c) Installed capacity (GW)	d) Electricity price

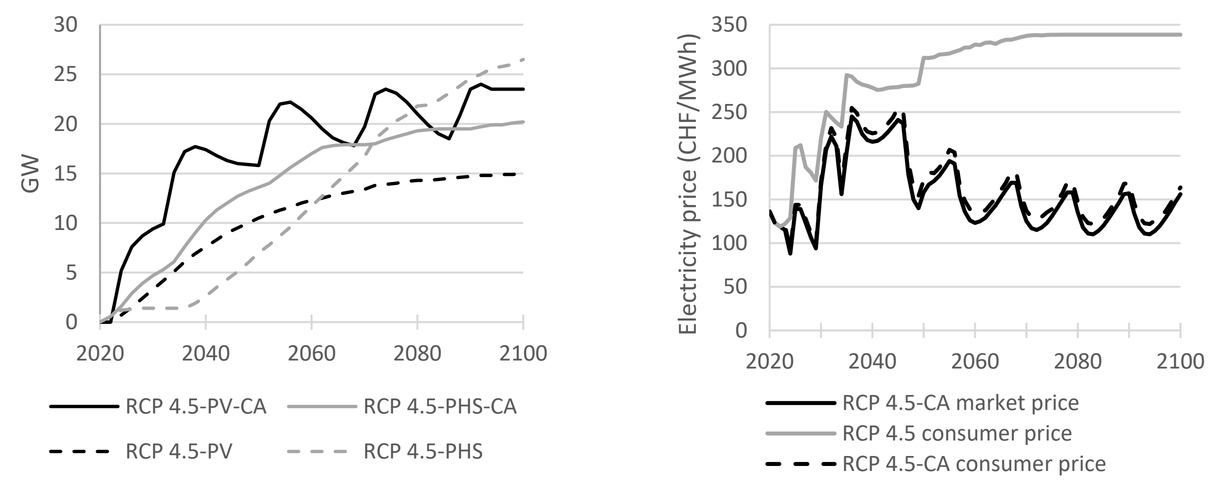


Figure 3. Annual energy margin, and ROI/Desired ROI, installed capacity and electricity price with and without Capacity Auctions

4.2 Demand Side Management

The previous analysis has illustrated how CA allows the system to avoid blackouts. As an experiment, we next explore a mechanism on the demand side. We propose a DSM scenario focused on when electric car owners recharge their vehicle. Figure 4 shows the recharge pattern for a representative winter day at the end of the simulation (December 2099) for the base case and the DSM scenario. In the RCP 4.5 scenario, owners do not have any incentive to recharge their car at a specific time. We use the recharge patterns shown in Engel et al. (2018) in which owners favor recharging either at night, late morning/noon or early evening. Our assumption for the RCP 4.5-DSM scenario is that owners will be encouraged to recharge their cars preferably at noon/early afternoon, when PV generation is at its maximum, while avoiding early evening hours.

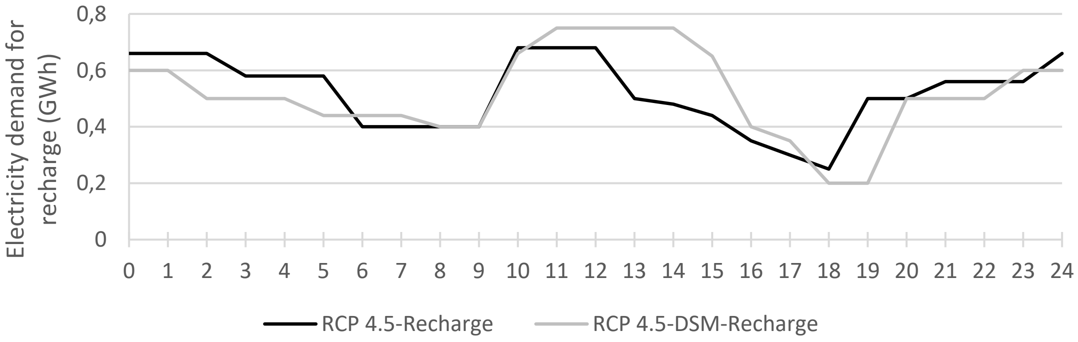


Figure 4. Electricity demand for cars on a typical day in 2099

Figure 5a shows the impact of this DSM policy on unmet demand: a 16% reduction by 2100. The electricity price does not change significantly (figure 5b). While this scenario exemplifies the potential gains of a behavioral change, it also illustrates the relatively limited impact. As discussed in the next section, incentives in capacity investments are still required to avoid blackouts.

