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SECURITY OF SUPPLY IN THE ELECTRICITY SECTOR: THE CASE OF SWITZERLAND

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UNIL | Université de Lausanne

FACULTÉ DES HAUTES ÉTUDES COMMERCIALES

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THÈSE DE DOCTORAT

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par

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Prof. Ann Van Ackere

Jury

Prof. Jacques Duparc, Président
Prof. Yves Pigneur, expert interne
Prof. Derek Bunn, expert externe
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Université de Lausanne
Faculté des Hautes Études Commerciales

Doctorat en Systèmes d'Information

Par la présente, je certifie avoir examiné la thèse de doctorat de

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EXECUTIVE SUMMARY

Over the past decades the electricity supply has been reliable in Switzerland, the country having one of the lowest levels of interruptions in Europe. Supply in Switzerland is generated mainly by hydropower and nuclear power, which cover respectively on average 60% and 35% of total demand. The country is a net-exporter in most years and has a positive exchange balance. However, it is uncertain how the electricity supply will evolve in the long-term given the potential changes in the generation-mix in Switzerland, resulting from the nuclear phase-out and the increasing share of non-hydro renewable energies (mostly PV). Simultaneously, its neighbouring markets, with which Switzerland is increasingly interconnected, are facing similar changes that will affect the country. These issues threaten the security of supply not only in Switzerland, but also in other countries facing similar challenges. The objective of this research is to elaborate on the concept of security of supply in the electricity sector (SoES), and to analyse in particular the case of Switzerland.

We start by developing a system dynamics model to analyse the impact of these changes on three main components of SoES: generation adequacy, affordability and import dependency. Our results show that with the current regulatory framework, the only investments committed to are those assumed for PV and wind energy until 2035. The country becomes a net importer, its dependency being exacerbated in winter. This highlights a generation adequacy problem. To analyse this we develop a new metric: the annual energy margin. This metric accounts for the energy storability and operational flexibility of hydro-storage power plants. These results are nonetheless highly dependent on the hypotheses and parameters assumed in the model, in particular the availability of imports.

In the last decade there have been large investments in pumped-storage power plants (PSP) projects. Their aim was to benefit from energy arbitrage as well as to help integrating variable

renewable energies. However, price dynamics in recent years, together with the expected changes in the Swiss electricity market threaten their profitability. We develop an algorithm aimed at simulating the PSP operational decisions and integrate it into our model. Although the changes in the generation-mix lead to higher within-day price differences, PSP lack arbitrage opportunities in the long-term, given the drop of available cheap excess energy to pump. Therefore, profitable large scale arbitrage requires measures that increase the available supply and thus to create excess energy, e.g., encouraging demand efficiency programs and supporting base-load technologies like nuclear power and PV.

Current electricity systems are very complex; the elements in our model are not the only ones affecting the SoES. Based on a literature review, we develop a framework comprising twelve dimensions, which cover all aspects of long-term SoES. We provide at least one metric for each dimension. Metrics range from objective, easily measurable indicators (e.g., the electricity intensity to measure demand efficiency) to proxies (e.g., the delay caused by NIMBY to projects to measure socio-cultural factors).

Our overall conclusion is that the security of supply is threatened in Switzerland. In particular, the nuclear phase-out, whatever its timing, will have major effects on prices and on the country’s self-sufficiency. In the medium-term the country could benefit from low prices across European markets. However, the decision-makers should provide a stable regulatory framework that ensures the profitability of hydro-storage in the medium-term, encourages long-term efficiency measures and sends adequate investment signals. Our framework can be used to monitor the electricity market over time in order to provide insights about the expected evolution of all the aspects of SoES and provide guidance for action.

SOMMAIRE EXECUTIF

Au cours des dernières décennies l'approvisionnement d'électricité en Suisse a été fiable; le a pays l'un des niveaux d'interruption les plus bas d'Europe. L'électricité en Suisse est produite principalement par des centrales hydrauliques et nucléaires, lesquelles couvrent respectivement en moyenne 60% et 35% de la demande totale. Le pays est un exportateur net la plupart des années et il a un bilan positif de l'échange. Cependant, étant donné les changements potentiels du *mix* de production en Suisse, lesquels résultent de la sortie progressive du nucléaire et la production croissante des énergies renouvelables hors hydroélectricité (plutôt photovoltaïque [PV]), il y a une grande incertitude concernant l'approvisionnement de l'électricité sur le long terme. En même temps, les marchés voisins, avec lesquels la Suisse est de plus en plus interconnectée, font face à des changements similaires qui affectent aussi la Suisse. Ces enjeux menacent la sécurité d'approvisionnement en Suisse ainsi que dans d'autres pays qui font face à des défis similaires. L'objectif de cette recherche est de préciser le concept de sécurité de l'approvisionnement dans le secteur de l'électricité (SoES) et d'analyser en particulier le cas de la Suisse.

Dans une première étape nous développons un modèle de dynamique des systèmes pour analyser l'impact de ces enjeux sur trois composantes principales de la SoES : l'adéquation de la capacité, un prix abordable et la dépendance envers les importations. Nos résultats montrent que, avec le cadre légal actuel, les seuls investissements en capacité sont planifiés de façon exogène pour le PV et le solaire sur la période 2014-2035. Le pays devient un importateur net; sa dépendance est particulièrement élevée en hiver. Ceci met en lumière un problème d'adéquation de la capacité. Nous développons une nouvelle mesure pour analyser cela : la marge d'énergie annuelle. Cette mesure tient compte de la possibilité de stocker l'électricité à travers le pompage turbinage et de la flexibilité opérationnelle offerte par des centrales à barrages. Ces résultats sont néanmoins très dépendants des hypothèses et paramètres utilisés dans le modèle, en particulière la disponibilité des importations.

Dans la dernière décennie, il y a eu de gros investissements dans des centrales à pompage-turbinage (PSP). Leur objectif était de profiter des opportunités d'arbitrage ainsi que de faciliter l'intégration des énergies renouvelables intermittentes (NDRES). Cependant, la dynamique des prix ces dernières années, conjointement avec les changements attendus dans le marché suisse menacent leur rentabilité. Nous développons un algorithme qui a pour but de simuler les décisions opérationnelles des PSP, que nous intégrons dans notre modèle. Même si les changements dans le *mix* de production engendrent des différences entre les prix aux heures de pointe et les prix hors heure de pointe plus élevées, les PSP manquent d'opportunités d'arbitrage dans le long terme à cause de manque de l'énergie bon marché pour le pompage. En conséquence, pour que l'arbitrage à grande échelle soit rentable, il faut des politiques axées sur l'augmentation de la production disponible et donc sur la création d'excédents d'énergie, p. ex., encourager les programmes d'efficacité énergétique et aider les centrales de base telle que le nucléaire et le PV.

Les systèmes électriques actuels sont très complexes ; les éléments de notre modèle ne sont pas les seuls à affecter la SoES. Fondés sur une revue bibliographique, nous développons un cadre conceptuel comprenant douze dimensions, lesquelles couvrent tous les aspects de la SoES dans le long terme. Nous fournissons au moins une mesure pour chaque dimension. Parmi les mesures proposées, certaines sont des indicateurs objectifs et mesurables (p. ex., l'intensité de l'électricité pour mesurer l'efficacité énergétique); d'autres sont plutôt des approximations (p. ex., le retard causé par l'opposition par des résidents à un projet local d'intérêt général [phénomène *« not in my backyard »*, NIMBY en anglais], pour mesurer les facteurs socioculturels).

Notre conclusion générale est que la SoES est menacée en Suisse. En particulier, la sortie progressive du nucléaire, à quel moment que ce soit, aura des effets majeurs sur les prix et sur l'autosuffisance du pays. À moyen terme le pays pourrait bénéficier des prix bas qui prévalent dans l'ensemble des marchés européens. Cependant, les décideurs doivent fournir un cadre légal stable qui garantisse la rentabilité des centrales à barrages à moyen terme, qui encourage les politiques d'efficacité énergétique dans le long terme et qui envoie des signaux d'investissement adéquats. Le cadre conceptuel que nous proposons peut être utilisé pour suivre l'évolution du marché électrique au fil du temps dans le but de fournir des renseignements sur l'évolution attendue de tous les aspects de la SoES aux différents partis impliqués dans les prises de décision.

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LIST OF ACRONYMS

SoS: Security of Supply

SoES: Security of electricity supply

SD: System Dynamics

NDRES: Non-dispatchable renewable energies, i.e., PV and wind energy

VRES: Variable (or intermittent technologies), i.e., PV and wind energy

HS: Hydro-Storage

RR: Run-of-river

NUC: Nuclear power

CCGT: Combined cycle gas turbine

PV: Photovoltaic

WI: Wind energy

TH: Conventional thermal

LTI: Long-term imports

BI: Balancing imports, i.e., spot imports.

PSP: Pumped-storage power plants

FiT: Feed-in tariff

VOLL: Value of loss load

1. INTRODUCTION

The electricity supply has been reliable so far in Switzerland, the country having one of the lowest levels of interruptions in Europe. Indeed, reliability has improved in most European countries recently (their System Average Interruption Duration Index - SAIDI in 2013 being mostly lower than the previous 5-year average (CEER, 2015)). However, it is uncertain how the electricity supply will evolve in the long-term given the potential changes in the generation-mix in Switzerland, e.g., the nuclear phase-out. Simultaneously, electricity markets around the world should comply with stronger environmental commitments as well as ensuring economic feasibility for both the demand- and the supply-sides, which are sometimes conflictive objectives. These changes, together with the increasing complexity of managing electricity systems threat the Swiss electricity market. This thesis thus aims to analyse the long-term dynamics of the Swiss electricity market and intends to provide a general framework to analyse quantitatively the security of electricity supply (SoES) of any system.

The current situation of the Swiss electricity market shows stability and prosperity. Nuclear power covers on average 35% and hydropower about 60% of total demand. There is capacity surplus that allows the country to be a net-exporter in most years. The country has also long-term import contracts with France, which allow imports at very cheap prices. Currently, hydropower is used mainly at peak times to export at higher prices to Italy. However, this picture might change in the medium-term: there is a heated debate about the future of nuclear power and all the plants are likely to be decommissioned over the next 30 years. Although hydropower could be considered to fill the gap left by nuclear power, the expansion potential for this technology is limited, not only because the best spots are already used (rivers, dams, etc.), but also because of people’s strong opposition to their environmental impact. Additionally, the long-term import contracts with France are progressively expiring: they will no longer be available after 2040. Given the evolution of the Italian market, it is uncertain if exports to Italy will continue to be as profitable. Also, the recent price dynamics make new investments unprofitable. Under current conditions, even the nuclear phase-out is unlikely to trigger new investments. However, the installed capacity of non-dispatchable renewable energies (NDRES) is likely to increase significantly, in particular photovoltaic, due to the government financial support. However, this implies an additional fee that must be included by customers via the electricity bills.

With the purpose of analysing how these changes could affect the SoES in Switzerland, we built a system dynamics model. We focus on understanding how the expiration of contracts, the nuclear phase-out and the encouragement of renewable energies will affect future prices and the supply of electricity in Switzerland. These changes, combined with recent price dynamics across Europe, pose a significant threat to peak generators, e.g., hydro-storage plants. Given the recent large investments done in Switzerland in large hydropower, we also intend to analyse the arbitrage opportunities for pumped-storage plants (PSP) in the long-term. Our results show that the security of supply in the Swiss electricity market is compromised in the long-term. In the model we focus on three elements (import dependency, generation adequacy and economic sustainability), but there are additional elements affecting the SoES that one should consider. Especially right now, when, among other issues, environmental commitments are gaining in importance, the demand-side is playing a more active role and markets are becoming increasingly interconnected, a holistic view of SoES is necessary.

Therefore, a question arises: what other elements do we need to consider when analysing security of supply in electricity markets? We could not find any comprehensive framework addressing this question specifically for the electricity sector. Based on the literature concerning security of supply of different energy sources and end-uses, we develop a framework that allows us to assess the security of supply of an electricity system. We identify 12 dimensions that cover all the aspects of SoES in the long-term. They are: generation adequacy, resilience, reliability, supply flexibility, network infrastructure, imports dependency, demand management, environmental and economic sustainability, regulatory efficiency, access, socio-cultural factors and terrorism. In our framework we propose a metric for each of these. This provides a quantitative tool for decisions makers to follow the evolution of these different aspects over time, identify potential problems and decide if and when to intervene.

This thesis is organised as follows: in Section 2 we describe the Swiss electricity market and explain the main transformations it is currently facing, as well as the challenges it might face in the medium- to long-term. We also summarise the papers “From the nuclear phase-out to renewable energies” (*Paper_SwissMarket*), aiming at analysing the impact of potential changes in the generation-mix on the electricity supply in Switzerland, and the paper “Arbitrage Opportunities for Pumped Storage Power Plants in Switzerland” (*Paper_PSP*), aiming at evaluating the future of energy arbitrage in Switzerland given the expected transformation of the Swiss electricity market. In Section 3 we discuss the previous work on energy security assessment and, based on that, propose a set of dimensions and measures aimed at evaluating security of supply specifically in the electricity sector. Next we summarise the framework aimed at evaluating SoES developed in the paper “Security of supply in the electricity sector” (*Paper_SoES*). Finally, in Section 4, we provide a general conclusion of this research project. Appendix A presents the detailed description of the model used in the papers *Paper_SwissMarket* and *Paper_PSP*, including the data, the hypothesis and the equations. Appendix B contains the three papers.

2. THE SWISS ELECTRICITY MARKET

The Swiss market relies mainly on hydropower and nuclear power. Its favourable topography allowed the country to develop hydropower on a large-scale. This technology was complemented in the 70s and the 80s by the procurement of nuclear power plants. The large installed capacity and Switzerland's central location in Europe have allowed the country to play an important role in the continental electricity exchange. This position was enhanced in 2009, when the country started participating in the common market. However, the current liberalisation process and strong generation-mix changes in the medium term pose challenges to the system. The current state of the market and the main challenges Switzerland will face in the future are presented in Sections 2.1 to 2.6. An analysis of the impact of the nuclear phase-out and the increasing share of NDRES on the market dynamics in the long-term is presented in Section 2.7. Finally, motivated by the recent price dynamics in Europe (see Section 2.8) and the difficulties encountered by large hydro-storage in Switzerland (see Section 2.6.2), an analysis of the future of pumped storage power plants energy arbitrage is presented 2.9.

2.1. Supply

Generation in Switzerland is mainly based on hydro-power and nuclear energy. In 2015 nuclear energy accounted for 33% of electricity generation and hydro-power accounted for 60% (see Figure 1). Conventional thermal plants and renewable energy facilities have generated the remaining 7% of total production. The share of non-hydro renewable alternatives in 2015 was 4.2%, of which 1.6% was produced by PV. Specifically, hydro-storage plants supplied 55% of total hydropower generation in 2015 (SFOE, 2016a). On average, hydropower and nuclear plants have supplied 56% and 38% in the last 10 years. The hydro-power share in 2015 exceeded the 10 years average because of the larger water inflows and because of the unplanned supply interruptions of the nuclear plants Beznau I and II, and

Leibstadt in the second semester of 2015 (the aggregate load factor of all nuclear plants decreased from 91% in 2014 to 76%). Overall, electricity accounted for one quarter of Swiss final energy consumption in 2015 (SFOE, 2016b).

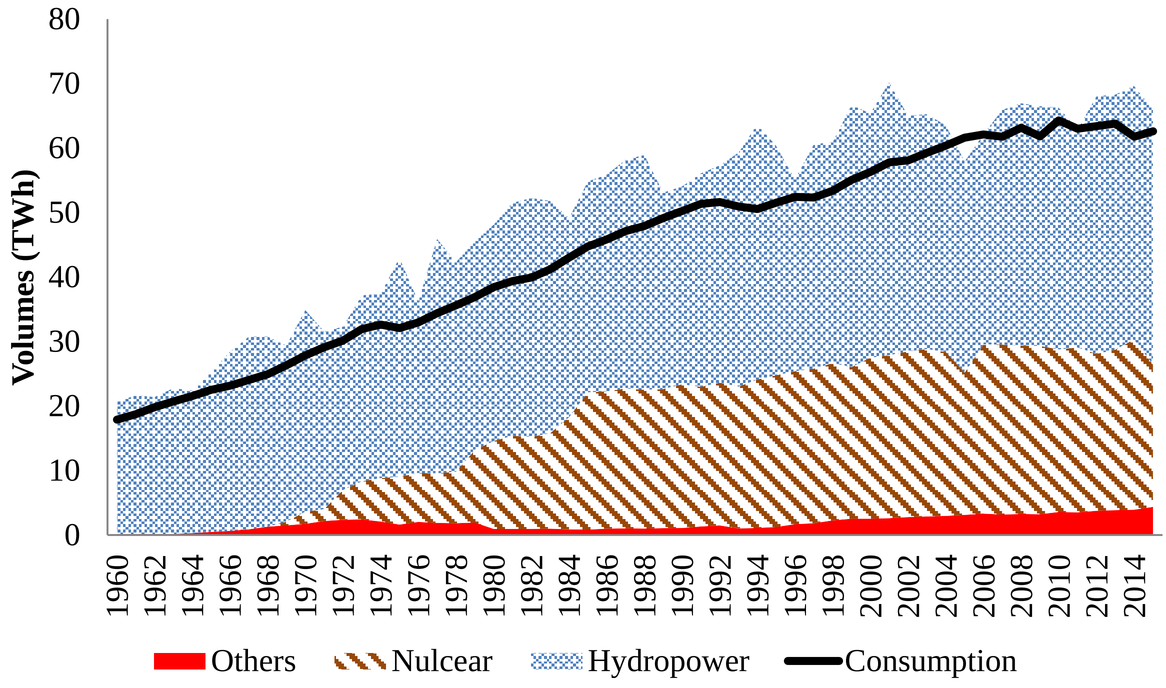

Figure 1. Generation and consumption in Switzerland between 1960 and 2015. Data from SFOE (2016a).

Hydro-storage plants play a major role in the system, not only because of their high share in the generation-mix, but also because they allow storing large water volumes in summer that are used to cover higher demand needs in winter. For instance, in 2015, while only 28% of stream flows occurred during winter, 43% of hydropower generation occurred during these months (50% if only generation from hydro-storage plants is considered). Water reservoirs are normally at their highest level at the end of September (around 85%). This energy is used in winter when demand is higher (in the last 10 years at least 54% of consumption occurred between October and March). Water reservoirs thus normally reach their lowest level at the end of March (slightly above 10%). Afterwards, spring water flows due to higher rainfall and melting snow fill reservoirs again.

As shown in Figure 1, consumption in Switzerland has remained fairly stable over the last 10 years. This has allowed the country to have a production surplus despite generation capacity remaining stable since 2000 (see Figure 2). The last major investment to be commissioned was the hydro-storage plant Riddis (1,285 MW) in 1999. Most recent investments are in PV, whose capacity at the end of 2014 reached 1,064 MW. Besides the expected investments in renewable energies (mainly in PV), there currently are 1,985 MW of hydropower under construction, the bulk of which corresponds to two major projects: Limmern (1,000 MW) and Nant de Drance (900 MW), which are expected to start operations respectively in 2016 and 2018.

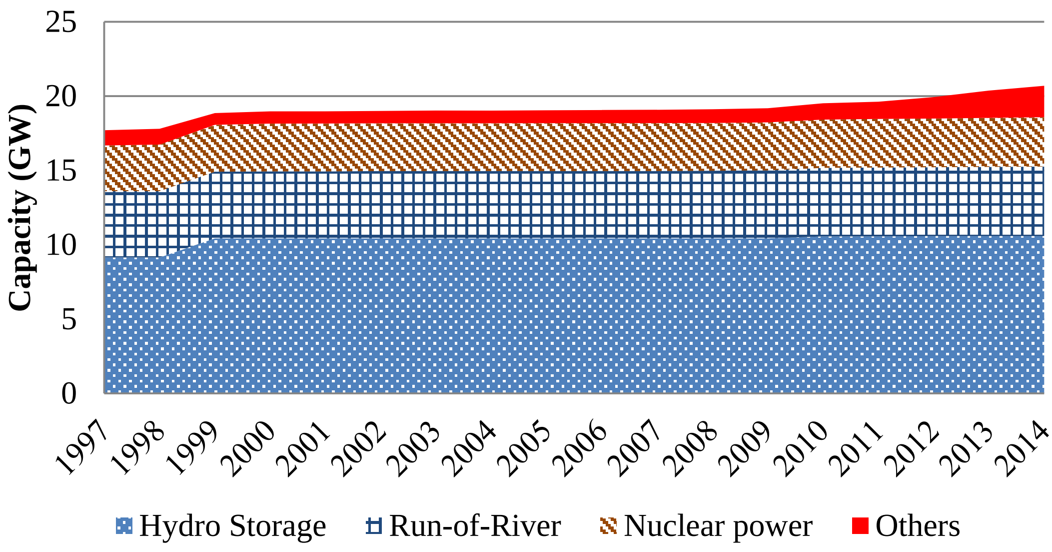

Figure 2. Evolution of installed capacity in Switzerland between 1997 and 2014. Data from SFOE (2016c) and SFOE (2016d).

2.2. Demand

Consumption in Switzerland (after deducting the 4.4 TWh of transmission and distribution losses) was 58.2 TWh in 2015, 1.4% more than in 2014. Demand in winter accounted for 54% of the total. This is explained in part by the fact that heating represents about 10% of demand. Consumption per sector was as follows: industry, 31%; households, 32%; services, 27%; and transport, 8% (SFOE, 2016a). The average tariff for users in 2015 was 169.5 CHF/MWh (SFOE, 2016a). The tariff consists of the following components: power procurement (36%), distribution system (47%), transmission system (7%), charge to support renewables (7%) and taxes (3%) (Swissgrid, 2016a).

2.3. The grid

The Swiss electricity grid is split into seven different grid levels. Swissgrid is responsible for operating grid level 1 – the transmission grid (6,700 km). The railway company (SBB/CFF/FFS) is currently the only end-consumer to be directly connected to the transmission grid (Swissgrid, 2011). All other end-consumers get their electricity via the distribution grids. The entire Swiss electricity grid measures over 250,000 km (Swissgrid, 2016a).

Nearly two-thirds of today's transmission grid was built in the 1950s and 60s. Also, demand has grown and generation is increasingly decentralised following the rise in renewable energy. Consequently, the grid needs to be expanded and modernised. The project "*Strategic Grid 2025*" plans to expand the transmission grid by 390 km and to optimise another 280 km, which will alleviate certain bottlenecks. This will require an investment of 2,500 million CHF (Swissgrid, 2015a). One major barrier to this development is the approval process. Currently, the period between the start of a project and its commissioning averages 15 years. However, the processes can take up to 30 years (e.g., the 35 km line Chamoson – Chippis to connect the new Nant de Drance PSP). Objections and federal court rulings in a late phase frequently cause a project to be delayed by years, e.g., six years for the construction of the 17 km line to connect the new Linth-Limmern PSP (Swissgrid, 2016a).

2.4. Electricity exchange

In 2015, Switzerland's exports were 1 TWh higher than imports. However, this balance was significantly lower than that of 2014, when the country's exports were 5.5 TWh higher than imports. The country is usually a net exporter; since 1960 the country has been a net importer in only 4 years, all after 2005. The country is typically a net importer during the winter months (October to March); without the large water reservoirs (and still the same inflows), this dependency would be even larger.

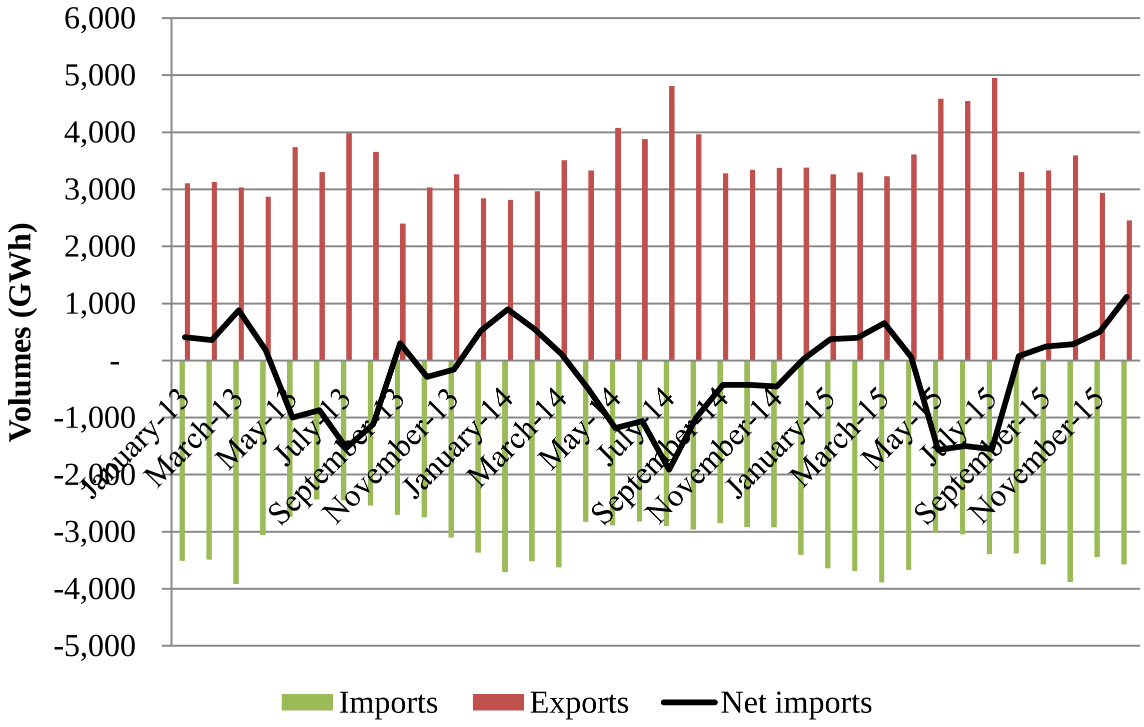

Figure 3. Monthly electricity exchange balance between 2013 and 2015. Data from SFOE (2016a).

The country trades large amounts of electricity, working as a hub for Europe. The volumes imported and exported in 2015 (42 and 43 TWh, respectively) are equivalent to about 70% of local consumption. In this electricity exchange, the long-term contracts with French nuclear plants play a major role. At the end of 2015 there were debit rights on 2,455 MW, the use of which resulted in about 46% of imports during that year (SFOE, 2016a). The country thus uses its large dam and pumped-hydro facilities to import cheap off-peak electricity from France and export during peak hours to Italy (Académies Suisses des Sciences, 2012). Recently, imports from Germany have increased significantly due to the production surpluses resulting from large PV and wind energy installed capacity in that country. Imports from Germany and France account for almost 100% of the total, while exports to Italy account for almost 60% of exports (see Figure 4).

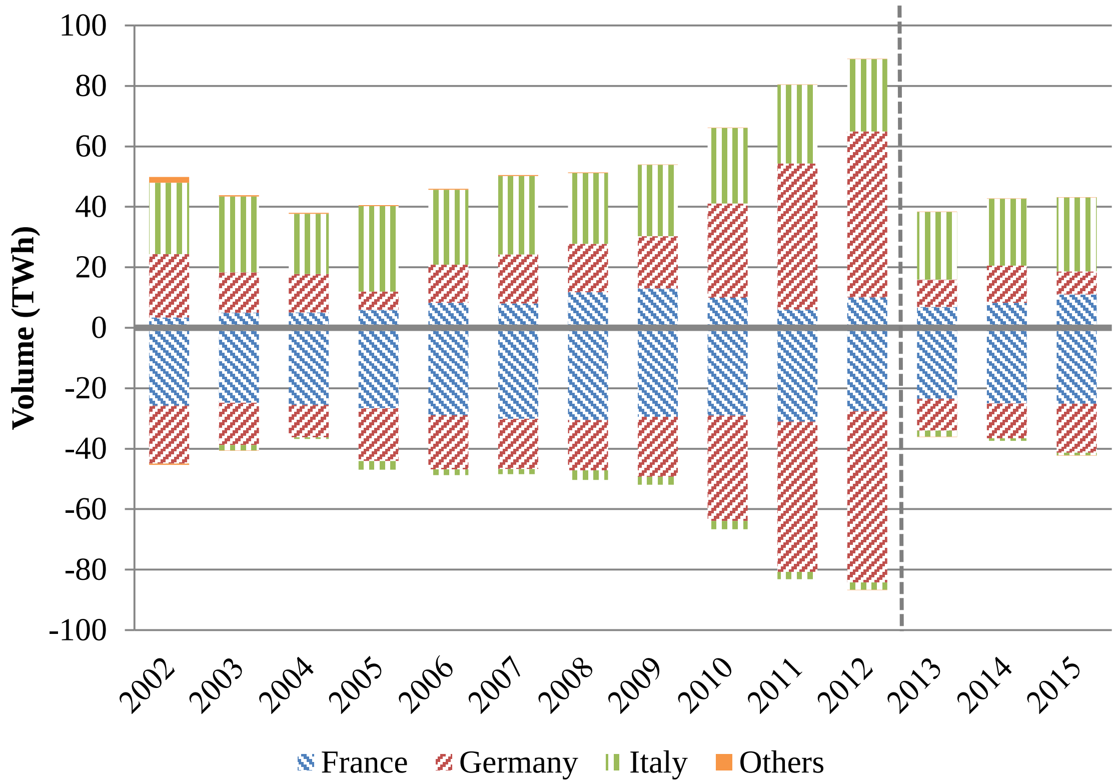

Figure 4. Exports (positive values) and imports (negative values) per country in the 2002-2015 period. Note: Statistics of imports and exports changed in 2013. Since that year, exchange only accounts for net transactions. Data from SFOE (2016a).

Imports are typically cheaper that exports (see lines in Figure 5). Cheap imports come from long-term contracts with France and renewables in Germany, while most exports are go to Italy, where prices have been historically higher than in central Europe. This has allowed Switzerland to have a financial exchange surplus, even in years in which the country has been a net importer, e.g., 737 CHF Million in 2005. However, this surplus has been decreasing in recent years, from 1,071 million CHF in 2006 to 234 million CHF in 2015. While in 2015 the average price of exports was 47.2 CHF/MWh, that of imports was 42.6 CHF/MWh (SFOE, 2016a). There is a decreasing trend in both prices since 2008, the drop of average export prices being notably more pronounced. Note that the average export price in 2015 is 37% lower than the 2006-2015 average (74.6 CHF/MWh) (SFOE, 2016a).

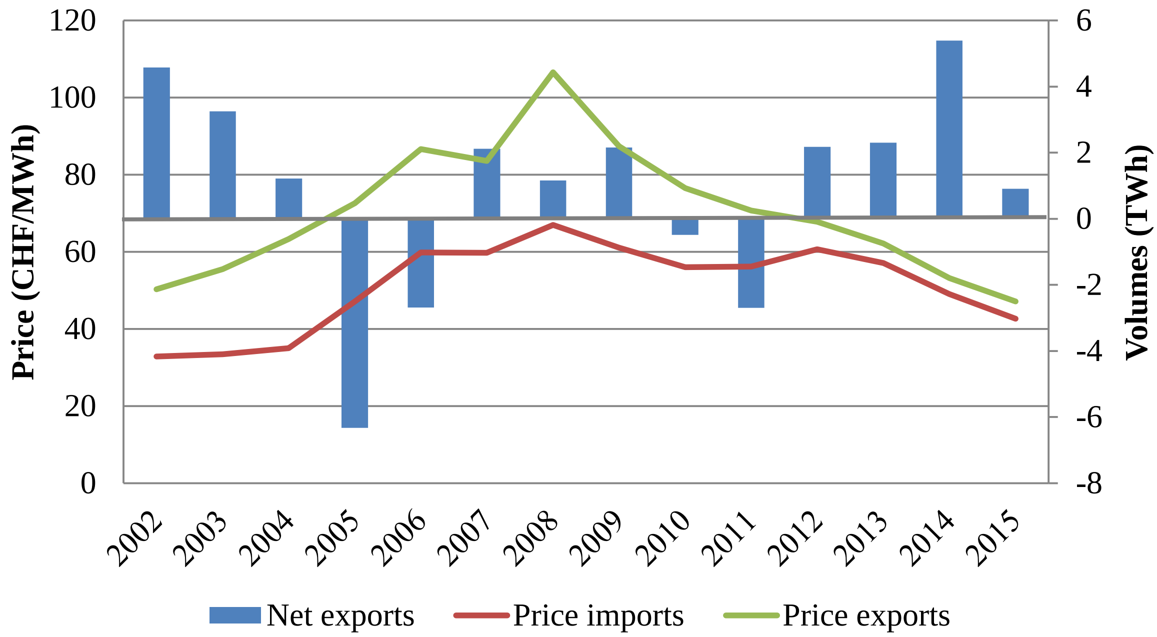

Figure 5. Net exports volumes and weighted average prices of imports and exports. Data from SFOE (2016a).

Currently, Swissgrid conducts the trade of cross-border transmission rights by means of explicit auctions, while energy is traded in the energy exchange. EPEX SPOT SE operates the power spot markets for France, Germany, Austria and Switzerland (day-Ahead and intraday). Together these countries account for more than one third of the European electricity consumption. Switzerland participates in the day-ahead market since 2006 and in the intraday market since 2013. In November 2013 Swissgrid and the EPEX SPOT European electricity exchange signed an agreement to couple the Swiss and European electricity markets, and by 2014 the technical requirements of the coupling were already met by Swissgrid. However, the introduction of actual market coupling will only take place when Switzerland and the European Commission reach a political agreement (Swissgrid, 2016b).

2.5. Recent evolution of the market

The country is currently experiencing a transformation affecting the market regulation and the investments in new generation capacity.

2.5.1. Market liberalisation

Switzerland is still going through a liberalisation period. This liberalisation follows the directives issued by the EU which establishes the non-discriminatory access of all companies to the grid. The Electricity Supply Act (LApEl) of 2007 (last update in June 2015) (The Swiss Federal Council, 2015) aims to improve security of electricity supply in Switzerland by increasing competition and transparency in the electricity market and establishes the basis for the liberalisation of the market. It stipulates that the high-voltage grid should be operated by a neutral body. As a consequence, the national grid company, Swissgrid, was created. Also, the previously monopolised local markets were unbundled in 2009. In the first phase, large companies with an annual consumption of more than 100 MWh have been able to choose their supplier. While the electricity market was scheduled to be fully liberalized in 2014, this keeps being postponed. When this happens, households and other small-scale consumers will be able to freely choose their electricity supplier. The new deadline for complete liberalisation is 2019, but it is still uncertain if and when this will occur because the current low electricity prices affect the profitability of certain companies. Full liberalisation would increase the risks for retail companies, whose hedging opportunities through long-term contracts would be limited without a captive customers base (Leuthard, 2016).

2.5.2. Encouragement of renewable energies

The Energy Act (LEne) of 1998 (last update in May 2014) (The Swiss Federal Council, 2014) addresses who is responsible for the different aspects of energy supply: adequacy, diversity, security, and economic and environmental sustainability. According to the Act, "a secure energy supply implies an adequate and diversified offer of energy as well as a technically secure and effective distribution system" (al 1, art 5). In order to increase diversification in electricity generation, the LApEl subsidises green electricity. It also provides funding for energy efficiency measures. Funding is available for electricity generated by renewable sources like water, sun, wind, biogas, biomass and geothermal energy.

The electricity generation from renewable sources is being promoted by the compensatory feed-in tariff at cost (RPC by the acronym in french), a feed-in tariff, since 2009. The RPC is available for the following technologies: hydropower (capacity up to 10 MW), photovoltaic, wind energy, geothermal energy, biomass and biological waste. The remuneration tariffs for green power are specified in the Energy Order (OEne) of 1998 (last update in August 2016) (The Swiss Federal Council, 2016) on the basis of reference power plants for each technology and output category. Depending on the technology, remuneration lasts for 20 to 25 years. In view of the anticipated technological progress and the increasing degree of market maturity of new technologies, the remuneration rates are subject to a gradual downward curve in the case of PV.

The RPC is funded by a surcharge paid by all electricity consumers, which has increased from 4.5 CHF/MWh during the 2009-2013 period to 13 CHF/MWh in 2016 (The Federal Council, 2016). Wholesale prices affect the fund supporting the RPC, as this fund covers the difference between the producers' costs and the market price. As there is a certain budget resulting from the surcharge paid by users, low market prices reduce the funds available to support new projects with feed-in tariffs (RPC, 2012). Due to budget constraints, the Federal Council already announced a new rise of the surcharge to support the RPC: this will be 15 CHF/MWh in 2017 and might increase to 23 CHF/MWh once the long-term energy policy (*Strategy 2050*) is approved (not before 2018) (The Federal Council, 2016). The surcharge to finance the RPC and the new water conservation measures is set by the Federal Council via the LEne. Since 2012, a new surcharge of 1 CHF/MWh is being levied to finance water conservation measures (revision of the Swiss Federal Water Conservation Act of December 2009). The LEne also establishes the partial exoneration of RPC surcharge for large consumers.

Due to the lower expansion potential of wind energy in the country and the higher opposition from local communities to this technology (explained in detail in Section 2.6.3), the encouragement policy has been more successful for PV than for wind energy: while wind energy capacity has only increased from 42 MW to 60 MW between 2010 and 2014, PV capacity has increased from 111 MW to 1,061 MW in the same period. This implies a respective annual average increase of 9% and 76% (SFOE, 2016a).

2.6. The challenges facing the Swiss electricity market

The generation-mix will change not only in the short-term due to the large investments in NDRES, but also in the medium-term if the nuclear phase-out occurs. The potential adequacy problems resulting from these changes require investments in new generation capacity. However, these investments are seriously limited by the low hydropower expansion potential and the NINMY phenomenon affecting different technologies.

2.6.1. The nuclear phase-out

There are currently five nuclear plants installed in Switzerland, which accounted for a total capacity of 3,333 MW at the end of 2015. All of them were installed between 1969 and 1984. Since their first days, the utilisation of nuclear power has been controversial, and six popular initiatives have been called against this technology (see Table 1). Only the one voted in 1990, establishing a moratorium on new nuclear plants construction, was approved. Results, nonetheless, have been always tight, despite the Government recommended rejection.

Table 1. List of popular initiatives against nuclear power in Switzerland (Federal Administration, 2016).

Initiative	Called	Voted	Result
Programmed phase-out of nuclear power at the latest 7 year after approval	2013	*	--
Programmed phase-out of nuclear power (a maximum lifespan of 45 years: Mühleberg, and Beznau I and II, 2017; Gösgen, 2024; Leibstadt, 2029)	2011	2016**	Rejected
Programmed phase-out of nuclear power (Beznau I and II, and Mühleberg, at the latest 10 years after approval; the remaining plants at the latest 30 years)	1998	2003	Rejected
Extension of the moratorium on the construction and allowances of nuclear plants (10 years extension)	1998	2003	Rejected
10 year moratorium on new nuclear plants construction	1986	1990	Approved
Interruption of the nuclear power programme	1980	*	--

*Initiative failing to collect the minimum number of signatures

**Vote on 27 November 2016 (ATS, 2016).

After the Fukushima accident (Japan) in March 2011, the Federal Council expressed the intention to decommission Switzerland's nuclear power plants at the end of their 50 year lifespan, and not build new ones. This initial plan thus indicated that the five nuclear plants would be decommissioned as follows: Beznau I: 2019; Beznau II and Mühleberg: 2022; Gösgen: 2029; Leibstadt 2034 (The Swiss Federal Council, 2011). Note that the call for a moratorium accepted in 1990 and the 2011 decision of the Federal Government establishing the progressive nuclear phase-out followed the two major nuclear accidents in history: Chernobyl in 1986 and Fukushima in 2011.

Decommissioning nuclear plants is a major problem for the Swiss market given the high share of this technology in the electricity mix. According to The Swiss Federal Council (2011), the capacity could be inadequate to meet national demand from 2019 onwards and it is not clear how this gap will be filled. Furthermore, since any significant investment in Switzerland must follow a long democratic process to gain people's approval, investments in capacity take a long time to materialize (Ochoa, 2007).

Following the rejection of the most recent referendum to accelerate the nuclear phase-out, it remains uncertain when the nuclear phase-out will occur. At the end of 2015, the Government decided to only decommission Mühleberg, whose operator is not able to fulfil the financial requirements for its safe operation and future waste disposal. The plant will stop operating on 20 December 2019 (Wuthrich, 2016a, p. 20). The Government also decided that Beznau I and II will be allowed to operate at most 60 years, while Gösgen and Leibstadt can ask for successive 10 years extension after a 60 year lifespan, as long as the security measures are fulfilled (ATS/LT, 2015).

