Long term impacts of climate change on the transition towards renewables in Switzerland

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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.

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 [1]. 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 [2–4].

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 [5,6]. Total renewable 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, with hydropower representing 43% of this total [7]. 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 [8].

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 [2,9] or through storage [10]. Hydro-storage is by far the most efficient and most used storage technology, accounting for over 94% of worldwide installed storage capacity [11]. 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 [12].

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 [13]. In 2020 hydropower represented 58% of the total generation, nuclear accounted for 36% and the remaining 6% came from thermal and renewables [13]. 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 [14], two decisions which endanger the future Swiss energy

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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 [15]. Over the same period reservoirs are expected to receive less water in summer and more during fall. Gaudard et al. (2014) [16] 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.

A system based on 100% renewables is technically feasible for Switzerland [17]. To achieve this, the country must encourage PV investments, as solar is by far the technology with the highest potential: nine times that of wind and three times that of biomass and geothermal combined [18]. Today total solar roof-top yearly generation potential alone is quantified at 32 TWh. There is also a significant potential for high-altitude PV, including floating panels on water reservoirs and panels on reservoir dams [19,20]. Another key element is the required increase in storage capacity: in this respect, heightening existing dams (within technically feasible limits) and increasing turbine efficiency would allow for a 10% increase.

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 [21]. One of the key proposals of this strategy is the implementation of a storage reserve which seeks to ensure security of supply by imposing a 10% reserve level in the reservoirs [22].

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. (2022) [23], 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) [24] 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 [25].

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 80–100% generation coming from VRES for countries such as Ireland, Portugal, the United States and Denmark [3, 26–28]. 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) [29]. The most used technology is hydro-storage, which is highly dependent on climatic conditions, including seasonality; adding pumping mitigates the variability of natural inflows [12].

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 [30]. However, while energy transitions are proposed as strategies to mitigate climate change, these studies rarely include the long-term effects of climate change [31,32] due to the challenge of developing plausible scenarios that capture the uncertainty resulting from extreme events caused by climate change [33]. Such models focus on three main topics. The first one is the development of tools and approaches for modelling the energy transition [34]. The second one is the analysis of the technical feasibility of systems relying on a high share of renewable energy [35]. And the third one concerns the analysis of the economic impact of the transition process [36]. This literature includes a few studies focusing specifically on the challenges of the transition towards renewables in Switzerland [37,38].

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)) [39]. 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 [40]. Under CA, investors submit a bid at which they are willing to build the required new capacity [40]. 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 [41]. Furthermore, CA reveal the true market price by increasing competition. FITs and CA both induce innovation in initially costly technologies and reduce entry barriers [40,42].

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 [43], thereby reducing consumer welfare as prices and/or subsidies increase [44]. 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 [2,45].

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

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[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 [59].

total consumption by increasing the energy efficiency [46]. Broberg et al. (2021) [46] 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 [39].

Guo et al. (2018) [47] 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.

Building on this literature, we seek to analyze if and how Switzerland can successfully manage the simultaneous increase in demand and reduction in water resources in its electricity system caused by climate change. We focus on the potential of capacity auctions, and briefly consider the potential of demand-side management. Our main conclusion is that subsidizing PV indirectly encourages Pumped Hydro-Storage investments, the combination of which allows the country to avoid blackouts and soring electricity prices.

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 [48]. SD has been used extensively to study electricity markets to address different challenges such as VRES diffusion [49], capacity adequacy [50], regulation [51] and investment dynamics [52], among others.

We extend the model presented in Martínez-Jaramillo et al. (2022) [23] 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.[2] Fig. 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 Return on Investment (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[3] 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 resources (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. Given the environmental and legal constraints we assume the reservoir capacity as constant during the simulation period.

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 [24]. We further assume that Switzerland will reach a 100% electric car fleet by 2100.

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.

Climate change has two impacts in our model. On the one hand, electricity demand pattern changes due to two main drivers: higher temperature induces to more consumption for air conditioning and public awareness of climate change leads to an increase in the electric vehicles fleet. On the other hand, higher temperature impacts the availability of resources required for renewable generation (sun and water). In our model we introduce the possible pattern of precipitations given the RCP scenario.

Table 1 provides an overview of the model modifications compared to the model used in Ref. [23]. 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 [53]. 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.

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

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[2] Our focus is on the long-term, with a particular view to understand the effect of climate change on the inter-seasonal dynamics. This is crucial for the Swiss system due to the seasonal patterns of hydro and PV generation, coupled with the limited capacity of inter-seasonal storage. Within this context, a representative day for each month is appropriate, as we aim to capture seasonal variations, not inter-day variation.