a) Unmet demand (% of total demand) b) Electricity price

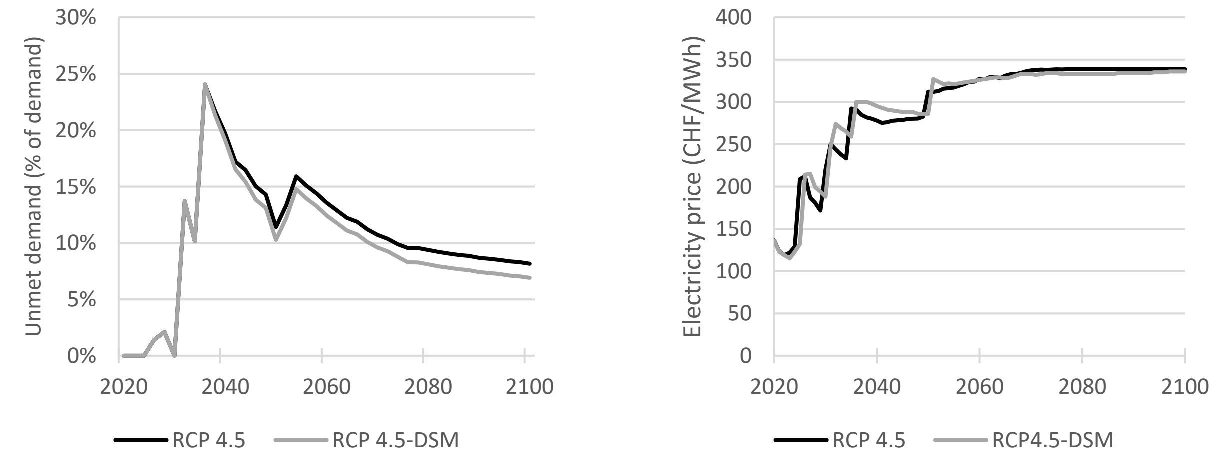
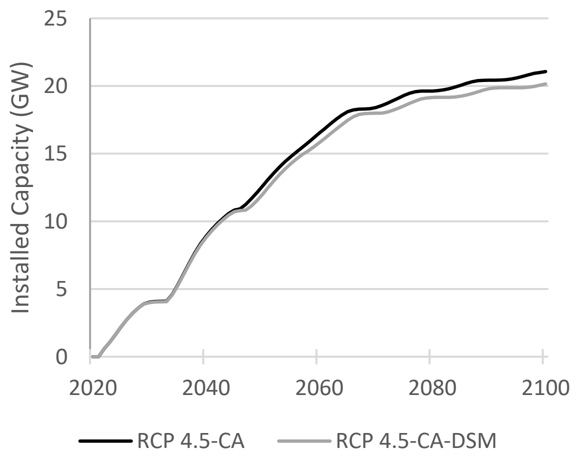


Figure 5. Unmet demand RCP 4.5 and electricity price with and without DSM

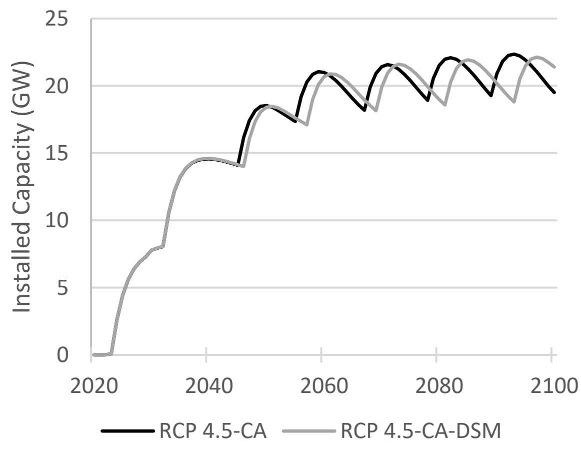
4.3 Demand side management and capacity auctions

In previous subsections we explored the impact of CA and DSM in isolation. Next, we consider their combined effect on the electricity system. Figure 6a shows the PHS installed capacity for the RCP 4.5-CA and RCP 4.5-CA-DSM scenarios. The difference between the two scenarios increases in line with the penetration of electric cars. Adding DSM reduces the required PHS capacity by 4.4%. Figure 6b shows the evolution of PV capacity. Given the oscillations, we take the average value over the last cycle, which is 1 % lower in the RCP 4.5-CA-DSM scenario. The decrease in installed capacity for PV and PHS results from a better usage of electricity: there is less curtailment (see Figure 6c) as electric car owners tend to recharge their vehicle when there is excess electricity. Curtailment starts to diverge with the increasing penetration of electric cars. This difference in curtailment delays the occurrence of a tight energy margin, and thus the time at which the regulator needs to intervene. The volume of curtailment reflects the energy margin: as reservoir size is assumed constant, this excess cannot be used for pumping. Likewise, we observe that the consumer prices start to diverge after 2040 (Figure 6d), in line with the penetration of electric cars. Around 2060 the consumer price starts exhibiting a cyclical pattern with a period of about 10 years, with RCP 4.5-CA-DSM having both lower maxima and minima than RCP 4.5-CA. Considering the average over the last cycle, the consumer price increases respectively by 9% and 3% in the CA and CA-DSM scenarios in comparison to the initial price. Both scenarios lead to a similar total cost of subsidies, the RCP 4.5-CA-DSM being barely 0.5% higher. Neither RCP 4.5-CA nor RCP 4.5-CA-DSM exhibit blackouts.