2.6.2. Problems for hydro-power

As mentioned before, Switzerland has a long tradition of building hydropower plants due to its favourable topography. There are currently 15,282 MW installed of generation capacity (including those plants undergoing a conversion or refurbishment process), of which 10,581 MW are hydro-storage plants and the remaining 4,701 MW run-of-river. Additionally, installed pumping capacity is 1,817 MW. There are currently 35 projects under construction that will increase generation by 1,985 MW by 2020, of which 1,900 correspond to two major hydro-storage projects: Nant de Drance (900 MW of both generation and pumping capacity) and Limmern (1,000 MW of both generation and pumping capacity). The remaining capacity under construction consists of run-of-river projects. Reservoir capacity of all hydro-storage plants is 8,815 GWh, which is equivalent to about 15% of annual demand.

These projects aim to contribute to making Switzerland the battery of Europe and to facilitate the integration of renewable energies, not only in Switzerland but also in other European countries. These projects will more than double the pumping capacity by 2018. This was expected to support the aforementioned objectives and allow these plants to improve their arbitrage opportunities. However, the current situation is very different to that when investment decisions were taken. Prices have decreased across Europe, and Switzerland is no exception. This situation has worried not only the investors of these projects but all the hydro-storage plants stakeholders.

In 2014, when the debate about the *Strategy 2050* started, the first warning signs concerning the future of hydropower became visible (Wuthrich, 2016b). The hydropower plants' value has decreased by half due to the price drop caused by, among others, the higher share of renewables in Germany (which are subsidised and have increased the cheap electricity imports) and the lower fossil-fuel prices. A new debate has thus arisen. Should the government subsidise large hydropower? A first measure taken by the Government consists of a contribution of up to 40% of capital costs for new projects, which would be funded by users through a 1 CHF/MWh surcharge in the transmission fees (Wuthrich, 2016b).

Prices across Europe have kept decreasing and plants are becoming increasingly unprofitable. Their main problem is covering fixed costs –debt and interests- (Le Temps, 2014a). The average cost of production in Switzerland is about 65 CHF/MWh, of which a third corresponds to fixed costs and taxes (Boder, 2016a). The Council of States thus decided to include in the *Strategy 2050* a mechanism to support existing large hydro plants who face financial difficulties. This support would consist of a market premium of 10 CHF/MWh and a reduction of royalties that plants pay to regions (Wuthrich, 2016b). The market premium would be charged to customers through the RPC, which is currently 15 CHF/MWh and will increase to 23 CHF/MWh once the *Strategy 2050* is implemented (presumably in 2018). An amount of 2 CHF/MWh would be allocated to cover large hydro market premiums. It has been proposed to charge the difference in royalties directly to consumers; this implies a cost for hydro-sorage of approximately 15 CHF/MWh generated (Le Temps, 2016). The cases of plants with financial problems would be studied independently and support would be allocated for a maximum period of 5 years (Le Temps, 2014a).

As the law only establishes the maximum amount that cantons can charge hydropower through royalties, some cantons have recently decreased the fixed royalties that large hydro-storage plants have to pay, e.g., Bern, from 110 to 100 CHF/kW (Le Temps, 2016). However, other cantons such as Valais and Grisons, the main producing regions, have refused to do so. Changing the structure of these royalties implies modifying the law, which can only be done after 2019. In the absence of measures to help hydropower, the consequences of such a difficult situation are already visible. Recently Alpiq[1], one of the largest companies in Switzerland, announced it would have to sell half of its investments in large hydropower (Boder, 2016b). The implications of the current situation of hydropower go beyond their economic viability. According to the National Council, their lack of profitability threatens the nuclear phase-out and the renewable energies promotion programme (Le Temps, 2014b).

2.6.3. NIMBY

The system's capacity expansion is limited not only by economic and technical feasibility problems but also by social opposition to certain types of energy. Besides the well-known case of nuclear energy, hydro-power and wind energy might not develop their entire potential

[1] Alpiq owns 18 large hydropower plants with a total capacity of 2,700 MW and an annual production of 5 TWh (Boder, 2016a), i.e., about 20% of national hydropower capacity, which allows covering almost 10% of national consumption.

if social pressure keeps narrowing the number of sites available for developing projects using these technologies. Among the reasons expressed by people, protecting the environment is mentioned the most.

According to SFOE (2012), a study concerning the development of hydro-power potential in Switzerland, the additional potential is less than the 4 TWh/year by 2050 mentioned in several documents of the SFOE. Based on SFOE (2012), 90% of water flows in Switzerland are already exploited. However, the ecological obstacles are strongly related to value judgements. When it comes to large hydro-power plants, people tend to attribute a high weight to issues linked to environmental protection. Also, some projects located in protected areas are rejected immediately, while small hydro-power plants are usually rejected regardless of their qualification of “national interest” because of their low contribution to the total production. In addition, the low popularity of hydropower has led to a weak political support.

Wind energy is currently hotly debated in Switzerland. Opponents criticise the construction of wind farms, arguing the impact of wind turbines on the landscape. Although the debate seems to be more emotional than rational, some of the projects have been stopped (Guillaume, 2011). For instance, in 2014 no new wind turbines were installed (Le Temps, 2014c). The hostility that often emerges towards wind energy in Switzerland appears to be due to NIMBY-type phenomena rather than to a general hostility towards this type of energy, contrary to the case of nuclear energy.

NIMBY is also one of the reasons for the slow approval process of grid projects, mentioned in Section 2.3. For instance, the upgrade of the line Chamoson – Chippis, needed to connect the hydro-storage plant Nant de Drance when it starts operations in 2018, has been the subject of an appeal, which carried a suspensive effect (Swissgrid, 2016c). Due to the existing congestion, about one-third of the hydropower that could be produced in Valais cannot be transferred without upgrading this line (Swissgrid, 2016d).

2.7. The future of the Swiss electricity market

As described before, the Swiss electricity market is facing strong transformations, notably the nuclear phase-out and the encouragement of renewable energies. Simultaneously, its neighbouring markets, with which Switzerland is increasingly interconnected, are facing similar changes that will affect the country. The changing generation mix and the evolution of European markets are thus expected to affect the dynamics of the Swiss electricity market and might threaten the security of electricity supply. The paper *"From the nuclear phase-out to renewable energies"* (*Paper_SwissMarket* - Osorio and van Ackere (2016), see Appendix B.1), co-authored with Prof. Ann van Ackere, analyses the impact of the nuclear phase-out and the encouragement of renewable energies (mainly PV and wind) on three main components of SoES: generation adequacy, affordability and import dependency. In this paper we also evaluate investment decisions under different scenarios of imports availability and CO_2 costs. For this purpose we build a system dynamics (SD) model, which was calibrated for the Swiss electricity market. The remaining of section 2.7 is a condensed version of the *Paper_SwissMarket*.

2.7.1. Methodology

Because of electricity systems' complexity, behavioural approaches like system dynamics are more suitable than optimisation approaches to address these problems. Modelling causality and delays is important to account for policy effects on electricity systems and helps investigating whether intended policies trigger instabilities that may affect system performance (Arango, 2007). A survey of SD models of energy systems can be found in Teufel et al. (2013).

Model description

We develop a system dynamics model and calibrate it for the Swiss electricity market. Investments are made in each technology according to their expected profitability. Capacity construction is thus encouraged by high profits, which increases the future supply. A higher expected supply increases the expected reserve margin. As electricity prices reflect the scarcity of supply, a higher reserve margin leads to lower prices and, in turn, to lower expected profits. As NDRES' marginal costs are very close to zero, a larger share of these technologies leads to lower prices and a lower residual demand. This implies lower revenues for the other technologies, discouraging new investments, except for NDRES, which are typically subsidised by feed-in tariffs (FiTs). As FiTs are expected to cover all the plant's costs and are allocated regardless of the market price, prices do not affect the expected profits of NDRES, so investments in NDRES are not subject to market dynamics. There is thus a distortion in the investment dynamics. The detailed model documentation is presented in Appendix A.

Data and hypotheses

Since NDRES are supported in Switzerland by FiTs and this is expected to continue in the medium term, we assume that investments in these technologies are exogenous until 2035. The capacity installed corresponds to the investments needed to achieve the renewables target by that year. Unlike investments in other technologies, which are assumed to be endogenous, we assume exogenous investments in NDRES because they are subsidised by FiT. This implies that investments are done as long as the budget is adequate to cover the FiTs during the length of the support (up to 25 years for PV). This budget is funded by a fee paid by consumers set by law. Therefore, the availability of support for NDRES, and thus, investments in NDRES are a political decision. This makes it difficult modelling investments in NDRES endogenously. This and the existence of an official target for renewables generation are the ground for our hypothesis to model investments in technologies supported by FiTs exogenously.

We are aware that this is a strong assumption, in particular in view of the results (explained in detail later), according to which investments in NDRES are not profitable and thus, there is no replacement of obsolete capacity. Consequently, NDRES capacity decreases after 2035. Likewise, capacity mechanisms are not considered as they are not currently implemented (the swiss market operates as an energy-only market) and there currently is not even a debate about implementing them. These hypotheses are clearly theoretical and aim to show the consequences of doing nothing. These hypotheses reflect the current policies and the lack of proactivity that decision-makers have shown so far, e.g., there is no solution yet to help the hydropower plants who are facing losses. Investments in other technologies are assumed to be endogenous, i.e., investments take place only if they are profitable.

Our parameters estimates are based on a variety of sources. Those regarding costs, i.e., operational, fuel, investments and fixed costs, and CO_2 prices are taken from Poyry (2012), which focuses on Switzerland. This report also provides forecast for the entire simulation horizon. CO_2 prices are assumed to increase over time (from 21 to 60 €/tCO_2) due to stringent regulation on greenhouse emissions. Gas prices, on the contrary are assumed to remain constant during the entire simulation at 30 CHF/MWh. Although Poyry (2012) also assumes rising prices due to growing imbalances between supply and demand, prices have shown a decreasing trend after 2010. Given the high uncertainty of fossil-fuel markets, we decided to assume a constant gas price (30 CHF/MWh). Likewise, variable costs for all technologies except HS remain constant during the entire simulation, i.e., the marginal costs depend on exogenous parameters. In the case of HS, the price at which it bids (the reservation price) is a function of substitutes' prices and the expected reservoir level, following the approach of van

Ackere and Ochoa (2010) and Ochoa and van Ackere (2015). The HS bid price is capped at the scarcity price, which is set at 500 CHF/MWh.

Finally, another important hypothesis concerns the neighbouring countries' prices. We assume hourly prices for each season for each country. These are calculated using 2012-2013 data. These prices remain constant during the entire simulation. This assumption is due to the lack of data concerning future prices. For instance, Knopf et al. (2014) compare long-term forecast of average prices in Germany from different studies; there is no common pattern and forecasted prices in 2015 vary between 42 and 70 €/MWh, and those of 2050 between 50 and 90 €/MWh. This highlights the high uncertainty concerning future electricity prices. Electricity markets depend on multiple variables, e.g., generation-mix, fossil fuel prices and penetration of renewables. As they constantly evolve, it is difficult to estimate reliable price forecast. It can be argued that assuming constant prices for neighbouring countries might not be realistic. However, the lack of available information does not allow us to estimate the long-term variation of these parameters.

Finally, while NDRES capital costs are assumed to decrease in the long-term, those of other technologies are kept constant. Still, the assumed decrease in NDRES is lower than the one that has occurred in the recent years. For instance, PV capital costs were expected to decrease from 2,490 in 2012 to 1,440 $/kW in 2035 in IEA (2014a); in the most recent report from IEA (IEA, 2016), costs are expected to decrease from 1,320 in 2015 to 780 $/kW in 2040. This highlights the uncertainty concerning NDRES costs and fast technology evolution.

It is important to keep in mind that the objective of the *Paper_SwissMarket* is not to forecast future prices; we aim to provide insights and understanding of how the Swiss market might evolve under different scenarios and hypotheses, with a particular attention to the current problems, i.e., renewables expansion and nuclear phase-out. More complex -and arbitraryassumptions concerning parameters would add noise to the model results and complexify the analysis, making it more difficult to identify the key insights. However, we are aware that the model results are highly dependent on the evolution of these parameters. Therefore, we have performed a detailed sensitivity analysis, a summary of which is presented in Section 2.7.2. A more detailed description of the data is presented in Appendix A.2.

Simulation setup

We run the simulation from 2014 to 2050. For each quarter (season) we simulate a representative day. For each representative day, hourly demand shapes for each season are estimated using historical data from 2009-2013. This allows us to capture the hourly and seasonal patterns of supply and demand. Seven technologies are considered: hydro-storage, run-of-river, nuclear power, PV, wind, CCGT and conventional thermal. Our model implements the government objectives of NDRES generation: 4.4 TWh by 2020 and 14.5 TWh by 2035 (The Swiss Federal Council, 2013). We thus assume a planned expansion over the simulation horizon of PV and wind energy, proportional to their expansion potential. We assume that FiTs last 20 years, as is currently the case. Investments after 2035 are determined by their profitability and are limited by their remaining potential. In our base case scenario (*BAU*) we assume what by summer 2015 seemed to be the most likely scenario: Muhleberg being decommissioned in 2019 and the others plants being decommissioned after 60 years of operation. We also assume that hydro projects currently under construction will come online at their scheduled start of operation.

Cross-border transmission capacity remains fixed at 7,500 MW for imports. We consider two types of imports: long-term imports based on existing contracts and balancing imports. Long-term imports availability is assumed to decrease progressively according to AES (2012). Balancing imports are traded in the spot market and their availability equals the difference between the imports transmission capacity and the available long-term import contracts. Hence, the expiration of long term import contracts increases the transmission capacity availability for short-term imports. We run our simulation in Vensim® DSS 6.1.

2.7.2. Simulation results and discussion

We focus our analysis on the impact of the nuclear phase-out and the increasing penetration of NDRES on SoES. The three core elements of SoES we focus on are capacity adequacy, imports dependency and affordability. Our results show that the only investments committed to are the exogenous investments, i.e., those assumed for PV and wind energy until 2035, and the hydropower projects currently under construction. There are no further investments in these technologies after 2035, when FiTs for new projects are no longer available. In the absence of new investments, capacity of both PV and wind energy decreases from 2035 onwards as a consequence of obsolescence. The changing capacity-mix affects the generation-mix: nuclear production is replaced mainly by PV and imports. The country becomes a net importer, this dependency being exacerbated in winter, when net imports reach on average 51% of national consumption in the 2041-2050 period. Although high import dependency might highlight the strength of regional institutions and imports availability provide backup, dependency is risky. Imports might be cut by neighbours for political reasons or due to extreme weather conditions. Despite the larger share of PV, prices increase. This is due to the changing generation-mix: nuclear energy is replaced by less expensive technologies such as PV and wind, but also by more expensive sources such as balancing imports. This, together with the subsidies needed to support NDRES, lead to a rise in tariffs.

Increasing net imports and prices respectively increase dependency and decrease affordability. This evolution points to a problem of capacity adequacy. The de-rated capacity margin, which allows measuring the system's capacity to meet annual peak demand, is one of the most used measures for capacity adequacy (CAISO, 2014; OFGEM, 2013; Royal Academy of Engineering, 2013). However, this measure could be misleading in some cases. For instance, countries with a significant share of hydro-storage generation might overestimate their capacity adequacy. As an alternative metric, we propose the annual energy margin, which we define as the ratio between excess energy (see detail explanation in p.14 of *Paper_SwissMarket*) and annual domestic demand. The energy margin captures the seasonal patterns of intermittent sources and the actual availability of hydro-storage generation, incorporating the idea that this technology could serve as a battery. Unlike the de-rated margin, the energy margin captures the medium-term capacity adequacy improvements resulting from the addition of PV, but it shows a much less reassuring long-term picture for three demand scenarios. In *BAU*, the annual energy margin even turns negative after 2038. This means that even with optimal reservoir management, the total amount of electricity available is insufficient to cover annual demand. This does not necessarily imply blackouts, but the country must rely on imports to satisfy local demand.

This metric can be used by policy makers in the same way as that the de-rated margin. This helps monitoring the current capacity adequacy and allows estimating the future capacity needs. This margin indeed provides information about the capacity requirement for achieving a certain level of self-sufficiency. Moreover, this could help estimate the impact of a certain level of storage capacity on capacity adequacy and support the decision of whether to expand generation or storage capacity. The time horizon for using this metric depends on the objective of the analysis. For monitoring purposes, data should cover the maximum length possible, since this historic data could help identifying the presence of cycles (more than 20 years of annual information, given the long lead times in this sector). For a prospective analysis, the time horizon should exceed the maximum lead time for planning and construction.

We are aware that our results are highly dependent on our hypotheses and parameter values. Besides other validity tests, e.g., extreme values and equations consistence, we perform a sensitivity analysis of the following parameters: import demand, exports availability and prices in neighbouring countries; CO_2 prices, gas prices, investment capital costs and demand. This analysis shows that CCGT only becomes profitable under certain combinations of Italian prices and CO_2 prices, which can be also achieved if gas prices decrease significantly, so that the marginal cost of CCGT decreases. Investments in CCGT are also done if the availability of imports from France and Germany decreases by more than 30% as blackouts could occur otherwise. Other technologies are not profitable under any of the variations considered.

Prices are sensitive to price variations in Germany, the main exporter to Switzerland, and exports are sensitive to price decreases in Italy, the main export destination of Switzerland. Average prices decrease up to 8% when a decreasing demand is considered (according to SFOE (2013) scenarios, it might decrease by 24% by 2050 compared with *BAU*). We also evaluated the impact of a potential cross-border transmission expansion (higher import availability). If this capacity increases by 33% in 2020 (according to ENTSO-E (2014) estimations), prices in Switzerland decrease by 11%. This is caused by a change in supply patters: higher imports availability leads to higher off-peak imports, which allows HS to save water for peak hours, displacing more expensive sources.

2.8. Price dynamics across European electricity markets

As mentioned in Section 2.6.2, prices across European markets have decreased significantly since 2008. The large investments in NDRES, triggered by the EU environmental commitments (goal 20-20: 20% renewables by 2020), have played a paramount role as they are highly subsidised (typically by feed-in tariffs), which allow them to bid in the day-ahead market at a price close to zero (their marginal costs). The impact of an increasing share of renewables on electricity prices has been discussed in the literature in recent years. For instance, Würzburg et al. (2013) provides a survey of the estimated impact of NDRES on prices in different countries.

To analyse the recent price dynamics across European markets, we focus on three countries: Germany, France Italy. We chose Germany, the country with the highest amount of NDRES capacity installed in Europe. These technologies have had a negative impact on prices in recent years, as has been widely studied. Since prices are influenced by other variables such as imports, demand, weather patterns, fuel costs, etc., we chose another country with a large development of NDRES, but with different characteristics: Italy. Although Italy is directly interconnected with France, through which German price dynamics can spread, the volumes traded between both countries are significantly lower than those between France and Germany (ENTSO-E, 2016). Italy imports mainly from Switzerland, which also has large-scale exchange with France and Germany. However, Switzerland performs an arbitrage role between on the one hand France and Germany, and on the other hand Italy. Hence, price dynamics in France or Germany are less likely to affect price dynamics in Italy, i.e., internal factors like the generation-mix has a higher impact on prices. The German and Italian generation-mixes and interconnection levels are very different and, while their NDRES' shares are significant, they were installed at different times. Finally, France is considered as a control case to analyse to what extent the NDRES price-lowering effect spreads to a neighbouring country with lower NDRES share.

Germany has been the most successful case and constitutes the reference point concerning NDRES encouragement for other countries. This policy has gained even more importance since 2011, when the country re-accelerated the nuclear phase-out after the Fukushima accident (Steinbacher and Pahle, 2015). The implementation of strong incentives for non-hydro renewables, e.g., feed-in tariffs of up to 500 €/MWh for PV in 2004 (BMWi, 2014), has resulted into a large and quick deployment of PV (from 2 GW to 39 GW between 2005 and 2015) and wind capacity (from 18 GW to 45 GW between 2005 and 2015), with annual average increases of respectively 34% and 9% (BMWi, 2016). The installed wind energy capacity exceeds that of any other generation source in Germany. In 2015 solar and wind accounted for 21% of consumption in Germany and the total share of renewable energy reached 30% (BMWi, 2016).

Among other reasons, the large development of NDRES has led to a significant drop in prices: from 50.9 CHF/MWh in 2006 to 31.7 in CHF/MWh in 2015 (BMWi, 2016). Germany has even been increasingly experiencing negative prices (from 12 hours in 2010 to 126 hours in 2015 (EPEX SPOT, 2016)). The large drop in prices, together with a shift in the relative prices of gas and coal, and combined with plummeting emissions cost, have significantly affected gas plant profitability. Even recently built plants have been closed down (Bloomberg, 2013), or kept open as reserve power to stabilise the grid (Reuters, 2013).

Because of the increasing integration of European markets, the NDRES price-lowering effect has spread to other countries, regardless of their generation-mix. An example is France, a country coupled with Germany. While France is also encouraging NDRES, its market share for these technologies is still very low compared to Germany. NDRES production increased from 10.2 TWh in 2010 to 28.5 TWh in 2015 (8% of total consumption and 7% of total production). Nuclear power, with almost half of the installed capacity, remains dominant, allowing the country to be a net exporter (they accounted 64 TWh, i.e., 12% of total production in 2015). Nuclear power accounted 76% of total production and 88% of national consumption in 2015. In the same year, the remaining production was generated by hydropower (11%) and conventional thermal plants (coal, oil and gas, 7%) (ENTSO-E, 2016). Average prices have decreased from 47.5 €/MWh in 2010 to 38.5 €/MWh in 2015, with a minimum of 34.6 €/MWh in 2014 (EPEX SPOT, 2016).

Italy is also strongly encouraging renewable energies through feed-in tariffs. This has resulted in increased NDRES production: from 10.9 TWh (3.3% of total consumption in 2010) to 38.6 TWh (12.3% of total consumption in 2015). This, and a demand struggling to recover (having fallen from 330 TWh in 2010 to 309 TWh in 2014, and recovering to 314 TWh in 2015 (ENTSO-E, 2016)) have led to a significant drop of CCGT production (from 142 TWh in 2010 to 91 TWh in 2015). Still, this technology is the largest producer in the country. The changes in the generation-mix, the still low demand and the lower gas prices have decreased electricity prices in the recent years. In 2015 the price was 52 €/MWh, 0.4% higher than that of 2014, but 18% lower than in 2010 (GME, 2016).

As shown in Figure 6, prices in Germany, France and Italy increased sharply in 2008, which might be explained by the commodities boom in that year. Afterwards, the price shows a decreasing trend in the three countries. In the case of Germany, this is coherent with results presented in Paraschiv et al. (2014), who estimate time-varying effect of different generation technologies on wholesale prices, the one of solar gaining in importance over the recent years. French and German prices have exhibited a high degree of correlation; the price patterns have only started to diverge in 2011. Overall, the volatility resulting from the increasing wind power share has led to a noticeable decoupling between Germany and its neighbouring markets since 2011 (de Menezes and Houllier, 2015). However, the correlation between both countries' prices is still very strong (de Menezes et al., 2016). Historically, Italian prices exceeded those of France and Germany, but they have dropped significantly in the last five years and are starting to converge to those of Germany and France. Italy thus exhibits price drops similar to those of Germany and France, despite its very different generation-mix. These elements, together with the coupling with France and Austria launched in February 2015, create the conditions for further convergence and an improvement of Italian competitiveness compared to other European countries.

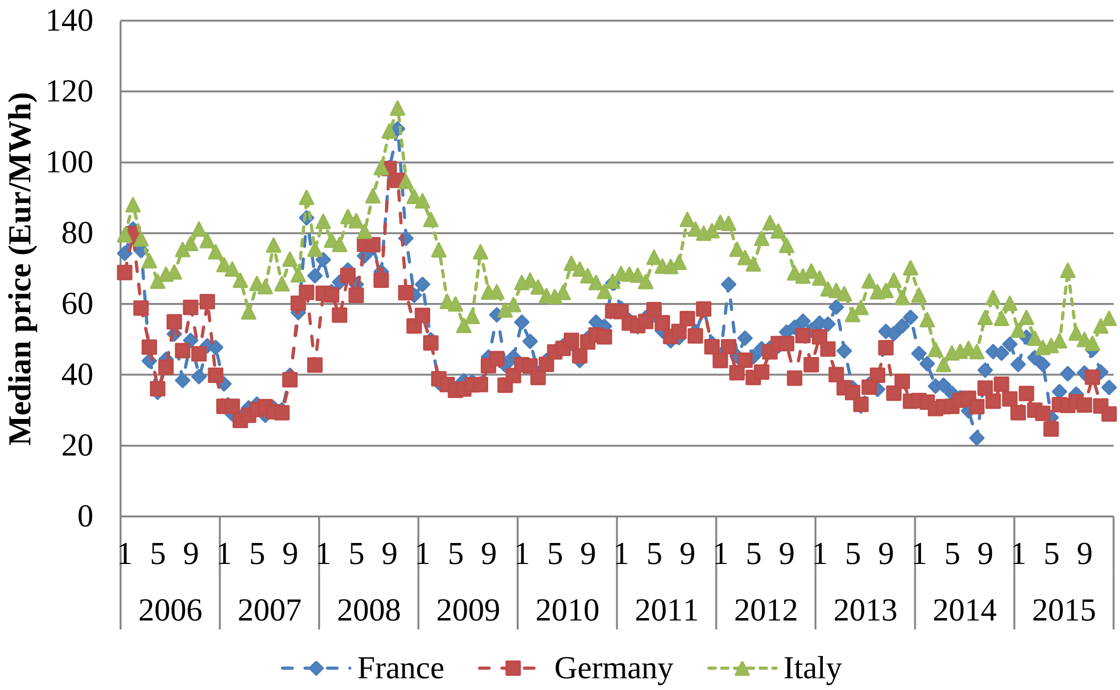

Figure 6. Comparison of German, French and Italian monthly prices, 2006-2015. Data from EPEX SPOT (2016).

In addition to the change in median prices, the three countries have also witnessed a change in their day-ahead price pattern, in particular lower variation within day-ahead prices. Figure 7 shows the evolution of the monthly median of the daily IQR[2] from 2006 to 2015 for the three countries. The following analysis is background work for a paper (work in progress) co-authored with Prof. Ann van Ackere, Prof. Erik Larsen and Prof. Valerie Chavez, focused on the changing patterns of prices in those countries. The curves of daily IQR monthly medians for Germany and France seem much more stable from 2009 onwards than before. This more stable pattern appears in Italy around 2011.

[2] The interquartile range (IQR) is used to estimate the variability within day-ahead hourly prices. This is the difference between the daily upper (Q3) and lower (Q1) quartiles, and take the median for each month.

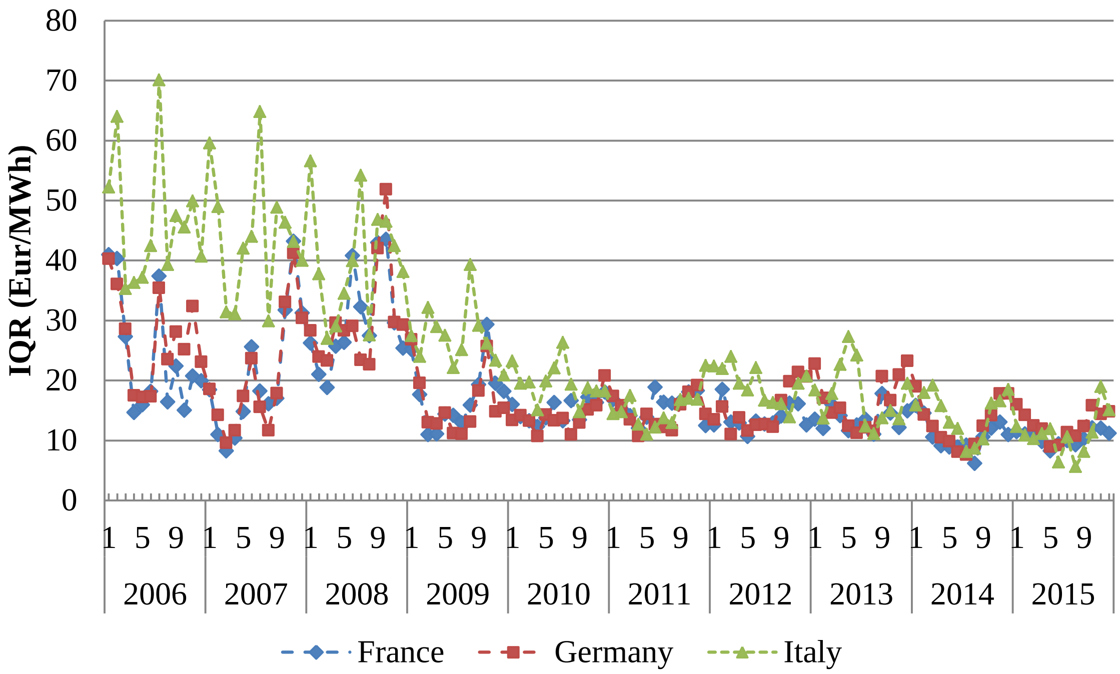

Figure 7. Median daily IQR per month in Germany, France and Italy. Data from EPEX SPOT (2016).

To confirm and understand the monthly and annual time-effects over years and months, we perform different ANOVAs on the monthly median of the daily IQR. All ANOVAs are summarised in Table 2. The median has been chosen as it is generally considered to be more representative of the central tendency than the mean. Although we do not perform an explicit analysis of the NDRES impact on IQR, the impact of the variable YEAR is partially explained by NDRES, as their share has been increasing constantly over the last 10 years. The variable MONTH accounts partially for the seasonal impact of NDRES on IQR.

Table 2. Anova for IQR.

Period	**Variable**	**Df**	**Sum Sq**	**Mean Sq**	**F value**	**Pr(>F)**	
All the countries							
2006-2015	Country	2	5,089	2,545	56.6	< 2e-16	***
	Year	9	21,809	2,423	53.9	< 2e-16	***
	Month	11	2,274	207	4.6	1.60E-06	***
	Residuals	337	15,154	45			

Period	Variable	Df	Sum Sq	Mean Sq	F value	Pr(>F)	
2006-2015	Country	2	5,089	2,545	82.5	< 2e-16	***
	YearFactor	9	21,809	2,423	78.6	< 2e-16	***
	MonthFactor	11	2,274	207	6.7	4.11E-10	***
	Country:YearFactor	18	5,313	295	9.6	< 2e-16	***
	Residuals	319	9,841	31			
Germany							
2006-2015	YearFactor	9	3,955	439	20.1	< 2e-16	***
	MonthFactor	11	1,431	130	6.0	2.20E-07	***
	Residuals	99	2,159	22			
2009-2013	Year	4	57	14	1.9	0.131	
	Month	11	492	45	5.9	8.70E-06	***
	Residuals	44	333	8			
2014-2015	Year	1	0	0	0.0	0.86588	
	Month	11	205	19	7.9	0.00093	***
	Residuals	11	26	2			
France							
2006-2015	YearFactor	9	4,079	453	15.2	2.79E-15	***
	MonthFactor	11	727	66	2.2	0.0189	*
	Residuals	99	2,946	30			
2010-2013	Year	3	37	12	3.1	0.0391	*
	Month	11	59	5	1.4	0.2347	
	Residuals	33	130	4			
2014-2015	Year	1	1	1	0.5	0.5124	
	Month	11	75	7	3.5	0.0238	*
	Residuals	11	21	2			
Italy							
2006-	YearFactor	9	19,088	2,121	52.6	<2e-16	***

Period	Variable	Df	Sum Sq	Mean Sq	F value	Pr(>F)	
2015	MonthFactor	11	861	78	1.9	0.0427	*
	Residuals	99	3,990	40			
2012-2013	Year	1	20	20	1.7	0.219	
	Month	11	263	24	2.0	0.134	
	Residuals	11	132	12			
2014-2015	Year	1	65	65	11.1	0.00665	**
	Month	11	243	22	3.8	0.01829	*
	Residuals	11	64	6			
2006-2011	YearFactor	5	10670	2134	46.04	< 2e-16	***
	MonthFactor	11	1601	145.5	3.14	0.00238	**
	Residuals	55	2549	46.3			
2006-2009	YearFactor	4	975.7	243.9	13.552	2.80E-07	***
	MonthFactor	11	96.7	8.8	0.489	0.9	
	Residuals	44	792	18			
2011-2015	YearFactor	4	472.1	118.02	10.521	4.55E-06	***
	MonthFactor	11	315.7	28.7	2.558	0.0134	*
	Residuals	44	493.6	11.22			

Note: Signif. codes: 0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1

The ANOVA analyses confirm that variables COUNTRY, YEAR and MONTH have an effect on IQR. However, there are interactions between YEAR and COUNTRY, which indicates that the IQR changes over time and is country specific. We thus perform the analysis for each country. In the case of Germany, the IQR has decreased significantly over the 2006 - 2009 period, and remained stable afterwards: "YEAR" is significant over the full period (p-value < 2e-16), but not in 2009-2013 (p-value > 0.13). As can be seen from the variable "MONTH" in the 2006-2015 and 2009-2013 panels (p-values < 8.7e-6), the seasonal variations in IQR remain highly significant throughout the whole period. A further analysis (not shown) indicates that “YEAR” becomes significant when considering the period 2009-2015, which indicates that the IQR continues to decrease after 2014. Between 2014 and 2015, the IQR remained stable since “YEAR” is not significant (p-value > 0.86).

Qualitative results for French IQR are very similar to those of Germany. IQR also decreases, but, unlike Germany, “YEAR” is still significant in the period 2009-2013 (results not shown). However, IQR stabilises during the period 2010-2013 (p-value <0.04). The later drop of IQR in France might be due to still low NDRES capacity in Germany at that time, which together with the congestion between the two countries limited the spread of the NDRES price-lowering effect. Afterwards, like in Germany, IQR stabilises during the period 2014-2015 (p-value > 0.51).

Turning to the Italian data, the results of the ANOVA for the IQR again show a significant decrease in differences within day-ahead prices (p-value < 2e-16 for “YEAR” over 2006-2011). In this case, IQR stabilises in 2012 (p-value > 0.21 over the period 2012-2013), later than in Germany and France, due to the more recent large deployment of NDRES facilities in the Italian market. However, unlike the German and French case, “YEAR” is still significant over the period 2014-2015 (p-value < 0.006), indicating IQR has continued to decrease over this period. This highlights the larger margin of Italian prices to decrease and converge to those of Germany and France, as NDRES capacity continues to grow and market prices are less affected by other factors such as gas prices. The seasonal pattern is much less pronounced in the Italian case, but gaining in importance over time: the p-value of “MONTH” is > 0.04 when considering the full period and < 0.014 when considering the 2011-2015 period. This is due to the more stable output of PV in Italy across seasons because of its geographical location.

Results of the ANOVA analysis show that within-day price differences have decreased significantly over time and are season-dependant in Germany, France and Italy. In particular, the cases of Germany and Italy highlight the NDRES price-lowering effect on within-day price differences despite their different generation-mix and level of interconnection. The case of France highlights the impact of interconnection as this country has low NDRES penetration, but is interconnected with Germany, a country that have a high NDRES share. Overall, these changes in price patterns in Germany, France and Italy highlight the impact of NDRES larger penetration on prices.

As shown, NDRES' downward pressure on within-day price differences spread from one country to another. These dynamics might affect the Swiss electricity market. Evidence shows that peak plants, e.g., gas plants in Germany and hydropower plants in Switzerland, are already suffering severe profit drops. Belgium and the UK have also expressed major concerns about the decommissioning of thermal power plants (La Libre, 2014; OFGEM, 2014). Furthermore, lower within-day prices differences might affect profitability of Swiss pumped-storage power plants (PSP), which play a merchant role in energy arbitrage. Although Switzerland is also encouraging NDRES and interconnection with these countries is increasingly important, it is uncertain what the situation will be in the long-term, given the particularities of the Swiss electricity market and the expected changes in its generation-mix.

In the next section we analyse the impact of the changing generation-mix in Switzerland on arbitrage opportunities of the Swiss PSP. We focus on these plants because major investments have been made in this technology aiming at turning Switzerland into the battery of Europe. However, recent decisions about the nuclear phase-out and the encouragement of NDRES might threaten PSP profitability in the long-term.

2.9. The future of PSP

Over the past decade Switzerland has invested significantly in pumped storage plants (PSP), but the situation is very different from that when the investment decisions were taken. Historically, the significant difference between the low night prices and the noon or evening peak prices created arbitrage opportunities for PSP. These plants aim to exploit arbitrage opportunities by pumping water from a lower reservoir to an upper reservoir to store electricity in the form of hydraulic potential energy when prices are low and generating when prices are high. This arbitrage becomes increasingly less attractive as variability within day-ahead hourly prices decreases. The situation is further complicated by the current bi-modal distribution of the timing of peak prices, particularly in summer: on certain days the price peaks at night, i.e. when electricity traditionally has been the cheapest. Pumped-storage power plants need accurate short term (24 hours) price-forecasts to be able to bid in the day-ahead market. The increasing uncertainty about when it will be profitable to pump and to produce could seriously affect their profitability. There is high uncertainty about the price dynamics in Switzerland given the expected changes in the generation-mix in the long-term. In the paper *"Arbitrage Opportunities for Pumped Storage Power Plants in Switzerland"* (*Paper_PSP*, see Appendix B.2), co-authored with Prof. Ann van Ackere, we study the future of PSP arbitrage opportunities in Switzerland in the long-term and identify under what conditions these could be enhanced.

2.9.1. Methodology

The model used here is an extension of the one used in *Paper_SwissMarket* and described in section 2.7.1. We carried out three main changes for the *Paper_PSP*: (*i*) we improved the reservoir modelling in order to better capture the seasonal storage and conventional hydro-storage strategy (see Appendix A.3.4 for the detailed formulation), (*ii*) we include Italy as a potential importer since the current situation (imports from Italy are negligible) might change in the long-term depending on the investments in Switzerland, and (*iii*) we endogenise PSP decisions regarding volumes and timing of pumping and generation (see Appendix A.3.5 for the detailed formulation and its integration in the Swiss market model). The latter is essential to capture how the changes in the energy-mix of the Swiss electricity market affect the operation of PSP. For this purpose we develop an algorithm in which we assume a daily cycle for PSP and we consider only PSP's participation as a merchant unit in the wholesale market. We assume PSP have perfect information about other technologies' bid prices and bid-offers. PSP thus assess a "pre-dispatch", which allows them to calculate the volumes of allocated and unallocated supply of each technology. With this information, PSP can assess the optimal daily operation, i.e., the volume of energy to pump that equals the potential sales, while ensuring that the bid price covers the purchase price plus the efficiency losses. Recall that the simulation runs from 2014 to 2050 with a quarterly time step. All the assumptions concerning investment decisions, market clearing and nuclear-phase out are the same of those mentioned in section 2.7.1.

In the model, for each representative day we consider there is perfect foresight of demand and supply, i.e., we do not deal with load balance through the intra-day market, nor with ancillary services. To consider the intra-day market, a different approach is needed. In particular, the model should be extended to explicitly include stochastic demand and supply variables, e.g., forecasted PV output and real output. Therefore, in our model PSP only plays an arbitrage role. This is a limitation of our work, which prevents us from estimating the profitability of PSP. However, our results provide insights about the future profitability as the scale of any balancing operation is expected to be small. As shown in the *Paper_SwissMarket*, investments in NDRES will concentrate mainly in PV. Although PV output is subject to variations, these are significantly lower than those of wind energy. Because of limited potential and the NIMBY phenomenon, wind energy is expected to have a lower development than PV in Switzerland. The potential to provide ancillary services to foreign markets is limited. Germany is the only neighbouring country with a significant share of wind energy, but most of its facilities are in the north and there is significant congestion between north and south. This prevents a potentially active participation of Swiss PSP in the German market. The increase of the value of the intra-day market and ancillary services in Switzerland is expected to be limited and is unlikely to compensate for the lack of arbitrage opportunities.

2.9.2. Simulation results and discussion

Changes in the availability of energy sources resulting mainly from nuclear plant decommissioning, expiration of long-term contracts and PV deployment affect the difference between peak and off-peak prices and the amount of cheap energy available for pumping, which in the end affect pumping patterns. While initially the increase of photovoltaic capacity and the larger PSP capacity encourages pumping, the nuclear phase-out and the expiration of long-term import contracts significantly decrease the available cheap energy. These changes also lead to higher purchase and sales prices for PSP, which mostly result into higher differences between peak and off-peak prices in the long-term. However, PSP are unable to exploit these because of the low availability of cheap energy to pump.

