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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.

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 et al., 2011). Due to technological progress and economies of scale, the capacity cost of VRES has been falling in recent years (Batalla-Bejerano and Trujillo-Baute, 2016; Kaldellis and 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 et al., 2017; Carley and Lawrence, 2014; Johannsdottir and 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 and 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 and 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 and Dragoon, 2016). While batteries are used in a few electricity systems, such as in Australia (Green and 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 and Lejeune, 2012). Hydro-storage has the

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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 et al., 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 and 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 and 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 et al., 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 et al., 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 80–100% generation coming from VRES for different countries. Tables 1 and A1 summarizes the key findings of selected studies.

Most studies conclude that energy storage is key to achieving a 100% renewable system. Schill and 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.

Table 1
Technical feasibility studies for selected countries.

Country	Authors	Key points
Ireland	Connolly et al. (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 and 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.

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. Fig. 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.

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.

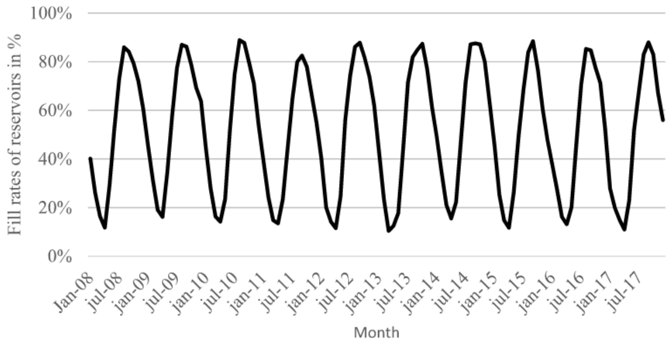

Fig. 1. Fill rate of hydro reservoirs in Switzerland (2008)–2017 (SFOE, 2017a).

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 et al., 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 and Breyer, 2018; Ranjbaran et al., 2019). While this is likely to be highly controversial for reservoirs located in protected areas, 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 (Bauer et al., 2017). 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 and 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 et al., 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 and 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

[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.

Appendix 2 for a flowchart providing an overview of the methodology).

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 (PV^c), while the remainder is used for pumping ($PV^p = PV - PV^c$). Consequently, the HS is generated from two inflows: natural inflows (HS^n) and pumping (HS^p). The latter is calculated as $HS^p = 0.8{*}PV^p$ due to losses (Chandel et al., 2015).

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

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

Recall that D, RR and HS^n are derived from historical data. Using the fact that $HS^p = 0.8{*}PV^p$, 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 PV^c and 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:

$$G = RR + HS^n + HS^p + PV^c + PV^p. \tag{4}$$

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:

$$PNG = RR + HS^n + \overline{PV}. \tag{5}$$

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

$$NG = RR + HS^n + HS^p + PV^c. \tag{6}$$

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.

$$PG_t = RR_t + HS_t^n + HS_t^p + PV_t^c + PV_t^p + CT_t. \tag{7}$$

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–23.1 GW, i.e., a factor of more than fourteen; reservoir capacity should almost double from 8800 GWh to 16,000 GWh, and pumping capacity should increase by 60% from 2.3 GW to 3.9 GW. Fig. 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.

Fig. 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.

Fig. 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 (Fig. 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.

Fig. 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.

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 (8800 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.

Fig. 4 visualizes the trade-off between the required reservoir size and

Table 2
Data sources.

Inputs	Source
Electricity demand, electricity generation, installed capacity, solar potential, new hydro projects, dam's water level and pumping facilities	SFOE, 2010, 2014, 2016a, b, 2017a, Bauer et al., 2017
Solar irradiation in Switzerland	MeteoSwiss (2017)
Solar cell efficiency	Assouline et al. (2015)
Losses from pumped hydro-storage	Chandel et al. (2015)