[3] This parallel model allows us to forecast how much capacity would be available in the absence of further investment decisions, taking into account planned capacity retirements and capacity currently under construction coming online over the next 3 years.
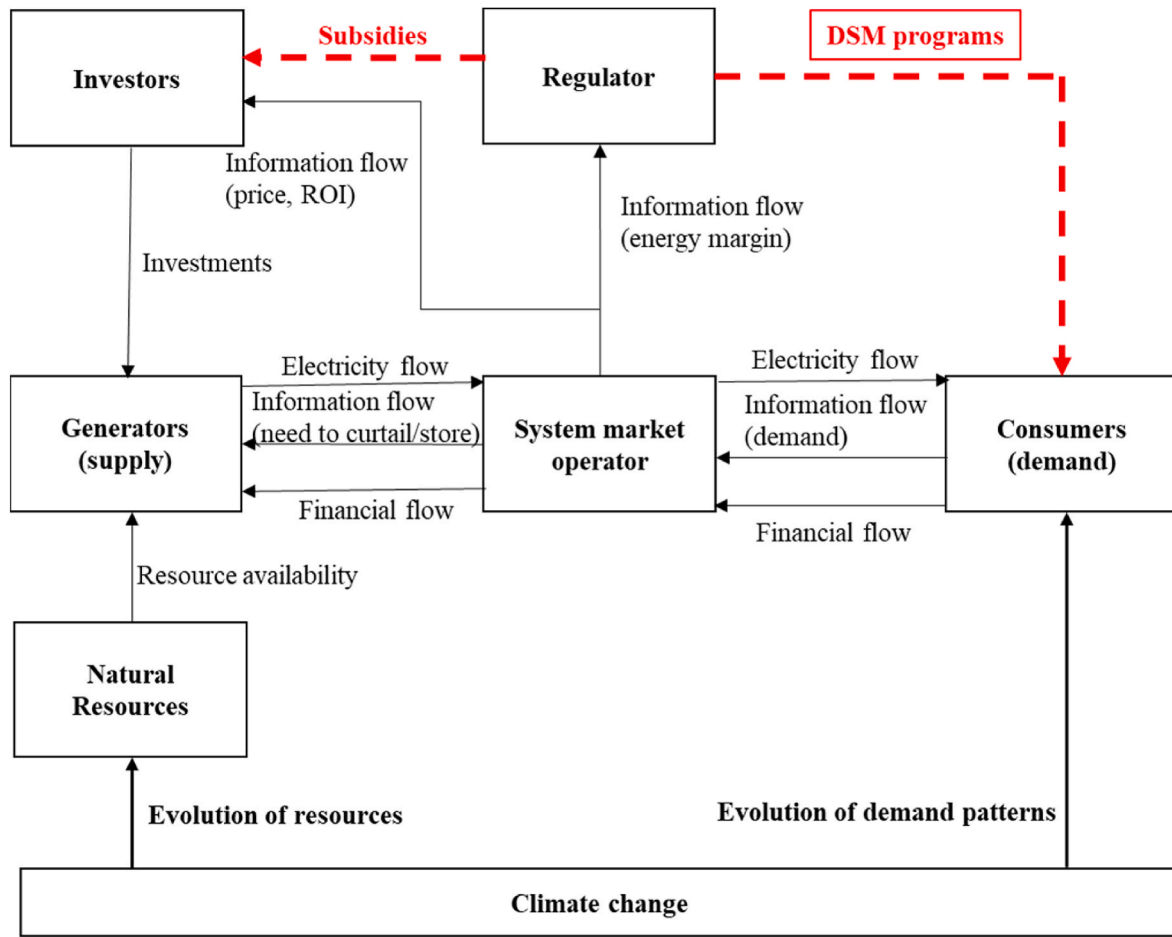
Fig. 1. Model overview.

Table 1
Overview of model modifications compared to the model presented in Martínez-Jaramillo et al. (2022) [23].

Model element	[23]	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 [54,55]; (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)
Reservoir inflows and RoR generation	Same seasonal pattern over 20 years	Evolution of reservoir 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 2
Overview of the climate change scenarios. Temperature: expected absolute increase in average temperature by the end of the period compared to the pre-industrial baseline. Other inputs: Expected percentage increase at the end of the period compared to 2002. In the simulation model we assume a linear progression during each of the periods.