To show this we calculate the average price at which PSP buys energy and that at which they sell it. Using the resulting hourly prices, i.e., the set of 24 prices for each season (time step), we identify that the former is always below the 20th percentile and the latter is above the 80th percentile. We thus use the 10th percentile of hourly prices (P10) as a reference for the price of "cheap energy" and the 90th percentile of hourly prices (P90) as reference for the revenues of PSP. This is an ex-post calculation, i.e., this does not affect the model results. We use the difference between P90 and P10 to show the potential profits from arbitrage. We also identify the generating volumes whose marginal costs are below P10. This allows us to show how unallocated cheap supply decreases over time. Therefore, although the potential profits increase or remain stable in the in all seasons, the drop of cheap available supply leads to lower pumping in the long-term.

This situation severely limits arbitrage opportunities in the long-term. Although pumping increases in the medium-term (2025-2035), profitability of PSP is threatened even in this period because pumping does not increase in the same proportion as pumping capacity. The changing generation-mix in Switzerland thus threatens these arbitrage opportunities in the long-term.

The impact of different scenarios on PSP operation is evaluated. When pumping is encouraged either through direct subsidies (market premiums) or via the encouragement of NDRES (in order to increase cheap energy availability), PSP achieve better results in terms of average pumping and profits. However, the decreasing trend of pumping in the long-term remains. If alternative nuclear phase-out schedules are implemented, i.e., permission to certain plants to operate until at least 2050, pumping is higher than in *BAU*[3] as more excess supply is available. This leads not only to more income, but also to higher operational margins. However, the situation in the 2040-2050 period remains critical as even the availability of close to the current nuclear capacity cannot prevent the drop in pumping.

A question thus arises: is there a plausible evolution in which PSP arbitrage could be profitable? We evaluate three scenarios: (*i*) higher prices and lower exports availability in Germany in the evening, (*ii*) encouragement of NDRES after 2035 and no nuclear phase-out and (*iii*) same conditions as in scenario (ii), while also assuming lower local consumption. In

[3] Recall that in our base case scenario (*BAU*, identical to BAU of the *Paper_SwissMarket*), we assume that Muhleberg is decommissioned in 2019 and the others plants are decommissioned after 60 years of operation. We also assume that hydro projects currently under construction will come online at their scheduled start of operation and that NDRES are subsidised so as to achieve the 2020 and 2035 renewable targets.

scenario (i) pumping is significantly higher than in *BAU* in the medium-term, but shows a decreasing trend in the long-term, remaining similar to *BAU*. In the last two scenarios pumping increases in the long-term, this rise being more significant when consumption is lower. Large scale arbitrage thus requires the availability of cheap excess energy. This can be achieved either by demand management or by supporting base load technologies.

2.10. Insights and limitations

The simulation results presented in both the *Paper_SwissMarket* and *Paper_PSP* show that the future of the Swiss electricity market is compromised. Can we say that supply is threatened? Yes, at least in the long-term. However, evidence shown so far does not allow stating that the elements in our model are the only ones affecting the security of electricity supply. Particularly right now, when climate change commitments, active demand participation and interconnection issues are playing such a major role in energy policy, we cannot have such a narrow view. In the next chapter we thus address the broader concept of security of electricity supply. What else do we need to consider when analysing it? Based on a literature review, we develop a framework that allows us to assess the security of any electricity market. In this framework we identify the dimensions that cover all the aspects of SoES in the long-term. We propose a metric for each of them, so as to provide a quantitative tool for decisions makers to follow the evolution of these different dimensions over time, identify potential problems and decide if and when to intervene.

3. SECURITY OF ELECTRICITY SUPPLY

The concept of security of energy supply has been widely analysed in the literature as equivalent to energy security, which aims to cover the different types of energy sources, e.g., oil and gas. Energy security received major attention in the 1970s when the oil crisis occurred. This led to energy security to be seen as part of a country's foreign policy. The interaction among nations gained in importance (Yergin, 2006) and in the oil market, dependency on imports became a symptom of insecurity. While fossil fuels have received major attention, security of supply in the electricity sector has been only considered as a part of overall energy security, without elaborating on its particular aspects. The structure of this chapter is as follows: first the definition of energy security is presented, followed by a discussion on the energy security dimensions and their metrics based on the literature reviewed. Finally, a summary of the *Paper_SoES* (see Appendix B.3), which provides a framework to evaluate security of supply in the electricity sector, is presented.

3.1. Definition of energy security

Different bodies and authors define energy security (or security of supply) differently. According to International Energy Agency (IEA, 2014b), energy security refers to the uninterrupted availability of energy sources at an affordable price. In addition to low affordability, non-competitive or overly volatile prices are also considered elements of energy insecurity (Jansen and Seebregts, 2010). The Asia Pacific Energy Research Centre (APERC, 2007) defines energy security as the "ability of an economy to guarantee the availability of energy supply in a sustainable and timely manner with the energy price being at a level that will not adversely affect the economic performance of the economy" (p. 6). Sovacool et al. (2011), define energy security as "how to equitably provide available, affordable, reliable, efficient, environmentally benign, proactively governed and socially acceptable energy services to end-users" (p. 5846). These definitions highlight the difficulty of defining energy security. This concept does not relate to a single property but rather to multiple dimensions (Chester, 2010).

3.2. Energy security assessment

There are many studies aimed at evaluating either energy security or security of supply of a certain resource. They not only focus on different energy resources, but they approach the problem differently. While some analyse energy systems' risk, others analyse the properties needed to ensure the energy supply. Another difference is the time-frame of the studies. This is highlighted by Gracceva and Zeniewski (2014), who structure their framework according to the time-frame of various energy-related threats, e.g., variability of energy demand (short-term) and resource depletion (long-term).

APERC (2007) provides a significant contribution to the frameworks. Their analysis is based on the four A's: availability, affordability, accessibility and acceptability. However, given the vast range of aspects covered by these properties, their measurement is complex. As a result, the quantitative assessment made in this work is not explicitly linked to these properties. Addressing this problem, Ren and Sovacool (2014) propose different metrics to cover the aspects covered by these properties, e.g., price stability and market liquidity as part of 'Affordability'. As an alternative to the 4 A's approach, most authors focus directly on the different aspects (dimensions) of energy security. Using a dimensions approach allows a more precise description of the energy-related aspects, which makes possible their quantitative assessment. The properties and the dimensions approaches remain, nonetheless, complementary as the 4 A's allow identifying the potential conflicts among different dimensions (Kruyt et al., 2009).

Table 3 presents the main characteristics of a selection of papers assessing security of supply in energy systems. This is not an exhaustive list. An initial search was performed using the keywords “energy security”, “security of energy supply” and “security of electricity supply”, and this selection was broadened by including references in these papers. Among these papers, we selected those that elaborate (implicitly or explicitly) on the security of supply dimensions rather than just provide a definition or a discussion about the concept in itself. We also aimed to include a wide range of approaches: in terms of methodology by including those explicitly providing a quantitative framework as well as those just discussing the aspects of energy security without even providing a qualitative assessment; in terms of energy sources by including all the primary energy sources and potential energy uses, as well as those aggregating all energy sources; in terms of location by including papers focusing on the world as well as on a single country; in terms of time-frame, by including short- as well as long-term analyses; and in terms of quantitative assessment by including studies with more than 300 indicators as well as those intending to aggregate different metrics into a single one. This list is thus a representative selection of the work addressing energy security.

Table 3 specifies the type of energy resource studied and the region considered. It also shows if indicators are proposed and if an aggregated indicator is calculated, and whether the authors compare different regions using these indicators. The studies by APERC (2007) and Scheepers et al. (2007) are presented in two lines because they use two very different approaches. The dimensions found in the literature review are presented as follows. In Section 3.2.1 we classify these according to the main stakeholders/segments concerned, and discuss how different authors define these dimensions and the metrics they propose. In section 3.2.2 we conclude on the main challenges to measuring these dimensions.

Table 3. Characteristics of reviewed studies on energy security.

Publication	Energy source	Region	Indicators	Cross-country comparison
APERC (2007) – 5 indicators	Primary energy sources	Asia Pacific countries	Yes	Yes
APERC (2007) – oil case	Oil	Asia Pacific countries	Yes (aggregated)	Yes
IEA (2007)	Coal, gas and oil	Czech Republic, France, Italy, the Netherlands, and UK	Yes (aggregated)	Yes
Scheepers et al. (2007) – S/D index	Primary energy sources and end uses of them	EU25 and Netherlands, Poland, Spain and UK	Yes (aggregated)	Yes
Scheepers et al. (2007) – CC index	Primary energy sources and end uses of them	ND	Yes	No
Gupta (2008)	Oil	26 net oil-importing countries	Yes (aggregated)	Yes
Kruyt et al. (2009)	Primary energy sources	World	Yes	No
Chester (2010)	Energy as a whole	ND	No	No
Jansen and Seebregts (2010)	Primary energy sources and end uses of them	EU 27 countries	Yes	Yes
Lefèvre (2010)	Coal, gas and oil	France and UK	Yes	Yes
Lévêque et al. (2010)	Natural gas, hydrogen and nuclear	Europe	No	No

Publication	Energy source	Region	Indicators	Cross-country comparison
Löschel et al. (2010)	Primary energy sources	USA, Germany, Netherlands and Spain	Yes (aggregated)	Yes
Vivoda (2010)	Primary energy sources and electricity	Asia Pacific countries	Yes	Yes
Cohen et al. (2011)	Oil and gas	26 developed countries	Yes	Yes
IEA (2011)	Primary energy sources	OECD countries	Yes	Yes
Sovacool et al. (2011)	Primary energy sources and electricity	Asia Pacific countries	Yes (aggregated)	Yes
Sovacool and Mukherjee (2011)	Primary energy sources and electricity	ND	Yes	No
von Hippel et al. (2011a)	Primary energy sources	Japan	Yes	No
von Hippel et al. (2011b)	Primary energy sources	Northeast Asia	Yes	No
Cherp et al. (2012)	Primary energy sources	World	Yes	No
Zhang et al. (2013)	Oil	China	Yes	No
Gouveia et al. (2014)	Electricity	Portugal	Yes	No
Gracceva and Zeniewski (2014)	Primary energy sources	ND	No	No
(IEA, 2014c)	Oil and gas	OECD countries	Yes	Yes

Publication	**Energy source**	**Region**	**Indicators**	**Cross-country comparison**
Portugal-Pereira and Esteban (2014)	Electricity	Japan	Yes	No
Ren and Sovacool (2014)	Primary energy sources	China	Yes	No
Yao and Chang (2014)	Primary energy sources	China	Yes (aggreagated)	No
Jonsson et al. (2015)	Oil, gas and electricity	EU	No	No

3.2.1. Dimensions

While some authors elaborate on security of supply in terms of dimensions, other do it in terms of properties or risks. Regardless of the approach used, when they intend to assess SoS quantitatively, they focus on energy security dimensions. We define a dimension as an aspect related to the vulnerabilities of an energy system, understanding that the main objectives of SoS are to avoid disruptions (physical aspect) and to ensure affordable prices (economic aspect).

The papers of Table 3 use 18 dimensions to address security of supply. For each paper of Table 3, Table 4 indicates which dimensions are included. In this section we intend to give insights about how the dimensions have been defined and measured in the selected literature, regardless of the type of resources. Therefore, metrics mentioned are not applied specifically to the electricity sector but to different primary energy sources and end-uses of energy. We also group these dimensions to show which stakeholders either are influenced or have a higher direct influence on issues concerning each of them. This helps mapping to whom a policy should be addressed when intending to improve any dimension. The dimensions and their respective groups are: availability, capacity adequacy, resilience, reliability, vulnerability of imports, imports dependency (Production/Transport/Retail), price stability, affordability, environmental sustainability, social factors, demand management, access (Customers), terrorism, governance/institutions/policy, economic issues, research and development (R+D), quality of information, and equity (Government/Regulator/Decision makers).

Table 4. Dimensions considered in studies on energy security.

Publication	Availability	Capacity adequacy	Resilience	Reliability/ Infrastructure	Vulnerability of imports	Imports dependency	Price stability	Affordability	Environment	Social factors	Governance/ Institutions/ Policy	Demand management	Access	Terrorism	Economic issues	I+D	Quality of information	Equity
APERC (2007) – 5 indicators	X	X	X		X	X	X	X	X		X			X	X			
APERC (2007) – oil case	X	X	X		X			X	X			X						
IEA (2007)	X	X	X		X			X										
Scheepers et al. (2007) – S/D index	X	X	X	X		X						X						
Scheepers et al. (2007) – CC index	X	X	X	X	X				X			X						
Gupta (2008)	X		X		X			X										
Kruyt et al. (2009)	X		X		X	X		X	X		X	X						
Chester (2010)	X	X						X	X									
Jansen and Seebregts (2010)	X	X	X	X	X	X	X	X	X		X	X						
Lefèvre (2010)	X		X		X			X										
Lévêque et al. (2010)	X	X	X		X	X		X	X		X	X						
Löschel et al. (2010)	X				X			X										
Vivoda (2010)	X	X	X	X	X	X		X	X	X	X	X	X	X		X	X	
Cohen et al. (2011)					X	X												
IEA (2011)			X	X	X	X						X						
Sovacool et al. (2011)	X		X	X		X	X	X	X		X	X	X					

Publication	**Availability**	**Capacity adequacy**	**Resilience**	**Reliability/ Infrastructure**	**Vulnerability of imports**	**Imports dependency**	**Price stability**	**Affordability**	**Environment**	**Social factors**	**Governance/ Institutions/ Policy**	**Demand management**	**Access**	**Terrorism**	**Economic issues**	**I+D**	**Quality of information**	**Equity**
Sovacool and Mukherjee (2011)	X	X	X	X	X	X	X	X	X	X	X	X	X		X	X	X	
von Hippel et al. (2011a)	X		X	X		X		X	X	X				X		X		
von Hippel et al. (2011b)	X		X	X		X		X	X	X				X		X		
Cherp et al. (2012)	X	X	X	X	X	X	X	X	X		X	X	X	X	X			
Zhang et al. (2013)					X	X	X											
Gouveia et al. (2014)	X	X	X	X		X		X	X		X	X						
Gracceva and Zeniewski (2014)	X	X	X	X					X				X					
(IEA, 2014c)	X	X	X	X		X					X							
Portugal-Pereira and Esteban (2014)			X	X		X			X			X						
Ren and Sovacool (2014)	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Yao and Chang (2014)	X	X				X	X	X	X			X				X		
Jonsson et al. (2015)	X		X	X	X	X	X	X	X						X			

3.2.1.1.Production/Transport/Retail

The following dimensions affect mainly the companies in charge of generating, transporting (transmission and distribution) and commercialising electricity. These cover mainly the technical and operational aspects of electricity supply, i.e., those ensuring the physical availability of electricity supply.

Availability

This dimension refers mainly to the existence of resources, which is particularly important in fossil fuel markets. Several metrics are proposed, but some of them offer ambiguous interpretations. For instance, Sovacool et al. (2011) use supply per capita as a metric. While a drop of this metric is interpreted as negative for energy security in the Sovacool et al. (2011)'s framework, this could capture energy efficiency improvements that increase security of supply. The ratio between reserves and consumption (Gupta, 2008; Jansen et al., 2004; Yao and Chang, 2014) seems more appropriate for this dimension as it links the geological existence of resources with their consumption. Other metrics, such as share of pipeline imports in demand (IEA, 2007; Lefèvre, 2010) and the share of renewable energy in demand (Ren and Sovacool, 2014) do not capture the available energy.

Capacity adequacy

This dimension relates to the availability of capacity to exploit the existing resources. Metrics involving the installed production capacity are the most used, although frameworks such as those proposed in (IEA, 2014c) and Scheepers et al. (2007) include the different supply chain segments, differentiating production, storage and transportation. However, the term "adequacy" directly links supply and demand. Metrics should thus capture the proportion between consumption and production capacity. This is why those frameworks, in which capacity adequacy is measured only by investments in the energy sector or by capacity, do not account for the ability of installed capacity to cover demand needs under current conditions. Alternative metrics such as access and demand growth are tightly related to capacity adequacy but do not address the "adequacy" issue. They are rather complementary metrics. Low access in the electricity sector might warn about future capacity adequacy problems if more customers are connected without investing in new generation and transmission capacity. The demand growth rate can help explain the evolution of the capacity adequacy margins or warn about the trend in demand.

Resilience

Resilience is defined as the ability of a system to withstand disruptions (Cherp et al., 2012). As the diversification of resources reduces the sensitivity to disturbances in the supply (Grubb et al., 2006; Jonsson et al., 2015; Kruyt et al., 2009), there is a high consensus among authors regarding diversification as the metric for this dimension. Indexes such as the Shannon-Weiner index[4] are used to measure the diversification of resources, suppliers, fuels, technologies or import routes. Although the use of this index is more common than that of the Herfindhal–Hirschman index (HHI), qualitative results of both indices are identical. While the former assesses diversity, the latter assesses concentration. One exception is Ren and Sovacool (2014), who propose imports dependency as a metric.

Higher resilience can also be achieved with flexibility of fuel usage (APERC, 2007; IEA, 2014c; Jonsson et al., 2015; Scheepers et al., 2007), but measuring this aspect or including it into a diversification index is complex. We could not find any quantitative measure addressing fuel flexibility. Finally, very specific metrics can be used depending on the resource. For instance, in the coal sector, resilience is measured by the share of mining underground (IEA, 2011).

[4] $\sum_i p_i ln(p_i)$, where p_i is the share of the resource.

Reliability

This dimension is intended to capture the frequency or risk of a physical disruption. While in the oil market, physical unavailability of supply is limited to extreme cases, this is a major concern in electricity markets, and to a lesser extent in gas markets (IEA, 2014c). Consequently, measuring reliability typically refers to electricity systems rather than other energy sources. Still, several attempts have been made in order to capture the reliability of energy systems. For instance, Jonsson et al. (2015) propose the occurrence of accidents in the energy sector. Although accidents inevitably have financial consequences for stakeholders, they do not always lead to supply cuts. The reliance on proven technologies or overall technological maturity is also claimed to be a metric for reliability (Ren and Sovacool, 2014; von Hippel et al., 2011b, 2011a), but its qualitative nature renders it very subjective and difficult to apply. Likewise, Vivoda (2010) propose technological risks as a metric, but they do not clearly explain this concept. Another metric is infrastructure ageing (Cherp et al., 2012; IEA, 2011); however it does not directly account for supply disruptions.

In the electricity sector there are well-established metrics for reliability: they measure directly the time and frequency of electricity disruptions, e.g., the SAIDI index (Gouveia et al., 2014; IEA, 2011). Alternative metrics such as the system stress, defined as the period when demand exceeds 85% of total capacity and used as metric for this dimension (Portugal-Pereira and Esteban, 2014), could be more suitable when assessing capacity adequacy.

Import dependency

Dependency plays an important role in the literature concerning energy security. In some papers focusing on security of oil supply this dimension, together with the geopolitical risks of trade, are considered the only aspects affecting security of supply, e.g., Gupta (2008). When other energy sources are included in the analysis, import dependency is still a relevant issue, but less central. Import dependency is not a problem per se as countries' vulnerability depends on the diversity, the market liquidity and governance mechanisms. However, import dependency may cause insecurity when markets fail as this creates exposure to trade and production decisions of international actors (Jonsson et al., 2015).

While import dependency is problematic, authors such as Costantini et al. (2007) argue that this is part of a broader picture and can be compensated by an exchange surplus in other products. Particularly, interdependence between industrialised countries and energy exporters has deepened, financial markets and energy markets are closely linked, and technology has created interdependencies between electricity and oil refining, as well as natural gas processing (Chester, 2010). Interconnectedness of energy markets favours SoS. The larger the geographic area of energy markets, the more they are able to absorb disruptions because more resources are available to damp price spikes. In addition to this insurance or resilience effect that improves short-term security of supply, wider markets also provide more diversity of primary fuel types and geographic sources, and therefore ensure better long-term SoS (Leveque 2010). In that sense, interconnectedness has been included as one dimension of SoS assessments. However, there is little agreement about how to measure it. While the use of congestion as a metric (Gouveia et al., 2014; Scheepers et al., 2007) can lead to a misleading interpretation as it does not capture the size of the interconnection, other metrics such as energy exports (Sovacool et al., 2011) or import capacity (Sovacool and Mukherjee, 2011) do not really express to what degree interconnections between countries are detrimental to SoS.

Imports vulnerability

Overall, there is a general acknowledgement that import dependency is a risk factor for energy systems. However, it can be argued that the severity of such a risk is case specific and its assessment is extremely complex. In order to evaluate to what extent import dependency is dangerous, vulnerability of imports has been expressed in terms of diversification of either fuels or exporting countries (Cohen et al., 2011; Gupta, 2008; Jansen and Seebregts, 2010; Lefèvre, 2010; Scheepers et al., 2007). Additionally, some authors incorporate the geopolitical risk as a factor that increases imports vulnerability. Various country-level indices are used to weight imports vulnerability, e.g., socio-political stability in UNDP's human development indicator (Jansen et al., 2004), and the OECD political stability rating (IEA, 2007, 2014c). Still, these indices do not accurately capture the willingness to trade of these countries (Kruyt et al., 2009).

3.2.1.2. Customers

The following dimensions affect mainly the customers. They cover the economic and social aspects of the relationship between customers and electricity markets.

Price stability

Price stability is important as uncertainty affects investment decisions (Jonsson et al., 2015). These authors use the price volatility of different fuels as a metric.

Affordability

Measuring affordability is less straightforward and approaches are multiple. Some authors directly address the issue of high costs in energy markets by considering fuel prices as a metric (Kruyt et al., 2009; Löschel et al., 2010; Sovacool et al., 2011). Others propose proxis such as market concentration (IEA, 2007; Lefèvre, 2010) and consumption per capita (Yao and Chang, 2014). Other metrics depend on very detailed information that is not always available, e.g., energy systems' internal costs (von Hippel et al., 2011a). However, these metrics do not capture the expensiveness of resources. A suitable metric should thus relate costs and income, e.g., by calculating the ratio between fuel costs and GDP (Vivoda, 2010) or fuel expenses as a share of household revenues (Sovacool and Mukherjee, 2011).

Environmental sustainability

The environmental dimension has received major attention. Environmental acceptability is used as a synonym for environmental sustainability in some studies (Chester, 2010). Environmental commitments are acknowledged to have a significant impact on security of supply because of the enormous transformations and investments required to reduce the environmental effects of energy systems. For instance, despite considering environmental regulation and constraints as boundaries to energy security in the short-term, Scheepers et al. (2007) are aware of the need to minimise the environmental impact of energy use. Security of electricity supply is central for energy policy at both national and EU levels (Directive 2005/89/EC) and increasing the environmental sustainability of EU energy systems dominates current energy policy (Chalvatzis and Hooper, 2009).

However, discussion persists on whether environmental sustainability should be considered as one of the dimensions. Chalvatzis and Hooper (2009) focus on policies related to two separate objectives: climate change mitigation and improving electricity supply security. Likewise, by focusing on the impacts of the low-carbon transition on security of supply, Gracceva and Zeniewski (2014) implicitly split environmental sustainability and energy security. One might think that environmental sustainability only affects energy security through an economic impact and even that a dichotomy exists, i.e., environmental protection prevents increasing security of supply. However, environmental consequences of energy production and consumption affect energy systems, e.g., climate change has an effect on water patterns and availability (Cherp et al., 2012).

Given all the potential environment impacts, issues related to this dimension are multiple. Consequently, diverse metrics have been proposed. Examples include fossil-fuel production, nuclear waste, water pollution, water availability, land use, deforestation, emissions, terrestrial acidification, and reliance on fossil fuels. Others, like Vivoda (2010) and von Hippel et al. (2011b) propose the exposure to environmental-related risks as a metric, but are not clear about how to measure it, and in some cases a qualitative assessment is made. The wide range of environmental impacts highlights the complexity of measuring the exposure to such risks (climate change, sea level rise, extreme weather, etc). Most metrics thus relate either to the causes (e.g., greenhouse emissions) or to the consequences (e.g., water availability) of climate change.

Socio-cultural factors

Like environmental sustainability, there are multiple aspects related to socio-cultural factors that might affect or be affected by energy systems. However, socio-cultural factors are more subjective and difficult to measure. For instance, von Hippel et al. (2011b) propose the exposure to social or cultural energy-related risks (e.g., NIMBYism and energy sector labour unrest), but their calculation remains unclear. Alternatively, Yao and Chang (2014) propose a qualitative measure of the social satisfaction with energy systems, but this remains vague. This illustrates that there is little consensus about how to measure this dimension.

Demand management

Demand management is playing an increasingly important role in energy security as high demand growth rates might reduce energy security (Vivoda, 2010), while demand reduction could relieve stress on the system. Demand management measures have different time horizons. In the short-term, the implementation of demand response, e.g., rationing procedures and interruptible contracts, is considered as a measure for mitigating sudden supply shortages (Scheepers et al., 2007). In the long-term, energy demand reduction is often the result of efficiency measures encouraged by policy incentives. The most commonly used metric is energy intensity (ratio between energy consumption and GDP). Given the strong correlation between countries' energy consumption and GDP, this metric helps identifying if the demand reduction results from a weak economic performance. Although the term 'efficiency' is usually related to efficiency in consumption, Sovacool et al. (2011) and Portugal-Pereira and Esteban (2014) also measure the efficiency of the electricity sector using grid losses as a metric.

Access

This dimension is used to put into perspective the results of other measures rather than as an independent dimension, i.e., a high level of SoS is only relevant if the access rate is high. For instance, Sovacool and Mukherjee (2011) define affordability as "equitably enabling access to energy services at the lowest cost with stable prices" (p. 5346). However, access is not measured directly given the difficulty to define who has access to energy sources. Conversely, given the rigidity of the electricity network, access is easily measurable in the electricity sector using the connection rate to the grid (Sovacool et al., 2011; Vivoda, 2010). As a low access rate might imply a potential problem of capacity adequacy if electrification is intended to be expanded, access rate is used as a capacity adequacy metric in Cherp et al. (2012).

3.2.1.3. Government/Regulator/Decision makers

The following dimensions affect mainly the Government and its institutions in their aim to ensure energy supply in a country and the potential impacts on the country's economy. These cover regulatory, social and economic aspects.

Governance, institutions and policy performance

The broadness of this dimension makes its measurement highly complex. For instance, while APERC (2007) highlight the importance of having an efficient regulatory framework, but do not measure such a efficiency, other authors propose qualitative metrics to assess the ability of national institutions to properly govern and regulate the energy sector (Ren and Sovacool, 2014; Sovacool et al., 2011; Sovacool and Mukherjee, 2011; Vivoda, 2010). The only quantitative measures found in the literature are those concerning competition and market power (Cherp et al., 2012; Gouveia et al., 2014; Kruyt et al., 2009), and the reliance of energy systems on market mechanisms (Sovacool et al., 2011; Sovacool and Mukherjee, 2011; Vivoda, 2010).

Terrorism

A very specific dimension included in some of the studies is terrorism, given the impact that attacks, e.g., on oil transportation fleets (APERC, 2007), could have on energy security. However, such events do not always lead to supply disruptions. As a result, measuring this dimension is not straightforward. Some alternatives are found in literature. For instance, Vivoda (2010) proposes the general energy-related military/security risks as a metric, but its calculation remains unclear. Other authors, like Ren and Sovacool (2014), state that military power should be measured by a qualitative assessment, but do not explain how to do so.

Other dimensions

There are further aspects that play a role in energy security assessments. These additional dimensions are mentioned in Table 4. One is economic issues, which consider some elements like the occurrence of the resource curse, which can lead to the Dutch disease (Jonsson et al., 2015; Sovacool and Mukherjee, 2011; Vivoda, 2010). These hamper the development of strong institutions and could eventually affect the governance and the energy market performance. The studies considering these issues are aware that despite the strong relationship with energy systems development, their occurrence does not always endanger energy security. Consequently, no metric is proposed to assess these issues. Likewise, the impact on energy security of other economic issues such as workforce constraints (APERC, 2007), appears to be weak.

R+D can be measured by, e.g., state-owned patents (Yao and Chang, 2014). Quality of information can be measured by a qualitative metric for information transparency proposed in Sovacool and Mukherjee (2011). Finally, for measuring equity, Ren and Sovacool (2014) propose the share of households depending on traditional solid fuels such as wood. However, these last three dimensions seem to have a weak link with energy security.

3.2.2. The challenge of measuring dimensions

As discussed in the previous section, for some dimensions the proposed metric is straightforward, e.g., the ratio between imports and demand for imports dependency. For other dimensions, the proposed metrics differ even across papers focusing on the same energy sources, e.g., availability can be measured in terms of supply per capita (Sovacool et al., 2011) or as oil and gas reserves

(Vivoda, 2010). A question thus arises: which metrics are meaningful for each dimension? The lack of agreement among authors shows the difficulty of formulating metrics that address unambiguously the state of each dimension.

The discussion of the different metrics of Table 4 highlights several difficulties. First, a given metric can be used for different dimensions by different authors with different interpretations. For instance, while decentralisation of electricity generation sources favours affordability for Sovacool and Mukherjee (2011), it poses control risks that affect reliability for Gracceva and Zeniewski (2014). Secondly, some measures are hard to compute because of the complexity of calculations and unavailability of information (e.g., exposure to environmental risks (Vivoda, 2010)), due to an incomplete description (e.g., technological maturity for measuring reliability (Ren and Sovacool, 2014)) or because of their qualitative nature (e.g., international relations when measuring the vulnerability of imports (Ren and Sovacool, 2014)). This is usually the case of metrics proposed for socio-cultural factors due to the elusive nature of this dimension, e.g., one might argue whether some proxis can be used to address aspects such as the occurrence of the NIMBY phenomenon.

Besides determining the best measure for each dimension, some authors attempt to build an aggregated measure of security of supply (Gupta, 2008; IEA, 2007; Scheepers et al., 2007; Sovacool et al., 2011; Yao and Chang, 2014). This implies scaling or weighting each metric, which inevitably induces subjectivity into the aggregate indicator. One of the most widely used indicators is the S/D Index (Scheepers et al., 2007), in which metrics from the entire energy supply chain are aggregated using weighting factors and scoring rules. Scheepers et al. (2007) are aware of the subjective nature of the weights and scoring rules, and make them explicit. However, very different scenarios can yield very similar values of the index due to the high level of aggregation (Kruyt et al., 2009). They criticise the indicators proposed in IEA (2007) for the same reason. Whatever the approach, a cross-country comparison should be done in absolute terms since comparisons based on relative improvements, as done in Sovacool et al. (2011), can lead to misleading interpretations. Still, Kruyt et al. (2009) acknowledge that while aggregate indicators should not be used to rank best practices in energy policy, as they ignore the particularities of each energy system, they are useful for comparison over time.

Considering the energy security dimensions and their respective metrics presented in the last two sections, a framework aimed at evaluating security of electricity supply is formulated. This framework is presented in the paper "*A Framework to Evaluate Security of Supply in the Electricity Sector*" (*Paper_SoES*, see Appendix B.3), co-authored with professors Erik Larsen and Ann van Ackere, and summarised in the next section.

3.3. Security of supply in the electricity sector

EURELECTRIC defines security of electricity supply (SoES) as "the ability of the electrical power system to provide electricity to end-users with a specified level of continuity and quality in a sustainable manner, relating to the existing standards and contractual agreements at the points of delivery" (Eurelectric, 2004, p. 9). More precisely, according to this body, SoES is related in the short-term to the operational reliability of the system, while in the long-term it depends on the simultaneous adequacy of access to fuels, generation, networks and markets.

The share of electricity in world energy consumption grew from 9.4% in 1973 to 18% in 2013 (IEA, 2015), showing that electricity supply is critical to energy security. Liberalisation of the electricity sector in numerous countries brought attention to the study of the security of the electricity supply. This became a policy issue after major power failures (e.g., California in 2000 and 2001, Norway in 2002, France and Germany in 2003, South Africa in 2008 and 2009, or most recently, Japan in 2011 (Linares and Rey, 2013)), fuelling existing debates about the adequacy of investment in production and networks. These events highlight that in liberalised markets, investments are made based on profitability rather than on security concerns (Lieb-Dóczy et al., 2003).

In electricity markets, the concept of security of supply has been associated almost exclusively with capacity adequacy. Most work focuses on the improvement of SoES by providing signals for new investments, e.g., by implementing capacity mechanisms (Batlle and Rodilla, 2010; Schwenen, 2014). However, the emergence of NDRES (PV and wind power) integrated into markets on a large scale, triggered by environmental commitments, raises concerns about grid stability, and more recently about the economic sustainability of electricity systems. The increasingly active role of the demand-side and the population's impact on the execution of new projects pose additional challenges to the electricity sector. Decision-makers thus face the complex task of guaranteeing the continuity of supply, while ensuring its long-term availability and affordability. All these issues highlight the multidimensional nature of SoES, as is the case of other energy systems.

The oil, gas, coal and electricity markets exhibit significant differences in terms of, among others, rigidity of transport infrastructure, difficulty of storage, and the regional nature of markets (Chester, 2010). They thus require different approaches. In the *Paper_SoES* we aim to provide a framework for evaluating security of supply specifically for the electricity sector.

3.3.1. Framework characteristics

The main characteristics of our framework are: (*i*) it is focused on the electricity sector; (*ii*) it provides a metric for each dimension, without intending to aggregate them into a single measure; (*iii*) it allows decision makers to follow the evolution of dimensions over time; (*iv*) it focuses on a single jurisdiction, i.e., the region in which a regulator has authority; and (*v*) it is not intended to compare jurisdictions. Based on the literature summarised in Table 4, and other studies focusing specifically on electricity systems, we identify the relevant dimensions that allow us to assess security of supply in an electricity system. We summarise the twelve dimensions included in our framework, and their metrics, in Table 5.

3.3.2. Dimensions

Given the particularities of electricity systems, some of the dimensions mentioned in Table 4 are not considered, while additional ones need to be included. Generation adequacy, resilience, reliability, access and geopolitics (including imports dependency and imports vulnerability), and their specific metrics for electricity systems are considered in our framework. For generation adequacy we propose an additional metric to the de-rated margin, which is widely used in electricity systems planning (e.g., in UK (OFGEM, 2014) and in California (CAISO, 2014)). We propose the 'energy margin' (Osorio and van Ackere, 2016). This is more appropriate than the de-rated margin for systems with a high hydro-storage penetration because it captures the operational flexibility resulting from storage.

The rigidity of electricity transportation renders network capacity adequacy as important as generation adequacy. The metric should reflect the impact of grid utilisation, i.e., congestion costs. Its calculation depends on the congestion management mechanism (Alomoush, 2005).

Furthermore, unlike generation facilities, ageing seems to be more relevant for network reliability (Nepal and Jamasb, 2013; Xie and Li, 2009). The average age of the grid is used as a metric for grid ageing. The dimension 'Network condition' thus considers two aspects: adequacy and grid ageing.

The dimension 'Governance, institutions and policy performance' is included under the name of 'Regulatory efficiency'. Given its breadth and the particularities of the electricity sector, we focus on two aspects: need for subsidies and market performance. For the former, following Sovacool et al. (2011), we use the cost of subsidies for conventional generators as metric. For the latter we focus on market power as a symptom of weak market performance, using market concentration as a proxy.

Likewise, the impact of socio-cultural factors and terrorism is relevant in the electricity sector; therefore, we include them in our framework. However, the metrics for these dimensions found in literature are not appropriate to capture SoES issues. Given the elusive nature of these two dimensions, we use respectively the ratio of effective planning and construction time over minimum required time, and the 'business cost of terrorism' (index from the World Economic Forum Report) as proxys to measure them.

Other dimensions from Table 4 are merged into a single dimension. Sustainability thus comprises the economic and environmental aspects. The former additionally captures the economic sustainability from the demand- and the supply-side. Economic sustainability from the demand-side (affordability) is indeed one of the core aspects in energy security definitions and one of the dimensions included in most studies presented in the previous section. Following Sovacool and

Mukherjee (2011), we propose the share of electricity expenses in household's expenses as a metric.

As electricity systems should not only be affordable for consumers, but also profitable for generators, we include the economic sustainability from the supply-side. We focus on generators because the transmission and retail segments usually have regulated tariffs that ensure their economic viability. This is not the case of generators, which are increasingly facing very difficult conditions in electricity markets due to the larger penetration of subsidised NDRES (Newbery, 2016). Consequently, not only are prices decreasing, but so is the residual load, and in turn the load factor of peak generators. The resulting lack of profitability is endangering their operational feasibility, e.g., plants are being mothballed across Europe (Bloomberg, 2013; La Libre, 2014; Reuters, 2012). Although the reasons vary, peak plants are facing similar problems in other regions, e.g., Colombia (El Tiempo, 2015). The number of full operating hours of peak generators is thus used as a metric.

Environmental sustainability is the third aspect of this dimension. Given the complexity of measuring to what extent electricity-related environmental impacts affect the electricity sector, the CO_2 emissions are taken as a proxy. Including other types of emissions is also possible depending on the jurisdiction's characteristics.

Finally, a forth aspect is included: reliance on fossil fuels. Although dependency on fossil-fuels is included by Vivoda (2010) in the measurement of the environmental impact, the explicit inclusion in our framework is not redundant. This is indeed tightly related to the economic and the environmental aspects: fossil-fuels are expected to become more expensive not only because of the environmental commitments, but also because of their depletion. The finite nature of fossil fuels thus will require the eventual replacement of the fossil-based generation.

The comprehensiveness of the framework is strongly enhanced by the inclusion of important demand aspects, as recommended by Scheepers et al. (2007). Given the increasingly active role of demand in electricity markets, which is expected to gain even more relevance with the entry of smart grids, and the weight of demand reduction in current energy policies, we include the dimension ‘demand management’ in our framework. As the time-frame of actions aimed at reducing demand growth varies significantly, we focus on three measures. Demand conservation mainly refers to interruptible contracts (short-term action), and we include its measurement in the de-rated margin (the generation adequacy metric). Demand flexibility is measured by the share of peak demand that can be shifted. Demand efficiency, which aims to capture the effects of policies to reduce demand in the long-term, is measured by electricity intensity. This metric has been used by Gouveia et al. (2014) and is an adaptation of energy intensity, a commonly used metric to measure energy efficiency.

All the dimensions discussed so far have been at least partially developed in the literature. Given the particularities of electricity systems, we include a new dimension: supply flexibility. Unlike other energy markets, electricity demand should match supply at all time. Given the rigidity of the grid, local load unbalances can create a cascade effect, spreading a bownout. As the larger penetration of NDRES is rendering load-balancing more complex, flexible generators are needed to cope with the inherent variability of NDRES and the increasing load-following ramp requirements of photovoltaic. We thus use the ratio between the capacity of flexible technologies, e.g. CCGT and hydro-storage, and the maximum load supplied by NDRES over the last year.

Table 5. Summary of dimensions and metrics of the framework proposed in *Paper_SoES*. This table is presented in the working paper "Interdependencies in security of electricity supply", currently in progress.

Dimensions	**Metric**
1. Generation adequacy	De-rated capacity margin and energy margin
2. Resilience	Herfindahl - Hirschman Index (HHI) of concentration of generation technologies
3. Reliability	System Average Interruption Duration Index (SAIDI: ratio between annual customer-minutes without service and number of customers in the system)
4. Supply flexibility	Ratio between the capacity of flexible load (hydro and CCGT) and maximum load supplied by NDRES over the last year.
5. Condition of the grid	
- Capacity adequacy	Dispersion of zonal prices (market splitting) Congestion charge per MWh (redispatching)
- Ageing	Average age of the grid
6. Demand management	
- Conservation	Amount of interruptible contracts (to be subtracted from demand when computing de-rated margin)
- Efficiency	Electricity intensity of GDP
- Demand flexibility	Flexible demand relative to total demand
7. Regulatory efficiency	
- Market performance	HHI of generating companies
- Incentives for conventional generators	Subsidy to conventional generators per MWh
8. Sustainability	
- Demand side – Affordability	Electricity costs as share of median wage
- Supply side - Profitability	Load factor of conventional and peak generators

Dimensions	**Metric**
- Environmental	Carbon emissions per MWh
- Fossil fuel dependency	Ratio between fossil-based generation and renewables expansion potential
9. Geopolitics	
- Import dependency	Fraction of domestic consumption covered by electricity imports and electricity generated by imported fuels
- Vulnerability	HHI of geographical concentration of imports HHI of concentration of imports by type (electricity and fuel)
10. Socio-cultural factors	Ratio of effective planning and construction time over minimum required time.
11. Terrorism	Business cost of terrorism from the World Economic Forum Report
12. Access	Rate of access to the grid

This framework excludes some of the dimensions discusses in Table 4. Availability, referring mainly to the existence of fossil fuel reserves, is not considered because these resources are also used in sectors others than electricity and because the potential dangers of local resource unavailability are already partially addressed in ‘import dependency’ and fossil-fuel dependency. Other metrics such as R+D, economic issues and quality of information are not included as we could not find any evidence of a strong link with electricity supply insecurity. Additionally, in the specific case of economic issues, one of the main motivations of authors to include these is to capture the potential economic problems of energy systems. Our framework considers that in the dimension “economic sustainability – profitability”.