a) PHS installed capacity



b) PV installed capacity



c) Curtailment (% of demand) d) Consumer price

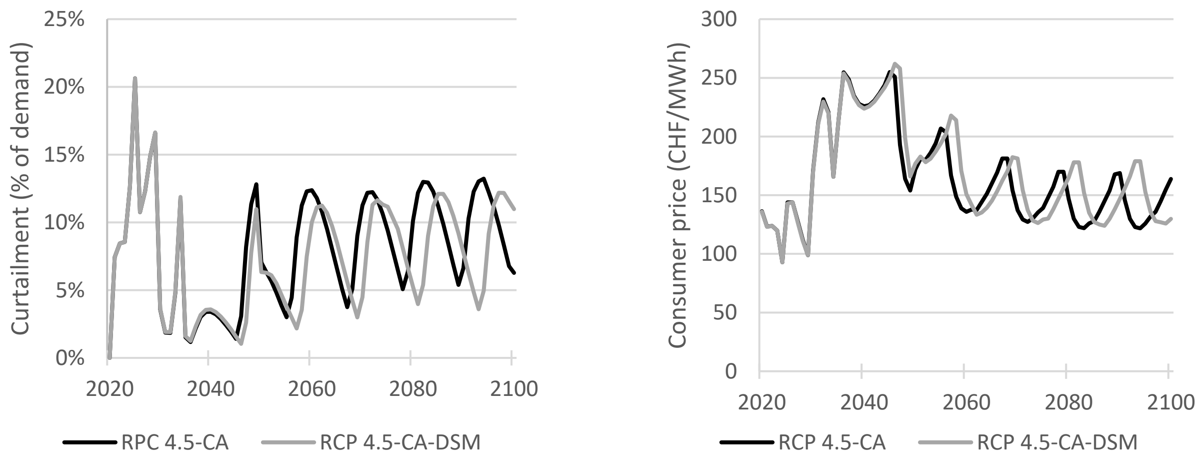


Figure 6. RCP.4.5-CA curtailment, consumer price, PHS and PV installed capacity with and without DSM

4.4 RCP 2.6 and 8.5

Up to this point, we have focused on climate scenario RCP 4.5. Next, we explore the robustness of these insights by considering the alternative scenarios RCP 2.6 and 8.5. While CA eliminate blackouts for the three scenarios, climate change does affect the required installed capacity, the share of generation by technology, the electricity price and the required subsidies. Table 3 provides an overview of this analysis. As mentioned before, the CA and CA-DSM scenarios present cycles for installed capacity and consumer price. Therefore, in the table we consider the average values over the last cycle; these are indicated in italics.

The results provide evidence of the high uncertainty resulting from climate change. We observe that, as climate gets worse lower precipitations and higher demand lead to an increase in the PV generation share. Under the CA and CA-DSM mechanisms, this increase in PV share leads to excess PV generation in certain periods, which cannot be stored due to limited reservoir capacity. This increased curtailment results in lower electricity prices. The latter observation has to be interpreted carefully as, from a purely economic perspective, one might superficially conclude that a worse climate scenario positively impacts consumer welfare. For a more comprehensive analysis other elements should be considered, such as the increase in price volatility, the reduction in flexibility and the risk of blackouts as the system increases its dependence on variable generation.

We can conclude that our previous results remain valid for the RCP 2.5 and 8.5 scenarios. In particular, the worst decision policy makers can make is not taking any action. The DSM scenarios, while an improvement on the base case on all criteria, fail to eliminate blackouts. The CA and CA-DSM scenarios eliminate blackouts and lead to lower prices, but at the expense of very significant levels of curtailment of both PV and hydro. The CA-DSM scenario outperforms CA with respect to total curtailment and price, enabling us to conclude that CA-DSM is preferable to CA.