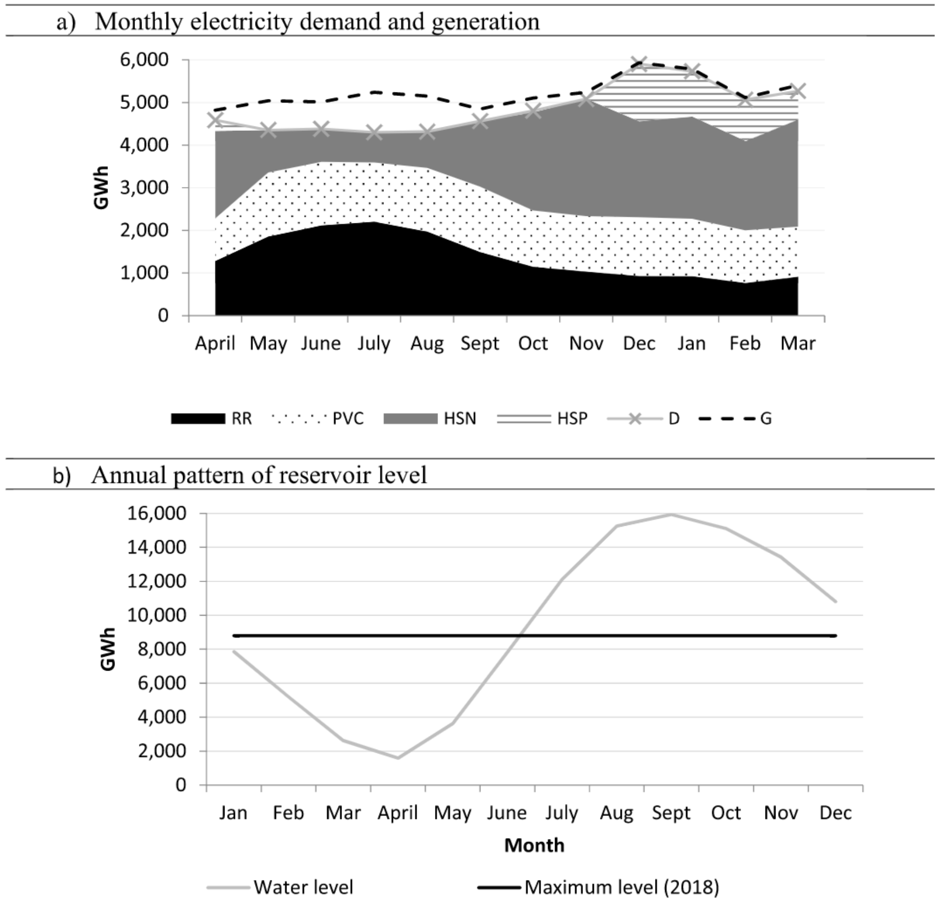

Fig. 2. Electricity demand and generation by month for the XL scenario.

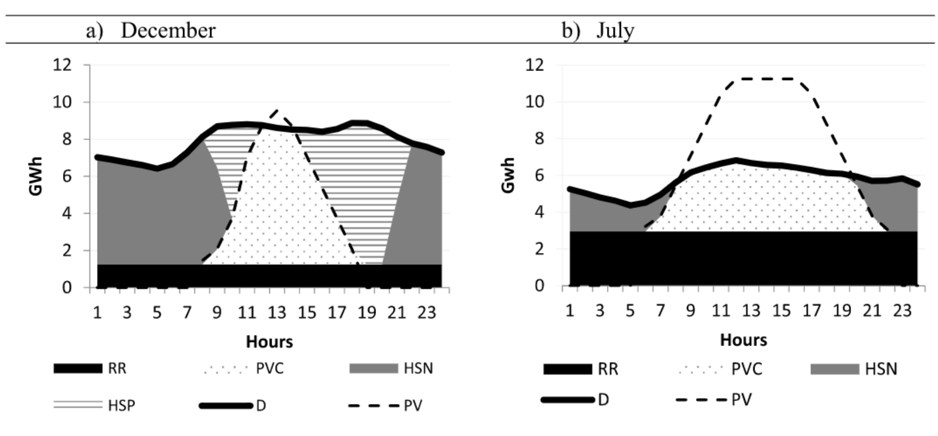

Fig. 3. Demand and Supply for the representative day in December and July.