This framework helps monitoring the achievement of certain policy goals, e.g., reducing emissions by X% over the next 10 years. Sometimes there might be a misalignment between policies and capacity-mix, e.g., stringent CO2 limitations in a country with a large share of coal-based generation. Since changing the capacity mix takes a long time due to construction and planning delays, changes in the regulation and/or policy (e.g., forcing coal-plants to close down) could harm security of electricity supply. This is why implementing significant policy changes requires a transitory period to allow for adjustment of the capacity-mix. For instance, there is an emerging debate in Germany about coal phase-out, but this cannot realistically be implemented before 2045 (Agora Energiewende, 2016). The potential of our framework to assess the consequences of a misalignment between capacity-mix and policy goals is nonetheless rather limited because metrics depend mostly on historical data, e.g., the SAIDI index for measuring reliability. When using the framework for prospective analysis, complementary analyses are thus needed, e.g., a model of the grid for assessing redispatch costs. It is worth noting again that our framework is a tool aimed at helping stakeholders, who have a sound understanding of the jurisdiction's electricity sector, to evaluate the SoES.

We are aware that, although the framework allows following the evolution of the different dimensions over time, its ability to provide insights about the potential impact of an intervention is limited because the dimensions are interrelated. An intervention might thus lead to unexpected and undesirable consequences, e.g., responding to environmental challenges typically leads to higher generation costs. A new question thus arises: how are the dimensions interrelated and what is the degree of interdependence among them. While several authors have pointed out the existence of interdependencies among dimensions, they do not represent these explicitly, nor do they assess their importance. In the paper *"Interdependencies in security of electricity supply"* (work in progress), co-authored with professors Erik R. Larsen and Ann van Ackere, we intend not only to identify the interdependencies and assess the strength and importance of each, but also to provide a general framework to interpret such interdependencies.

3.4. Interdependencies in SoES

Understanding these interdependencies is important because a system's view of the problem is necessary to understand the system's behaviour and prevent potential (undesirable) side-effects of any action and because, due to limited resources, authorities must often rely on incremental measures to improve SoES.

3.4.1. Quantifying interdependencies

To analyse these interdependencies, we use Cross Impact Analysis (CIA), a method developed to understand the structure underlying a set of variables. The method explicitly establishes the relationships among relevant factors and has been applied to analyse socio-economic problems, such as the evaluation of global-warming mitigation options (Hayashi et al., 2006). CIA consists of three steps. The first step is to establish, for each factor, how strong an effect it has, if any, on each of the other factors. This is done by using a simple square matrix with one line and one column for each factor. The strength of the impact is expressed using a simple numerical scale, usually ranging from 0 (no impact) to a maximum of 2 or 3 (maximum impact). Starting from this matrix, we present two complementary ways of visualising the interactions between the dimensions. The first approach focuses on the role of each dimension in the system by categorizing them as a driver, connector, outcome or independent variable. The second one aims to provide a global view of the main influences, including the identification of possible feedbacks. Here the focus is generally restricted to the stronger links.

Table 6 shows the cross-impact matrix of the full set of 18 dimensions and sub-dimensions presented in Table 5, using a scale from 0 to 2. These are the result of several iterations between the co-authors of this working paper, Prof. van Ackere and Prof. Larsen, and me. Each of us has developed the matrix independently and then we have discussed the one-to-one relationships and the most appropriate impact value.

The values given in the matrix are an illustrative example of an electricity system; they are country- and system-specific. The sums of the rows and columns indicate respectively to what extend a dimension influences (row totals) and is influenced by (column totals) the other dimensions. Each dimension is thus characterised by two values, which are used to create a scatter plot (Figure 8). Next, we calculate the average of the row and column totals to subdivide the plot into four quadrants, which corresponds to the dimensions categorised as independent, driver, connector or outcome.

We acknowledge that using ordinal scales is not only subjective, but also constraints the data treatment, i.e., ordinal are not meant to be summed. Summing them, as we do, implies two major assumptions: *i*) the distance between the scales is the same, i.e., the distance between maximum impact and medium impact equals the distance between medium impact and no impact; and *ii*) the impact of scoring the minimum or maximum values, is the same for each dimensions,. i.e., the impact of generation adequacy on reliability (maximum) equals the impact of socio-cultural factors on generation adequacy (maximum). The first assumption is appropriate given the description of the categories (no, medium and maximum impact). We thus expect that the distance between consecutive categories is inferred in the same way by all readers. The second assumption is less straightforward. Given the very different nature, impact horizon and units of metrics, the hypothesis that the maximum impacts among dimensions are comparable is arguable. An alternative to deal with this problem would be to use weights or different scales for each dimension. However, this is a complex task given the differences among dimensions and the difficulty in measuring the impact in a single ‘unit’, i.e., measuring the impact in terms of to what extent security of supply is affected. Even if this were possible, it would add more subjectivity to the analysis. We are thus aware of this limitation in our work, and this should be addressed in future research. However, given that we do not attempt to categorize the dimensions, nor to estimate impact probabilities, we think that this approach is acceptable for providing insights into the role of each dimension, i.e., to what extent each dimension is influenced by and influences the others. The overall aim is to provide a comprehensive view of how the dimensions of SoES are interrelated, rather than to quantify the impact of each one on the system.

Table 6. Illustrative full-scale cross-impact matrix.

	Generation adequacy	Resilience	Reliability	Supply flexibility	Grid capacity adequacy	Grid ageing	Demand efficiency and conservation	Demand flexibility	Regulatory performance	Economic sustainability - supplier profitability	Economic sustainability - affordability	Environmental sustainability	Fossil fuel dependency	Geopolitics – Import dependency	Geopolitics - Vulnerability	Socio-cultural factors	Terrorism	Access	
Generation adequacy		2	2	0	0	0	0	0	1	2	2	0	0	2	0	0	0	0	11
Resilience	0		2	0	0	0	0	0	1	0	0	0	0	1	0	0	0	0	4
Reliability	0	0		0	0	0	0	0	2	0	0	0	0	0	0	1	0	0	3
Supply flexibility	0	1	2		0	0	0	0	0	1	0	0	0	0	0	0	0	0	4
Grid capacity adequacy	0	2	2	0		1	0	0	1	0	2	1	0	1	1	0	0	0	11
Grid ageing	0	1	1	0	1		0	0	0	0	1	0	0	0	0	0	0	0	4
Demand efficiency and conservation	2	1	0	0	2	0		0	0	1	1	2	1	1	0	0	0	0	11
Demand flexibility	1	1	1	0	2	0	0		1	1	1	2	0	0	0	0	0	0	10
Regulatory performance	1	1	1	1	1	0	0	0		2	2	1	1	1	0	0	0	0	12
Economic sustainability - supplier profitability	2	1	0	0	0	0	0	0	2		1	0	0	0	0	0	0	0	6
Economic sustainability - affordability	0	0	0	0	0	0	1	1	0	0		0	0	0	0	1	0	0	3
Environmental sustainability	0	0	0	1	0	0	0	0	1	1	1		1	1	0	2	0	0	8
Fossil fuel dependency	0	2	1	1	0	0	0	0	0	0	0	2		1	1	0	0	0	8
Geopolitics - Import dependency	1	1	1	0	0	0	0	0	1	2	0	0	0		2	0	0	0	8
Geopolitics - Vulnerability	0	0	1	0	0	0	0	0	0	0	1	0	0	0		0	0	0	2
Socio-cultural factors	2	1	0	0	2	0	1	2	1	0	1	2	2	1	0		0	1	16
Terrorism	1	0	2	0	2	0	0	0	0	1	1	1	0	0	0	1		0	9
Access	2	0	0	0	1	0	0	0	0	0	0	0	0	0	0	1	0		4
	12	14	16	3	11	1	2	3	11	11	14	11	5	9	4	6	0	1	

3.4.2. What do the interdependencies tell us?

The scatter plot, which visualises the aggregate role of each dimension, is shown in Figure 8. The upper left quadrant contains the drivers, which are dimensions that significantly influence other dimensions but are themselves fairly independent of the other dimensions, e.g., *demand efficiency and conservation*, *demand flexibility* and *fossil-fuel dependency*. Actions targeting these dimensions are potentially the more effective ones a regulator can take, as the consequences will gradually ripple through the system.

The upper right quadrant contains the connectors, which are the dimensions that are both influenced by, and have an influence on, other dimensions, e.g., *grid capacity adequacy* and *generation adequacy*. The regulator can influence these via incentives to expand or dismantle assets (*regulatory performance*), or by encouraging *demand efficiency and conservation* measures, in order to improve *affordability* and *reliability* (outcomes).

The dimensions in the lower right quadrant are influenced by other dimensions, but have limited knock-on effects. They are the outcome of choices made for the other dimensions, i.e., a type of dependent variables. Consider for instance *reliability*, which is determined among others by the choices made w.r.t. *generation* and *grid capacity adequacy*, and *supply flexibility*, but has very limited influence on any other dimension. Finally, in the lower left quadrant we find the independent dimensions, which have few connections to the other dimensions in the electricity system. These dimensions (e.g., *grid ageing*) are neither directly influenced by other dimensions, nor do they exert a strong impact on them.

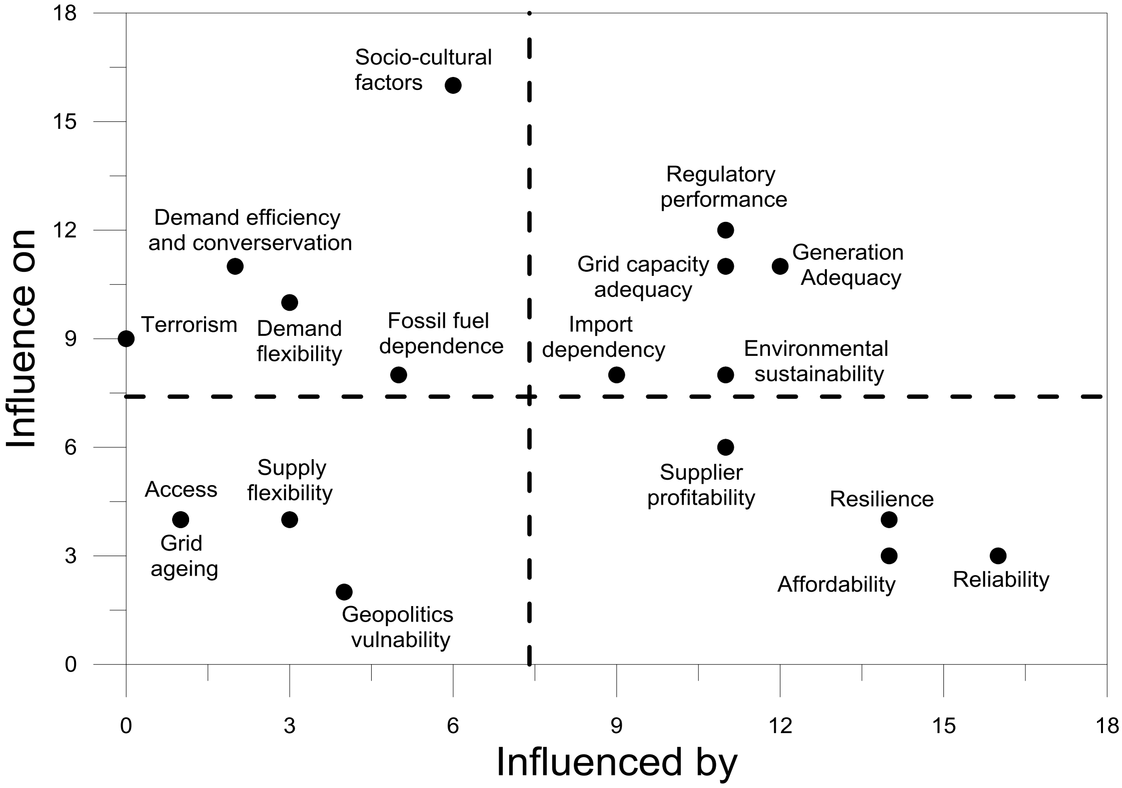

Figure 8. Scatter plot.

The influence diagram capturing the strongest links of Table 6 (values of 2) is shown in Figure 9. The middle panel includes the more technical aspects, i.e., those related to the electricity supply and transportation. For instance, *Grid capaci*ty *adequacy* is a key connector. Demand drives the need for grid capacity, while *socio-cultural factors* can be a major barrier to increasing this capacity, e.g., the lengthy delays in building the new north-south transmission lines in Germany (Steinbach, 2013). As in any market, electricity wholesale prices typically reflect scarcity of resources (Stoft, 2002). Low *generation adequacy* drives prices up, which threatens *affordability*, particularly for unregulated consumers and industrial consumers, and improves *supplier profitability*. This encourages generators to invest, increasing *generation adequacy*. The inherent delays in this process are the cause of the over- and under-investment cycles that characterise many electricity markets (Arango and Larsen, 2011; Bunn and Larsen, 1992). Insufficient *generation adequacy* will worsen *import dependency* within the limits of the available cross-border transmission capacity. The role of neighbouring countries will become more central in increasingly interconnected electricity markets. High *import dependency* increases jurisdictions' *geopolitic vulnerability*, as they do not have control over the jurisdictions from which they import, and negatively affects the *profitability* of the national suppliers.

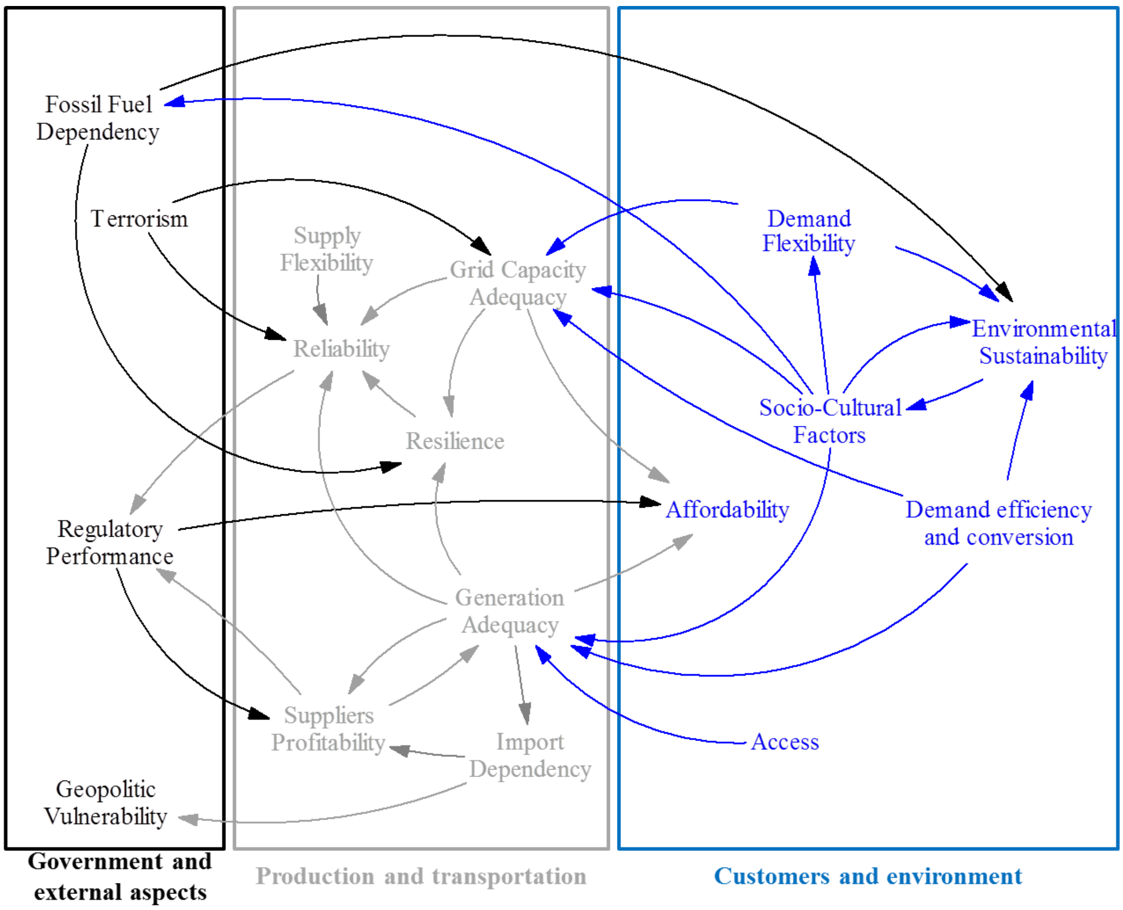

Figure 9. Influence diagram

The right panel focuses on the customer-side and the environment. *Demand flexibility* and *demand efficiency and conservation* influence *environmental sustainability* through their impact on peak demand and total demand. *Socio-cultural factors* and *environmental sustainability* interact, as people's attitude can affect the environmental targets setting and achievement, while a highly polluted environment increases people's awareness of the importance of *environmental sustainability*.

The left panel focuses on the government and external aspects. External factors such as *terrorism* influence technical aspects tightly related to the physical availability of electricity, i.e., *grid capacity adequacy* and *reliability*. Dimensions on which the government exercises an important control are *fossil fuel dependency* and *regulatory performance*. The former not only threatens the *environmental sustainability*, but also renders the jurisdiction's generation vulnerable to international market shocks (*resilience*). The latter impacts the economics of the system. When low *supplier profitability* endangers *generation adequacy*, the regulator may choose to intervene to encourage investments (*regulatory performance*). Such intervention can take the form of direct subsidies, as is often the case for renewables (Frondel et al., 2010), or of various forms of capacity mechanisms (Finon and Pignon, 2008).

3.4.3. Implications

The scatter-plot and the influences diagram allow having an overview of the system and help identifying towards which dimensions an intervention effect can spread with its potential consequences. More specifically, the analysis shows that socio-cultural factors, being the strongest driver, play a major role in electricity systems since they influence consumption habits, preferences for certain technologies and the NIMBY phenomenon. The latter is important for Switzerland since there is strong opposition towards wind energy and new power lines, despite a supporting governmental policy. In the current decarbonisation process of markets, decision-makers need to communicate clearly the need of low-carbon generation and insure that the population adheres to this objective. As the transition towards renewable might not be as fast as desired, alternatives actions are required. Significant progress could be achieved by decreasing consumption through demand efficiency and conservation measures and by load-shifting, leading to fewer emissions and reducing the need for generation and transmission capacity. Overall, this overview of the dimensions' interdependencies provides a solid foundation for policymakers and regulators on which to base their decisions, the final step of the analysis.

4. CONCLUSION

In this research we elaborate on the concept of security of supply in electricity markets and, in particular, on the long-term dynamics of SoES in Switzerland. In the first part of this research we propose a model for the Swiss electricity market, whose results show that in the absence of financial support, investments in generation capacity are not profitable. This and the nuclear phase-out lead to a significant drop in generation adequacy as well as an increase of prices, tariffs and import dependency in the long-term. Given the importance of hydropower and the recent huge investments in this technology, we focus on the long-term profitability of PSP as merchant players in the energy arbitrage business. Contrary to what is currently happening across European markets, within-day price differences increase in the long-term due to the changes in the Swiss generation-mix. However, PSP are not able to profit from those higher differences because of the lower availability of energy to pump. These results, however, only cover a certain number of the important elements of SoES, e.g., imports dependency and generation adequacy. Acknowledging the multidimensional nature of SoES, we elaborate on the dimensions necessary to evaluate this in the electricity sector. Based on certain dimensions used to evaluate the broad concept of energy security and on the current challenges of electricity systems, we propose a quantitative framework, i.e., a set of dimensions with its respective metrics.

Our model allows understanding the Swiss electricity market in this period of major change and its results provide insight into the long-term consequences of the nuclear phase-out and the increasingly important role of NDRES on SoES. In particular, the nuclear phase-out appears to be the most critical decision for the Swiss electricity market, given the deterioration of generation adequacy and the resulting increased imports dependency. Following the rejection of the referendum to accelerate the nuclear phase-out, the future of this technology remains uncertain, and given the particularities of the Swiss political system, a decision cannot be expected in the near future. The timing and transparency of this decision is critical for the implementation of alternatives to fill the nuclear power gap. Accoding to our results, the gap left by each plant decommissioning is mainly filled by imports. Current prices across European markets and medium-term expectations are nonetheless favourable for the Swiss market. This should also constitute an opportunity for the Swiss electricity market to improve its integration with neighbouring electricity markets, which could enhance the complementarity among countries. Interconnectedness is to be improved in terms of more transparent and integrated markets as well as higher cross-border capacity since, according to our model results, higher interconnection capacity would lead to lower prices, with dependency remaining unchanged. While the backup provided by imports would be important if the nuclear phase-out occurs, this should be considered as a transition period. It is essential for the government to provide a stable regulatory framework for generation investments, whatever the outcome of the referendum. The decisions focused on one specific technology are critical not only for this technology but also for others, since market expectations for all the firms in the market can change significantly due to, e.g., the support to a particular technology.

The government, being aware of the need to promote alternative technologies if the nuclear phase-out occurs, should focus particularly on how to improve the economic conditions of hydro-storage. Because of its energy storage ability, this technology helps limiting imports dependency, even if cross-border capacity increases. However, the current price dynamics and the future decrease in arbitrage opportunities threaten its profitability in the long-term. Although it is uncertain how the lack of profitability would affect hydro-storage plant operation, there is a risk of shortage that should not be underestimated. Further research should focus on mechanisms aimed at supporting this technology. Given the limited impact of premiums on energy arbitrage, mechanisms should reward the operational flexibility provided by this technology in terms of balance in the short-term and flexible allocation in the day-ahead market. This also highlights the need for further research on climate change impact on water stream flows in Switzerland.

These concluding remarks are based on a critical scenario for Switzerland: completion of the nuclear phase-out. However, the scenario with nuclear power is not very promising under expected demand growth conditions. Demand thus plays an important role when ensuring electricity supply in the long-term. However, the model limitations do not allow capturing more than the aggregate demand behaviour. Furthermore, customers play an essential role in current electricity systems, not only because of their behaviour as consumers but because of their preferences for certain technologies. These elements could have a significant impact on the SoES in Switzerland. Likewise, other elements of paramount importance, e.g., the very short-term balance and congestion of the power lines, are not captured by our model nor by comparable long-term policy models found in the literature. These aspects affect not only the Swiss electricity market, but the entire electricity sector.

To fill that gap, the dimensions included in our framework cover all the aspects needed to evaluate security of supply in the electricity sector. This framework highlights the multidimensional nature of SoES, which makes it impossible to come up with a single indicator to assess the global situation of SoES. Differentiating these dimensions is important when formulating policies. However, they cannot be analysed in isolation as they are strongly interrelated. This highlights the care needed when implementing policies so as to avoid unintended effects.

The metrics does not only allow evaluating quantitatively each dimension; they also provide insights about the impact of one dimension on the others as well as about the different time-frames of benchmarks that decision-makers should use when implementing this framework.

For instance, while low supply flexibility metric could have an impact in the short-term, a low energy margin (generation adequacy metric) is likely to have an impact in the longer-term. Likewise, the metrics provide insight on when the policies will have an effect.

The contribution of this framework to the energy security field is important because, among the energy sectors, electricity is the one currently facing the stronger challenges. This framework thus provides a tool expected to facilitate the evaluation of electricity sectors by including dimensions that respond to current evolution, e.g., the more active role of demand, and current threats, e.g., social opposition to certain technologies. The value of such a framework relies on its flexibility and its comprehensiveness. This framework can be adapted to any electricity system as this includes all the aspects affecting the electricity sector. Its usefulness and adaptativeness is also enhanced by the quantification of all metrics. This allows a more transparent and objective evaluation of those dimensions that are normally evaluated by qualitative assessments.

To conclude, this research highlights the complexity of electricity systems and the need to resort to a different kind of approaches when aiming to understand electricity market dynamics under the current changes, and evaluating SoES in a comprehensive way. At the same time, there is a complementarity between a general framework and a long-term simulation model. They consider different time-frames and quantitative tools that allow not only to provide a clear picture of the current situation, but also to understand the potential effects of different policies. At the same time, simulation models could help understanding the current situation, e.g., to identify if a policy has not had the desirable effect or if it has not yet had the time to deploy its full effect. Alternatively, simulation models could be used to feed the framework with data that could be used to perform prospective SoES evaluations. This complementarity is enhanced if there is a continuous and simultaneous utilisation of both approaches. However, the resulting analysis is only useful if governments provide transparent information and a clear and stable regulatory framework that enable making valid assessments about the current state of a certain electricity system and its expected evaluation.

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APPENDIX A: MODEL DOCUMENTATION

In this Appendix the model used in *Paper_SwissMarket* and the *Paper_PSP* is explained in detail. In Appendix A.1 the model is described briefly, in Appendix A.2 we present the model assumptions and parameters, and finally in Appendix A.3 all the model equations are presented.

A.1. Model description

Figure A.1 presents the description of simulation of the investments. We distinguish NDRES from other technologies; the investment dynamics are different since the former are typically subsidised. When deciding to expand their generation capacity, investors compute the market clearing price with the expected capacity (installed plus under construction) in order to calculate their profitability. The higher the NDRES expected supply, the lower the residual load, making the other technologies' expected supply lower. The lower the expected residual load, the lower the prices. The other technologies' expected supply is also affected by the price and availability of imports. If prices are lower than other technologies' marginal costs, imports will increase to the detriment of other technologies' expected supply. If the expected supply decreases, the expected LCOE increases, which leads to a lower expected profitability. Low profitability discourages new investments. However, if a technology is subsidised by FiTs, which is currently the case of NDRES in Switzerland, investments only depend on the availability of FiTs. If they are not subsidised or they are encouraged by market-based mechanisms, e.g., market premiums, they become vulnerable to market prices. In this case (dotted arrows), high prices increase profitability, which triggers new investments. The logic for computing the market clearing explained above is the same for the "current" market clearance, but only the installed capacity is considered.

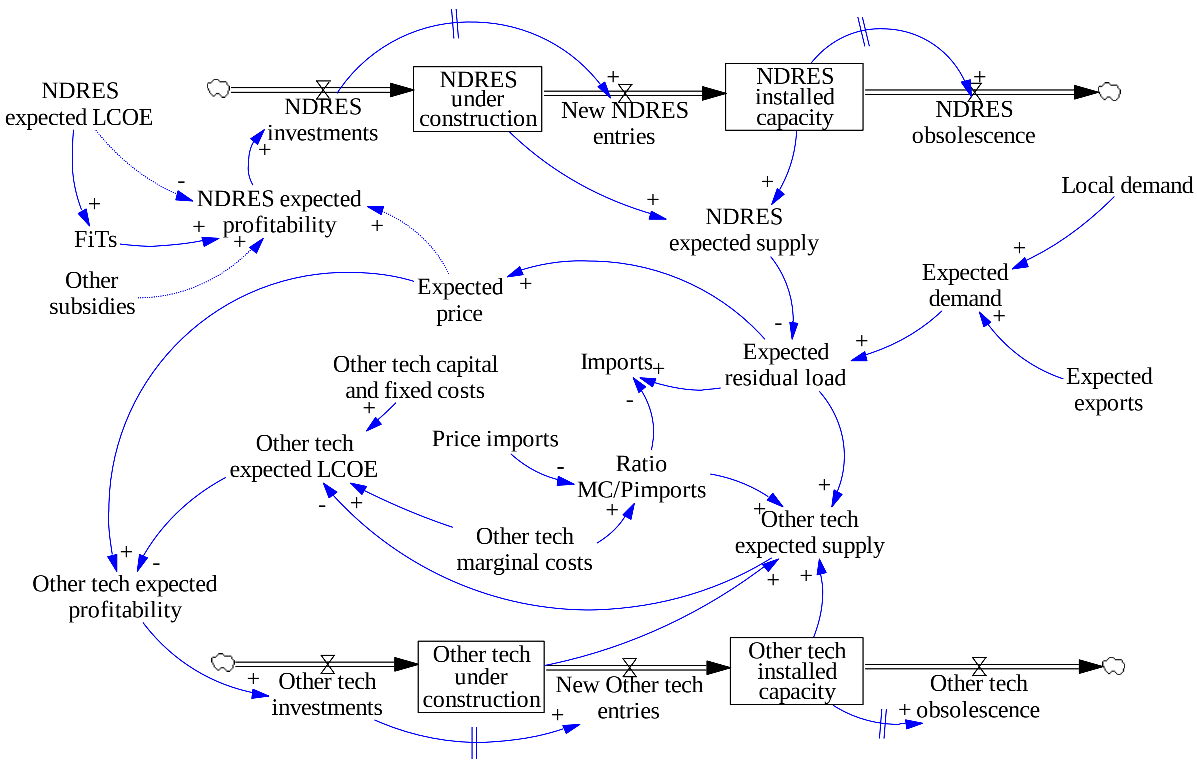

Figure A.1. Stock and flow diagram of investments simulation.

A.2. Data and assumptions

The parameters for each technology are presented in Table A.1. For calculating the specific potential for hydro-storage (HS) and run-of-river (RR), we divide the estimated potential of 4 TWh (SFOE, 2012) proportional to the installed capacity (72% of HS). Since the expansion potential estimated by AES (2012) is expressed in terms of annual production under current conditions, we compute the current expansion potential in MW using the number of hours of production at full load. The marginal costs used for clearing the market are calculated by aggregating the fuel costs, the emission costs and other marginal costs. The cost of emissions is calculated using a CO_2 price forecast (see Figure A.2). The marginal costs, the fixed costs and the capital costs are used to calculate the LCOE when computing the expected profitability of generation capacity expansions.

Table A.1. Assumed parameters per technology.

	HS	RR	NUC	GAS	PV	WI	TH
Initial conditions							
Capacity (MW)	9,920[a]	3,853 [a]	3,278[b]	89[c]	755[d]	60[d]	760[c]
Technology characteristics							
Construction time (years)[e]	4	3	10	2.5	1.5	1.5	3
Lifespan (years)[f]	80	80	50	30	20	20	20
Max Size of investment per period (MW)	400	100	200	600	200	100	200
Expansion potential							
Potential (TWh)	3 [g]	1 [g]	--	19 [h]	18 [h]	4 [h]	5 [h]
Hours of production at full load [h]	2,200	4,400	8,000	6,000	950	1,800	3,750
Potential (MW)	1,310	254	--	3,167	18,947	2,222	1,333
Costs							
Capital costs 2015 (CHF/kW) [i]	4,750	5,300	4,620	1,015	3,300	2,100	2,500
Capital costs 2020 (CHF/kW) [i]	4,750	5,300	4,620	1,015	2,600	2,000	2,500
Capital costs 2025 (CHF/kW) [i]	4,750	5,300	4,620	1,015	2,300	1,900	2,500
Capital costs 2035 (CHF/kW) [i]	4,750	5,300	4,620	1,015	2,000	1,860	2,500
Capital costs 2050 (CHF/kW) [i]	4,750	5,300	4,620	1,015	1,500	1,770	2,500

	HS	**RR**	**NUC**	**GAS**	**PV**	**WI**	**TH**
Required return [i]	8%	8%	10%	10%	12%	11%	9%
Annual fixed costs (CHF/kW/yr) [i]	24	53	89	42	23	38	25
Fuel cost (CHF/MWh) [i]	--	--	--	30	--	--	60
Other variable costs (CHF/MWh) [i]	11	11	9*	3	0	0	25
Heat revenue (CHF/MWh) [i]	--	--	--	--	--	--	90
Emissions (kgCO_2/MWh) [h]	15	15	20	400	80	24	330

[a] SFOE (2014a)

[b] SFOE (2014b)

[c] SFOE (2015)

[d] SFOE (2014c)

[e] IEA (2012)

[f] Kannan and Turton (2012)

[g] SFOE (2012)

[h] AES (2012)

[i] Poyry (2012)

*The nuclear power variable cost includes the fuel cost

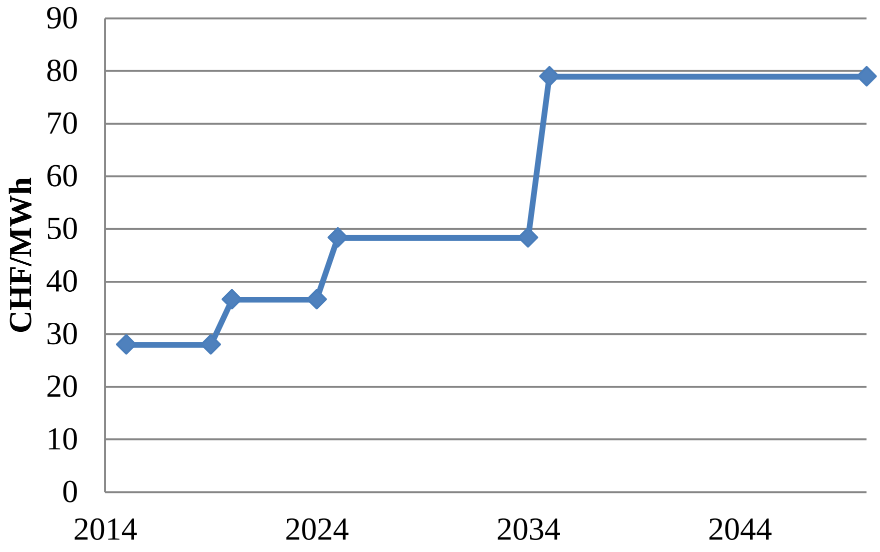

Figure A.2. Forecast of CO_2 price (data from Poyry (2012)).

Additional assumptions, parameters and initial conditions are presented in Table A.2.

Table A.2. Additional parameters.

Market clearing	
Scarcity price (CHF/MW)	500
VOLL (CHF/MW)	3,000
LTI price (CHF/MW)	35
Monetary exchange	
CHF/Euro	1.32
CHF/USD	1.10
PSP	
Pumping capacity (MW) [a]	1,560
Generation capacity PSP (MW) [a]	1,977
Efficiency pumping [b]	80%
Others	
Initial fill ratio [c]	63%

Losses [c]	8%
Share of households [b]	30%

[a] SFOE (2014a)

[b] SFOE (2014b)

[c] SFOE (2016c)

A.2.1. Demand

Our objective is to estimate a demand pattern for each representative day. Using final consumption (without losses, self-generation nor pumping) from 2013 (data from Swissgrid (2015b)), we compute, for each season, the average consumption for each of the 24 hours of a the day. We then take the maximum of these 96 (24*4) values (peak average demand). Next we express each of the 96 values as a fraction of this peak average demand. We apply the same procedure to the data from the years 2009 to 2012 to verify that there has not been a significant change in demand patterns. Finally, for each season we calculate the average factors of the 24 hours with the 2009-2013 data to derive the demand patterns used in our model. We use the maximum load of 2013 (8,307 MW) to build the hourly consumption curves per season (see Figure A.3). This value does not include transmission losses or pumping consumption. Energy losses are estimated to be 8% of final consumption (data from the SFOE (2016c)).

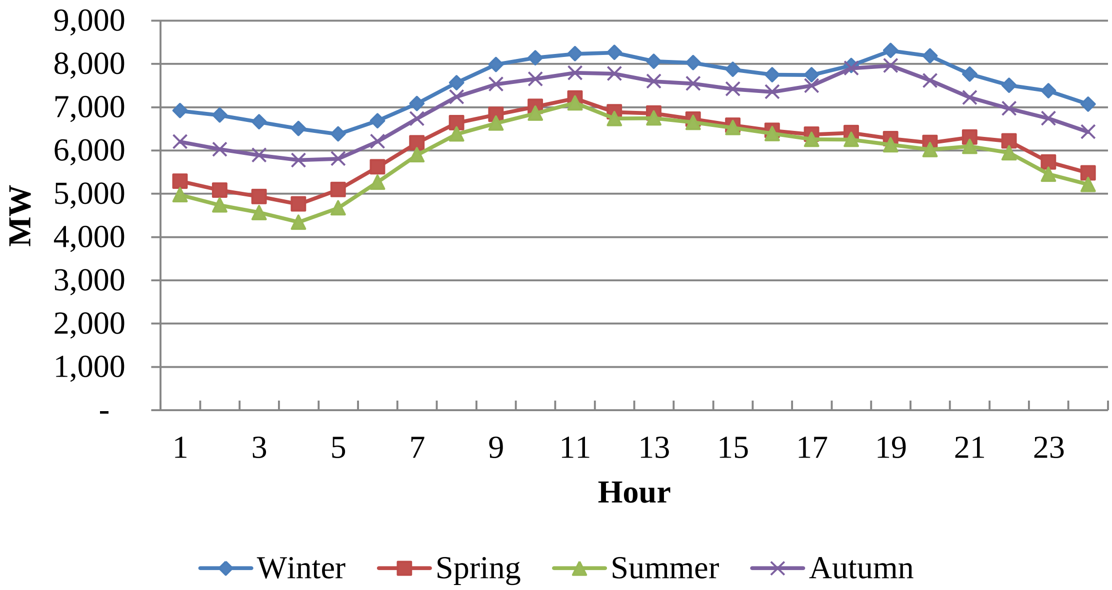

Figure A.3. Initial conditions of hourly consumption per season.

Next, we estimate an hourly consumption for a representative day of each quarter for the simulation period (2014 to 2050). We use the annual demand forecast for the three scenarios from SFOE (2013), updating them using SFOE (2014b) data to calculate the demand growth factors with respect to the 2013 annual consumption. Hence, we multiply the volumes shown in Figure A.3 by the factors presented in Figure A.4.

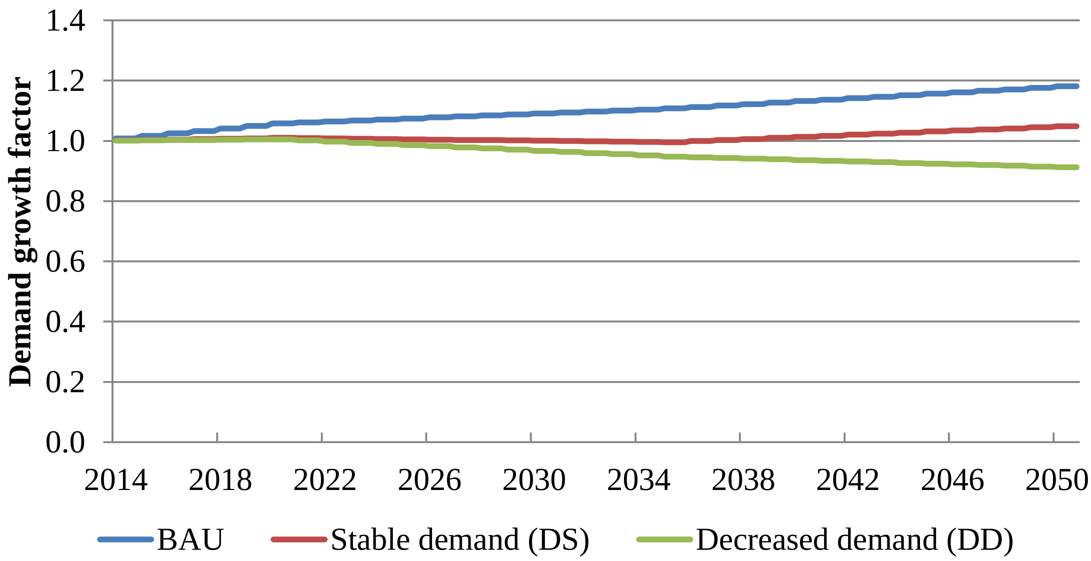

Figure A.4. Growth factor for different demand scenarios.