	RCP 2.6				RCP 4.5				RCP 8.5			
	BC	**CA**	**DSM**	**CA-DSM**	**BC**	**CA**	**DSM**	**CA-DSM**	**BC**	**CA**	**DSM**	**CA-DSM**
PV capacity (GW)[2, 3]	14.7	*17.8*	13.3	*17.4*	14.9	*21.0*	14.1	*20.4*	15.2	*22.5*	14.6	*21.6*
PHS capacity (GW)[2, 3]	25.7	*18.6*	20.2	*18.4*	27.7	*21*	23.7	*20.2*	27.8	*22*	24.6	*21.3*
RoR generation (TWh)[2]	13.2	13.2	13.2	13.2	13.1	13.1	13.1	13.1	13.8	13.8	13.8	13.8
PV generation (TWh)[2]	22.1	35.4	21.9	33.8	22.4	42.9	22.3	43.2	22.5	46.9	22.6	47.5
PV consumed (TWh)[2]	19.8	20.9	19.8	21.2	20.7	23	20.7	23.6	20.8	23.7	20.9	24.1
PHS generation (TWh)[2]	1.8	9.6	1.7	8.5	1.4	12.5	1.3	13.3	1.4	14.7	1.3	14.6
Hn generation (TWh)[2]	19.7	17.3	19.6	18	17.8	15.1	17.7	13.5	17	12.7	17	12.3
RoR generation share (%)[2]	23%	17%	23%	18%	24%	16%	24%	16%	25.5%	15.6%	25%	15.6%
PV generation share (%)[2]	39%	47%	39%	46%	41%	51%	41%	52%	41%	53%	41%	54%
PHS generation share (%)[2]	3%	13%	3%	12%	2.5%	15%	2.3%	16%	2.5%	17%	2.4%	16.6%
Hn generation share (%)[2]	35%	23%	35%	24%	32.5%	18%	32.7%	16%	31%	14.4%	31.6%	14%
Unmet demand (TWh)[2]	6.5	-	6.6	-	10.7	-	10.7	-	12	-	11.7	-
Unmet demand (%)[2]	2%	-	1.5%	-	8%	-	7%	-	15%	-	13%	-
Overflow (TWh)[2]	-	2.3	-	1.7	-	2.7	-	4.3	-	4.3	-	4.7
PV curtailed (TWh)[2]	-	2.5	-	2	-	4.3	-	2.9	-	4.8	-	5.2
Curtailment (TWh)[1]	30	348	23	345	32	405	25	369	25	417	22	400
Subsidies (Millions CHF)[1]	-	40,074	-	40,216	-	54,420	-	54,722	-	61,304	-	61,615
Market price (CHF/MWh)[2, 3]	291	*137.2*	284	*131.5*	340	*130.3*	337	*122.2*	345	*123*	341	*114*
Consumer price (CHF/MWh)[2, 3]	291	*143*	284	*137*	340	*138*	337	*130*	345	*132*	341	*124*

[1]Cummulative over the simulation period; [2]Final value; [3]Italics refer to average over final cycle

Table 3. Overview of the results

5. Conclusions and Policy Implications

In this paper, we adapted an SD based simulation model to analyze how to manage a transition towards 100% renewable generation, while at the same time facing an increase in demand and a reduction in precipitations, considering only a hydro-solar combination complemented with PHS to store energy. This represents a country, like Switzerland, which has significant hydro resources, a stated objective of phasing out nuclear energy and limited potential for wind generation. The model shows that, under all climate scenarios, without governmental interventions, the system is unable to meet the annual demand after the start of the nuclear retirement process: the blackouts and significant price increases point to a need for regulatory intervention.

We explore which type of interventions are required by testing three different policies within three different climate scenarios. Unmet demand is a major concern for policy makers and regulators and we can assume that this will be their top priority, whatever the climate scenario. We first run the model with a capacity auction mechanism that aims to mitigate the risk of a blackout during the transition period by subsidizing PV investments. Results show that this avoids blackouts and makes energy storage profitable earlier (recall Figure 3c) in all three climate scenarios. The downside of this policy are the large curtailments, which increase with the temperature, albeit at a declining rate. The second intervention is a simple DSM mechanism to encourage electric car owners to recharge their cars at times where there is excess generation to improve the match between electricity generation and demand. This change in the demand pattern only marginally reduces unmet demand which, in particular, remains high in the two most severe scenarios. Curtailment decreases somewhat compared to the base case and is at a level that would not be a concern for most regulators. The third policy experiment combines the CA and DSM from the initial two experiments. Blackout are eliminated as was the case in the first experiment. Curtailment decreases marginally (1%-8%) compared to the CA-only policy, but this is unlikely to be seen as important, particularly given the high degree of uncertainty characterizing these long-term simulations. It might be concluded that the most effective regulatory intervention explored here with respect to avoiding blackouts is CA, with DSM being a potentially useful additional measure. While DSM limits curtailment, a regulator will prioritize security of supply over avoiding curtailments.