Variable	Years	RCP 2.6	RCP 4.5	RCP 8.5	Sources
Temperature	2020–2030	+0.2 °C	+0.3 °C	+0.4 °C	[54,55]
	2030–2070	+1.0 °C	+1.4 °C	+2.0 °C	
	2070–2100	+1.4 °C	+1.8 °C	+3.7 °C	
RoR generation	2020–2030	+0.1%	+0.4%	+0.6%	[15]
	2030–2070	+0.5%	+2.0%	+3.0%	
	2070–2100	+2.0%	+1.5%	+5.0%	
Reservoir inflows	2020–2030	+0.2%	+0.1%	+0.6%	[15]
	2030–2070	+1.0%	+0.5%	+3.0%	
	2070–2100	−9.0%	+1.0%	−14.0%	
Demand	2020–2030	−0.6%	−0.1%	+0.5%	[56]
	2030–2070	−3.0%	−0.5%	+2.5%	
	2070–2100	+2.0%	−3.0%	+5.0%	

brooding in line with the Representative Concentration Pathways (RCP): 2.6, 4.5 and 8.5. These scenarios were developed by the IPCC [54,55] 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 as guideline previous studies that incorporate the RCPs to model the impact of the increase of temperature on both demand [56] and supply [15]. Table 2 provides the hypothesized impact of each RCP scenario on key model inputs.

Without any governmental intervention all three cases exhibit unmet demand (Fig. 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. Fig. 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
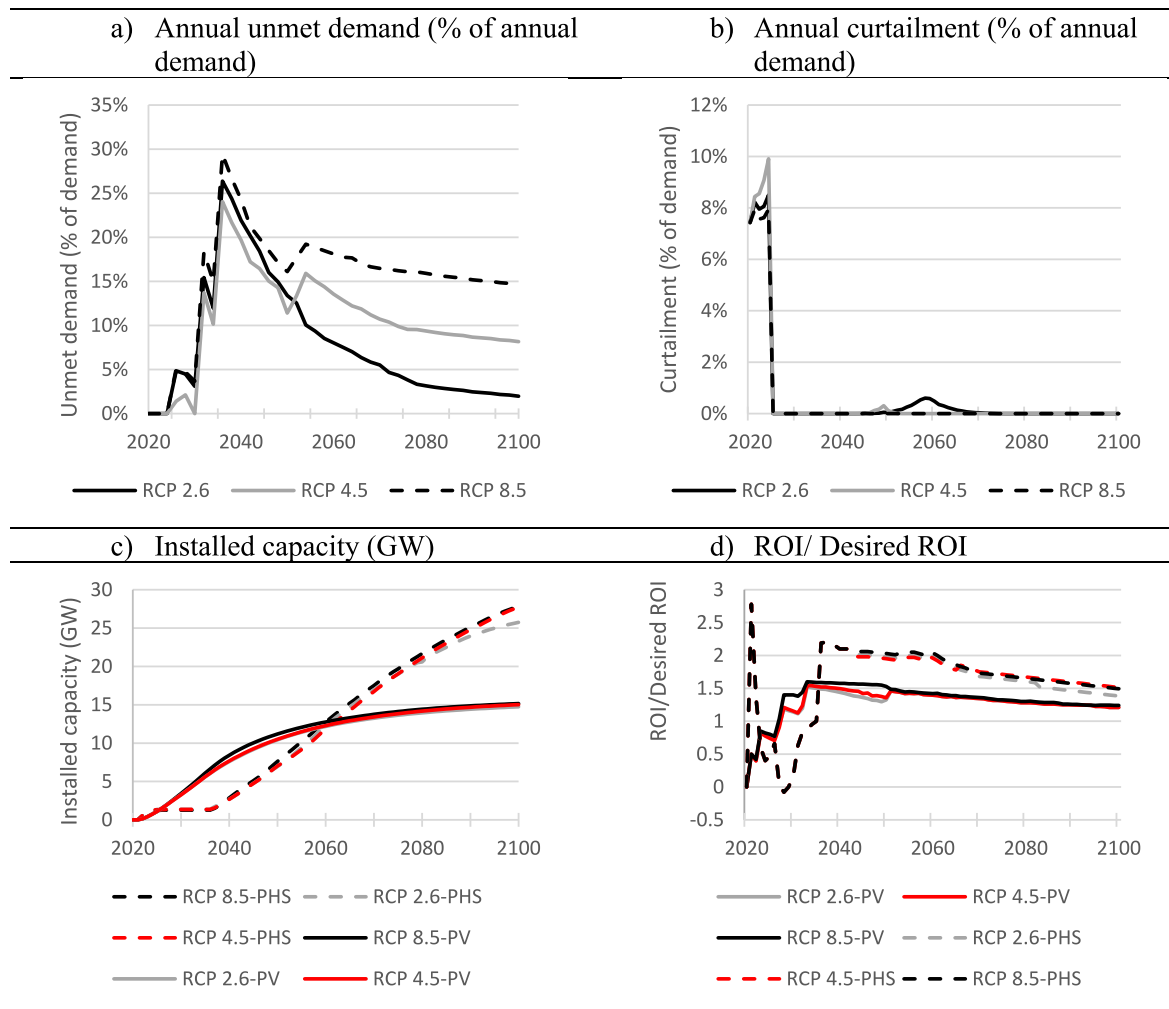
Fig. 2. Unmet demand, curtailment, installed capacity and ROI for the three climate change scenarios.