Total consumption is thus the sum of final consumption, losses and pumping. Since there is no data available concerning hourly pumping, we made the following hypotheses. From Swissgrid (2015b) data, we can only calculate the joint volume of generators' self-consumption and pumping consumption. Furthermore, the annual aggregate of these volumes is lower than the pumping presented in SFOE (2016c) reports of the years 2009-2013. We thus use the hourly volumes of self-consumption and pumping consumption as weights to allocate the pumping per season (assumed to be the average pumping of the 2009-2013 period, see Table A.3) to the 24 hours. As shown in Figure A.5, the pattern derived in this way is realistic as the pumping is concentrated on the off-peak hours. Recall that this data is only used in the *Paper_SwissMarket*, since pumping is computed endogenously in the *Paper_PSP*.

Table A.3. Assumed pumping per season in GWh (average of historical data from the 2009-2013 period). Original data from SFOE (2016c).

Winter	Spring	Summer	Autumn	Total
376	706	830	493	2,405

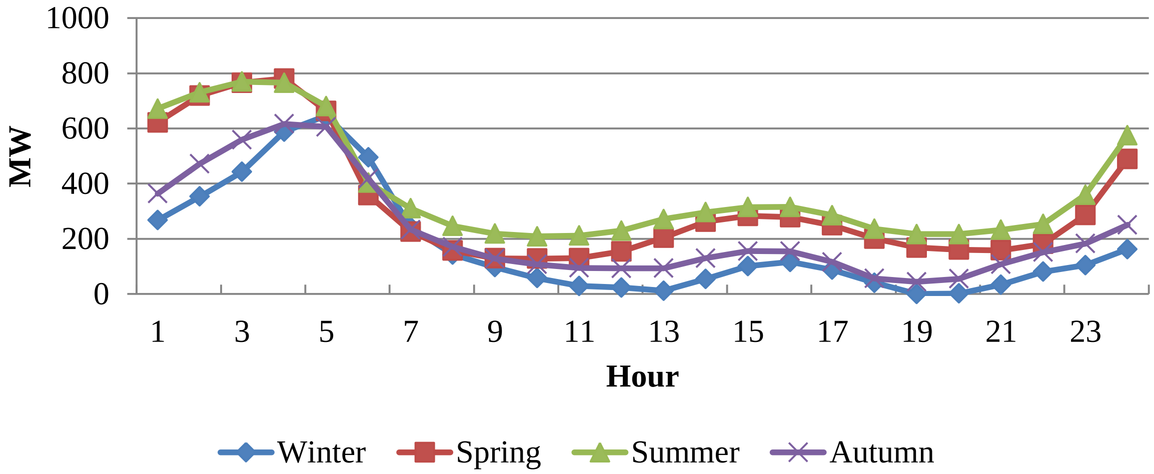

Figure A.5. Estimated for exogenous pumping used in *Paper_SwissMarket* for each representative day.

A.2.2. Availability factors

Availability factors vary according to the technology. For CCGT and conventional thermal we assume annual availability factors of respectively 91% (IEA-ETSAP, 2010) and 51% (Kannan and Turton, 2012). We use historical production from the 2003-2013 (data from SFOE (2016c)) period to estimate the seasonal availability factors for nuclear power (see Table A.4).

Given the unavailability of detailed information for Switzerland, we use data from Germany to estimate the PV and wind availability factors. To estimate them we use hourly production curves per month and the installed capacity in 2012 in Germany (data from Fraunhoffer ISE (2013)). The annual average of these factors (18% for wind and 11% for PV) are similar to those presented by Kannan and Turton (2012) for Switzerland. On the one hand, as there is no clear hourly pattern for wind energy, we only assume seasonal availability factors (see Table A.4). On the other hand, hourly availability factors are estimated for PV (see Figure A.6).

Table A.4. Seasonal availability factors for nuclear and wind energy.

Technology	Winter	Spring	Summer	Autumn
Nuclear	99%	84%	75%	100%
Wind	24%	15%	13%	21%

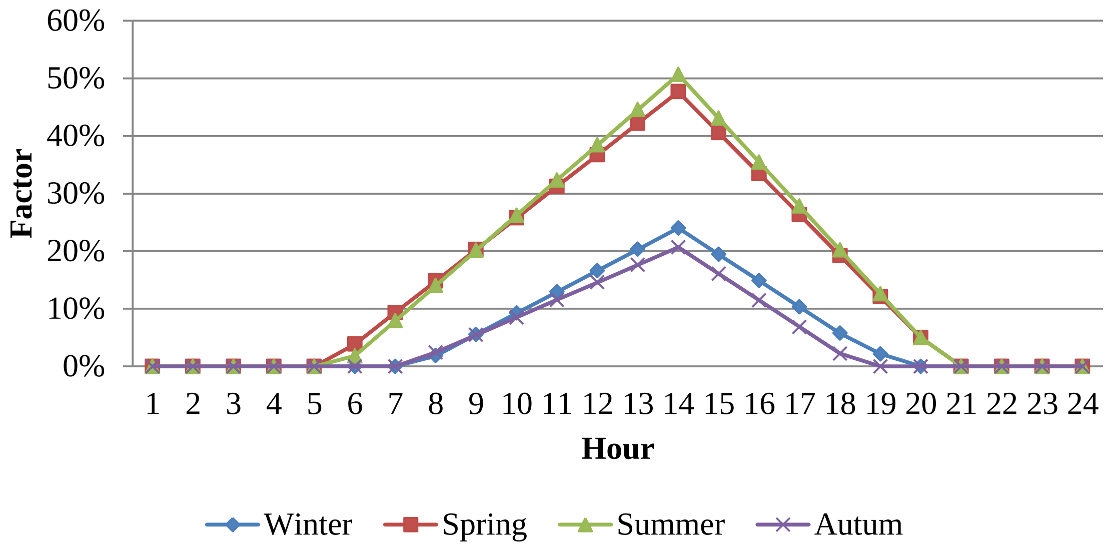

Figure A.6. Hourly availability factor per season of PV.

For calculating run-of-river availability, we assume that the water inflows of these plants equal the average production of this technology between 2009 and 2013 (data from SFOE (2016c), see Table A.5). We then assume that water availability is distributed evenly across the hours of the day.

Since reservoirs allow seasonal storage, hydro-storage availability is estimated differently. Using data from SFOE (2016c), we estimate seasonal water inflows as follows:

$$Inflow_t = ReservoirLevel_t - ReservoirLevel_{t-1} + HSproduction_t \\ - ConsumptionPSP_t * EfficiencyPSP \quad (1)$$

We estimate water inflow as the average of the historical water inflows between 2009 and 2013 for each season (see Table A.5). The estimation of hourly availability factors for HS is explained in Appendix A.3.

Table A.5. Seasonal availability for hydropower (GWh).

Technology	Winter	Spring	Summer	Autumn
Run-of-river	2,505	4,949	5,458	3,095
Hydro-storage	906	7,516	8,443	2,304

A.2.3. Exports

The neighbouring countries' willingness to pay for exports from Switzerland is assumed to be the average between hourly median prices of 2012 and 2013 (original data of German and French prices from EPEX SPOT (2016) and Italian prices from GME (2014)) (see Figure A.7).

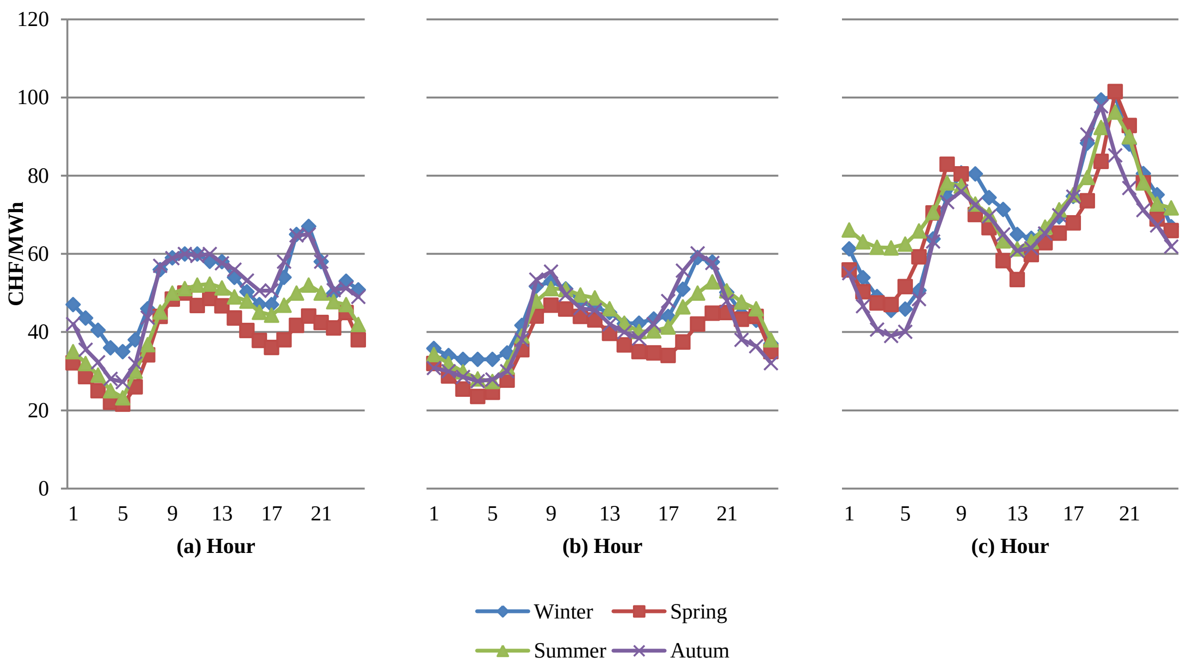

Figure A.7. Willingness to pay of (a) France, (b) Germany and (c) Italy for exports from Switzerland.

Likewise, demand for exports is assumed to be the median of hourly net transfer capacity (NTC) (data from Swissgrid (2016e)) between Switzerland and its neighbouring countries[5] in

[5] NTC between Switzerland and Germany includes that between Switzerland and Austria.

2013. NTC with France and with Germany remained constant respectively at 1,200 MW and 5,200 MW during the entire year. Figure A.8 shows the assumed demand from Italy.

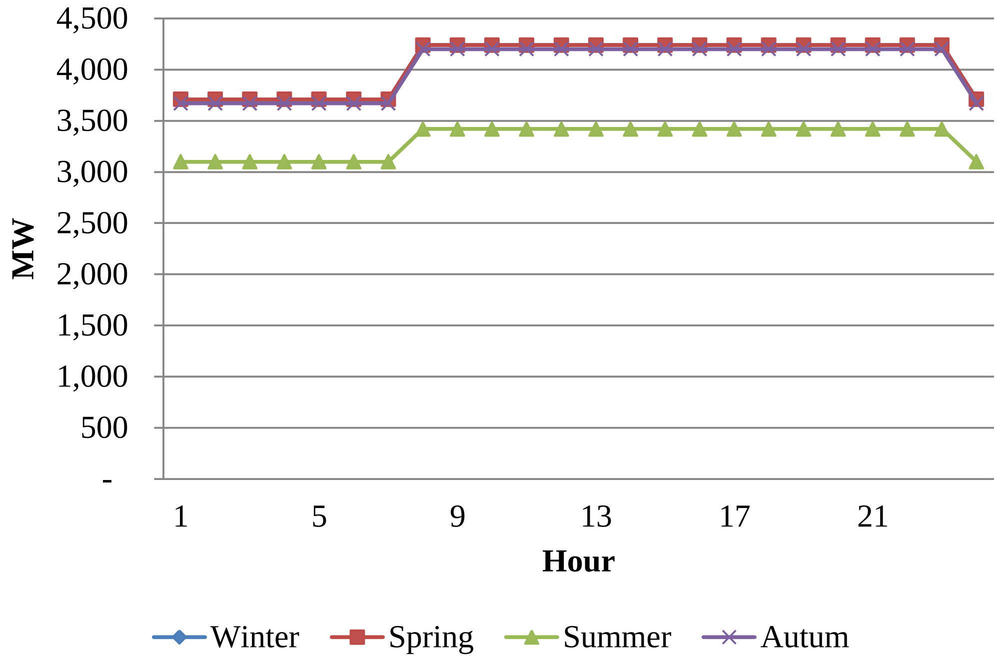

Figure A.8. Italy's demand for exports from Switzerland.

A.2.4. Imports

There are two types of imports: long-term contracts and spot imports. To simulate imports resulting from the former, we use data about debit rights on French nuclear plants from the AES (2012) (see Figure A.9).

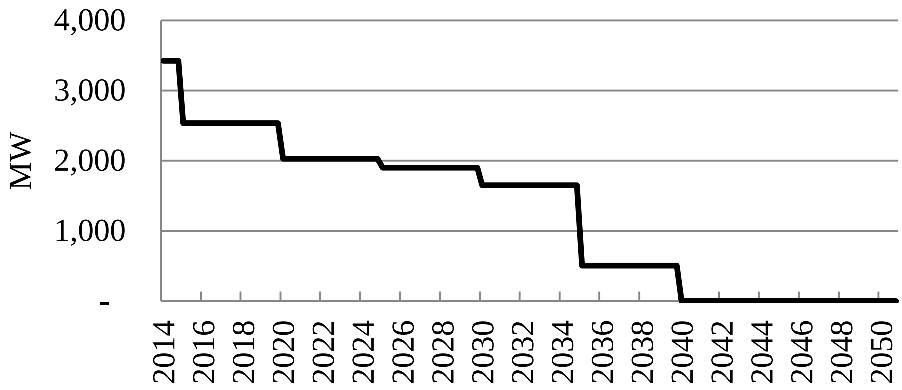

Figure A.9. Debit rights from French nuclear plants.

According to AES (2012), these plants are available on average 90% of the time. Due to the unavailability of more detailed data, we use the model to infer the seasonal availability factors during the model calibration process (see Table A.6). Availability of nuclear plants is lower in spring/summer because maintenance is usually done in this period.

Table A.6. Seasonal availability factors of long-term import contracts.

Winter	Spring	Summer	Autumn
100%	65%	90%	100%

For simulating imports, we use the 2013 NTC values for exports from France, Germany[6] and Italy to Switzerland (see Figure A.10). We aggregate the NTC of France and Germany because, due to the large-scale exchange between Germany and France (prices tend to converge), it is difficult to identify the real origin of certain imports.

[6] NTC between Germany and Switzerland includes that between Austria and Switzerland.

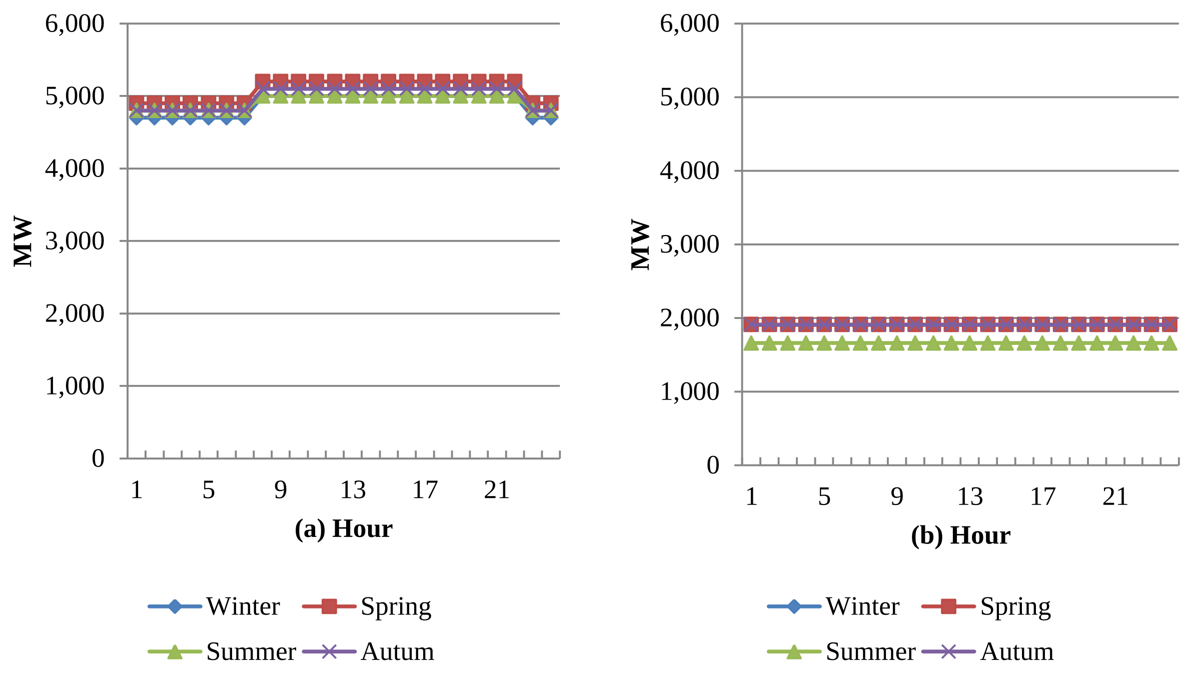

Figure A.10. Spot imports availability from (a) France/Germany and (b) Italy to Switzerland.

However, since the NTC comprises the entire availability of imports capacity, we subtract the available long-term imports from the France/Germany NTC. For instance, the actual availability of spot exports from those countries to Switzerland for the winter 2014 between 1 and 2 a.m. is 4700-3466*100% = 1234 MWh. The NTC from Italy to Switzerland is considered as the spot imports availability from this country.

We assume import prices are the same as the export prices because the maximum price that neighbouring countries are willing to pay for imports should equals the marginal cost at which they can produce. Since spot imports from France and Germany are aggregated, we estimate a single price for simulating their bid price in the Swiss market. Prices from both countries are weighted by the average share of imports from both countries between 2012 and 2013 (data from Swissgrid (2015b)) (see Figure A.11).

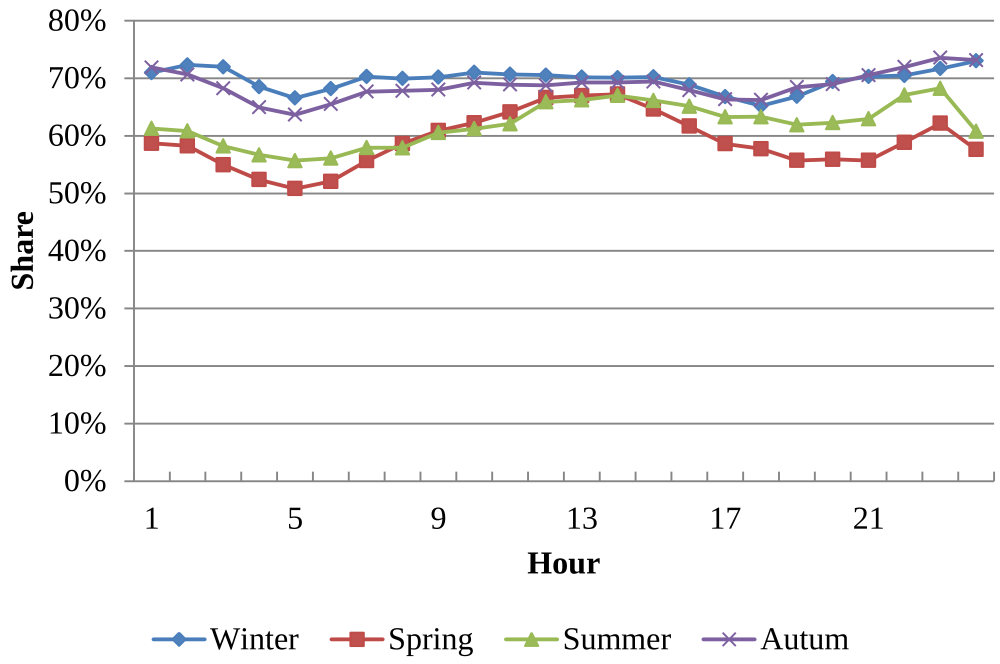

Figure A.11. Average share of German imports in aggregated imports from Germany and France.

A.3. Model equations

In this Appendix we present the detailed formulation of the model used in *Paper_SwissMarket* and *Paper_PSP*. The Appendix A.3.1 to A.3.3 present a more detailed version of the model formulation used in the *Paper_SwissMarket* and presented in its appendix. We present it again to help the reader understanding the Appendix A.3.4 and A.3.5, in which we explain the modifications done to the model in order to capture better the hydropower plants' behaviour for the *Paper_PSP*. The list of the variables used is presented in Table A.7.

Table A.7. Model variables and sub-indexes.

Sub-indexes	
c	Countries to where electricity is exported (France, Germany and Italy)
e	Possible capacity investments sizes (1,… 10), with 1 being the smallest and 10 the largest
h	Hour of the day (1,… 24)
j	Producers: these include the different technologies (HS, RR, NUC, CCGT, PV, WI, TH) and imports (long term import contracts [LTI] and balancing imports [BI])
m1	Possible alternatives (1, …5) of seasonal volumes of water to be allocated by HS
r1, r2	Possible patterns (1, …10) of hourly bids for HS. Note that we require two indices as we will consider the current and the next season.
s	Season (Winter [s=0], Spring [s=1], Summer [s=2], Autumn [s=3])
t, t1	Time (0,… 147) [quarters]. Note that we require two indices as we will consider estimations during the current season (*t*) about future seasons (*t1*).
T, n	Technology (Hydro-storage [HS], run-of-river [RR], nuclear [NUC], Combined cycle gas turbine [CCGT], photovoltaic [PV], wind energy [WI], other thermal [TH]). Note that we require two indices as we will consider estimations done by one technology (*T*) about the future capacity of others (*n*).
w1, w2	Possible patterns (1, …10) of hourly reservation prices at which HS bids. Note that we require two indices as we will consider the current and the next season.
Parameters	
$EP_{c,h}$	Maximum price paid by each importing neighbouring country *c* during hour *h* (CHF/MWh)
L_T	Lifespan of technology *T* (quarters)
$RLave_s$	Historical average filling ratio of the water reservoir at the end of season *s* (%)
$RLmax_s$	Historical maximum filling ratio of the water reservoir at the end of season *s* (%)
$RLmin_s$	Historical minimum filling ratio of the water reservoir at the end of season *s* (%)

α	Pumping efficiency (80%)
Variables	
$A_{T,h,t}$	Availability factor of technology *T* during hour h (%)
$Ac_t(B)$	Generation that PSP can allocate when bidding at a price *B* (MWh)
$AF^{t1}_{HS,t,r1}$	Pattern *r1* of HS hourly bids in *t1*, where *t1=t,t+1* (dimensionless)
$AFoff^{t1}_{t,h}$	Hourly bid pattern assuming HS focuses on off-peak hours in *t1*, where *t1=t,t+1* (dimensionless)
$AFpeak^{t1}_{t,h}$	Hourly bid pattern assuming HS focuses on peak hours in *t1*, where *t1=t,t+1* (dimensionless)
$CK_{T,t}$	Construction start of capacity of technology *T* (MW/quarter)
$ConsD_T$	Construction delay of technology *T* (quarters)
$D_{h,t}$	Hourly national demand (MWh)
$DE_{c,h,t}$	Demand for imports from Switzerland by country *c* during hour *h* (MWh)
$Dmax_{t,h}$	Maximum demand in hour *h* (MWh)
$E_{n,e,t}$	Capacity expansion of technology *n* assuming a capacity investment of size *e* (MW)
$EK_{T,t}$	New capacity of technology *T* coming online (MW/quarter)
$ELF^{T}_{e,t}$	Expected load factor of technology *T* assuming a capacity investment of size *e* (MWh/MW)
$ES_{j,c,h,t}$	Supply from producer *j* exported to country *c* during hour *h* (MWh)
$FC_{T,t}$	Fixed annual costs of technology *T* (CHF/MW)
FD_t	Dispatchability factor used by HS (dimensionless)
$FK_{T,t}$	Future capacity of technology *T* (in *t+20* [5 years])
$FKE^{T}_{n,e,t}$	Forecast of future installed capacity (in *t+20* [5 years]) of technology *n* made by technology *T*, assuming a capacity investment size *e* (MW)
FRL_t	Forecasted reservoir level before production (%)
I_t	Water inflow to reservoirs (MWh/quarter)
$K_{T,t}$	Installed capacity of technology *T* (MW)
K^{PU}_t	Pumping capacity of PSP (MW)
$KC_{T,t}$	Annualised capital costs of technology *T* (CHF/MW)

$LCOE^{T}_{e,t}$	Levelised cost of electricity expected by technology *T*, assuming a capacity investment of size *e* (CHF/MWh)
$MC_{j,h,t}$	Marginal costs of producer *j* during hour *h*, i.e., price at which each producer bids in the day-ahead auction (CHF/MWh)
$MC^{t1}_{HS,h,t,w1}$	Pattern *w1* of HS reservation price at which to bid during hour *h* in *t1*, where *t1=t,t+1* (CHF/MWh)
$NTC_{h,t}$	Net transfer capacity for imports during hour *h* (MW)
$OK_{T,t}$	Obsolescence of capacity of technology *T* (MW/quarter)
$OK^{*}_{T,t}$	Obsolete capacity of technology *T* over the next 5 years (MW)
$OldK_{T,t}$	Capacity of technology *T* that was installed before 2013 and remains available (MW)
P_t	Average weighted price (CHF/MWh)
$P_{h,t}$	Hourly price (CHF/MWh)
$P^{T}_{e,t}$	Expected price to be received by technology *T* assuming a capacity investment of size *e* (CHF/MWh)
P^{T}_{t}	Average price received by a technology *T* (CHF/MWh)
P^{PSP}_{t}	The maximum price that PSP is willing to pay for energy to pump (CHF/MWh)
PF_t	Historical prices factors used by HS (dimensionless)
$P^{t1}_{t,h,m1,r1w1}$	Price expected by HS during hour *h*, assuming a pattern *r1* of generation bids, a pattern *w1* of reservation prices and a volume *m1* of available water during quarter *t1*, where *t1=t,t+1* (MWh)
$Q_{j,t}$	Total supply from producer *j* (MWh)
$Q_{j,h,t}$	Total supply from producer *j* during hour *h* (MWh)
$Q^{t1}_{HS,t,h,m1,r1w1}$	HS supply during hour *h*, assuming a pattern *r1* of generation bids, a pattern *w1* of reservation prices and a volume *m1* of available water during quarter *t1*, where *t1=t,t+1* (MWh)
R_t	Reservoir capacity (MWh)
$R_{j,h,t}$	Energy bought by PSP at hour *h* from producer *j* (MWh)
RL_t	Reservoir level (%)
$RL^{t1}_{t,m1}$	Alternative *m1* of the filling ratio at the end of *t1*, where *t1=t,t+1* (%)
$S_{j,t}$	Available supply from producer *j* (MWh)

$S_{j,h,t}$	Available supply from producer *j* during *h* (MWh)
$S_{HS,t,m1}^{t1}$	Volume *m1* of water available to be allocated by HS in *t1*, where *t1=t,t+1* (MWh)
$S_{HS,t,h,m1,r1}^{t1}$	Pattern *r1* of HS generation to bid during hour *h* in period *t1* (where *t1=t,t+1*), assuming a volume *m1* of water available (MWh)
$S_{j,h,t}^{*}(P)$	Available volume for pumping during hour *h* from a producer *j* at a purchase price *P* (MWh)
$S_{h,t}^{*}(P)$	Available volume for pumping during hour *h* at a purchase price *P* (MWh)
$SD_{j,h,t}$	Supply dispatched from producer *j* during hour *h* in the Swiss market (MWh)
$Smin_{HS,t,h}^{t1}$	Minimum supply that HS has to generate during hour *h* in *t1*, where *t1=t,t+1* (MWh)
$Spill_t$	Water spillages (MWh/quarter)
$SR_{j,h,t}$	Remaining available supply from producer *j* during hour *h* after national dispatch, i.e., supply available for exports (MWh)
$SU_{j,h,t}$	Unallocated supply from a producer *j* during hour *h* (MWh)
$Uc_t(P)$	Available volume for pumping at a purchase price *P* (MWh)
$UK_{T,t}$	Capacity under construction of technology *T* (MW)
V_t^{PSP}	Energy available for PSP to generate (MWh)
$VC_{j,t}$	Variable production costs of producers *j* (CHF/MWh)
W_t	Stock of water in the reservoir (MWh)
$W^{T}{}_{e,t}$	Binary variable indicating whether a capacity expansion of a size *e* by technology *T* is expected to be profitable (1) or not (0)
$X^{T}{}_{e,t}$	Expected profitability of technology *T*, assuming a capacity investment of size *e* (%)
$X_{j,h,t}^{*}(B)$	Volume that could be supplied by PSP bidding at a price *B* during hour *h*, replacing a producer *j* (MWh)
$X_{h,t}^{*}(B)$	Volume that could be supplied by PSP bidding at a price *B* during hour *h* (MWh)
Y_t^{PSP}	Pumping consumption from PSP (MWh)
$Y_{h,t}^{PSP}$	Pumping consumption from PSP during hour *h* (MWh)

$Z_{j,h,t}$	Energy bid by PSP during hour h aimed at replacing supply from producer j (MWh)

A.3.1. Evolution of capacity

Installed capacity $K_{T,t}$ of each technology increases as new capacity comes online ($EK_{T,t}$) and decreases through obsolescence ($OK_{T,t}$).

$$\frac{\partial K_{T,t}}{\partial t} = EK_{T,t} - OK_{T,t} \tag{2}$$

Obsolesce is defined as the aggregated obsolescence of old projects and new projects as shown in Eq. (3). Old projects are those installed before 2013 that remain installed at time t ($OldK_{T,t}$). This capacity becomes obsolete depending on its lifespan (L_T). We do not use a decommission schedule for old projects as we do not have specific information about when each plant will be decommissioned. Obsolescence of old projects, $OldK_{T,t}$ is defined as

$$\frac{\partial OldK_{T,t}}{\partial t} = \frac{OldK_{T,t-1}}{L_T} \tag{3}$$

New projects correspond to the capacity coming online between 2014 and 2050 ($EK_{T,t}$). These become obsolete at the end of their lifespan.

$$OK_{T,t} = \frac{OldK_{T,t}}{L_T} + EK_{T,t-L_T} \tag{4}$$

We consider specific obsolescence conditions for hydropower and nuclear energy. We assume that hydro-storage and run-of-river capacity do not become obsolete but are refurbished to remain online without important losses of efficiency. We also assume that nuclear is decommissioned according to a fixed schedule which, for the *BAU*, is presented in Figure A.12.

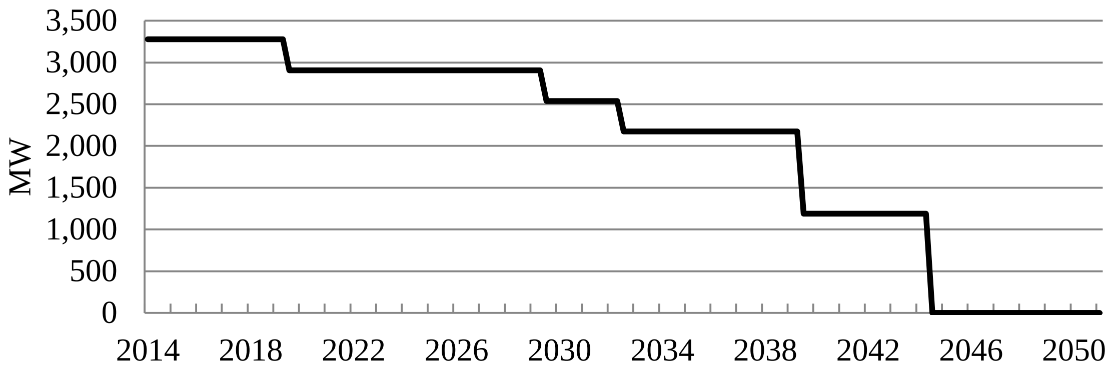

Figure A.12. Assumed evolution of nuclear power installed capacity in *BAU*.

Capacity under construction ($UK_{T,t}$) increases by capacity starting construction ($CK_{T,t}$) and decreases by the projects that start operation ($EK_{T,t}$).

$$\frac{\partial UK_{T,t}}{\partial t} = CK_{T,t} - EK_{T,t} \tag{5}$$

New capacity results from the projects that started construction ($CK_{T,t}$) and come online after a delay equivalent to the construction time, $ConsD_T$, which is technology-dependent.

$$EK_{T,t} = CK_{T,t-ConsD_T} \tag{6}$$

A.3.2. Market clearing

To compute the day-ahead auction for each hour of a representative day of each quarter, available supply and bid prices from producers are needed. Supply from producers comes from generation by the different technologies T considered and from imports. The latter might be of two types: long-term contracts (LTI) and balancing imports (BI). The availability of imports from LTI is exogenous based on the estimations of AES (2012) as explained in Appendix A.2.4.

We thus estimate the availability of imports from balancing markets as the remaining available capacity from the cross-border capacity represented by the NTC, which is assumed to be 7,500 MW during the entire simulation.

$$S_{BI,h,t} = NTC_{h,t} - S_{LTI,h,t} \tag{7}$$

The available supply from local technologies ($S_{T,h,t}$) depends on the availability factor ($A_{T,h,t}$) of each technology (recall Appendix A.2.2) during each hour h and on the installed capacity ($K_{T,t}$).

$$S_{T,h,t} = K_{T,t} \times A_{T,h,t} \tag{8}$$

Marginal costs of producers ($MC_{j,h,t}$) do not depend on the hour of the day and equal their variable production costs ($VC_{j,t}$), except for balancing imports (recall A.2.4) and hydro-storage. In the specific case of long-term import contracts, which refer to the contracts with French nuclear plants, we assume a price (marginal cost) of 35 CHF/MWh. The marginal cost for hydro-storage equals the hydro-storage reservation price.

$$\mathrm{MC}_{j,\mathrm{h},\mathrm{t}} = \mathrm{VC}_{j,\mathrm{t}} \ \forall j \neq HS, BI \tag{9}$$

Overall, modelling hydro-storage is slightly different than to other technologies, since availability depends on the reservoir level; the marginal cost reflects the water opportunity cost. This is modelled as a function of the forecasted maximum reservoir level (FRL_t) as well as of the substitutes' price, as presented in Figure A.13. The parameters *R1*, *R2*, *R3* and *R4* are estimated during model calibration. O_{HS} equals the variable production costs of HS ($VC_{HS,t}$), *Vmax* and *Vmin* are respectively the maximum and minimum prices of substitutes (CCGT, TH, LTI and BI), and *Vsca* is the scarcity price (assumed to be 500 CHF/MWh). The scarcity price was also estimated during model calibration. This way of modelling hydro-storage reservation prices is proposed by van Ackere and Ochoa (2010) and Ochoa and van Ackere

(2015), and allows modelling the strategic management of water reservoirs, which is crucial in countries highly dependent on hydro-storage.

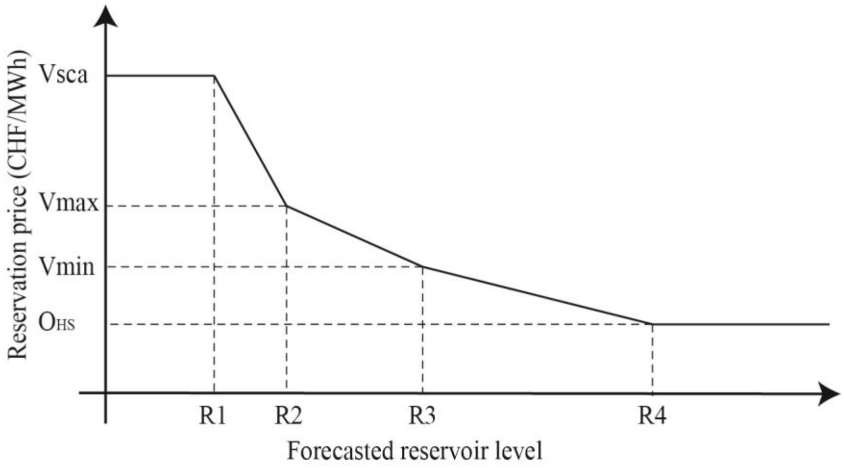

Figure A.13. Modelling of hydro-storage reservation prices.

The variable FRL_t captures the expected excess or shortage of water in a quarter. This is calculated in Eq. (10) considering the current amount of water in the reservoir (W_t), the water inflow I_t (inflow from natural stream flows and from pumping) and the reservoir capacity (R_t).

$$FRL_t = \frac{W_t + I_t}{R_t} \tag{10}$$

Unlike other technologies in which one might consider that the primary resource is infinite, HS must choose when to produce. This implies that a unit of water not used is not necessarily an opportunity lost, i.e., water used today can alternatively be used tomorrow. Water has thus an opportunity cost, and allocation of water should depends on which season HS expects to have a higher revenue. To simulate this behaviour, we assume that the available amount of water for generating in period *t* depends on the simulated historical prices HS has received in season *s* and season *s+1* (in which stored water could be available). We use the last two prices for each of these two seasons, e.g., in period 10 (summer), we take prices of periods 2 and 6 (summer), and 3 and 6 (autumn), to calculate the price factor. We use this in the function described in Figure A.14, to compute the dispatchability factor (FD_t), i.e., the fraction of available water that can be allocated this period. The historical prices factor (PF_t) is calculated in Eq. (11). This formulation ensures that if expected prices for the next period are higher than those for this period, HS is keen to store water from this period to the next one. Price expectations, as noted before, are based on historical prices received by HS (P_t^{HS}). The parameters PF_1 and FD_1 are estimated through the model calibration at 1.2 and 0.55, respectively. This means that HS can never save more than 45% of available water in a period *t* for period *t+1*.

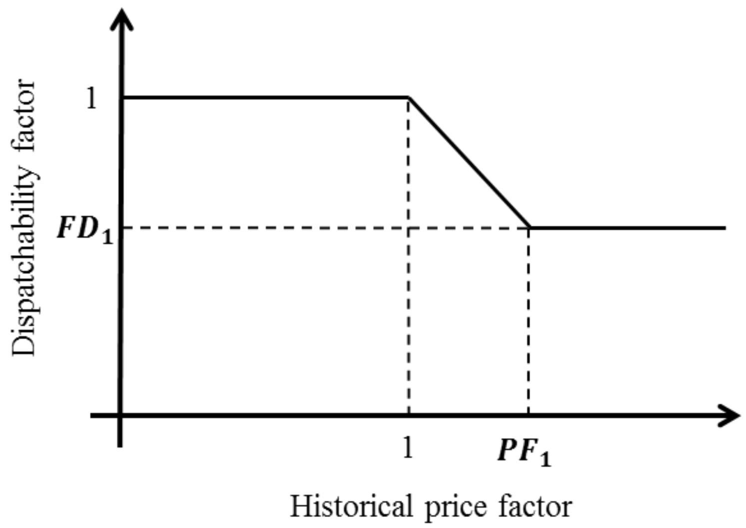

Figure A.14. Modelling of hydro allocable water.

$$PF_t = \frac{P_{t-3}^{HS} + P_{t-7}^{HS}}{P_{t-4}^{HS} + P_{t-8}^{HS}} \tag{11}$$

The available water volume for each representative day of period *t* is calculated as follows:

$$S_{HS,t}^{t} = \frac{FD_t * (W_t + I_t)}{90} \tag{12}$$

Hourly allocation of water, i.e., the available HS generation for each hour ($S_{HS,h,t}$), is estimated using an allocation rule that depend on the demand and potential exports.

With the available generation from all producers we can now clear the market in order to find the dispatched volume of each producer and the resulting prices. Recall that we run our model from 2014 to 2050 with a quarterly step, i.e. 148 quarters. For each quarter we run the hourly dispatch of a representative day, i.e., we consider the representative hourly demand of each season. We thus assume that the 90 days of each quarter present the same pattern. The available supply of each producer ($S_{j,h,t}$) and their marginal costs ($MC_{j,h,t}$) are used to build the supply curve for the hourly dispatch. We run a merit order dispatch according to producers' marginal costs, which yields the quantity $SD_{j,h,t}$ dispatched by each producer. First we compute the local dispatch, i.e., supply from producers is dispatched to cover local demand $D_{h,t}$, which includes the consumption from PSP. We assume $D_{h,t}$ is totally inelastic. Local dispatch is solved as a basic costs minimisation problem as follows:

$$\min_{SD_{j,h,t}} \sum_j MC_{j,h,t} SD_{j,h,t} \quad \forall\, h,t$$

$$\text{Subject to}$$

$$SD_{j,h,t} \leq S_{j,h,t} \tag{13}$$

$$D_{h,t} = \sum_j SD_{j,h,t}$$

The remaining supply ($SR_{j,h,t}$) is then available for exports. It will be used only if the prices in the countries that import from Switzerland exceed the marginal costs of this remaining supply.

$$SR_{j,h,t} = S_{j,h,t} - SD_{j,h,t} \tag{14}$$

Similar to the dispatch to cover national consumption, we compute a merit order dispatch for exports. However, unlike the national demand, which is inelastic, exports depend on the neighbouring countries' demand for imports from Switzerland ($DE_{c,h,t}$) and their willingness to pay. The former is an exogenous variable and is estimated based on historical data between 2009 and 2013. The latter equals the hourly prices in each country c (Italy, Germany and France), $EP_{c,h,t}$. Exports from producers to each country ($ES_{j,c,h,t}$) are calculated by solving a welfare maximisation problem, which allows calculating the clearing price $P_{h,t}$.

$$\max_{P_{h,t}, ES_{j,c,h,t}} \sum_{T,c} \left(EP_{c,h,t} - P_{h,t}\right) \times ES_{j,c,h,t} - \left(P_{h,t} - MC_{j,h,t}\right) \times ES_{j,c,h,t} \quad \forall\, h, t$$

Subject to

$$\sum_{c} ES_{j,c,h,t} \le SR_{j,h,t} \tag{15}$$

$$\sum_{j} ES_{j,c,h,t} \le DE_{c,h,t}$$

In the extreme case when the hourly supply (including imports) is lower than the national demand, the price would equal the VOLL, which is assumed to be 3,000 CHF/MWh.