Once regulators and policymakers have ensured sufficient generation capacity to satisfy demand, their next concern is likely to be price: how much will consumers have to pay to achieve this security of supply? In this respect the scenarios can be categorized into two groups. Let us first consider the Base case and DSM regulation: price increases in a similar way as the climate scenarios worsen. Similarly, price-wise there is little to choose between CA and CA-DSM: given the high level of uncertainty, the 6% difference cannot be considered significant. From these comparisons we can conclude that a limited DSM intervention, such as the one considered here, has little effect on the price.

Turning to generation capacity, encouraging investment in PV through CA in a country with a strong seasonal pattern necessarily leads to significant amounts of curtailment. Indeed, the need to install sufficient capacity to cover demand when PV generation is low unavoidably leads to excess capacity at other times. Climate change causes hydro-generation to decrease due to lower inflows. Additionally, the increase in PV generation due to CA leads to a certain amount of overflows, i.e., curtailment. As demand increases, hydro as a share of total generation decreases significantly.

To conclude, the model considers the uncertainty of climate change by testing three different climate paths (RCP 2.6, 4.5 and 8.5). While there are tradeoffs between the base case and the three regulatory interventions, it is fairly clear that no regulator can live with repeated, foreseeable blackouts. The base case shows that, without intervention, blackouts are likely to occur over the long run once nuclear capacity is retired. The results imply that, among the interventions tested here, CA is necessary to avoid blackouts. It is also clear that adding the proposed DSM policy to the CA intervention only has a marginal impact. More generally, while DSM is useful to improve efficiency of the system by shifting demand, thereby limiting curtailment, as a stand-alone measure its impact is insufficient to eliminate blackouts, even if applied on a much larger scale.

The model, as all models, has a number of limitations resulting both from certain choices, as well as from the model boundaries. Concerning generation, the model assumes fixed investment costs and efficiency, and no new technologies are being introduces. Future technological developments might reduce the requirements for subsidies. Likewise, it is probable that within the horizon of this simulation, other ways to store electricity will be developed, which could reduce the need for excess generation capacity, thereby reducing curtailment in the CA scenario. It is also assumed that there are neither exports nor imports from neighboring countries, which might be seen as a strong limitation. However, as discussed above, there are political reasons for why a country may decide to target self-sufficiency. In this context it should also be noted that neighboring countries are likely to converge towards similar technological mixes, thus experiencing excess electricity generation at similar times.

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APPENDIX

A full equation listing of the model of Martínez-Jaramillo et al. (2021) can be found online in its appendix In this appendix we list the equations of the extensions.

Index	*Values*	*Explanation*
s	2.6,4.8 and 8.5	Climate scenarios: RCP 2.6,4.5 and 8.5
w	1,2,…168	Hours of a week
y	1,2,…8760	Hours of a year
m	1,2,…12	Months of a year
d	1,2,…24	Hours of a day
c	1,2	2 periods of electric car penetration: before 2050 and afterwards
p	1,2,3	3 periods of climate change: (1) before 2030, (2) between 2030 and 2070, and (3) after 2070

A.1.1 List of abbreviations

Base load technology generation per hour	$BLTGH_{s,p,m}$
Base load technology installed capacity	$BLTIC$
Electricity demand per hour	$EDH_{s,p,m,w,d}$
Electric car demand	$ECD(t)_{s,c,w}$
Hourly and daily electric car demand factors	$ECDF_{s,c,w}$
Hourly and seasonal demand factors	$HSDF_{m,d}$
Hourly average demand	HAD

Intercept electric car demand	$IECD_{s,c,w}$
Monthly impact on natural inflows	$MINI_m$
Monthly impact on Run-of-river generation	$MIRoR_m$
Natural inflow	$NI_{s,p,m}$
Normal inflow	NoI
Slope baseload RCP	$SB_{s,p,m}$
Slope demand RCP	$SD_{s,p,m}$
Slope natural inflows RCP	$SNI_{s,p,m}$

Slope electric car	$SEC_{s,c,w}$
Simulation time	t

A.1.2 Equations

This subsection provides the equations concerning electricity demand, generation and natural inflows.

Name /Equation		***Unit***
	Parameter value	
BLTIC	3,500	MW
HAD	6,500	MWh/hour
$\text{IECD}_{s,c,w}$	$\begin{cases} 0.0067, & p=1 \\ 0.3255, & otherwise \end{cases}$	MWh/hour
$\text{SEC}_{s,c,w}$	$\begin{cases} 0.0161, & p=1 \\ 0.0051, & otherwise \end{cases}$	MWh/hour
NoI	3,500	MWh/hour

A.1.2.1 Electricity demand

We model the electric car demand explicitly. The total annual demand is composed of other sectors' demand plus the demand for recharging electric vehicles. Figure A1.1 shows the pattern for a weekly cycle of the recharge demand. Demand is highest at noon and has a second peak at night; on weekends, demand is lower.