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 generated (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 (Fig. 2c). Fig. 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.

Sections 4.1 to 4.3 explore the effects of governmental interventions: in section 4.1 we analyze the impact of subsidies on capacity, section 4.2 focuses on the consequences of regulations on the demand side, and section 4.3 studies the combined effect of capacity subsidies and demand side management. Finally, in section 4.4 we briefly discuss the

robustness of our results with respect to the 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. Fig. 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 (Fig. 3b); this leads to an increase of PV capacity (Fig. 3c) and the energy margin (Fig. 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.

Fig. 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 Fig. 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
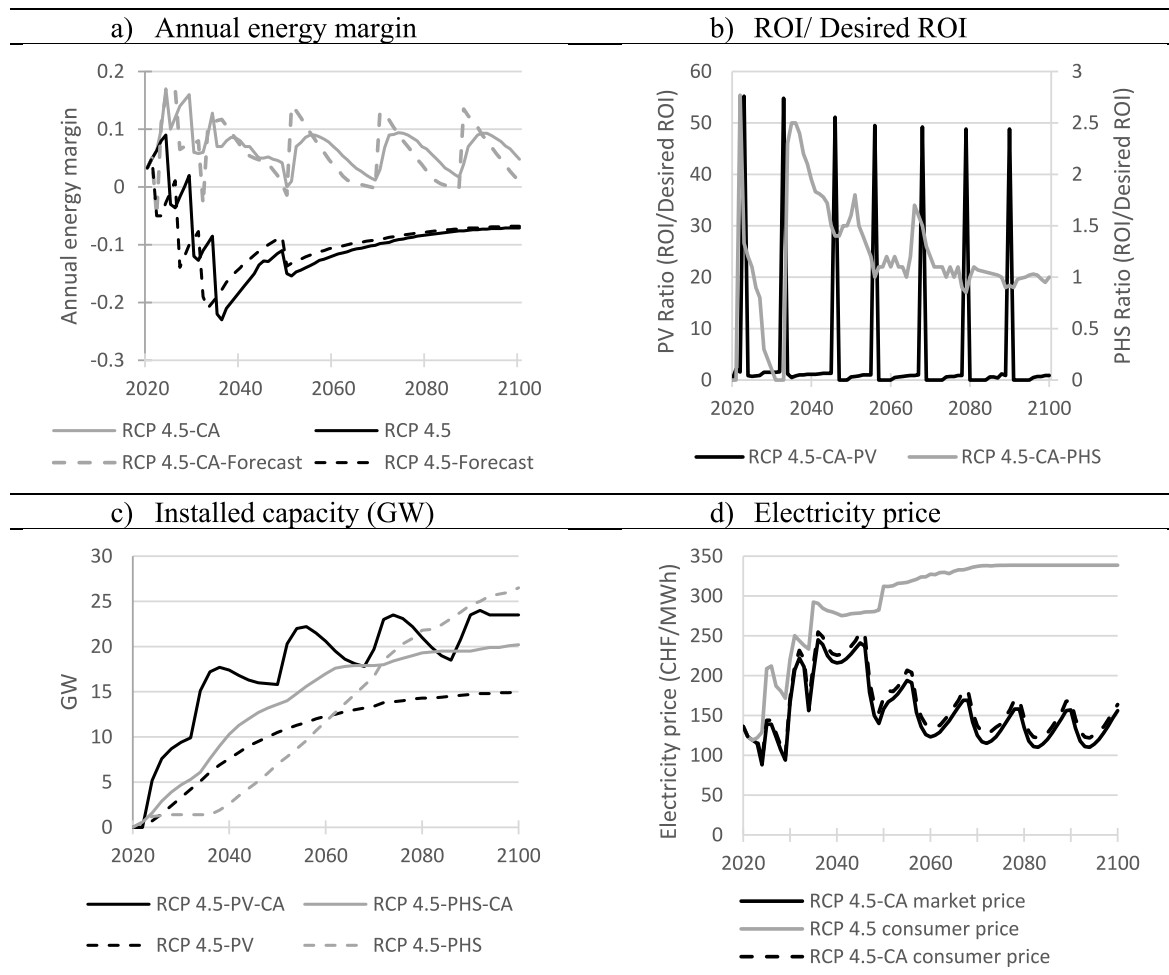
a) Annual energy margin

b) ROI/ Desired ROI

c) Installed capacity (GW)

d) Electricity price

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

(recall Fig. 2a).

Fig. 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 Ref. [57], 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. Fig. 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.

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. Fig. 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) [58] 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.

Fig. 5a shows the impact of this DSM policy on unmet demand: a 16% reduction by 2100. The electricity price does not change significantly (Fig. 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.