Then, the total quantity supplied ($Q_{j,t}$) by each producer in a quarter is calculated as follows, assuming 90 days per quarter.

$$Q_{j,t} = \left[\sum_{h} \left(SD_{j,h,t} + ES_{j,h,t}\right)\right] \times 90 \tag{16}$$

The stock of water in the reservoir varies from one quarter to another according to hydro-storage production, the water inflow and the spillages ($Spill_t$):

$$\frac{\partial W_t}{\partial t} = I_t - Q_{HS,t} - Spill_t \tag{17}$$

Spillages only occur if the stock of water at the end of the quarter exceeds the reservoir capacity.

$$Spill_t = Max\left(0, R_t + I_t - Q_{HS,t}\right) \tag{18}$$

The reservoir capacity (R_t) and the natural inflow evolve proportionally to the increase of hydro-storage generation capacity as presented in Eq. (19). Likewise, the amount of water pumped is adjusted by the increase of pumping capacity.

$$R_t = R_{t0} \frac{K_{HS,t}}{K_{HS,t0}} \tag{19}$$

A.3.3. Investments decisions

To make investment decisions, each technology calculates its expected profits. These depend on the future capacity and the resulting dispatch. Future capacity ($FK_{n,t}$) equals all the capacity already commissioned (i.e., installed capacity ($K_{n,t}$) and capacity under construction ($UK_{n,t}$)), minus capacity that will not be available in 5 years (the maximum time for a plant to come online) because of obsolescence ($OK^*_{n,t}$):

$$FK_{n,t} = K_{n,t} + UK_{n,t} - OK^*_{n,t} \tag{20}$$

Each technology T needs to calculate the future capacity of other technologies and its own future capacity under different capacity investment assumption, i.e., each technology T considers it is the only technology that expands. In other words, when evaluating their expected profitability, a technology T considers already planned expansion of others technologies but not further expansions. This is a realistic assumption as each technology T has incomplete and imperfect information about the others, i.e., they know what is currently under construction but they cannot know the investment decisions of competitors in real time.

Hence, the forecast of future installed capacity of technology n made by technology T, assuming a capacity investment size e ($FKE^T_{n,e,t}$), considers the capacity already commissioned ($FK_{n,t}$) and the expansion being considered ($E_{n,e,t}$).

$$FKE^{T}_{n,e,t} = \begin{cases} FK_{n,t} + E_{n,e,t} & if\ T = n \\ FK_{n,t} & if\ T \neq n \end{cases} \tag{21}$$

For each technology T we define a maximum quarterly capacity expansion ($MaxCK_T$). Then, to calculate $E_{n,e,t}$ we define 10 sizes, ranging from 10% to 100% of $MaxCK_T$.

$$E_{n,e.t} = e\left(\frac{MaxCK_n}{10}\right) \tag{22}$$

For instance, investments in CCGT vary between 60 and 600 MW. Considering more than 10 expansion sizes could increase significantly the computing time without affecting results. Allowing for different size alternatives is important as, for instance, the minimum size of a CCGT plant is 60 MW. This allows us to include these technical constraints and capture the potential effects of the discrete nature of investments.

For each of the expansion alternatives we compute the market clearing, in which future local demand should be satisfied, while future export demands depend on the residual supply. We thus use Eq. (9) to (15), but consider future expected installed capacity and imports availability. We assume that hydro-storage bids the same volumes and prices as in period t, i.e., the volumes and prices bid by HS at t are assumed to be the same in an hypothetical dispatch in $t+20$ (in 5 years). Assuming the current HS behaviour is a reasonable hypothesis given the uncertainty about future water availability and hydro-storage behaviour. When computing the market clearing, each technology T calculates the average price ($P^{T}_{e,t}$) it would receive if expanding by $E_{n,e,t}$.

The $LCOE^{T}_{e,t}$ is calculated in Eq. (23) by each technology T using its annualized capital costs ($KC_{T,t}$), annual fixed costs ($FC_{T,t}$), variable production costs ($VC_{T,t}$) and resulting load factor ($ELF^{T}_{e,t}$) when expanding $E_{n,e,t}$. The latter is used to calculate the annualized capital costs and the annual fixed costs per unit of electricity expected to be produced.

$$LCOE_{e,t}^{T} = \frac{KC_{T,e,t} + FC_{T,t}}{ELF_{e,t}^{T} \times 24 \times 360} + VC_{T,t} \tag{23}$$

(24×360 are the number of hours in a year)

The resulting price is compared to the levelised cost ($LCOE^{T}_{e,t}$) in order to calculate the expected profitability.

$$X_{e,t}^{T} = \frac{P_{e,t}^{T}}{LCOE_{e,t}^{T}} - 1 \tag{24}$$

Finally, the largest profitable investment size is selected.

$$CK_{T,t} = Max\left(E_{T,e.t} \times W_{e,t}^{T}\right), \tag{25}$$

where $W^{T}_{e,t}$ is defined as:

$$W_{e,t}^{T} = \begin{cases} 1, & if\ X_{e,t}^{T} > 0 \\ 0, & in\ other\ case \end{cases} \tag{26}$$

The model used in *Paper_SwissMarket* and described so far has several limitations. These are:

a) The prices and exports are very sensitive to hydro-storage behaviour. The current reservoir modelling (Eq. (10) to (18)) allows a very limited control of reservation prices and the water available for generating in each period, i.e., the volume to store for the next period. This leads to some periods with excess production, which results in sudden price drops, and could affect the PSP operation simulations. A new approach for modelling conventional hydro-storage is explained in Appendix A.3.4.
b) Pumping is exogenous. This does not allow assessing the long-term dynamics of energy arbitrage in Switzerland, which is the main goal of the *Paper_PSP*. Although results from *Paper_SwissMarket* indicate that prices and within-day price differences

increase in the long-term, the changes in the generation-mix make pumping dynamics highly uncertain. The algorithm used to simulate PSP operation is described in Appendix A.3.5

c) Italy is not considered as a potential exporter to Switzerland. Although exports from this country to Switzerland have been negligible so far, given the very precarious situation of local capacity adequacy in the long-term (one of the main results of *Paper_SwissMarket*), imports from this country might gain in importance in the long-term.

A.3.4. Modelling conventional hydro-storage

Unlike other producers, HS has limited volume of “fuel” (water), so they need to manage the reservoir and decide their generation among different hours. This is possible because of its flexibility. The water has an opportunity cost, i.e., the water not used at certain time can be used later. HS power plants thus need to decide how much water to store, how to bid and the price at which to bid in order to maximise their profits. Solving this problem implies a simultaneous maximization of HS profits and minimisation of costs when clearing the market, which is highly complex to solve given its non-linearity. This, together with the limitations of Vensim to carry out optimisation problems for each period leads us to follow a different approach in the *Paper_PSP*.

Considering that we model one representative day per season, conventional hydro-storage plants need to take two decisions when bidding in the day-ahead market:

- The available water to generate during the season, i.e., the desired filling ratio at the end of the season.
- The bid volumes for each hour.
- The price at which to bid these volumes each hour.

Further complexity is added to this decision given that there is seasonal water storage: the water inflows in spring and summer are higher than the aggregate production in those months, i.e., water is stored from one season to the next one. To simulate the HS bidding strategy, we assume five possible volumes of water available to be allocated during the current season, ten possible patterns of hourly bids and ten possible patterns of hourly bid prices. Since the decisions in a period *t* affect those in period *t+1* and the possibility of inter-seasonal storage, these three decisions are simulated for the next period. The formulation presented in this Appendix thus replaces in the model the one presented in Eq. (10) to (12).

The possible volumes of water available depend on the desired filling ratio at the end of the period. From historical data of the 1991-2013 period (SFOE, 2016c), we find the minimum and the maximum filling ratios for each season $RLmin_s$ and $RLmax_s$ (see Table A.8). Recall, *s=mod(t,4)*.

Table A.8. Minimum, average and maximum filling ratios of hydro-storage reservoirs at the end of each season, according to historical data from the 1991-2013 period (SFOE, 2016c)

	Winter	Spring	Summer	Autumn
Minimum	10%	35%	75%	50%
Average	19%	51%	89%	63%
Maximum	33%	67%	98%	77%

We use them to simulate five possible filling ratios at the end of the period *t1*, as follows.

$$RL_{t,m1}^{t1} = RLmin_t + (m1 - 1)\frac{RLmax_t - RLmin_t}{count(m1) - 1}, \text{ where } t1 = t \tag{27}$$

The volumes *m1* of water available to be allocated during the representative day of *t1* (assuming seasons of 90 days) is calculated as follows:

$$S_{HS,t,m1}^{t1} = \frac{[R_{t-1}RL_{t-1} + I_t - R_tRL_{t,m1}^{t1}]}{90}, \text{ where } t1 = t \tag{28}$$

For estimating the hourly bids, we first estimate the minimum that HS should produce each hour ($Smin_{HS,t,h}^{t}$) to insure the country does not have a shortage.

$$Smin_{HS,t,h}^{t1} = min\left(K_{HS,t}; D_{t,h} - \sum_{j \neq HS} S_{j,t,h}\right), \text{ where } t1 = t \tag{29}$$

Then, using the maximum demand volumes, i.e., the aggregated local demand and the demand for exports, as weights (eq. (30)), we define how water is allocated to the 24 hours of the day by calculating the pattern *r1* of HS hourly bids ($AF_{HS,t,h,r1}^{t1}$), i.e., the fraction of $S_{HS,t,m1}^{t1}$ to be produced each hour. We first calculate this fraction assuming HS focuses either on peak hours ($AFpeak_{t,h}^{t1}$) or on off-peak hours ($AFoff_{t,h}^{t1}$). From these two extreme patterns, we compute each pattern *r1* of hourly bids.

$$Dmax_{t,h} = D_{t,h} + \sum_{c} DE_{c.t,h} \tag{30}$$

$$AFpeak_{t,h}^{t1} = \frac{Dmax_{t,h} - min\left(Dmax_{t,h}\right)}{\sum_h Dmax_{t,h} - min\left(Dmax_{t,h}\right)}, \text{ where } t1 = t \tag{31}$$

$$AFoff_{t,h}^{t1} = \frac{abs\left(Dmax_{t,h} - max\left(Dmax_{t,h}\right)\right)}{\sum_h abs\left(Dmax_{t,h} - max\left(Dmax_{t,h}\right)\right)}, \text{ where } t1 = t \tag{32}$$

$$AF_{HS,t,h,r1}^{t1} = AFpeak_{t,h}^{t1} + (r1 - 1)\frac{abs\left(AFpeak_{t,h}^{t1} - AFoff_{t,h}^{t1}\right)}{count(r1) - 1}, \text{ where } t1 = t \tag{33}$$

Consequently the ten hourly bid curves are defined as:

$$S^{t1}_{HS,t,h,m1,r1} = Smin^{t1}_{HS,t,h} + AF^{t1}_{HS,t,h,r1}\left(S^{t1}_{HS,t,m1} - \sum_h Smin^{t1}_{HS,t,h}\right), \text{ where } t1 = t \tag{34}$$

We follow a similar process for computing the each pattern *w1* of hourly bid prices. The possible bid prices lie in-between the HS variable production cost and the maximum bid price of other producers. This implies that the HS bid price depends on substitutes' bid prices.

$$MC^{t1}_{HS,h,t,w1} = VC_{HS,t} + (w1-1)\frac{\max_{j\neq HS}(MC_{j,h,t}) - \min_{j\neq HS}(MC_{j,h,t})}{count(w1)-1}, \text{ where } t1 = t \tag{35}$$

Next, we compute the market clearings resulting for all the combinations (5*10*10=500) of HS bidding strategies. The market clearing includes the cost minimisation problem for satisfying local demand, and the welfare maximisation problem for satisfying exports demand described in equations (13) to (16).

Since we assume that the HS bidding strategy for a period *t* is based on a two-period optimisation, all the possible patterns of hourly bids and bidding prices for this period and the next one are also computed in *t* (see Figure A.15). Given that the volume of water available in *t1+1* depends on the reservoir filling ratio at the end of *t1* ($RL^{t1}_{t,m1}$), assuming five possible filling ratios at the end of *t1+1*, would yield 25 pairs of volumes of water available for the periods *t1* and *t1+1*. This approach has several problems. First, the computational time increases significantly. Second, this could lead to frontier problems: the resulting available volumes could be unrealisticly high, e.g., the reservoir could be emptied in *t1+1* because the optimisation does not consider the time beyond *t1+2* in which water is necessary for HS to operate. Since estimating the HS bidding strategy in *t* considering more than two periods is not realistic, we assume the reservoir filling ratio at the end of *t1+1* ($RL^{t1+1}_{t,m1}$) equals the historical average filling ratio for that season ($RLave_{t+1}$). This approach prevents the calculations to increase by a factor of 5 (the number of *m1* indexes) and provides control over the available water in the long-term. Hence, at time *t* only five pairs of volumes of water available are estimated for the periods *t1* and *t1+1*. The minimum, maximum and average filling ratios for each season were presented above in Table A.8.

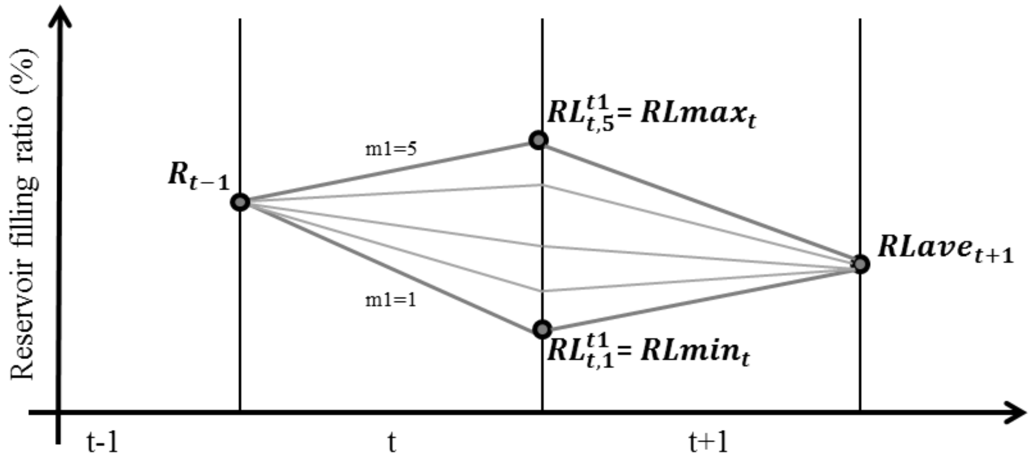

Figure A.15. Modelling the alternatives of water available in the next two periods.

Assuming seasons of 90 days, the volume *m1* of water available for each representative day of *t1+1* ($S^{t1+1}_{HS,t,m1}$) is calculated at *t* as follows:

$$S^{t1+1}_{HS,t,m1} = \frac{\left[R_t RL^{t1}_{t,m1} + I_{t+1} - R_{t+1} RLave_{t+1}\right]}{90}, \text{ where } t1 = t \tag{36}$$

For each of these volumes we next calculate each pattern *r2* of hourly bids ($S^{t1+1}_{HS,t,h,m1,r2}$), and each pattern *w2* of bid prices ($MC^{t1+1}_{HS,h,t,w2}$) for a representative day in quarter *t1+1* using equations (29) to (35). Subsequently, we compute the market clearing for a representative day in quarter *t1+1*. With the resulting estimation of HS dispatched volumes ($Q^{t1}_{HS,t,h,m1,r1w1}$ and $Q^{t1+1}_{HS,t,h,m1,r2w2}$) and the market prices ($P^{t1}_{t,h,m1,r1w1}$ and $P^{t1+1}_{t,h,m1,r2w2}$), we calculate the HS revenues over the two periods. Based on the maximum revenue, we identify the best bidding strategy for a representative day in quarter *t*, i.e., the bid volumes ($S_{HS,h,t}$) and prices ($MC_{HS,h,t}$).

A.3.5. PSP operation

We assume that PSP have perfect information about other producers concerning their available hourly supply and marginal costs (bidding prices). We run a dispatch (including the electricity exchange) excluding PSP and calculate the hourly prices and the volumes dispatched. We call this a "pre-dispatch". Recall $S_{j,h,t}$ denote the available supply from producer j for hour h. Producers bid these volumes at their marginal costs $MC_{j,h,t}$ and the market is cleared by merit-order dispatch; $Q_{j,h,t}$ denotes the quantity dispatched and $SU_{j,h,t}$ is the unallocated supply (Eq. (37)). The unallocated supply of each technology is associated with the respective marginal costs at which it can be dispatched. This allows us to calculate the volumes available for pumping at a purchase price P, i.e., $S^*_{j,h,t}(P)$ (Eq. (38)). We calculate the maximum pumping for each hour at each price $S^*_{h,t}(P)$ taking into account that pumping is constrained by the pumping capacity K_t^{PU} (Eq. (39)). Next we build the Unallocated curve (*Uc* in Figure A.16) from hourly unused supply volumes and considering the pumps' efficiency α so as to obtain the effective available energy (Eq. (40)).

$$SU_{j,h,t} = S_{j,h,t} - Q_{j,h,t} \;\forall j \neq PSP \tag{37}$$

$$S^*_{j,h,t}(P) = \begin{cases} SU_{j,h,t} & \text{if } P \geq MC_{j,h,t} \\ 0 & else \end{cases} \tag{38}$$

$$S^*_{h,t}(P) = min\left(\sum_j S^*_{j,h,t}(P)\,, K_t^{PU}\right) \tag{39}$$

$$Uc_t(P) = \alpha \sum_h S^*_{h,t}(P) \tag{40}$$

We follow a similar process to build the Allocated curve (*Ac* in Figure A.16). First, we calculate the volumes that can be supplied by PSP at a bid price B, $X^*_{j,h,t}(B)$, i.e., the allocated volumes that PSP would displace at that price (Eq. (41)). These are the volumes that can be supplied by PSP if they bid at *B*. Then, we calculate the maximum volumes that can be supplied per hour considering that generation is constrained by the generation capacity $K_{PSP,t}$ (Eq. (42)). Finally, we build the Allocated curve $X_t(B)$ as a function of the bid price *B* (Eq. (43)).

$$X^*_{j,h,t}(B) = \begin{cases} Q_{th} & \text{if } B \leq MC_{j,h,t} \\ 0 & else \end{cases} \tag{41}$$

$$X^*_{h,t}(B) = min\left(\sum_j X^*_{j,h,t}(B)\,, K_{PSP,t}\right) \tag{42}$$

$$Ac_t(B) = \sum_h X^*_{h,t}(B) \tag{43}$$

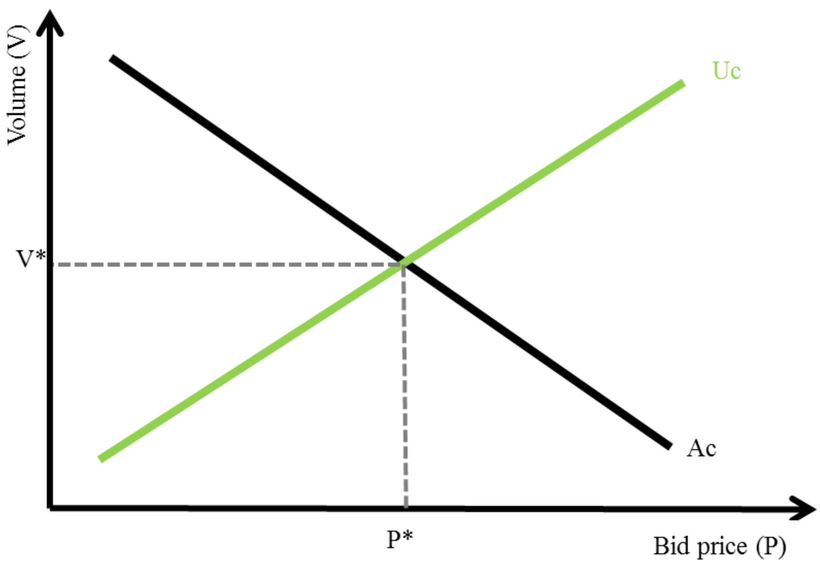

Figure A.16. Simplified representation of Allocated and Unallocated volumes.

Since $B = P/\alpha$, both the Unallocated curve Uc_t and the Allocated curve Ac_t for each time *t* can be written as a function of the purchase price *P*. The energy available for PSP to generate, V_t^{PSP}, can be calculated from the intersection of $Uc_t(P)$ and $Ac_t(B)$. The variables V_t^{PSP} is thus the energy available after subtracting the pumps' efficiency losses, while P_t^{PSP} the maximum price that PSP is willing to pay for energy to pump. Therefore, for a purchase price P_t^{PSP}, V_t^{PSP} is the energy obtained after pumping (Eq. (44)). Finally, the energy PSP have to buy, i.e., their pumping, is calculated as $Y_t^{PSP} = {V_t^{PSP}}/{\alpha}$.

$$V_t^{PSP} = Ac_t(P_t^{PSP}) = Uc_t(P_t^{PSP}) \qquad (44)$$

Next we calculate PSP hourly pumping $Y_{h,t}^{PSP}$ and hourly bids $S_{PSP,h,t}$, which are used for the "real" dispatch. The former are calculated from the cheapest unallocated volumes $R_{j,h,t}$ (see Eq. (45)), while the latter is calculated from the most expensive allocated volumes $Z_{j,h,t}$ (see Eq. (46)).

$$\min_{R_{j,h,t}} \sum_{j,h} MC_{j,h,t} R_{j,h,t} \qquad (45)$$

Subject to

$R_{j,h,t} \leq SU_{j,h,t}$ (availability of unallocated energy)

$Y_{h,t}^{PSP} = \sum_j R_{j,h,t}$ (hourly pumping)

$Y_t^{PSP} = \sum_h Y_{h,t}^{PSP}$ (daily pumping)

$$\max_{Z_{j,h,t}} \sum_{j,h} MC_{j,h,t} Z_{j,h,t} \qquad (46)$$

Subject to

$Z_{j,h,t} \leq Q_{j,h,t}$ (generation of expensive producers)

$$S_{PSP,h,t} = \sum_j Z_{j,h,t} \text{ (PSP hourly bids)}$$

$$V_t^{PSP} = \sum_h S_{PSP,h,t} \text{ (PSP daily generation)}$$

The volumes $Y_{h,t}^{PSP}$ are treated as an additional consumption, so they are aggregate to the local consumption (including losses) and PSP is included as the 11th producer with its hourly bids $S_{PSP,h,t}$ for computing the "real dispatch" (Eq. (13) in Appendix A.3.2).

APPENDIX B: PAPERS

Osorio, S., van Ackere, A., 2016. Energy Policy 93, 8–22. doi:10.1016/j.enpol.2016.02.043

Osorio, S., van Ackere, A. Submitted to “Renewable and Sustainable Energy Reviews” in August 2016.

Larsen, E.R., Osorio, S., van Ackere, A. Submitted to “Renewable and Sustainable Energy Reviews” in January 2016.

APPENDIX B.1

From nuclear phase-out to renewable energies in the Swiss electricity market

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Abstract

Liberalisation and the ever larger share of variable renewable energies (VRES), e.g. photovoltaic (PV) and wind energy, affect security of supply (SoS). We develop a system dynamics model to analyse the impact of VRES on the investment decision process and to understand how SoS is affected. We focus on the Swiss electricity market, which is currently undergoing a liberalisation process, and simultaneously faces the encouragement of VRES and a nuclear phase out. Our results show that nuclear production is replaced mainly by PV and imports; the country becomes a net importer. This evolution points to a problem of capacity adequacy. The resulting price rise, together with the subsidies needed to support VRES, lead to a rise in tariffs. In the presence of a high share of hydro, the de-rated margin may give a misleading picture of the capacity adequacy. We thus propose a new metric, the annual energy margin, which considers the energy available from all sources, while acknowledging that hydro-storage can function as a battery. This measure shows a much less reassuring picture of the country's capacity adequacy.

Keywords: Swiss electricity market, system dynamics, renewable energies, security of supply, capacity adequacy.

1. Introduction

Before the 1980s, electricity was mainly produced using hydro-power, nuclear and thermal-based units. Most markets were monopolies, whose only concern was to ensure capacity adequacy (Lieb-Dóczy et al., 2003). The liberalisation process of electricity markets, which started in the 1990s, has led to the creation of competitive wholesale and retail markets and the unbundling of the sector segments (generation, transmission and distribution), often resulting in the privatisation of generators (Joskow, 2006). As a consequence, guaranteeing the electricity supply has become more complex. In this paper we focus on the challenges currently faced by Switzerland, one of the last European countries to start a liberalisation process.

Liberalisation enhances competition among generators, resulting in investment decisions being increasingly based on profitability, at the expenses of system security (Lieb-Dóczy et al., 2003). The resulting lack of coordination in investments results in price and capacity cycles, which add complexity to the investment decision process (Arango and Larsen, 2011).

The electricity sector has also experienced several changes in generation technologies. Combined cycle gas turbines (CCGT) gained in importance in the 1990s due to significant efficiency improvements, reduced pollution and shorter construction lead times (Ford, 1997). Over the last two decades, governments have encouraged investments in renewable generation, mostly in variable renewable energies (VRES), i.e., solar and wind. However, these technologies create a new challenge for the sector. Their availability factors are significantly lower than those of, e.g., thermal generation, and their production is subject to inherent variability that needs to be balanced in real-time (Lise et al., 2013). Additionally, their large penetration has a price-lowering effect, which decreases the profitability of other generators. However, consumers do not benefit from these lower prices as they are charged cost of the subsidising renewable energies (BMWi, 2015). The uncertainty concerning new investments and rising tariffs due to VRES subsidies affects numerous markets. Many countries are thus facing the challenge of providing increasing amounts of affordable 'green' electricity, in the right place, at the right time.

Additionally, electricity markets are increasingly interconnected. This can improve security of supply (SoS) as it gives countries access to more supply, and helps balancing the load, e.g., in countries with complementary seasonal patterns. However, a high degree of dependency can discourage new investments in the long-term, negatively impacting SoS (Ochoa and van Ackere, 2009).

Although assessing SoS has been mainly addressed as a capacity adequacy problem, today other aspects such as import dependency, environmental issues and tariff affordability must be considered. Actions to enhance capacity adequacy may conflict with economic efficiency or environmental protection or both. Thus, understanding the dynamics of electricity markets is a necessity to develop appropriate policies.

We develop a simulation model calibrated to the Swiss electricity market to analyse the investment decision process and the impact on SoS of the changing generation mix. The model is developed using system dynamics (SD), which aims mainly at understanding a problem based on its causal structure, by analysing the feed-back loops among the key variables (Sterman, 2000). This methodology provides several advantages including (*i*) visualizing the interactions and causal relationships between the different variables, (*ii*) providing understanding of the impact of delays on the system's evolution, and (*iii*) allowing evaluating SoS under different scenarios of energy policy.

As shown in Table 1, in 2013 nuclear energy accounted for 36% of Swiss electricity generation and hydro-power for 58%, split between run-of-river (26%) and hydro-storage (32%). The share of other sources was only 6%, with PV and wind energy accounted for barely 1% (SFOE, 2014a). However, the government is strongly encouraging these technologies through feed-in tariffs (FiTs). For instance, the FiT for PV installed since January 1st, 2014, lasts 20 years, and varies, depending on the nominal capacity, between 172 and 304 CHF/MWh[7] (The Swiss Federal Council, 2015). It is noticeable that PV capacity has increased nearly ten-fold between 2009 and 2013: 755 MW compared to 79 MW (SFOE, 2014a). Switzerland appears self-sufficient, achieving net exports equivalent to 3% of net production. However, when considering the hydraulic year, we observe net exports of 2.0 TWh between September 2012 and August 2013, but net imports of 2.6 TWh between October 2012 and April 2013, indicating a strong import dependency in winter.

Table 1. Main statistics of the Swiss electricity market in 2013 (SFOE, 2014b).

	Volume (GWh)	**Share (%)**
Total production	68,312	100
Run-of-river	*17,759*	*26*
Hydro-storage	*21,813*	*32*
Nuclear	*24,871*	*26*
Others	*3869*	*6*
Net production	66,180	
Pumping	2132	
Net exports	2396	

[7] 1 CHF = 0.92 Euro (exchange rate December 2015).

National consumption	63,784

Switzerland currently benefits from long-term contracts for importing cheap off-peak energy from France but they will expire by 2040 (AES, 2012). Since the Federal Council plans to gradually decommission the nuclear power capacity, SoS is threatened in the middle- and long-term. The government expects VRES to partly replace the expiring contracts and the capacity that will be dismantled.

Besides the support to VRES, the government and the Swiss Federal Office of Energy (SFOE) aim to create a favourable framework for CCGT. This technology's availability is similar to nuclear power and it is flexible enough to complement hydro-storage to meet the balancing needs resulting from VRES. However, the high emissions challenge its profitability (carbon costs) and its acceptance by the Swiss population.

The next section motivates the methodology (SD) and describes the model. In Section 3 we present our results and we conclude with a discussion of policy implications.

2. Methods

Gary and Larsen (2000) argue that traditional economic equilibrium models do not adequately address the issues faced by recently liberalised industries: during their transition to competitive markets they do not comply with the equilibrium assumptions. We therefore model the system’s structure explicitly to gain understanding of the dynamics of the industry, using SD.

SD models take a system's view of strategic problems and focus on capturing the feedback mechanisms (created by a series of causal relationships) and time delays that define the structure of a system as understood by the decision makers (Sterman, 2000). The system is represented by a set of differential equations. Modelling causality and delays is important in energy policy formulation since this helps investigate whether policies trigger instabilities which may affect future system performance (Arango, 2007). SD has been used to explain the dynamics of electric markets. Bunn and Larsen (1992), Ford (1999) and Ochoa (2007) were among the first to use SD to analyse how these new investment dynamics impact capacity adequacy, and in turn the SoS, in respectively England and Wales, the western market of the U.S.A., and Switzerland. More recently Pereira and Saraiva (2013) developed an hybrid SD-optimisation model for the Spanish-Portuguese market to evaluate expansion plans in view of the increased renewable generation. A detailed review of the main system dynamics models used to simulate electricity systems can be found in Teufel et al. (2013).

SD is particularly suitable for capturing the dynamics of markets at an early stage of liberalisation since it allows incorporating bounded rationality and stakeholders' behaviour. Given that there is no historical data for a competitive Swiss market, this approach offers an attractive way of understanding how the market might evolve, generating for instance insights into the effect of price shocks or parameter uncertainties as well as illustrating potential undesirable consequences of the proposed regulation (Larsen and Bunn, 1999). Given the huge uncertainty concerning the future of nuclear power in Switzerland, the possibility to evaluate different scenarios is essential.

Our model includes VRES generation and expansion, which allows us to understand their long-term effect on the SoS. The model is divided into three modules: market clearance and electricity exchange, which are shown in Figure 1, and the investment decision process is presented in Figure 2. These diagrams show the relations among the main variables, whose interactions determine the dynamics of electricity markets.

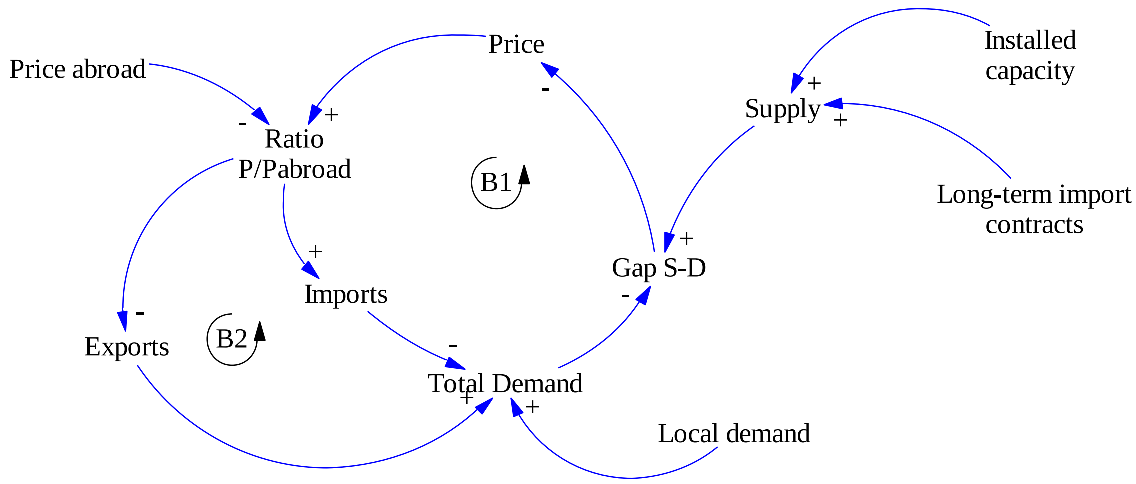

Figure 1. Electricity exchange and market clearance.

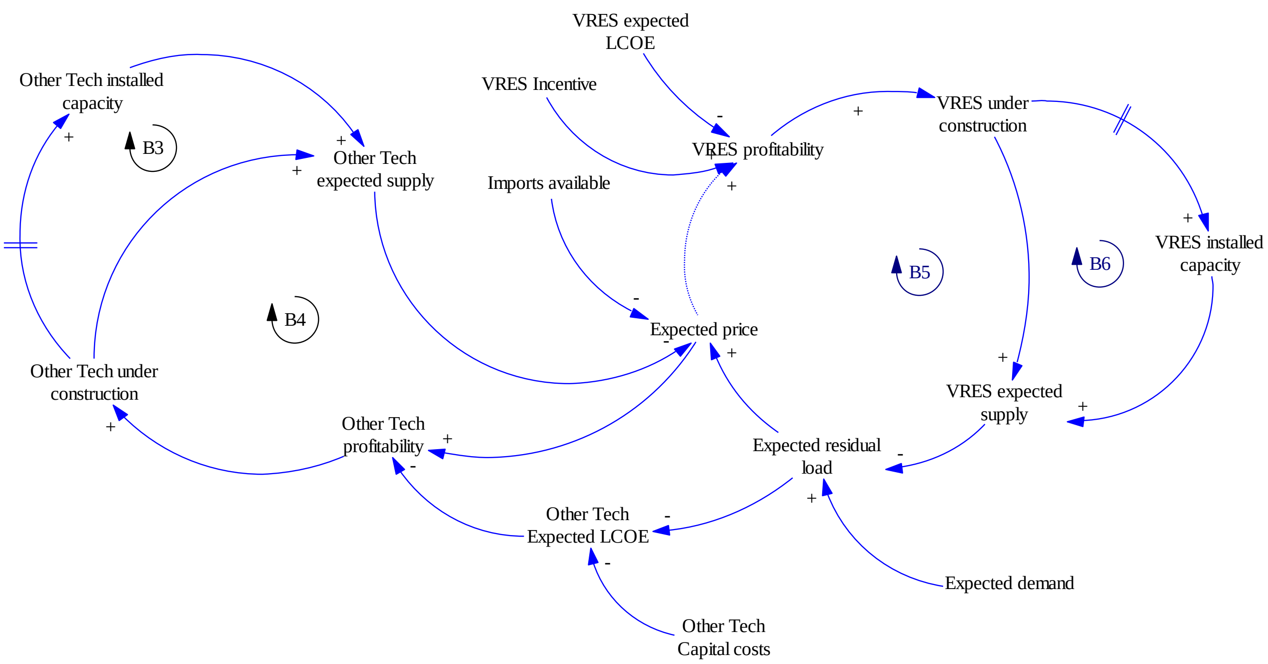

Figure 2. VRES effect on the investment decision process.

Figure 1 explains how the market is cleared. Total demand results from the local demand and the net flow of electricity exchange. Loops B1 and B2 explain the balance of exchanges (imports and exports). If total demand grows, the gap between supply and total demand (*Gap S-D*) will fall. Since the merit order dispatch depends on marginal costs, a tighter *Gap S-D* leads to higher prices. The market price is compared to the price abroad to determine whether the country imports (B1) or exports (B2).

Investment dynamics (Figure 2) represent Ford's (2002) theory of investor behaviour, according to which investment decisions are based on expected profitability. Such expectations are affected by expectations of future prices and costs, as well as competitors' investments. Capacity construction is thus encouraged by high profits, and in turn increases the future supply. As explained before, a higher expected supply leads to lower prices and, in turn, to lower profits. Hence, a balance is reached since lower profits discourage further investments (loops B3 and B4). The investors' expected profitability depends also on their expected costs (LCOE[8]). According to Ueckerdt et al. (2013), using LCOE for comparing technologies, in particular VRES with non-VRES, is not appropriate because VRES create balancing, grid and profile costs for the system. However, these costs are not supported by investors, who decide based on their financial costs.

If VRES are supported by FiTs, they always receive a fixed price, which is defined so as to allow them to recover their capital and fixed costs. Consequently, the expected price does not affect VRES profitability, nor investments in VRES. Without FiTs, lower prices lead to lower investments (loops B5 and B6), as for other technologies. In this paper we assume that, until 2035, VRES are supported by FiTs and grow according to a planned expansion in order to meet government targets. After 2035, investment decisions in VRES are endogenous and based on their profitability, which depends on market prices.

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[8] The levelized costs of electricity (LCOE) consider capital and operational costs and are expressed in money/electricity generation, i.e., CHF/kWh. The operational costs are easily assessed in these units. When assessing the capital cost per unit generated for a future plant, it is necessary to calculate the Full Load Equivalent Operating Hours (FLEOH) of the plant. As the plant incurs costs throughout its lifespan, it is necessary to take the present value of all the annualized costs.

The expected profitability of other technologies is affected by expected future capacity of all technologies, including VRES. Since electricity markets are dispatched by merit order and VRES have marginal costs close to zero, the same demand can be met by generation with lower variable costs, resulting in a lower clearing price. A reduction in the expected price will affect other technologies' profitability, discouraging investments in new capacity. Peak units (CCGT and hydro-storage) are particularly affected since larger amounts of VRES generation not only reduce prices, but also the residual demand (demand minus the production of VRES). Hence, generation needed from CCGT and hydro storage, and thus their operating hours, decrease. Consequently, their expected LCOE increases which, together with lower prices, decreases their expected profitability.

We assume that imports compete with local generation. Thus, the country imports either because local capacity is not sufficient to meet local demand or because the price of imports is below that of other alternatives (merit order dispatch).The possibility to import increase the expected supply, which might decrease prices. Appendix A provides a detailed model description, including the model equations.

We run the simulation from 2014 to 2050. For each quarter (season) we simulate a representative day. For each representative day, hourly demand shapes for each season are estimated using historical data from 2009-2013. This allows us to capture the hourly and seasonal patterns of supply and demand, both of which are important given the low short-term elasticity of demand and the non-storability of electricity. To fit the Swiss hydrological pattern, seasons are defined as follows: January-March (winter), April-June (spring), July-September (summer) and October-December (autumn). Following the SFOE (2013), we assume an increasing demand (on average 0.5%/year) for our base case, labelled business as usual (*BAU*). Other demand scenarios proposed in SFOE (2013) are considered later. This estimation of demand includes neither losses nor pumping consumption, which are thus added to build the hourly demand estimations. Losses are assumed to be 8%, according to historical data (SFOE, 2014b). During simulation, pumping and natural inflows are assumed to increase proportionally to pumping and hydro-storage generation capacity, respectively. The model is initialised (2014) using the average seasonal values from 2009 to 2013.