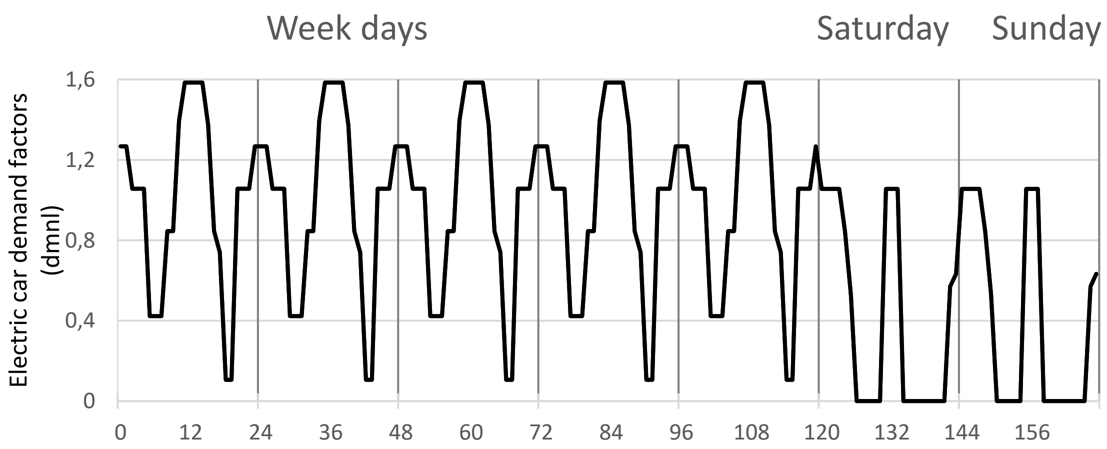

Figure A1.1 Electric car demand factors $\text{ECDF}_{s,c,w}$

This yields to the following equation for hourly electric car demand:

$\text{ECD(t)}_{s,c,w} = (\text{IECD}_{s,c,w} + \text{SEC}_{s,c,w} * t) * \text{ECDF}_{s,c,w}$ (MWh/hour) (1)

Figure A1.2 shows the seasonal impact on the daily pattern of demand assumed for each month. Demand reaches its maximum during winter, while the minimum occurs during summer.

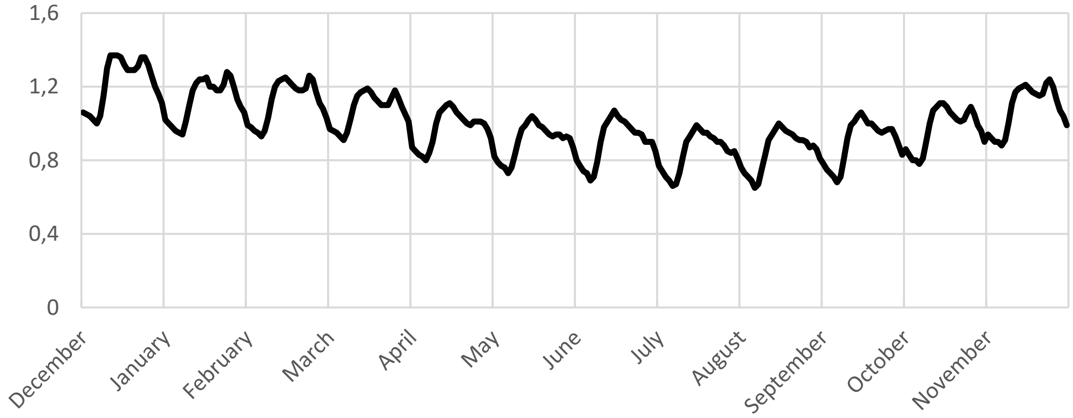

Figure A1.2 Hourly and seasonal demand factors $HSDF_{m,d}$

Figure A1.3 captures the effect of climate change on demand. Hotter summers will entail a higher consumption of electricity while less cold winters will decrease the demand for heat.