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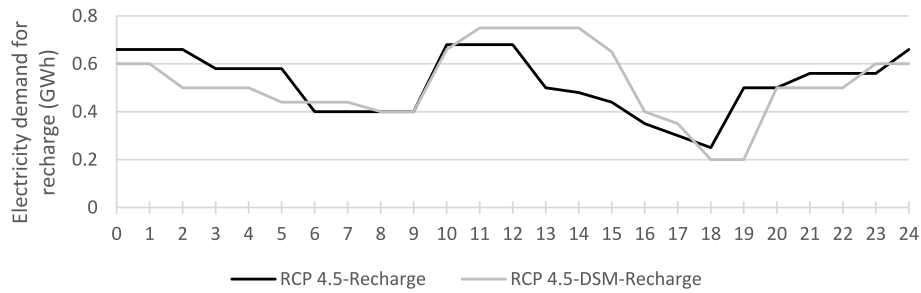
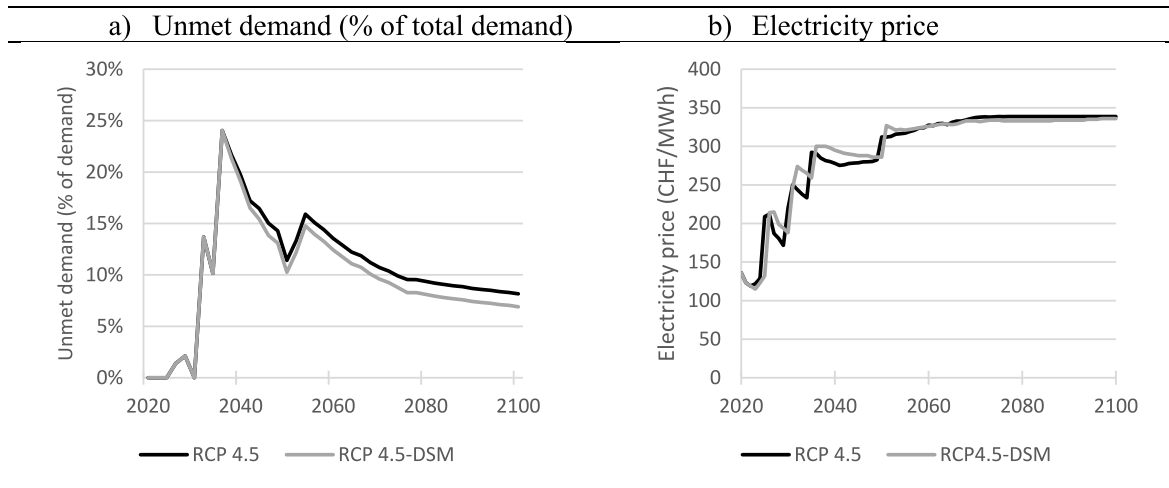**Fig. 4.** Electricity demand for cars on a typical day in 2099.

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

increases in line with the penetration of electric cars. Adding DSM reduces the required PHS capacity by 4.4%. Fig. 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 Fig. 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 (Fig. 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.

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.