We consider 7 technologies, whose initial capacities and expansion potential, i.e., the maximum they can expand, are specified in Table 2. Our model implements the government objectives of VRES generation: 4.4 TWh by 2020 and 14.5 TWh by 2035 (The Swiss Federal Council, 2013). We thus assume a planned expansion over the simulation horizon of PV and wind energy, proportional to their expansion potential. Given the potentials of PV and wind energy, 90% of the 4.4 TWh must be met by PV in 2020. The availability factor of PV, being 11%, 4110 MW of capacity are needed to produce 3.96 TWh (90% of 4.4 TWh) in 2020. We perform similar calculations for the 2035 objective and for wind energy. The FiT values specified in the Energy Act have been modified several times since their initial implementation in 2009. We thus set the FiTs so as to cover the expected LCOE of each technology, under the assumption that FiTs last 20 years, as is currently the case. Investments after 2035 are determined by their profitability and are limited by their remaining potential.

Table 2. Main simulation parameters.

	Initial capacity (MW)[a]	**Expansion potential (MW)[b,c]**	**Annual fixed costs (CHF/ MW)[d]**	**Marginal cost (CHF/ MWh)[d]**	**Lifetime (years) [d,e]**	**Average availability factors [b] (%)**
Hydro Storage (HS)	9920	1311	24,000	6-56*	80	28
Run-of-River (RR)	3853	254	53,000	11	80	65

	Initial capacity (MW)[a]	**Expansion potential (MW)[b,c]**	**Annual fixed costs (CHF/ MW)[d]**	**Marginal cost (CHF/ MWh)[d]**	**Lifetime (years) [d,e]**	**Average availability factors [b] (%)**
Nuclear (NUC)	3278	0	89,760	10	50	89
CCGT (CCGT)	89	3167	42,000	45-65**	30	92
Photovoltaic (PV)	755	18,947	23,000	2	20	11
Wind energy (WI)	60	2222	38,400	1	20	18
Other thermal (TH)	760	1333	25,000	4-21 **/***	20	51
Total	*18,715*	*27,234*				

[a] SFOE (2014a, 2014c, 2014b)

[b] AES (2012)

[c] SFOE (2012)

[d] Poyry (2012a)

[e] Kannan and Turton (2012)

*Opportunity cost, which depends on reservoir level and on the prices of other producers.

**We assume step-wise increases for fuel and CO_2 prices over the simulation period (Poyry, 2012a).

***Net cost after subtracting the income from heat sales.

After the Fukushima accident in March 2011, the Swiss Federal Council announced the phase-out of nuclear plants after 50 years of operation, i.e., between 2019 and 2034 (The Swiss Federal Council, 2011). This was a major commitment because nuclear capacity equalled 3278 MW in December 2013, accounting for 18% of total capacity. The Parliament is currently reconsidering this decision. Mühleberg (373 MW) should be decommissioned in

2019, as the investments needed are financially non-viable. Biznau I and II (365 MW each) will be decommissioned after 60 years of operation, in 2029 and 2032, respectively. Gösgen (985 MW) and Leibstadt (1190 MW), the more recent plants, can initially operate for 60 years, until 2039 and 2044, and request successive 10 year extensions, which will be granted if the security conditions are fulfilled (Le Temps, 2014). However, the future of nuclear power remains uncertain as at the same time, a referendum demanding that all plants be decommissioned after 45 years of operation is being launched (Swiss Confederation Administration, 2013).

In our base case scenario (*BAU*) we assume what currently seems to be the most likely scenario: Muhleberg being decommissioned in 2019 and the others plants being decommissioned after 60 years of operation. We also assume that hydro projects currently under construction will come online at their scheduled start of operation (SFOE, 2014c).

The market is dispatched according to the marginal costs of the different technologies (see Table 2), and the prices of imports, both of which are exogenous. Hydro-storage bids at its opportunity costs, which are a function of the reservoir level and the prices of other producers. Fossil-fuel generation includes CCGT and other thermal, (mainly cogeneration plants (CHP)). The costs of these plants depend on fuel and carbon prices; their marginal cost is assumed to increase step-wise according to the Poyry (2012a) forecast. The marginal costs of the other technologies are assumed constant over the entire simulation. We use capital costs, fixed costs, marginal costs, and the expected load factor to calculate the LCOE in the model. Annual fixed costs are given in Table 2 and capital costs in Figure 3.

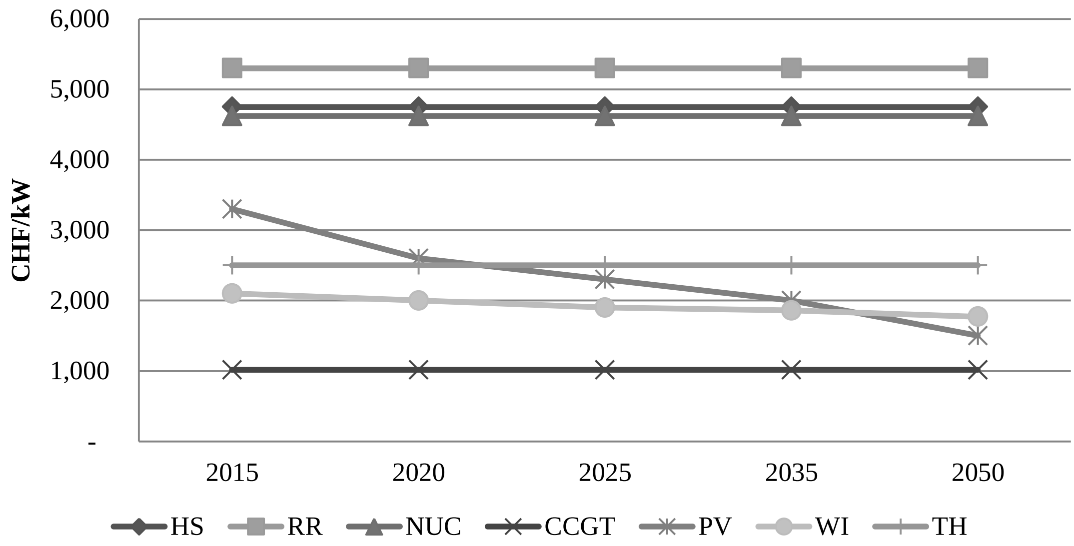

Figure 3. Capital costs of technologies considered in the model. Data from Poyry (2012a).

Cross-border transmission capacity remains fixed at 7500 MW for imports. We consider two types of imports: long-term imports based on existing contracts and balancing imports. Long-term imports availability is assumed to decrease progressively from 27 TWh/year in 2014 to zero in 2040, when these contracts will expire. We assume step-wise decreases according to AES (2012). Their cost is assumed to be 35 CHF/MWh, which lies within the range of costs of nuclear plants found in literature (Boccard, 2014; Lévêque, 2014). Balancing imports are traded in the spot market and their availability equals the difference between the imports transmission capacity and the available long-term import contracts. Hence, the expiration of long term import contracts increases the transmission capacity availability for short-term imports (see more detailed explanation in Appendix A). Balancing import and export prices are exogenous. For each representative day, we built a curve of import prices based on 2012-2013 historical data from France and Germany (97% of imports come from these countries). Likewise, we build hourly demand curves as a function of price for Italy, Germany and France, the countries to which Switzerland exports. As balancing imports and long-term imports are considered as additional technologies when clearing the Swiss market (meeting local and export demand), imports and exports can occur simultaneously, but not to the same country. We run our simulation in Vensim® DSS 6.1.

The model was calibrated using publicly available data, mainly from the SFOE, the Swiss Federal Council, the Swiss Utilities Association (AES), the International Energy Agency (IEA, 2012), the European Power Exchange (EPEX SPOT, 2014), the Swiss Transmission System Operator (Swissgrid, 2015) and the Italian System Operator (GME, 2014). Other sources included Boccard (2014), Kannan and Turton (2012), and reports from the management consulting company Poyry and the Fraunhofer Institute for Solar Energy (ISE). The impact of VRES inherent variability on grid stability is beyond the scope of this paper as balancing the load from VRES should not be a problem given the large hydro-storage capacity, which is very flexible.

We use the classical SD validation tests (Sterman, 2000). The model's equations correctly represent the structure presented in the causal diagrams and are dimensionally consistent, while results of the model are coherent under extreme conditions. We have also performed an extensive sensitivity analysis, which is summarised at the end of Section 3.

3. Results

We perform a long-term simulation of the Swiss electricity market, focussing on the impact of the nuclear phase-out and the increasing penetration of VRES on SoS. A thorough analysis of SoS requires considering multiple dimensions (Larsen et al., 2015), which could in the medium to long-term affect the continuity of supply. The three core elements of SoS we focus on are capacity adequacy, imports dependency and price.

The total available capacity grows from 19 GW at the start of simulation to a maximum of 33 GW in 2035 (see Figure 4). Recall that VRES expansion until 2035 and nuclear decommissioning are exogenous. PV capacity increases from 755 MW in 2013 to 14,436 MW in 2035, and has the highest absolute growth among all technologies; wind energy capacity grows from 60 MW to 917 MW between 2013 and 2035. There are no further investments in these technologies after 2035, when FiTs for new projects are no longer available. In the absence of new investments, capacity of both PV and wind energy decreases from 2035 onwards as a consequence of obsolescence.

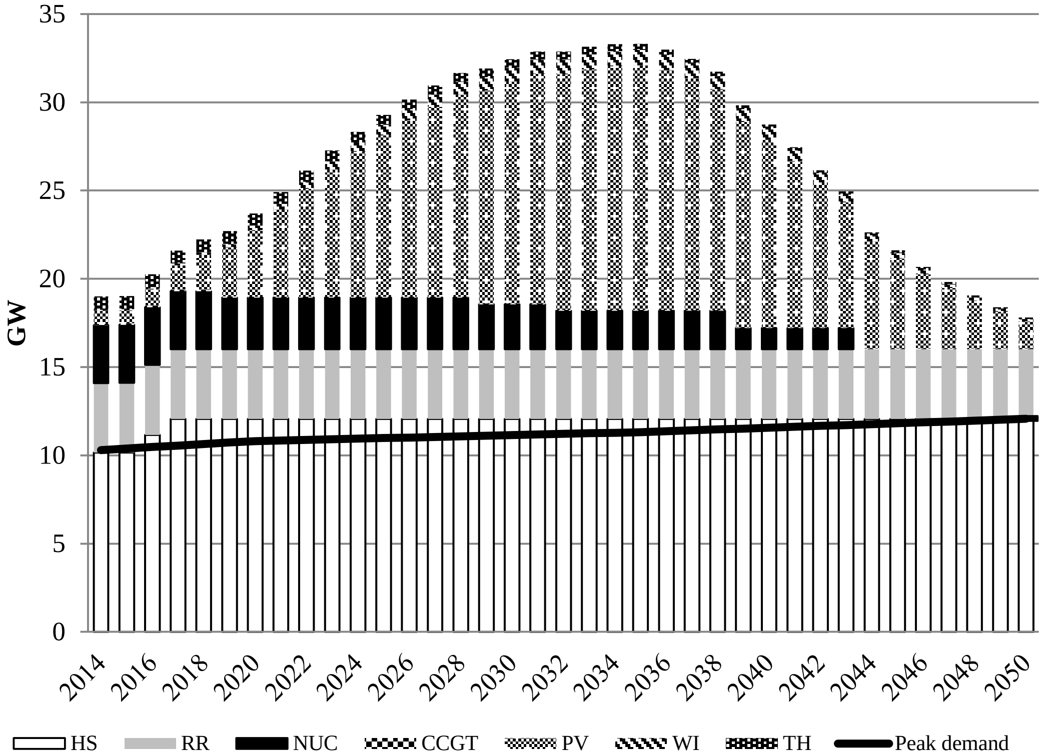

Figure 4. Simulation of installed capacity and peak demand from 2014 to 2050.

There are no investments in other technologies during the entire simulation horizon beyond the investments already committed to. For instance, hydro-storage generation capacity increases significantly in 2016 and 2017, when respectively Nante de Drance (900 MW) and Limmern (1000 MW) are scheduled to start operating (SFOE, 2014c). Both hydro-storage and run-of-river capacity remain constant after 2017. As a result of the massive retirements due to nuclear phase-out and the obsolescence of mainly VRES, total installed capacity decreases to 18 GW by 2050.

The changes in capacity mix also affect the amount and mix of electricity generated (Figure 5). From 2037 onwards the country is always a net importer (Figure 6). The situation deteriorates further in 2039 when Gösgen is decommissioned; net imports reach 33 TWh at the end of simulation (44% of national consumption). In comparison, over the 1993-2013 period, maximum net imports equalled 6.4 TWh in 2005, and in only 4 years out of 21 did imports exceeded exports. This dependency is exacerbated in winter, when net imports average 51% of national consumption in the 2041-2050 period. Nuclear generation is thus partially replaced by PV, but the gap left by the last nuclear plant (2044) is mostly filled by imports.

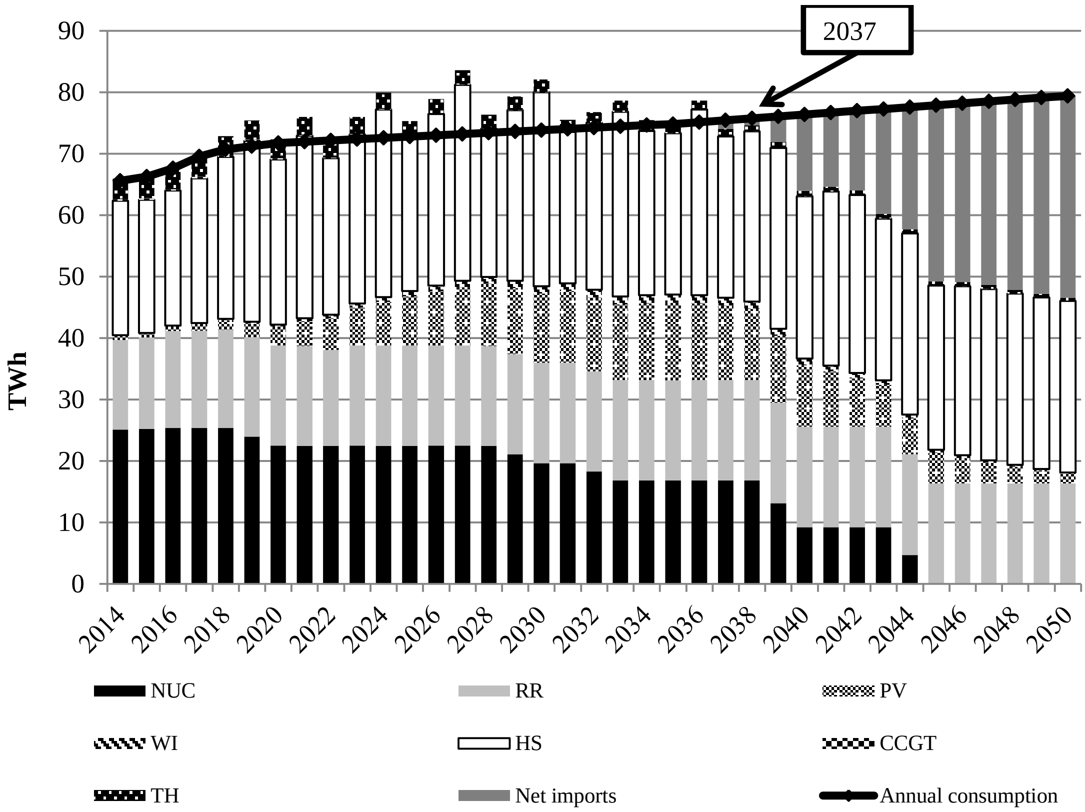

Figure 5. Simulation of energy mix of Swiss net production from 2014 to 2050.

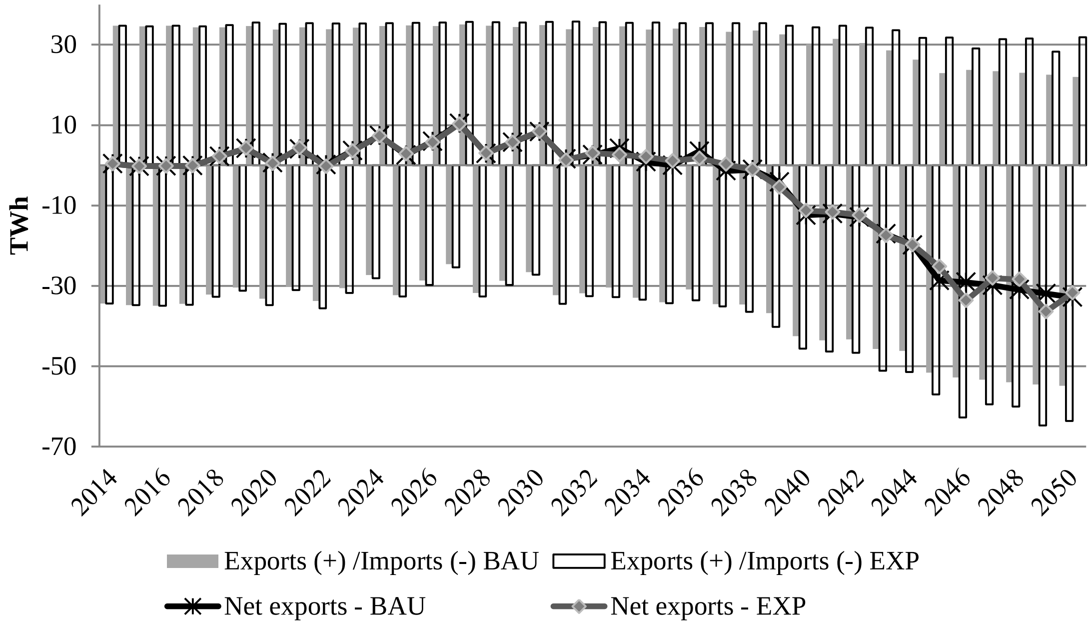

Figure 6. Exchange of electricity under *BAU* and *EXP* scenarios. Exports are expressed in positive values, while imports are expressed in negative values.

The availability of imports reduces the loss of load expectation (LOLE) (Baritaud and Volk, 2014). Also, purchases could be made at prices below those of national producers. However, such a dependency is risky. Imports might be cut by neighbours for political reasons or due to extreme weather conditions. For instance, in case of extremely cold weather, the supply in Switzerland would be seriously endangered if France and/or Germany lacked excess capacity. Besides geopolitical and climate factors, a large dependency might be politically unacceptable. Furthermore, dependency can have a negative impact on investments in the long-term (Ochoa and van Ackere, 2009).

An increasing dependency on imports is not the only element affecting future SoS in Switzerland. While one might expect prices to decrease due to the larger share of zero-marginal cost sources (PV and wind), we observe the opposite: the electricity price increases from 40 CHF/MWh in 2014 to 57 CHF/MWh in 2050 (Figure 7). The annual average price initially remains around 40 CHF/MWh, then increases slightly until the decommissioning of the last two nuclear plants (2039), and increases sharply over the next 7 years. According to our model, prices are expected to increase in Switzerland because of the changing generation-mix: nuclear energy is replaced by less expensive technologies such as PV and wind, but also by more expensive sources such as balancing imports.

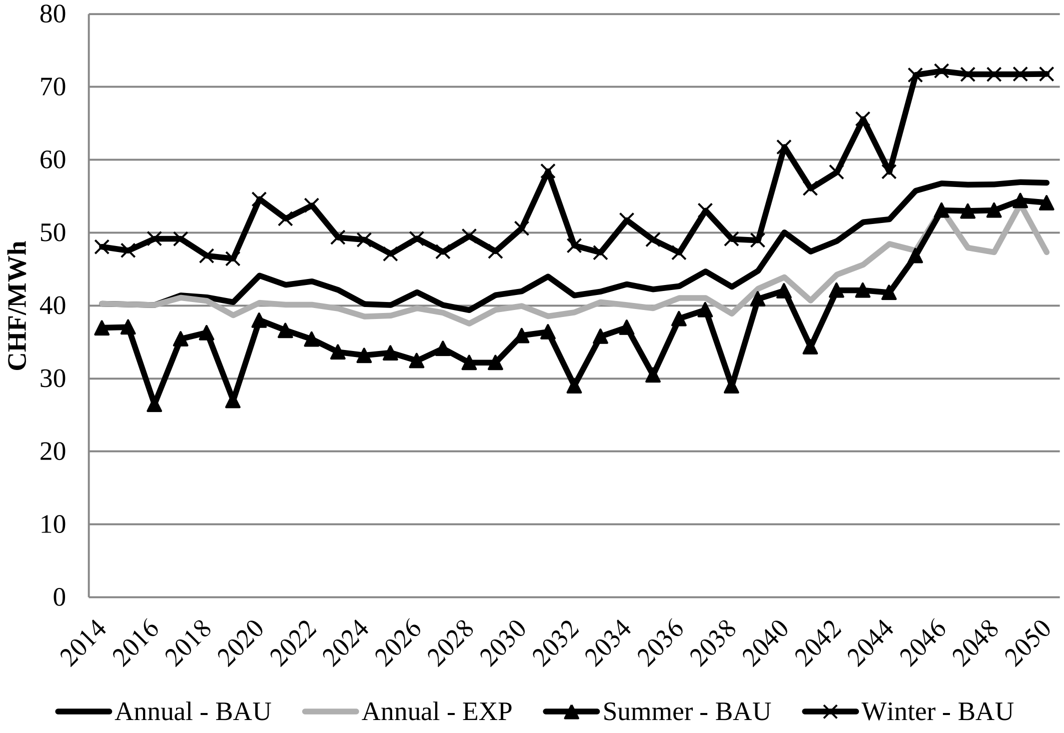

Figure 7. Seasonal and annual average wholesale prices in *BAU* and *EXP*.

This increase is mainly driven by prices in autumn and winter, when there is little (noon) or no (evening) solar generation when demand peaks (see results of winter in Figure 8). The price increase during the peak hours is higher in the evening than at noon. The decommissioning of nuclear plants has increased the ratio between peak load and base load, and the country has become dependent on balancing imports to meet both the noon and evening peaks. However, as there is some solar energy at noon, prices are lower than in the evening. Such higher evening peak prices and lower noon prices have already been observed in the German market since 2011, resulting from the larger penetration of PV.

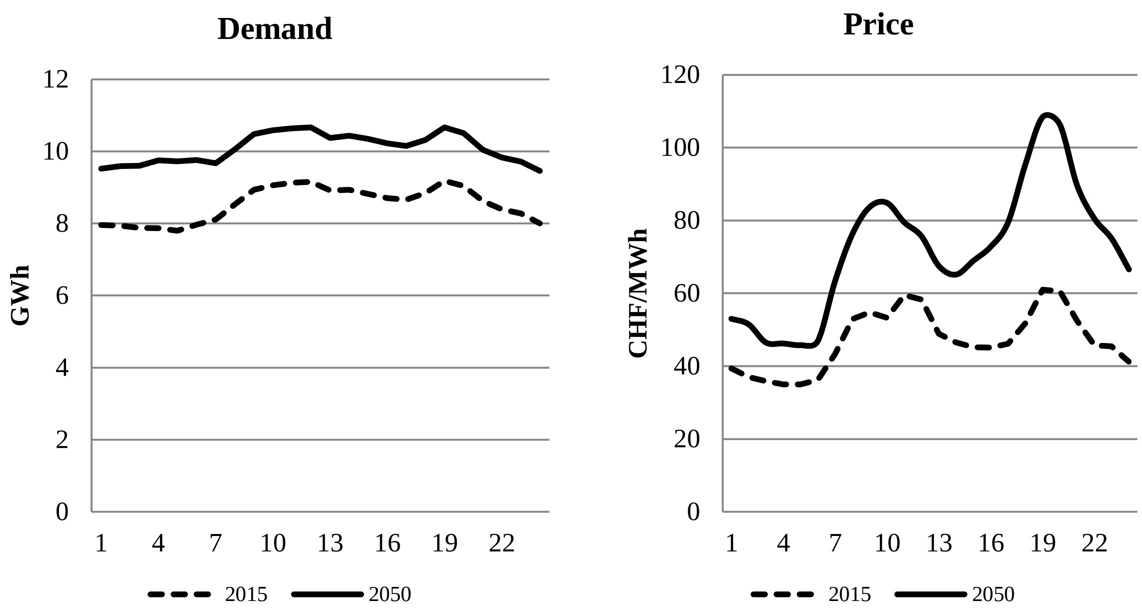

Figure 8. Comparison between hourly demand and prices in winter in 2015 and 2050.

The increasing price and RPC (fee aimed at covering FiTs for VRES) will certainly lead to higher tariffs. We distinguish tariffs from prices in that the former comprises wholesale prices and other levies included in consumers bills, while the latter refers exclusively to the wholesale price. We thus compute tariffs by aggregating wholesale prices (energy prices), transmission and distribution network levies (which are assumed to equal those of 2014), other public levies and RPC fees. The total levies are assumed to equal 135 CHF/MWh for the residential and the commercial sectors, and 85 CHF/MWh for the industrial and the transportation sectors, according to the regulated fees for 2014 (ElCom, 2015). Household tariffs are assumed for the service sector, while industry tariffs are assumed for the transportation sector.

The model generates prices based on the computed dispatch and exchange clearing, while RPC is calculated as follows. Based on capital and fixed costs, and investors' required return, the total cost of FiTs (PV and wind energy) is estimated exogenously at 105 CHF billion. To reflect government policy we assume that the RPC fee progressively increases until 2030, remains stable between 2030 and 2040 and gradually declines to zero by 2050. The RPC fee is recalculated each quarter to account for the change in demand and the revenues from renewable energy sales. RPC thus increase progressively from 10 CHF/MWh (defined by the Swiss Energy Act for 2015) to a maximum of 58 CHF/MWh in 2030 in BAU. This increase is realistic if one compares it for instance with Germany, where the fee paid by households to support renewable energies soared from 3 €/MWh in 2000 to 63 €/MWh in 2014 (BMWi, 2015). Figure 9 illustrates that under these assumptions household and industry tariffs in the BAU scenario increase respectively by 32% and 38% over the period 2014-2030 period and decrease after 2040.

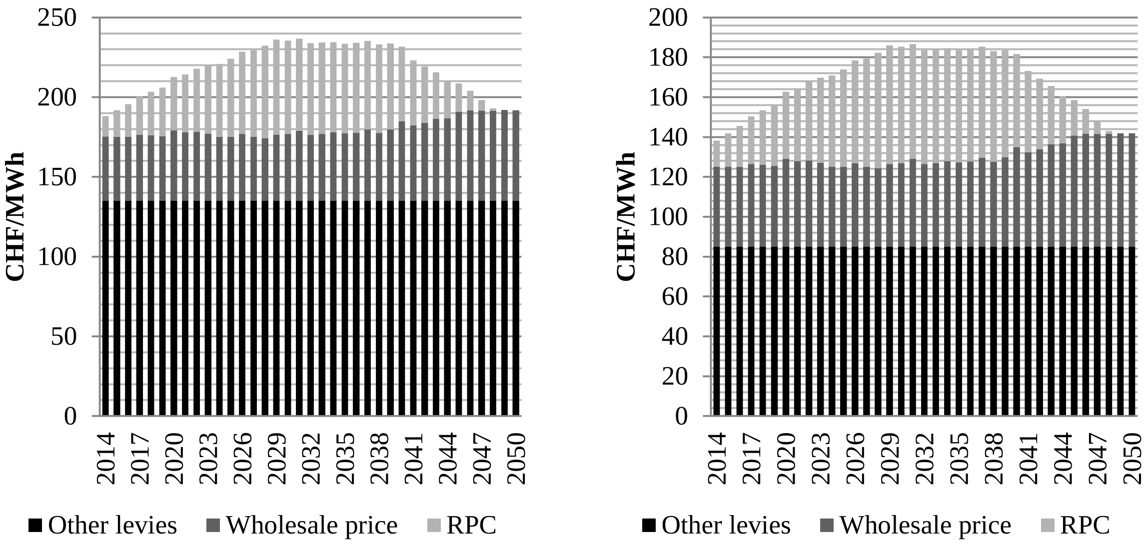

Figure 9. Composition of household (left) and industry (right) tariffs.

In general, we can conclude that all scenarios point to increasing net imports and prices, which increases dependency and decreases affordability. These signals warn about the unsustainability of the system. In particular, the increasing dependency can be interpreted as a symptom of inadequate investments in new capacity.

We now turn to a more detailed analysis of the capacity adequacy. Capacity adequacy has traditionally been measured by the reserve margin, which depends on the ratio between capacity and annual peak demand. This measure is appropriate for systems relying mainly on thermal and nuclear generation, in which technologies' availability is close to 100% or hydro-thermal systems in which seasonality of hydro is less pronounced. Given the increasing role of VRES, whose average availability is considerably more limited, the de-rated capacity margin, which allows measuring the system's capacity to meet annual peak demand, is increasingly preferred as capacity adequacy measure (OFGEM, 2013; Royal Academy of Engineering, 2013). However, this measure could be misleading in some cases. For instance, countries with a significant share of hydro-storage generation might overestimate their capacity adequacy. A very high de-rating factor (80% or more) is usually assumed for this technology, ignoring a possible winter shortage.

We propose an alternative metric, the annual energy margin, defined as the ratio between excess energy and annual domestic demand. The excess energy is calculated as the difference between the total hydro-storage availability (including pumping) and the annual unmet demand. The latter is estimated as follows. For each hour, we calculate the demand that cannot be met by technologies other than hydro-storage (hourly unmet demand). These are summed to calculate the annual unmet demand. A detailed description of both the de-rated and the annual energy margin are given in the Appendix 0. Note that when energy available from non-hydro-storage technologies exceeds domestic demand, this excess can be stored by pumped-storage plants (PSP), thus increasing total hydro-storage availability. This hydro-storage is also available to cover the annual unmet demand.

The energy margin thus captures the seasonal patterns of intermittent sources and the actual availability of hydro-storage generation, incorporating the idea that this technology could perform as a battery. We evaluate the de-rated margin and the energy margin under three scenarios of nuclear phase-out: the current *BAU*, a scenario in which the last two nuclear plants receive operation extensions that go beyond our simulation horizon (*NucInd*), and a scenario which assumes that the initiative to close all nuclear plants after 45 years is successful (*Nuc45*). Assuming a referendum in 2015, Muhleberg would close in 2015, and the others would close between 2015 and 2029.

As was shown in Figure 4, in the *BAU* case total capacity largely exceeds peak demand; however, the de-rated margin never exceeds 30% (Figure 10). It is important to recall that the de-rated capacity margin is calculated as spare de-rated capacity divided by total de-rated capacity. Between 2014 and 2018 the de-rated margin increases from 20% to 27% as the two large hydro-power plants currently under construction start operation. Afterwards, the de-rated margin gradually decreases to a minimum of -5% in 2050. In *BAU* and *NucInd* de-rated margins are identical until 2040, but afterwards the *BAU* de-rated margin in *BAU* decreases sharply due to the decommissioning of the last two nuclear plants. In *Nuc45*, the de-rated margin is below the other two scenarios until 2045; afterwards it equals that of *BAU,* as the generation-mix is the same. Negative margins, as in *Nuc45* and *BAU,* do not imply black-outs as the country can rely on imports. However, they show that even if water is saved to satisfy demand at this time, installed capacity is insufficient.

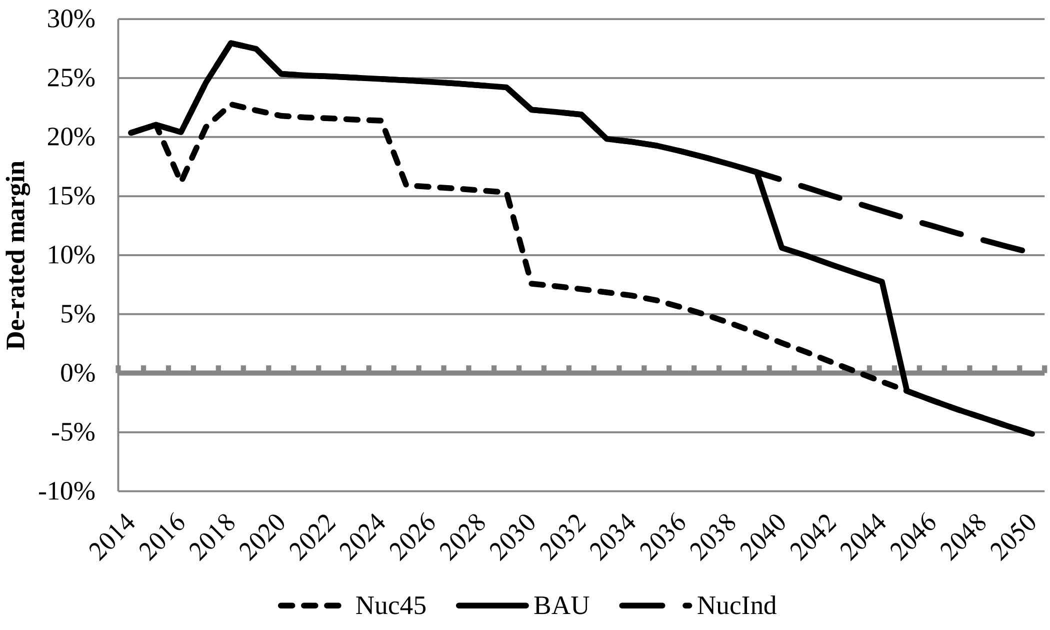

Figure 10. Evolution of the de-rated margin for the three scenarios.

There is a negative exponential relationship between the de-rated margin and the loss of load expectation (LOLE). For instance, according to OFGEM (2013), a de-rated margin of 4% could result in 3 h/year in which supply is expected to be lower than demand in UK. This does not mean that users are disconnected: the system operator may implement mitigation actions, e.g., voltage reduction, to solve the problem without disconnecting any consumers. Although this estimate corresponds to the capacity assessment of the UK and cannot be extrapolated to Switzerland, it gives some insight into the risk of having such a low de-rated margin. Reliability standards vary significantly across countries, e.g. 3 h in France and 18 hours in Belgium (OFGEM, 2013).

The annual energy margin captures the medium-term capacity adequacy improvements resulting from the addition of PV, but Figure 11 shows a much less reassuring long-term picture for the three scenarios in the long-terms. For instance, while the *BAU* de-rated margin showed a downward trend from 2019 onwards, the energy margin follows an up-ward trend until 2028. This is due to the large amounts of PV being installed, which are not considered in the de-rated margin. Although it is clear that PV cannot be used to meet annual peak demand, PV at noon allows hydro-storage to remain out of the merit-order or even pump, increasing its availability during the evening peak. The energy margin is thus a more appropriate metric to assess a country's capacity adequacy in the presence of VRES. Still, one should be aware of the implicit assumption that reservoirs are large enough to store water from one season to another.

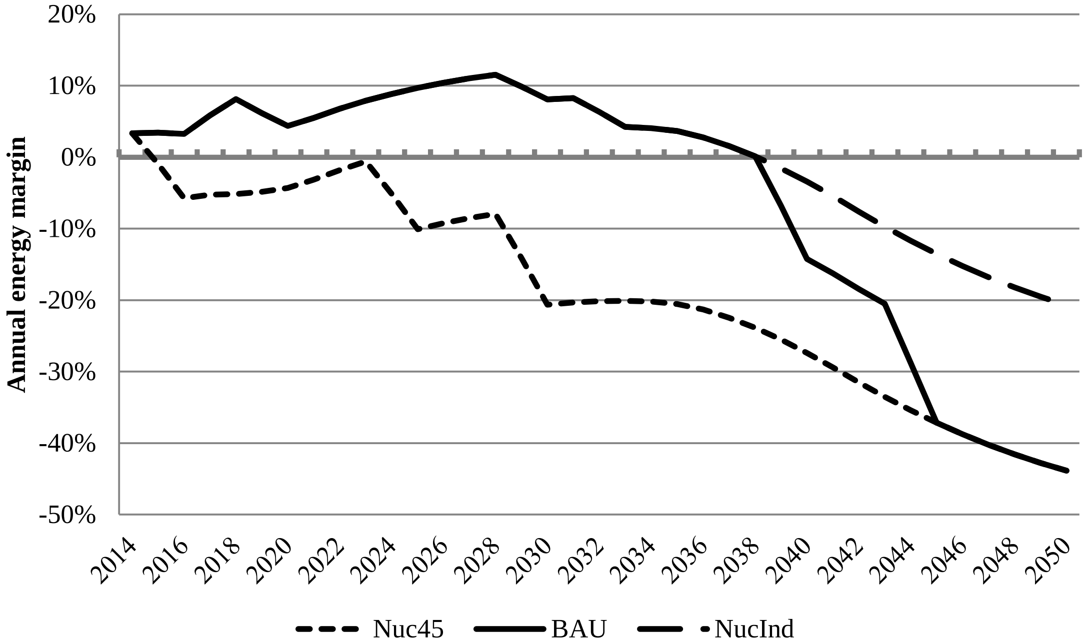

Figure 11. Evolution of the annual energy margin for the three scenarios.

In *BAU*, the annual energy margin turns negative after 2038. This means that even with optimal reservoir management, the total amount of electricity available is insufficient to cover annual demand. Again, this does not necessarily imply blackouts, but the country must rely on imports to satisfy local demand. Thus, dependency after 2037 (recall Figure 6) onwards is due to the unavailability of local sources to meet national consumption: investments in PV are insufficient to cover the increasing demand in the absence of a third of the nuclear power.

The *BAU* and *NucInd* energy margins are identical until the decommissioning of the last nuclear plants in the *BAU* scenario. The exit of the third part of nuclear capacity by 2033 leaves the country with insufficient resources to meet domestic demand; however, imports are sufficient. Although balancing imports increase prices, the rise is insufficient to trigger investments in new capacity. The system thus perpetuates its imports dependency.

The scenario *Nuc45* has the lowest energy margin, as expected. The margin turns negative in 2015, as the closures of Muhleberg and Biznau I have not been anticipated. The margin remains stable between 2016 and 2024 because of the two new large hydro-storage plants and the installation of PV. Two further drops occur in 2023 and 2028, as the remaining nuclear plants close. The margin reaches an all-time low in 2050 (-44%), i.e., net imports cover at least 44% of national consumption (without considering pumping consumption).This implies that, assuming an annual availability factor of 90%, 4,200 MW of CCGT would need to be installed to achieve self-sufficiency by 2050.

In summary, we can say that while the system deteriorates following the decommissioning of the first three nuclear plants in all three scenarios, it is the decommissioning of the last two plants that creates a critical situation. Whatever the decommissioning scenario, there are no investments in CCGT: their high marginal costs relegate these plants to the role of marginal producers, unable to recover their fixed costs. Marginal costs are particularly high after 2030 because of the CO_2 price assumption (see Figure 12). This lack of investments is problematic as CCGT is generally considered to be the most likely replacement for nuclear plants.

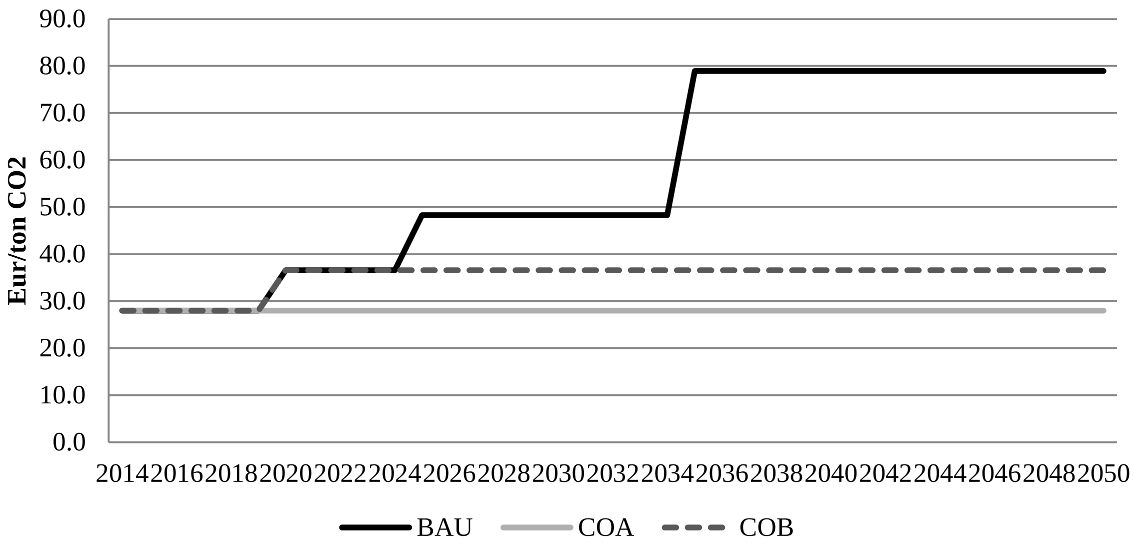

Figure 12. Scenarios of CO_2 prices.