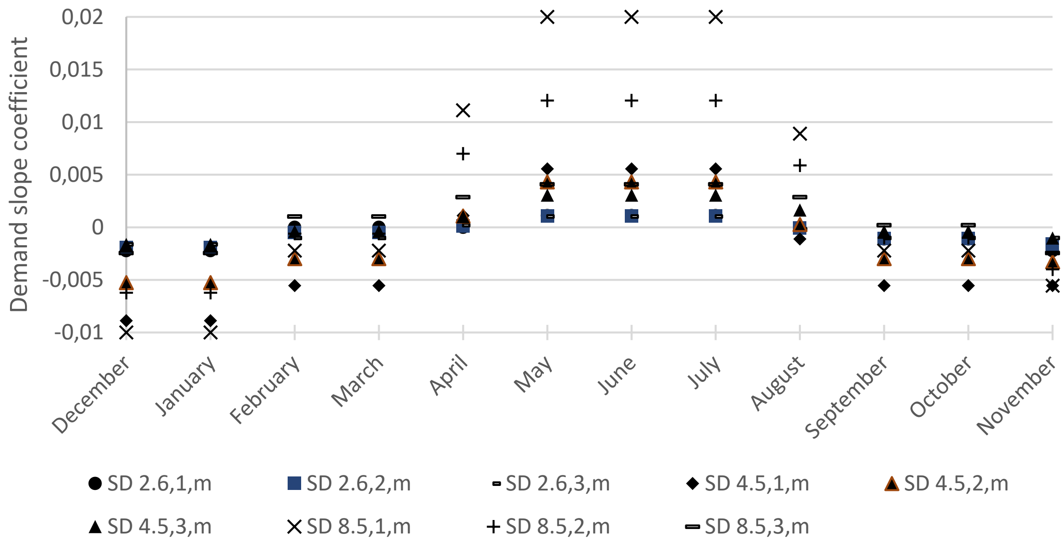

Figure A1.3. Demand slope coefficient $SD_{s,p,m}$ for each RCP scenario (s), period of climate change (p) and month (m)

This yields to the following equation for hourly electricity demand:

$$EDH_{s,p,m,w,d} = ECD_{s,c,w} + HAD * SD_{s,p,m} * HSDF_{m,d} \quad \text{(MWh/hour)} \qquad (2)$$

A.1.2.2 Electricity generation

Figure A1.4 captures the seasonal impact on RoR generation. During summer, there is more water as snow melts, while in winter there is less RoR generation (water freezes or fewer precipitations).

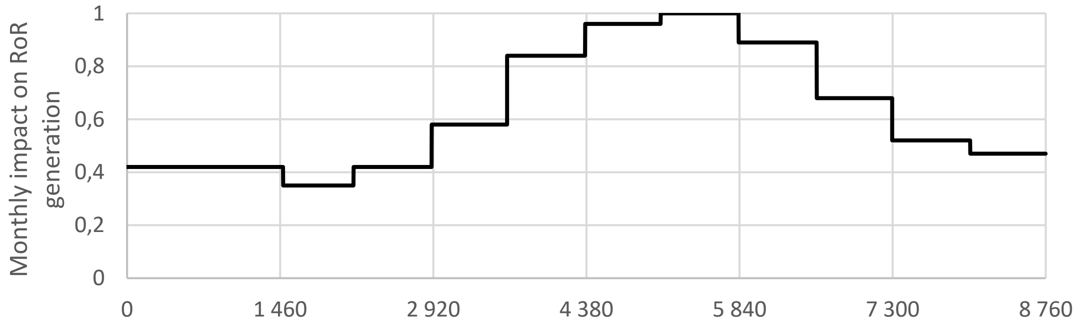

Figure A1.4. Monthly impact on RoR generation $MIRoR_m$

The effect of climate change on RoR generation is shown in figure A1.5. This figure illustrates how warmer winters that will produce more ice melting or precipitations during winter will increase the RoR generation.

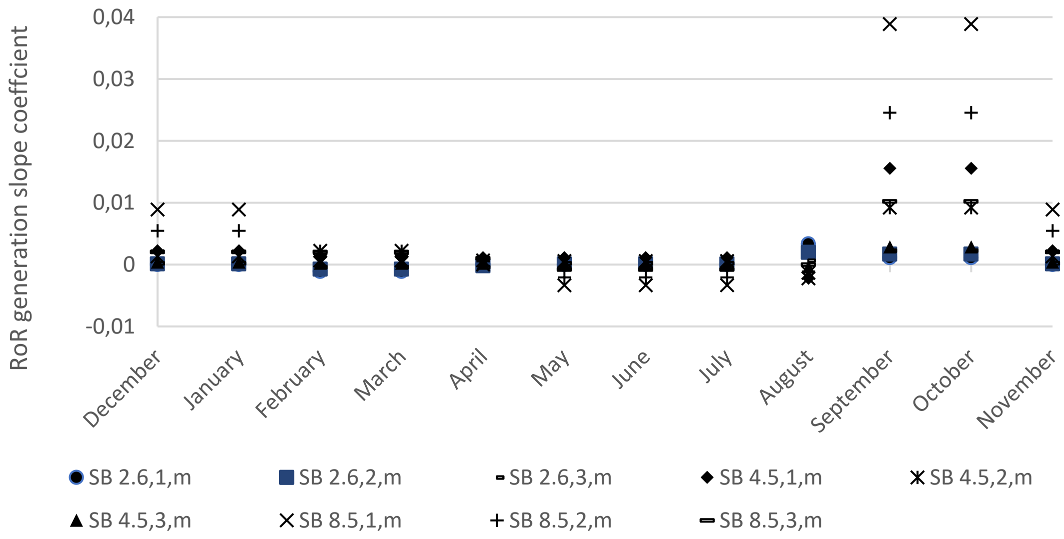

Figure A1.5. RoR generation slope coefficient $SB_{s,p,m}$ for each RCP scenario (s), period of climate change (p) and month (m)