Where Hn: hydropower from natural inflows, PHS: Pumped hydrostorage, BC: base case, CA: capacity auctions, DSM: Demand-side management and, CA-DSM: combination of CA and DSM.
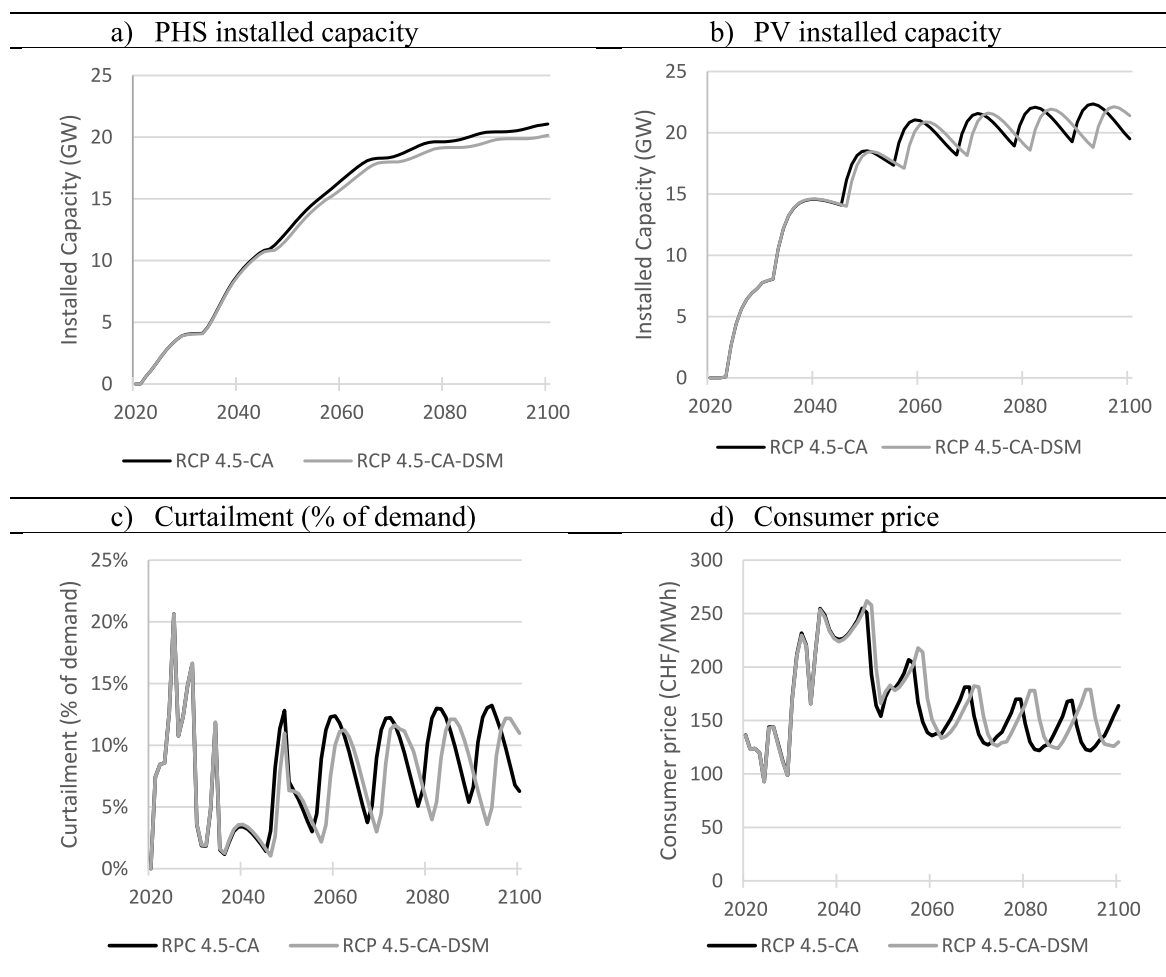
Fig. 6. RCP.4.5-CA curtailment, consumer price, PHS and PV installed capacity with and without DSM.

Table 3
Overview of the results.

	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)[b, c]	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)[b, c]	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)[b]	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)[b]	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)[b]	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)[b]	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)[b]	19.7	17.3	19.6	18	17.8	15.1	17.7	13.5	17	12.7	17	12.3
RoR generation share (%)[b]	23%	17%	23%	18%	24%	16%	24%	16%	25.5%	15.6%	25%	15.6%
PV generation share (%)[b]	39%	47%	39%	46%	41%	51%	41%	52%	41%	53%	41%	54%
PHS generation share (%)[b]	3%	13%	3%	12%	2.5%	15%	2.3%	16%	2.5%	17%	2.4%	16.6%
Hn generation share (%)[b]	35%	23%	35%	24%	32.5%	18%	32.7%	16%	31%	14.4%	31.6%	14%
Unmet demand (TWh)[b]	6.5	-	6.6	-	10.7	-	10.7	-	12	-	11.7	-
Unmet demand (%)[b]	2%	-	1.5%	-	8%	-	7%	-	15%	-	13%	-
Overflow (TWh)[b]	-	2.3	-	1.7	-	2.7	-	4.3	-	4.3	-	4.7
PV curtailed (TWh)[b]	-	2.5	-	2	-	4.3	-	2.9	-	4.8	-	5.2
Curtailment (TWh)[a]	30	348	23	345	32	405	25	369	25	417	22	400
Subsidies (Millions CHF)[a]	-	40,074	-	40,216	-	54,420	-	54,722	-	61,304	-	61,615
Market price (CHF/MWh)[b, c]	291	*137.2*	284	*131.5*	340	*130.3*	337	*122.2*	345	*123*	341	*114*
Consumer price (CHF/MWh)[b, c]	291	*143*	284	*137*	340	*138*	337	*130*	345	*132*	341	*124*

[a] Cummulative over the simulation period.
[b] Value for the final year.
[c] Italics refer to average over final cycle.

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 Fig. 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 introduced. 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.