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.

Fig. 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. Fig. 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.

Fig. 6 visualizes the electricity generation by technology (including

Table 3
Overview of scenarios.

Scenario	Reservoir size (GWh)	PV capacity (GW)	Pumping capacity (GW)	Required curtailment or exports (GW)
Current (C)	8800	43.0	16.0	19,078
Small (S)	10,600	36.0	13.0	11,350
Medium (M)	12,400	31.6	9.0	7203
Large (L)	14,200	26.7	5.0	4037
Extra Large (XL)	16,000	23.1	3.9	0

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 Figs. 5 and 6, the smaller the reservoir size, the higher the required curtailment, as a direct consequence of the large amount of PV capacity.

Fig. 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 Fig. 7).

5.3. 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.

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.

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.

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, Fig. 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.

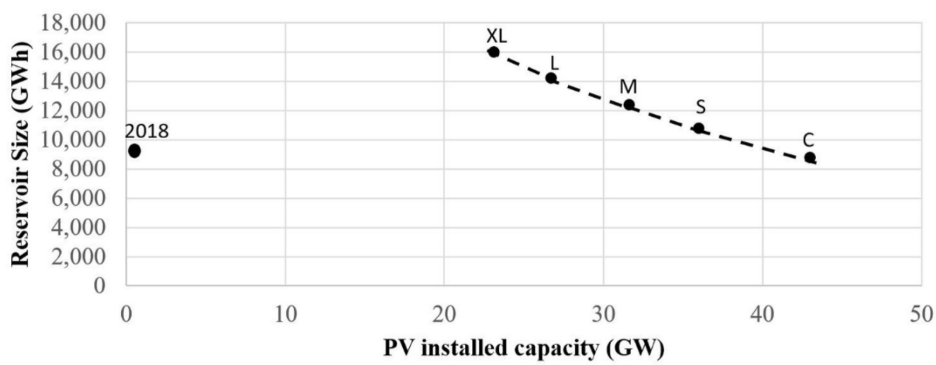

Fig. 4. Trade-off between reservoir size and PV installed capacity.