This yields to the following equation for hourly base load generation:

$BLTGH_{s,p,m} = BLTIC * SB_{s,p,m} * MIRoR_m$ (MWh/hour) (3)

A.1.2.2 Natural inflows

Figure A1.6 captures the seasonality of natural inflows. During summer natural inflows are higher as snow melts, while in winter inflows decrease as precipitation falls in the form of snow.

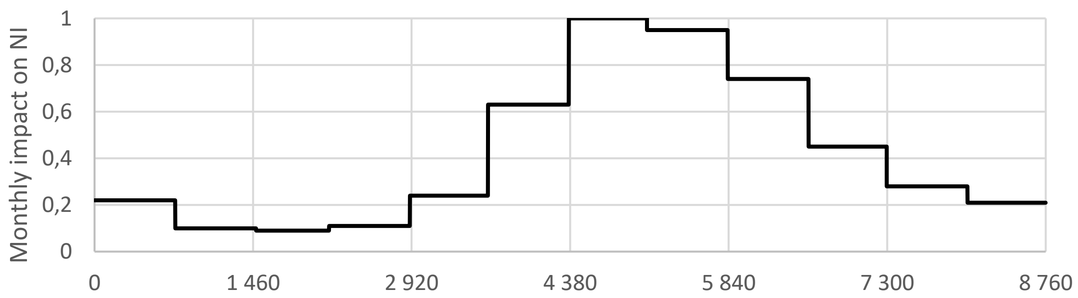

Figure A1.6. Monthly impact on natural inflows $MINI_m$

Figure A1.7 illustrates how natural inflows will increase due to climate change, particularly in fall, and decrease in spring. This figure shows the effect of each RCP scenario on natural inflows.

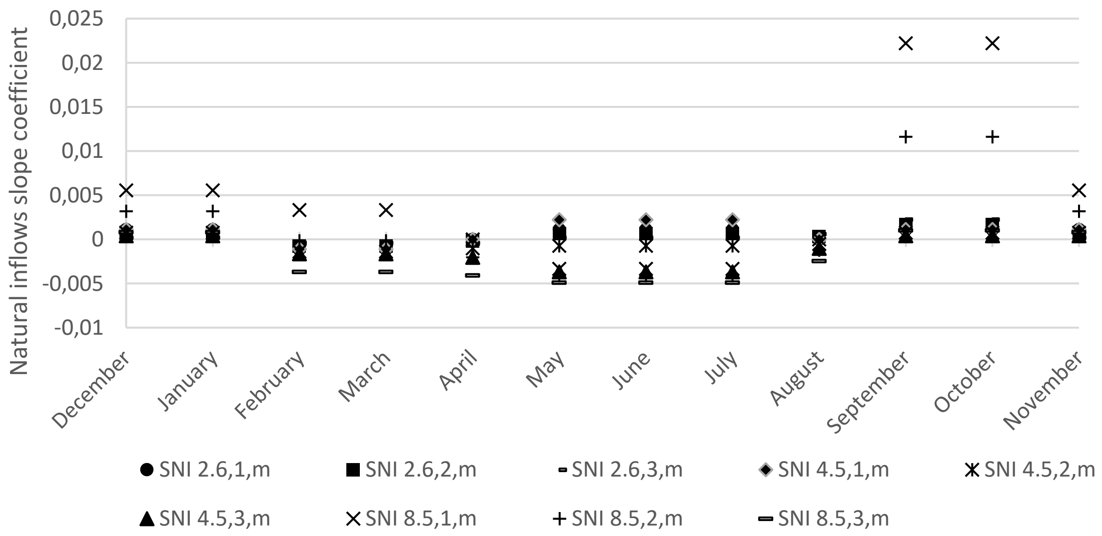

Figure A1.7. Natural inflow slope coefficients $SNI_{s,p,m}$ for each RCP scenario (s), period of climate change (p) and month (m)

This yields to the following equation for natural inflows:

$NI_{s,p,m} = NoI * MINI_m * SNI_{s,p,m}$ (MWh/hour) (4)