Author contributions section

Ann van Ackere: Conceptualization, Juan Esteban Martinez-Jaramillo: Methodology, Juan Esteban Martinez-Jaramillo: Investigation, **Juan Esteban Martinez-Jaramillo:** Validation, Juan Esteban Martinez-Jaramillo: Writing – original draft, **Ann van Ackere & Erik R. Larsen:** Writing – review & editing, **Ann van Ackere & Erik R. Larsen**: Funding acquisition

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

APPENDIX

A full equation listing of the model of [23] can be found https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3875968&_cf_chl_captcha_tk_
=pmd_2vn04s3KCG8hXjTwKd7ktyKqeehTPxwRJHkuZYUGKgk-1629969362-0-gqNtZGzNAvujcnBszQ2R 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	3500	MW
HAD	6500	MWh/hour
$IECD_{s,c,w}$	$\begin{cases} 0.0067, p = 1 \\ 0.3255, otherwise \end{cases}$	MWh/hour
$SEC_{s,c,w}$	$\begin{cases} 0.0161, p = 1 \\ 0.0051, otherwise \end{cases}$	MWh/hour
NoI	3500	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;
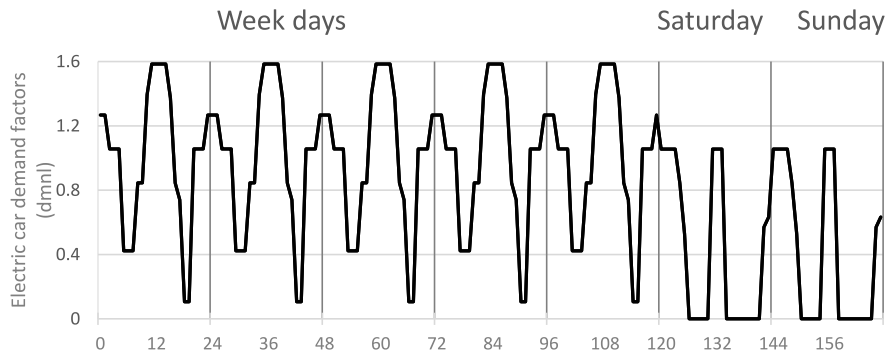on weekends, demand is lower.

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

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

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

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.
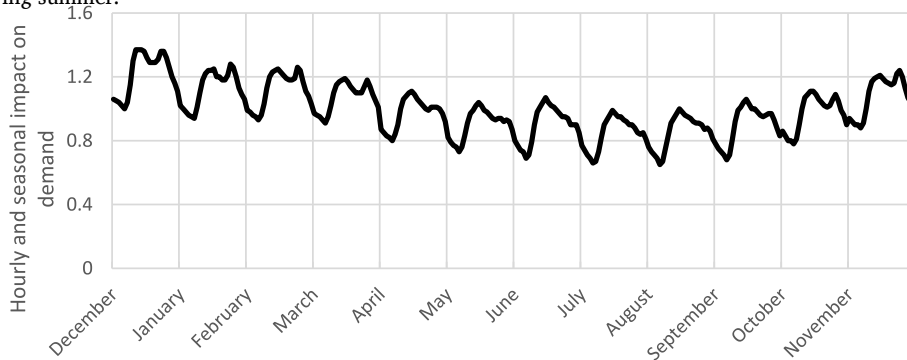

Fig. A1.2. Hourly and seasonal demand factors HSDF$_{m,d}$

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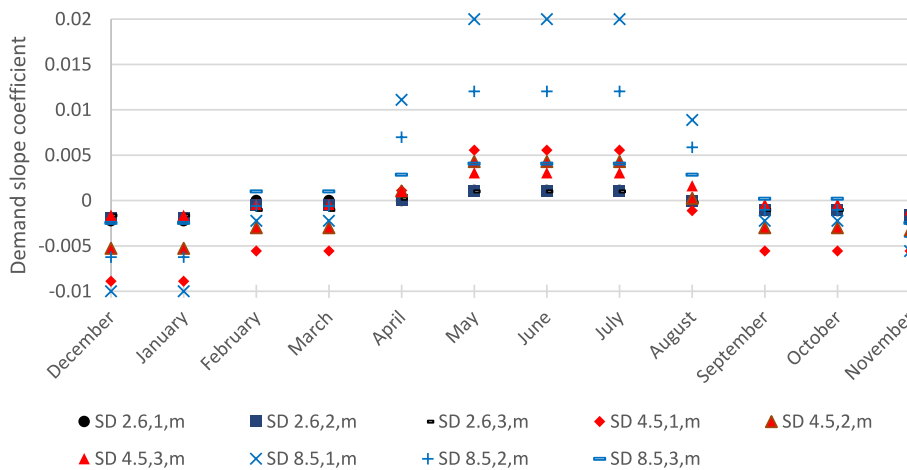
Fig. A1.3. Demand slope coefficient SD$_{s,p,m}$ for each RCP scenario (s), period of climate change (p) and month (m)

This yields to the following equation for hourly electricity demand:

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

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
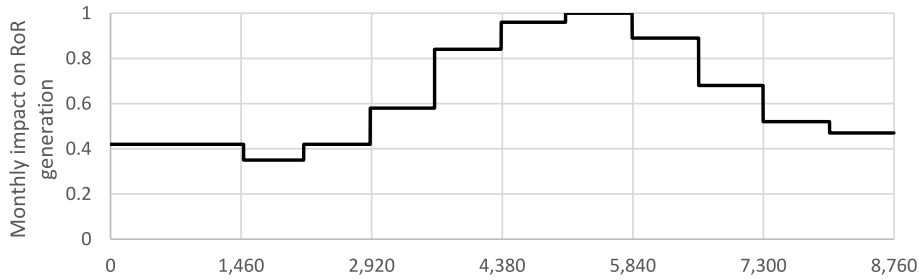
generation (water freezes or fewer precipitations).