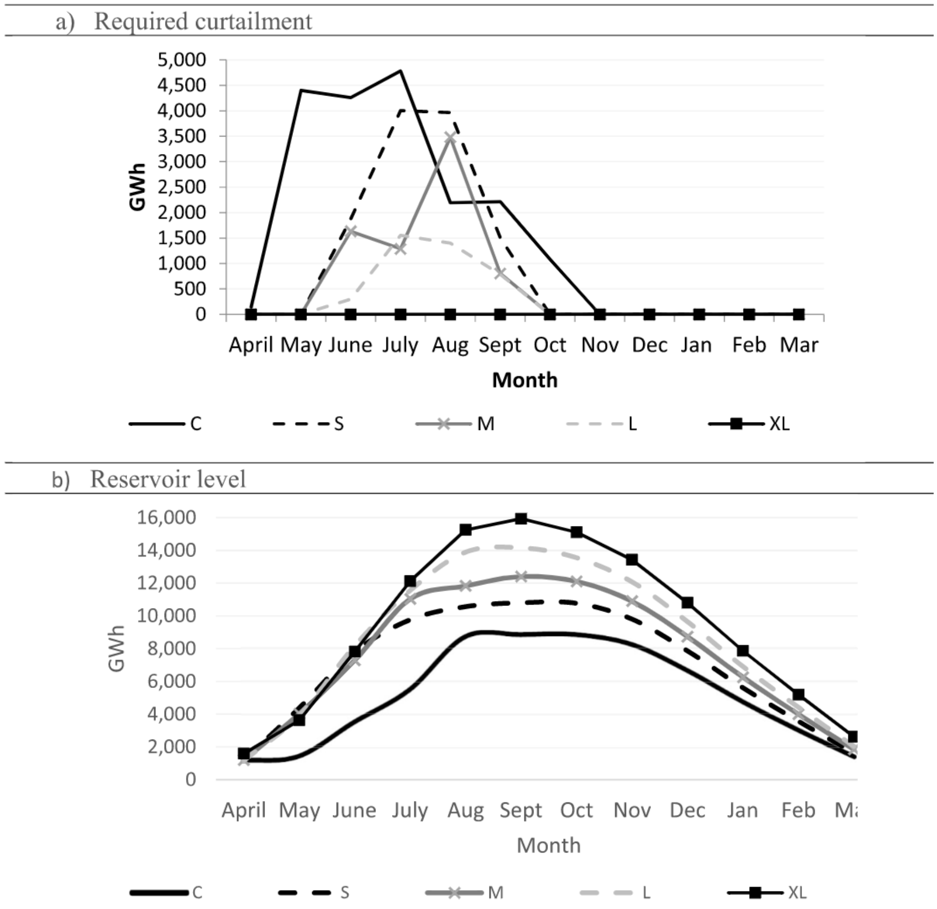

Fig. 5. Required curtailment and reservoir level by scenario.

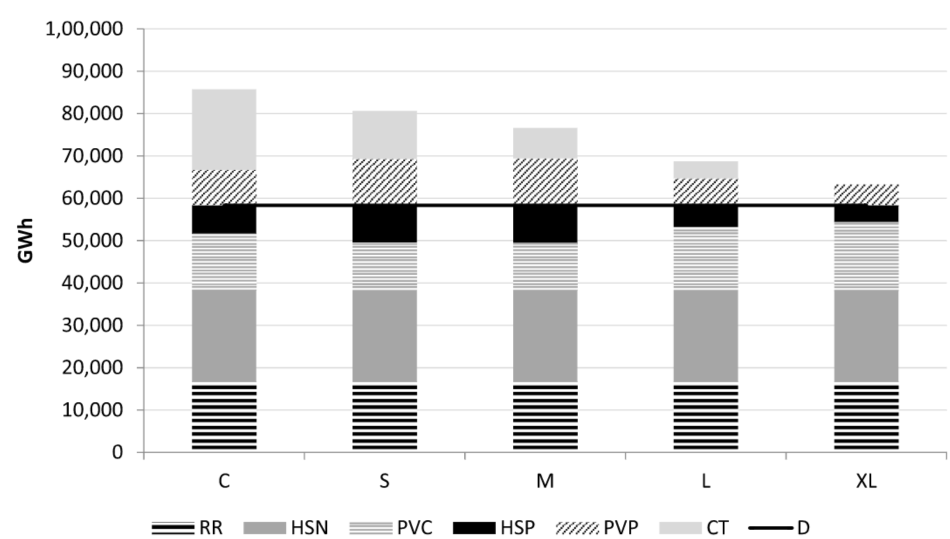

Fig. 6. Yearly electricity generation by technology.

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

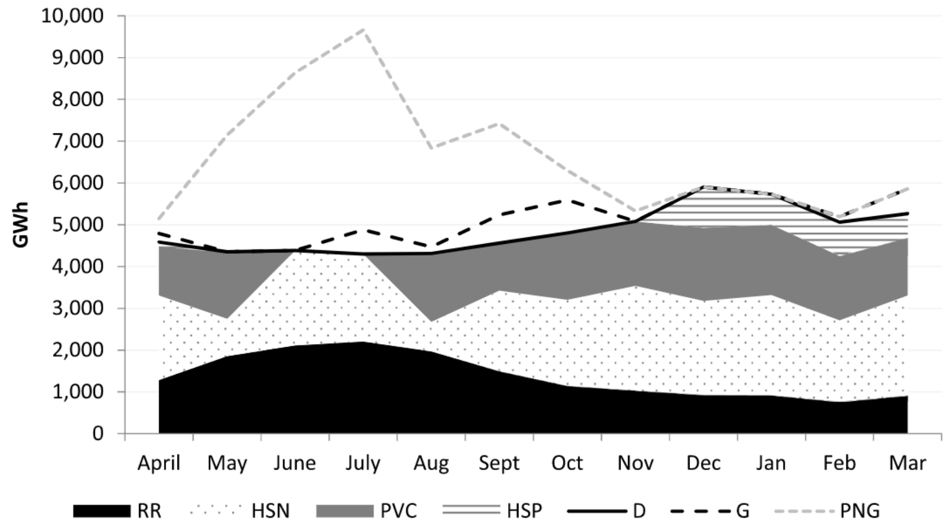

Fig. 7. Monthly electricity demand and generation for scenario C.