Fig. 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.
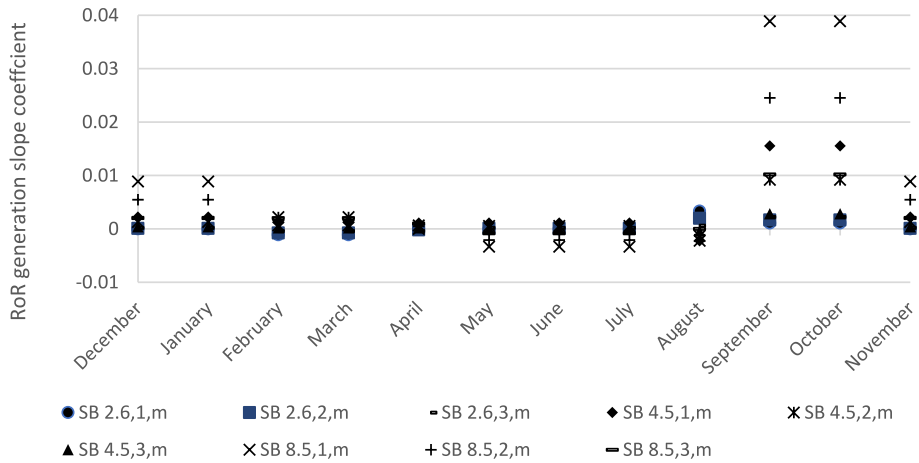

Fig. A1.5. RoR generation slope coefficient $SB_{s,p,m}$ for each RCP scenario (s), period of climate change (p) and month (m)

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

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

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. Natural inflows considers precipitations and glacier melting.
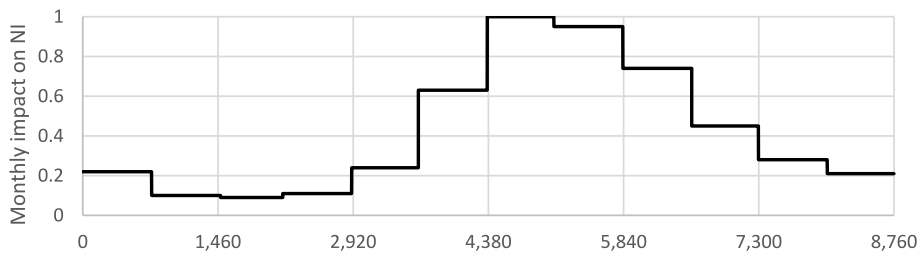

Fig. A1.6. Monthly impact on natural inflows $MINI_m$

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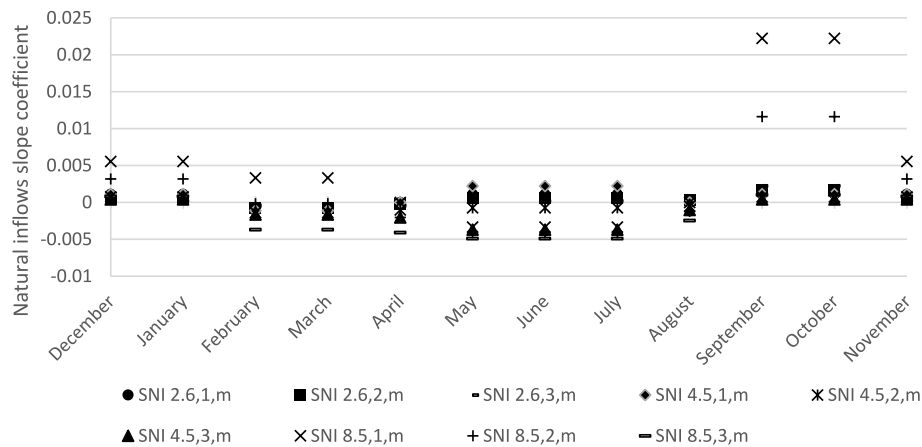
Fig. A1.7. Natural inflow slope coefficients $SNI_{s,p,m}$ for each RCP scenario (s), period of climate change (p) and month (m)

This yields to the following equation for natural inflows:

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

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