Table 4
Sensitivity analysis parameters.

Sensitivity Test	Water inflow	Radiation
	−10%	–
	–	−10%
	−10%	−10%
	+10%	−10%
	−10%	+10%

Table 5
Sensitivity analysis results.

Electricity balance (GWh)					
Case	C	S	M	L	XL
	12,450	6291	2051	−1500	−8000
	16,300	9500	5400	1494	−4800
	14,300	9014	5560	1980	−2350
	19,078	*12,000*	*7203*	*3800*	*0*
	17,215	10,792	7418	4200	900
	20,500	12,714	7561	2830	−600
PNG I^0R^0	77,420	69,690	65,546	63,380	58,343

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

Scenario					
Case	C	S	M	L	XL
	B +	B +	B +	B-	B-
	+	+	+	+	B-
	B +	B +	+	+	B-
	+	+	+	+	0
	B +	B +	+	+	+
	+	+	+	+	B-

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

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 et al., 2014). This will make the choice of keeping Switzerland

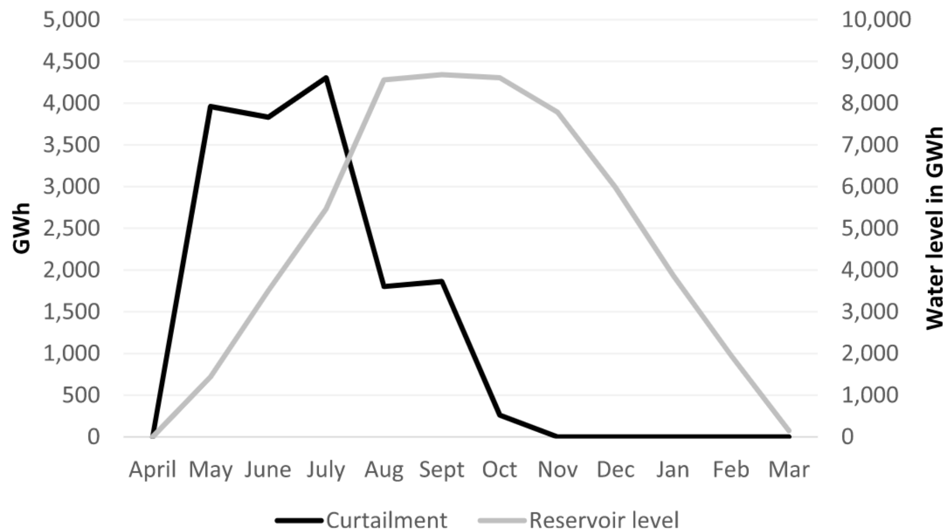

Fig. 8. Water level in reservoirs (scenario C, case R⁻).

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.

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.

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Appendix 1

Table A1
List of acronyms

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

Appendix 2

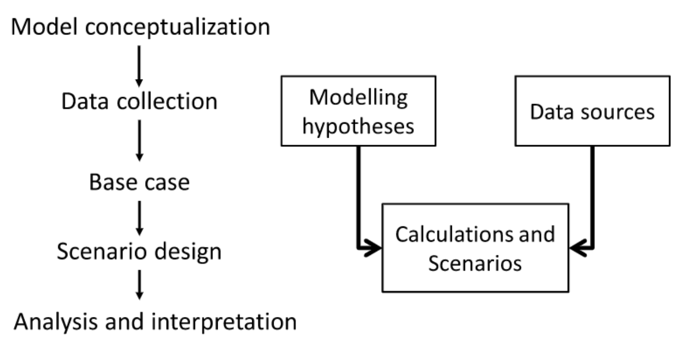

Fig. A1. Flowchart illustrating the methodology.

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