Since CCGT would produce at peak times, mainly to export, we run multiple combinations of CO_2 prices and Italian prices to identify favourable conditions for CCGT investments. We identify two scenarios in these are profitable, labelled *COA* and *COB*. In *COA* we assume that the CO_2 price remains at 36.6 CHF/ton CO_2 after 2023 and that the Italian prices increase by 30%, while in *COB* the CO_2 price remains in 28.0 CHF/ton CO_2 for the entire simulation (see Figure 12) and Italian prices increase by 20%. In both scenarios investments become profitable when the fourth nuclear plant closes (see Figure 13). This highlights that it is important for potential investors to know with certainty, with a reasonable lead time, when nuclear plants will close.

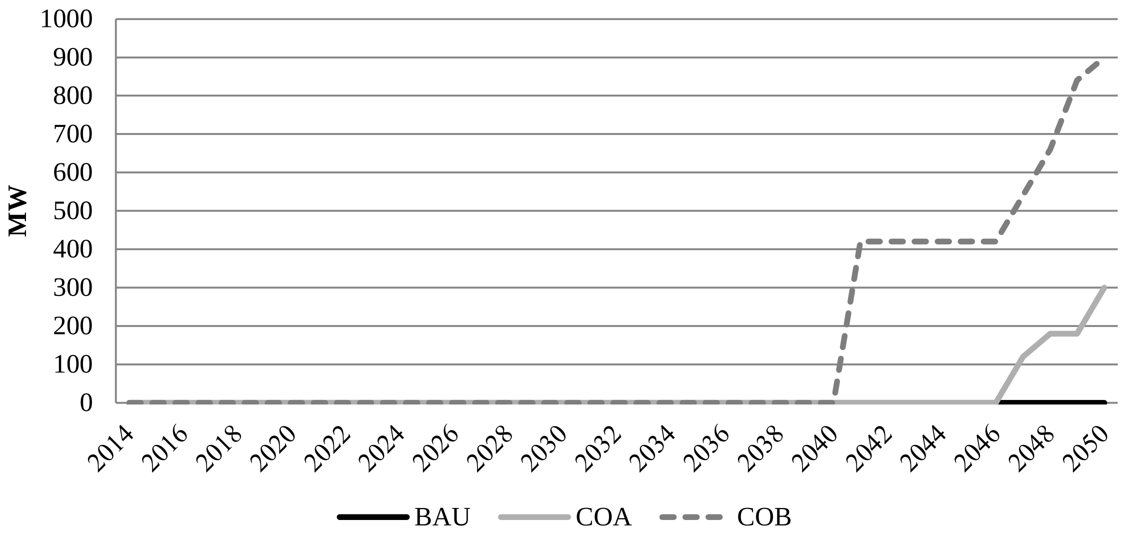

Figure 13. Installed capacity of CCGT under different CO_2 scenarios.

Since Italian prices are more likely to decrease than to increase in the medium-term, CCGT will not be profitable unless there is either a technological breakthrough in CCGT and/or a decrease in gas or CO_2 prices. Alternatively, programs aimed at supporting CCGT (e.g., subsidising investments in carbon capture and storage (CCS) technology) could be considered. An analysis of future fuel and CO_2 prices is beyond the scope of our work. These are traded in international markets, subject to political and geopolitical factors.

To assess the robustness of our results we perform a detailed sensitivity analysis with respect to, among others, prices of neighbouring countries (which affects their willingness to pay for imports from Switzerland and the price of volumes exported to Switzerland), their available volumes for exporting to Switzerland and their desired import volumes from Switzerland; responsiveness of demand to tariffs, the cross-border import capacity, and the costs of the different generation technologies. The main results are summarised below

First, we consider variations between -30% and 30% in German (main source of net imports in Switzerland) and Italian (main destination of net exports from Switzerland) prices, which could occur due to changes in their energy mix and have significant consequences for

Switzerland. The two countries have currently a large penetration of VRES (around 15%). Note that these prices not only affect the price that Switzerland pays for imports (in the case of Germany), but also the two countries' (Italy and Germany) willingness to pay for imports from Switzerland.

While import and export volumes are not sensitive to changes in the German prices, a 30% price change in Germany results in a 10% price change in Switzerland, because balancing imports are usually the marginal producer in the Swiss market. Exports do not vary since the difference between Italian and German prices is so large, that exports to Italy remain profitable. Our results are robust to changes in Italian prices between -20% and +30%. However, for larger drops (-30%), imports and exports decrease by about 10%, because of Italy's lower willingness to pay for imports from Switzerland. Net imports remain unchanged.

We observe that, regardless of the scenario, prices are expected to increase. This increase leads to a rise in tariffs, which in turn could affect consumption. In the case of Switzerland, assessing this impact is difficult due to the limited information about consumers' response to tariff variations, i.e., demand elasticity. We have therefore taken two different approaches to perform a sensitivity analysis with respect to our demand hypothesis: considering different demand scenarios (with implicit demand management) and modelling a tariff-dependant demand.

Aside from the demand assumed in *BAU*, the (SFOE, 2013) considers a scenario in which demand remains mostly stable (*DS*) and a scenario in which demand decreases compared to 2014 level (*DD),* as shown in Figure 14. Both scenarios implicitly consider some demand management measures. When simulating our model with the *DS* and *DD* demands, average prices are respectively 5% and 8% below those of the *BAU* scenario (Table 3). While the country eventually becomes a net importer in the three scenarios, the timing depends on the demand assumptions: 2037 in *BAU*, 2039 in *DS* and 2041 in *DD*. Also, the increase in net imports after the fourth nuclear plant is decommissioned is more limited in *DS* and *DD* than in *BAU*. Overall, as expected, measures aimed at decreasing demand lead to import dependency, while making electricity more affordable.

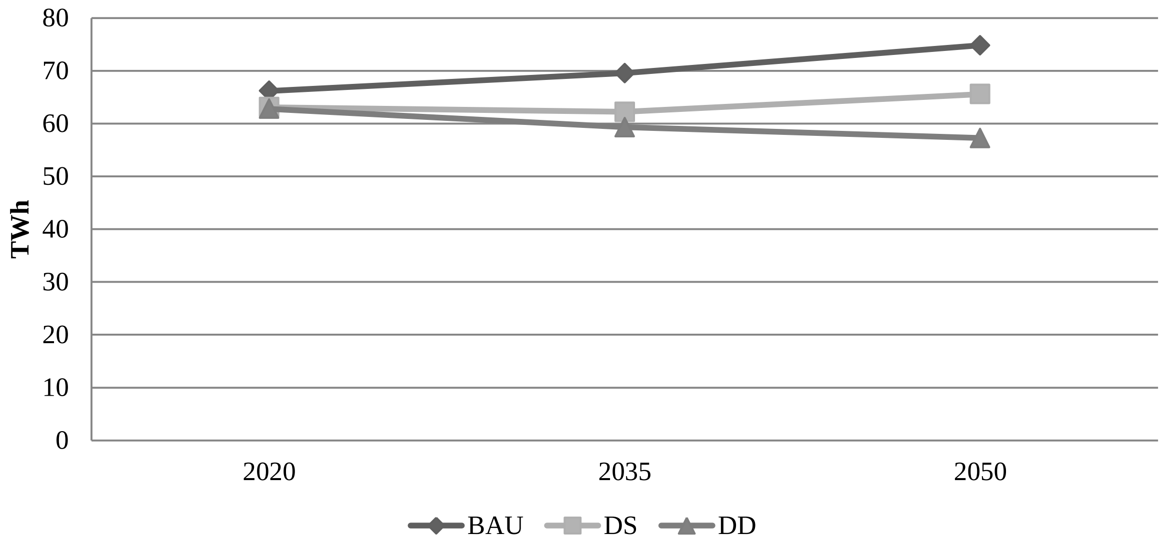

Figure 14. Annual demand for scenarios *BAU*, *DS* and *DD*. Forecast adapted from SFOE (2013) using SFOE (2014b) data.

Table 3. Comparison among scenarios of demand.

	BAU	**DS**	**DD**
Average price (CHF/MWh)	49.2	46.4	45.1
Average exports (TWh/year)	31.7	33.2	33.9
Average imports (TWh/year)	36.6	32.8	30.4
Average net imports (TWh/year)	4.9	-0.4	-3.5

Next we consider an extreme scenario where demand in Switzerland is highly sensitive to changes in tariffs. More specifically, based on a comparison between the *BAU* and *DD* scenarios (SFOE, 2013) we assume that a sharp increase in tariffs could cause long-term demand to decrease by as much as 28%. In this scenario, demand is endogenous to the model and depends on the simulated tariff.

Modelling demand as an endogenous function of tariffs also has a significant impact on international exchange volumes. In this scenario the country only becomes a net importer in 2044, compared to 2037 in *BAU*. The lower demand also leads to lower prices, but RPC is higher as total FiTs costs must be recovered from a lower volume of demand. Tariffs are slightly higher than in *BAU* (up to 7% for households and 9% for industry). Industry and household tariffs peak in 2038 at respectively 45% and 31% above 2014 tariffs. However, evidence from Germany, where demand did not decrease despite a 58% and 113% tariffs increase for households and industry respectively over the 2000-2013 period (BMWi, 2015), suggests that such a significant demand decrease, as simulated here, is unlikely. This scenario should thus be interpreted as an upper bound on potential changes in demand.

The next sensitivity analyses concern capital, fuel and CO_2 costs. First we assume a 20% decrease in capital costs for PV, for wind and for both. In these scenarios the country achieves its renewables target earlier as we assume that the fund aimed at supporting VRES remains unchanged. However, this leads neither to changes in prices, nor in electricity exchanges.

Next we consider a scenario without FiTs for new VRES plants (labelled *NoFiTs*), i.e., achieving the 2020 and 2035 targets is left in the hands of the market, and investment decisions are based on VRES expected profitability. Under this assumption there are no investments in VRES: prices are too low to cover capital expenses. Compared to *BAU*, net imports increase by 150%, mainly because exports decrease significantly. Wholesale prices are also higher in *NoFiTs* as the lower available capacity results in a tighter margin. However, tariffs are lower as the absence of an RPC levy (aimed at covering a total of CHF 105 billion) more than offsets the higher prices (extra cost of CHF 8 billion). Finally, our sensitivity analysis indicates that imports, exports and prices are not sensitive to fuel and CO_2 cost variations between -30% and 30%.

Finally, we turn to the cross-border import capacity, which in the *BAU* scenario is constraining at peak hours, with congestion increasing over the simulation period. To evaluate the impact of this constraint, we run a scenario in which, following the ENTSO-E (2014) forecast, cross-border transmission capacity for imports is assumed to increase from 7,500 MW in 2016 to 10,000 MW in 2020. In this scenario, labelled *EXP*, imports are higher than in *BAU* (recall Figure 6), particularly towards the end of the simulation period, where imports in *EXP* exceed those of *BAU* by 12%.. Exports are higher in *EXP* than in *BAU* because the higher availability of imports increases the country's ability to export. More precisely, the increase in off-peak imports allows shifting hydro production from off-peak to peak-times which, together with the increase in peak imports, enables Switzerland to increase exports to Italy. Consequently, net import volumes are very similar in the two scenarios. These higher imports replace more expensive local production, resulting in lower prices (on average 11% lower over the 2040-2050 period, see Figure 7). Cross-border expansion thus improves the country's SoS as it provides access to cheaper electricity, without increasing dependency.

As the availability of such imports is uncertain, we also tested the impact of reducing Switzerland's maximum hourly trade with France and Germany (under *BAU* assumptions). Total imports and exports are insensitive to a reduction of up to 30% due to Switzerland's large storage capacity: increased off-peak imports allow hydro-storage generation to compensate the shortage of imports at peak time, and exports to Italy are not affected. If import capacity is reduced by more than 30%, shortages occur from 2045 onwards. This results in significantly higher prices, which make CCGT investments profitable.

These sensitivity analyses allow us to conclude that our results are robust to reasonable changes in parameter values.

4. Conclusion and policy implications

The proposed model allows us to simulate the Swiss electricity market and, in particular, the impact of the nuclear phase-out and the incentives for VRES (mostly for PV) to partially replace nuclear power. While the country has historically been a net exporter, creating a surplus for Swiss utilities, our results indicate that imports are bound to increase significantly in the future; in all scenarios the country sooner or later becomes a net importer. Import dependency is expected to be particularly critical in winter.

These changes in the energy mix and exchange patterns cause prices to rise which, together with the RPC, cause tariffs to increase. The higher dependency on imports and the tariff increases highlight a capacity adequacy problem. We introduce a new metric, the annual energy margin, to assess the impact of investment decisions on capacity adequacy, and discuss its advantages compared to the de-rated margin. In the three scenarios of nuclear phase-out, the energy margin gives a less reassuring picture than the de-rated margin. Our results show that the generation capacity adequacy deteriorates to a level where the country is no longer capable of meeting domestic demand. Even when the last two nuclear plants are assumed to remain operational beyond a 60 years lifespan, available energy is insufficient to meet annual demand.

Our model thus helps to understand the new challenges that a large(r) capacity and output of VRES pose to regulators, and how this evolution can jeopardise SoS in electricity markets. In particular, the price-lowering effect of VRES has been widely discussed in the literature. Although the penetration of VRES increases significantly in the Swiss market, our simulations do not indicate a price drop, due to the cost of the sources that replace nuclear power. The impact of VRES and of the nuclear phase-out thus cannot be analysed separately. Import dependency and price rise are tightly interrelated and our results suggest that both are symptoms of a decreasing capacity adequacy.

Since the IEA (2014) refers to energy security as the uninterrupted availability of energy sources at an affordable price, we can conclude that the SoS in the Swiss electricity market is seriously threatened by this import dependency and the decreasing availability of energy, as well as by the significant tariff increases. This large dependency affects utilities' revenues and makes the country vulnerable to climatic and geopolitical risks.

Simulated imports and exports are sensitive to large drops in Italian prices. Historically, Italian prices have been significantly higher than in the rest of Europe. As the Italian market is changing (e.g., encouraging investments in VRES and renegotiating gas contracts), its prices are likely to decrease in the future. France's and Germany's available export volumes are dependent not only on technical and economic factors, but are also subject to political decisions. A major drop in these volumes (in excess of 30%) would significantly affect Swiss prices and CCGT investments.

Following the acceptance of a referendum on February 9th, 2014, the EU has unilaterally suspended negotiations on the entry of Switzerland in the European single energy market. This, together with the political unpopularity of such imports dependency, is leading the country to review its energy policy, in particular regarding nuclear power plants and the constraints on the expansion potential of hydro-power. The recent parliamentary proposal to allow four nuclear plants to operate for 60 years (with the possibility of an extension for two of them) shows that the Swiss politicians are aware that abandoning nuclear energy in the middle-term endangers self-sufficiency.

Policy should thus focus on sending adequate signals to investors so as to at least limit imports dependency. Under current policy, prices seem inadequate to encourage investments in hydro-storage, a reliable and clean technology, in order to fil the gap left by nuclear energy. Likewise, investments in CCGT are not profitable in the *BAU* scenario; lower CO_2 prices and/or a higher Italian willingness to pay for imports from Switzerland would be required. Furthermore, in those cases in which CCGT are profitable, investments only occur shortly before the nuclear phase-out completion. The lack of CCGT investments is particularly critical after the decommissioning of the fourth nuclear plant. Therefore, if the country really is committed to closing down all the nuclear power plants, it is essential to provide attractive conditions, including adequate infrastructure, incentives aimed at improving plant efficiency and/or reducing emissions, and a stable regulatory framework, so as to trigger investments in CCGT.

Supporting this technology might not be the most environmentally friendly alternative and could imply higher costs for the system, and in turn, for consumers, but it seems to be the only alternative given the current strong legislation concerning water flows. Still, this technology is likely to face strong opposition from the population. Given the Swiss direct democracy system, the population can delay and potentially block any policy the government might want to implement; this is an additional source of uncertainty for investors.

The population might also object to the expected tariff rise resulting from the support for renewable energies. Still, these potential additional costs might be justified in order to avoid a much more costly blackout. A 2008 study by the SFOE estimates the costs resulting from a blackout in Switzerland at between CHF 8 and 30 million/min. For a day-long power outage, the estimate is between CHF 12 and 42 billion (without including the damage to Switzerland's reputation as a business location) (Credit Suisse, 2013). In comparison, our model assumes that the investment necessary to support VRES is of the order of CHF 105 billion. The resulting price decrease s partially offsets the cost of these subsidies. Although total costs for consumers are higher in the scenario with incentives, policy maker should also consider that a scenario with FiTs leads to significantly lower dependency.

Another issue affecting dependency is market integration and cross-border capacity expansion. Our results show that if imports transmission capacity is expanded, prices would decrease, but import dependency would increase further. These issues illustrate the complex problem that the policy makers face: incentivising green technologies to meet environmental commitments, without discouraging investments in other technologies, so as to limit imports dependency.

Our model has several limitations. First, we assume that pumping will follow the same pattern as during the 2009-2013 period. However, changes in the generation-mix might affect this pattern: while higher price differences between peak and off-peak prices could enhance arbitrage opportunities and lead to more pumping, dismantling nuclear plants could significantly reduce the availability of cheap energy to pump. Another model boundary issue relates to the interaction with neighbouring markets. Our results are robust to realistic changes in German and Italian prices. However, since demand for exports from Switzerland is calibrated using historical data, our model can only partially capture the consequences of a significant expansion of cross-border transmission capacity.

5. Acknowledgement

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Appendix A. Model description

Below we provide a detailed description of the model explained in Section 2. A full list of the variables and parameters is presented in Table A1.

A.1. Dynamics of capacity

Installed capacity $K_{T,t}$ of each technology increases as new capacity comes online ($EK_{T,t}$) and decreases through obsolescence ($OK_{T,t}$).

$$\frac{\partial K_{T,t}}{\partial t} = EK_{T,t} - OK_{T,t} \tag{1}$$

Obsolesce is defined as the aggregated obsolescence of old projects and new projects as shown in Eq. (3). Old projects are those installed before 2013 that remain installed at time *t* ($OldK_{T,t}$). This capacity becomes obsolete depending on its lifespan (L_T). We do not use a decommission schedule for old projects as we do not have specific information about when each plant will be decommissioned. Obsolescence of old projects, $OldK_{T,t}$ is defined as

$$\frac{\partial OldK_{T,t}}{\partial t} = \frac{OldK_{T,t-1}}{L_T} \tag{2}$$

New projects correspond to the capacity coming online between 2014 and 2050 ($EK_{T,t}$). These become obsolete at the end of their lifespan.

$$OK_{T,t} = \frac{OldK_{T,t}}{L_T} + EK_{T,t-L_T} \tag{3}$$

We consider specific obsolescence conditions for hydropower and nuclear energy. We assume that hydro-storage and run-of-river capacity do not become obsolete but are refurbished to remain online without important losses of efficiency. We also assume that nuclear is decommissioned according to a fixed schedule, represented by the variable $OK_{T,t}$.

Capacity under construction ($UK_{T,t}$) increases by capacity starting construction ($CK_{T,t}$) and decreases by the projects that start operation ($EK_{T,t}$).

$$\frac{\partial UK_{T,t}}{\partial t} = CK_{T,t} - EK_{T,t} \tag{4}$$

New capacity results from the projects that started construction ($CK_{T,t}$) and come online after a delay equivalent to the construction time, $ConsD_T$, which is technology-dependent.

$$EK_{T,t} = CK_{T,t-ConsD_T} \tag{5}$$

A.2. Market clearing

To compute the day-ahead auction for each hour of a representative day of each quarter, available supply and bid prices from producers are needed. Supply from producers comes from generation by the different technologies *T* considered and from imports. The latter might be of two types: long-term contracts (LTI) and balancing imports (BI). The availability of imports from LTI is exogenous based on the estimations of AES (2012). The availability of LTI and BI per hour is presented in Figure A1.

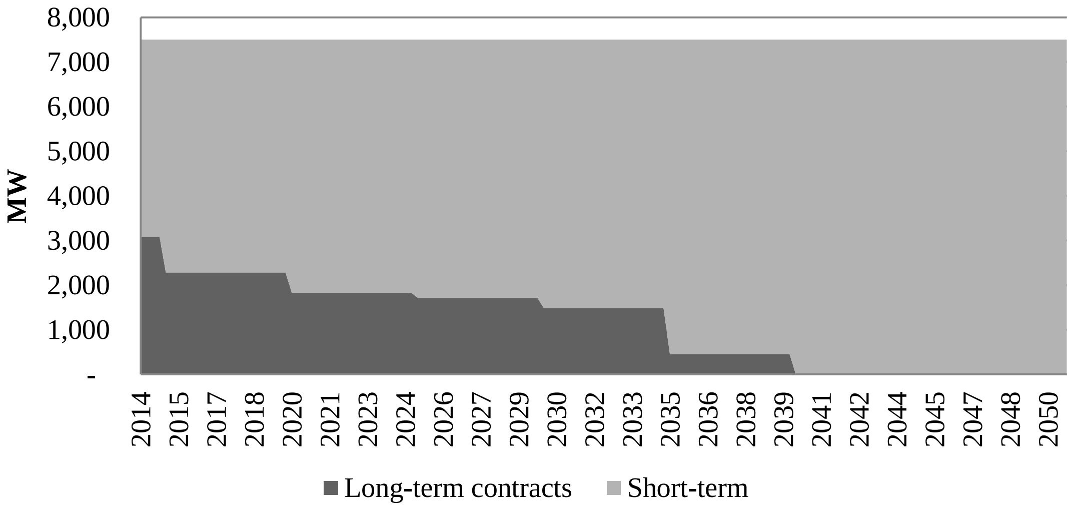

Figure A1. Imports availability by type in *BAU*. Data for long-term import availability ($A_{LTI,h,t}$) from AES (2012).

We thus estimate the availability of imports from balancing markets as the remaining available capacity from the cross-border capacity, which is assumed to be 7500 MW during the entire simulation.

$$A_{BI,h,t} = 7500 - A_{LTI,h,t} \tag{6}$$

The available supply from local technologies ($S_{T,h,t}$) depends on the availability factor ($A_{T,h,t}$) of each technology during each hour h and on the installed capacity ($K_{T,t}$).

$$S_{T,h,t} = K_{T,t} \times A_{T,h,t} \tag{7}$$

Marginal costs of producers ($MC_{j,h,t}$) do not depend on the hour of the day and equal their variable production costs ($VC_{j,t}$), except for hydro-storage and balancing imports, as shown in Eq. (8). In the specific case of long-term import contracts, which refer to the contracts with French nuclear plants, we assume a price (marginal cost) of 35 CHF/MWh.

$$\mathrm{MC}_{j,\mathrm{h,t}} = \mathrm{VC}_{j,\mathrm{t}}\ \forall j \neq HS, BI \tag{8}$$

The marginal cost for hydro-storage equals the hydro-storage reservation price, which will be explained in detail later (equations (14) – (17)). The marginal cost of balancing imports equals the weighted average price of the French and German spot markets ($EP_{France,h}$ and $EP_{Germany,h}$) according to the 2012 and 2013 shares of hourly imports.

$$MC_{BI,h,t} = F\left(EP_{Germany,h}, EP_{France,h}\right) \tag{9}$$

Recall that we run our model from 2014 to 2050 with a quarterly step, i.e. 147 quarters. For each quarter we run the hourly dispatch of a representative day, i.e., we consider the representative hourly demand of each season. We thus assume that the 90 days of each quarter present the same pattern. The available supply of each producer ($S_{j,h,t}$) and their marginal costs ($MC_{j,h,t}$) are used to build the supply curve for the hourly dispatch. We run a merit order dispatch according to producers' marginal costs, which yields the quantity $SD_{j,h,t}$ dispatched by each producer. First we compute the local dispatch, i.e., supply from producers is dispatched to cover local demand $D_{h,t}$, which includes the consumption from PSP. We assume $D_{h,t}$ is totally inelastic. Local dispatch is solved as a basic costs minimisation problem as follows:

$$\min_{SD_{j,h,t}} \sum_{j} MC_{j,h,t} SD_{j,h,t} \quad \forall\, h,t$$

Subject to

$$SD_{j,h,t} \leq S_{j,h,t} \tag{10}$$

$$D_{h,t} = \sum_{j} SD_{j,h,t}$$

The remaining supply ($SR_{j,h,t}$) is then available for exports. It will be used only if the prices in the countries that import from Switzerland exceed the marginal costs of this remaining supply.

$$SR_{j,h,t} = S_{j,h,t} - SD_{j,h,t} \tag{11}$$

Similar to the dispatch to cover national consumption, we compute a merit order dispatch for exports. However, unlike the national demand, which is inelastic, exports depend on the neighbouring countries' demand for imports from Switzerland ($DE_{c,h,t}$) and their willingness to pay. The former is an exogenous variable and is estimated based on historical data between 2009 and 2013. The latter equals the hourly prices in each country c (Italy, Germany and France), $EP_{c,h,t}$. Exports from producers to each country ($ES_{j,c,h,t}$) are calculated by solving a welfare maximisation problem, which allows calculating the clearing price $P_{h,t}$.

$$\max_{P_{h,t}, ES_{j,c,h,t}} \sum_{T,c} \left(EP_{c,h,t} - P_{h,t}\right) \times ES_{j,c,h,t} - \left(P_{h,t} - MC_{j,h,t}\right) \times ES_{j,c,h,t} \quad \forall\, h,t \tag{12}$$

Subject to

$$\sum_{c} ES_{j,c,h,t} \leq SR_{j,h,t}$$

$$\sum_{j} ES_{j,c,h,t} \leq DE_{c,h,t}$$

In the extreme case when the hourly supply (including imports) is lower than the national demand, the price would equal the VOLL, which is assumed to be 3000 CHF/MWh.

Then, the total quantity supplied ($Q_{j,h,t}$) by each producer in a quarter is calculated as follows, assuming 90 days per quarter.

$$Q_{j,t} = \left[\sum_{h} \left(SD_{j,h,t} + ES_{j,h,t}\right)\right] \times 90 \tag{13}$$

In the case of hydro-storage, the modelling is slightly different to that of other technologies as availability depends on reservoir level; the marginal cost reflects the water opportunity cost. This is modelled as a function of the forecasted maximum reservoir level (FRL_t) as well as of the substitutes' price, as presented in Figure A2. The parameters *R1*, *R2*, *R3* and *R4* are estimated during model calibration. O_{HS} equals the variable production costs of HS ($VC_{HS,t}$), *Vmax* and *Vmin* are respectively the maximum and minimum prices of substitutes (CCGT, TH, LTI and BI), and *Vsca* is the scarcity price (assumed to be 500 CHF/MWh). The scarcity price was also estimated during model calibration. This way of modelling hydro-storage reservation prices is proposed by van Ackere and Ochoa (2010) and Ochoa and van Ackere (2015), and allows modelling the strategic management of water reservoirs, which is crucial in countries highly dependent on hydro-storage.

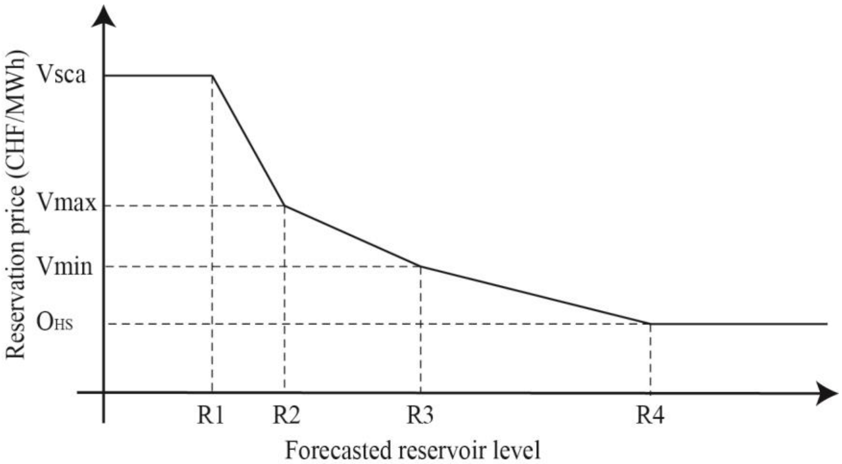

Figure A2. Modelling of hydro-storage reservation prices.

The variable FRL_t captures the expected excess or shortage of water in a quarter. This is calculated in Eq. (14) considering the current amount of water in the reservoir (W_t), the water inflow I_t (inflow from natural stream flows and from pumping) and the reservoir capacity (R_t).

$$FRL_t = \frac{W_t + I_t}{R_t} \tag{14}$$

The reservoir capacity (R_t) and the natural inflow evolve proportionally to the increase of hydro-storage generation capacity as presented in Eq. (15). Likewise, the amount of water pumped is adjusted by the increase of pumping capacity.

$$R_t = R_{t0} \frac{K_{HS,t}}{K_{HS,t0}} \tag{15}$$

The stock of water in the reservoir varies from one quarter to another according to hydro-storage production, the water inflow and the spillages ($Spill_t$):

$$\frac{\partial W_t}{\partial t} = I_t - Q_{HS,t} - Spill_t \tag{16}$$

Spillages only occur if the stock of water at the end of the quarter exceeds the reservoir capacity.

$$Spill_t = Max\left(0, R_t + I_t - Q_{HS,t}\right) \tag{17}$$

A.3. Investments decisions

To make investment decisions, each technology calculates its expected profits. These depend on the future capacity and the resulting dispatch. Future capacity ($FK_{n,t}$) equals all the capacity already commissioned (i.e., installed capacity ($K_{n,t}$) and capacity under construction ($UK_{n,t}$)), minus capacity that will not be available in 5 years (the maximum time for a plant to come online) because of obsolescence ($OK^*_{n,t}$):

$$FK_{n,t} = K_{n,t} + UK_{n,t} - OK^*_{n,t} \tag{18}$$

Each technology T needs to calculate the future capacity of other technologies and its own future capacity under different capacity investment assumption, i.e., each technology T considers it is the only technology that expands. In other words, when evaluating their expected profitability, a technology T considers already planned expansion of others technologies but not further expansions. This is a realistic assumption as each technology T has incomplete and imperfect information about the others, i.e., they know what is currently under construction but they cannot know the investment decisions of competitors in real time.

Hence, the forecast of future installed capacity of technology n made by technology T, assuming a capacity investment size e ($FKE^T_{n,e,t}$), considers the capacity already commissioned ($FK_{n,t}$) and the expansion being considered ($E_{n,e,t}$).

$$FKE^T_{n,e,t} = \begin{cases} FK_{n,t} + E_{n,e,t} & if\ T = n \\ FK_{n,t} & if\ T \neq n \end{cases} \tag{19}$$

For each technology T we define a maximum quarterly capacity expansion ($MaxCK_T$). Then, to calculate $E_{n,e,t}$ we define 10 sizes, ranging from 10% to 100% of $MaxCK_T$.

$$E_{n,e.t} = e\left(\frac{MaxCK_n}{10}\right) \tag{20}$$

For instance, investments in CCGT vary between 60 and 600 MW. Considering more than 10 expansion sizes could increase significantly the computing time without affecting results. Considering different size alternatives is important as, for instance, the minimum size of a CCGT plant is 60 MW. This allows us to include these technical constraints and capture the potential effects of the discrete nature of investments.

When computing the dispatch, imports availability and demand 5 years hence are considered. Each technology T calculates the average price it would receive when expanding ($P^T_{e,t}$). The resulting price is compared to the levelised cost ($LCOE^T_{e,t}$) in order to calculate the expected profitability.

$$X^T_{e,t} = \frac{P^T_{e,t}}{LCOE^T_{e,t}} - 1 \tag{21}$$

The $LCOE^T_{e,t}$ is calculated in Eq. (22) by each technology T using its annualized capital costs ($KC_{T,t}$), annual fixed costs ($FC_{T,t}$), variable production costs ($VC_{T,t}$) and resulting load factor ($ELF^T_{e,t}$) when expanding $E_{n,e,t}$. The latter is used to calculate the annualized capital costs and the annual fixed costs per unit of electricity expected to be produced.

$$LCOE^T_{e,t} = \frac{KC_{T,e,t} + FC_{T,t}}{ELF^T_{e,t} \times 24 \times 360} + VC_{T,t} \tag{22}$$

(24×360 are the number of hours in a year)

Finally, the largest profitable investment size is selected.

$$CK_{T,t} = Max\left(E_{T,e.t} \times W^T_{e,t}\right), \tag{23}$$

where $W^T_{e,t}$ is defined as:

$$W^T_{e,t} = \begin{cases} 1, & if\ X^T_{e,t} > 0 \\ 0, & in\ other\ case \end{cases} \tag{24}$$

Some exogenous variables such as natural water inflows, pumping, hourly demand, hourly prices for exports and imports, and PV and wind availability factors have seasonal (quarterly) patterns. The value thus depends on the season, which is modelled for each quarter t. For instance, the availability factor of PV ($A_{PV,h,t}$) equals $A_{PV,h,s}$, where s equals $mod(t,4)$ (see Figure A3). Availability factors of PV and wind energy are estimated from diurnal German power courses of presented in Fraunhoffer ISE (2013) and adjusted using the annual average values for Switzerland presented in Kannan and Turton (2012).

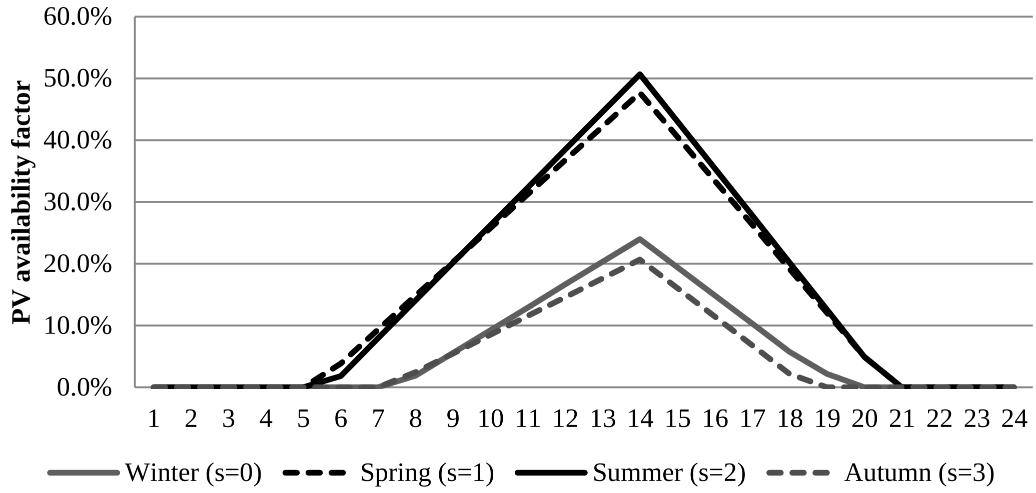

Figure A3. Seasonal availability factor of PV.

Table A1. Model variables and sub-indexes.

Sub-indexes	
t	Time (0,… 147) [quarters]
T, n	Technology (Hydro-storage [HS], run-of-river [RR], nuclear [NUC], Combined cycle gas turbine [CCGT], photovoltaic [PV], wind energy [WI], other thermal [TH])
j	Producers: these include the different technologies (HS, RR, NUC, CCGT,

	PV, WI, TH) and imports (long term import contracts [LTI] and balancing imports [BI])
h	Hour of the day (1,… 24)
s	Season (Winter [s=0], Spring [s=1], Summer [s=2], Autumn [s=3])
c	Countries to where electricity is exported (France, Germany and Italy)
e	Possible capacity investments sizes (1,… 10), with 1 being the smallest and 10 the largest
Parameters	
L_T	Lifespan of technology *T* (quarters)
$EP_{c,h}$	Maximum price paid by each country *c* to where export go at hour *h* (CHF/MWh)
Variables	
$K_{T,t}$	Installed capacity of technology *T* (MW)
$EK_{T,t}$	New capacity of technology *T* coming online (MW/quarter)
$OK_{T,t}$	Obsolescence of capacity of technology *T* (MW/quarter)
$CK_{T,t}$	Construction start of capacity of technology *T* (MW/quarter)
$UK_{T,t}$	Capacity under construction of technology *T* (MW)
$ConsD_T$	Construction delay of technology *T* (quarters)
$OldK_{T,t}$	Capacity of technology *T* that was installed before 2013 and remains available at time t (MW)
$A_{T,h,t}$	Availability factor of technology *T* at hour h (%)
$S_{j,h,t}$	Available supply from producer *j* at hour *h* (MWh)
$MC_{j,h,t}$	Marginal costs of producer *j* at hour *h*, i.e., price at which each producer bids in the day-ahead auction (CHF/MWh)

$VC_{j,t}$	Variable production costs of producers *j* (CHF/MWh)
$D_{h,t}$	Hourly national demand (MWh)
$SD_{j,h,t}$	Supply dispatched from producer *j* during hour *h* in the Swiss market (MWh)
$SR_{j,h,t}$	Remaining available supply from producer *j* during hour *h* after national dispatch, i.e., supply available for exports (MWh)
$DE_{c,h,t}$	Demand for imports from Switzerland by country *c* during hour *h* (MWh)
$ES_{j,c,h,t}$	Supply from producer *j* exported to country *c* during hour *h* (MWh)
$Q_{j,t}$	Total supply from producer *j* in a quarter *t* (MWh)
RL_t	Reservoir level (%)
FRL_t	Forecasted reservoir level before production (%)
W_t	Stock of water in the reservoir (MWh)
I_t	Water inflow to reservoirs (MWh/quarter)
R_t	Reservoir capacity (MWh)
$Spill_t$	Water spillages (MWh)
$FK_{T,t}$	Future capacity of technology *T* (in t+20 [5 years])
$FKE^{T}_{n,e,t}$	Forecast of future installed capacity (in *t+20* [5 years]) of technologies *n* made by technology *T*, assuming a capacity investment size *e* (MW)
$OK^{*}_{T,t}$	Obsolete capacity of technology *T* over the next 5 years (MW)
$P^{T}_{e,t}$	Expected price to be received by technology *T* assuming a capacity investment of size *e* (CHF/MWh)
$E_{n,e,t}$	Capacity expansion of technology *n* assumed, assuming a capacity investment of size *e* (MW)
$X^{T}_{e,t}$	Expected profitability of technology *T* assuming a capacity investment of size *e* (%)

$LCOE^{T}_{e,t}$	Levelised cost of electricity expected by a technology *T* assuming a capacity investment of size *e* (CHF/MWh)
$KC_{T,t}$	Annualised capital costs of technology *T* (CHF/MW)
$FC_{T,t}$	Fixed annual costs of technology *T* (CHF/MW)
$ELF^{T}_{e,t}$	Expected load factor of technology *T* assuming a capacity investment of size *e* (MWh/MW)
$W^{T}_{e,t}$	Binary variable for expected profitability of technology T assuming a capacity investment of size *e*

Appendix B. Description of generation capacity adequacy metrics

B.1. De-rated margin

De-rating factors are used to calculate the de-rated capacity, which is the amount of capacity that is available to meet the annual demand peak. The de-rated margin is calculated as the margin between peak demand and de-rated capacity. Since the demand peak in Switzerland occurs in the winter evening, the de-rating factor of PV is 0% (see Table B1). The de-rating factor of hydro-storage is significantly higher than its annual availability factor, because water can be saved to meet peak demand. We did not find any estimate for Switzerland; we therefore use the factor calculated for the UK (Poyry, 2012a). The de-rating factors for the remaining technologies equal their availability factor in winter.

Table B1. De-rated factors for the technologies considered (AES, 2012; Poyry, 2012b).

Technologies	De-rating factors
Hydro Storage	84%
Run-of-the-River	34%

Technologies	De-rating factors
Nuclear	89%
CCGT	92%
Photovoltaic	0%
Wind energy	24%
Other thermal	51%

B.2. Annual energy margin

We first calculate the demand that remains unmet after subtracting the total production of non-hydro-storage technologies for each season *s* at each hour *h* (Eq. (25)). As explained before, hydro-storage is the only technology *t* whose production can be shifted from one hour to another because of storability. If aggregated production of other technologies is higher than demand at certain time, this excess cannot be used at another moment unless it is pumped (Eq. (26))[9]. The additional energy available resulting from pumping is constrained by the pumping capacity (K_{PSP}) and efficiency (ρ) (Eq. (27)). The aggregated annual unmet demand can only be covered by hydro-storage, whose annual availability depends on the aggregated natural inflows (per season) plus those from pumping. The annual excess energy is calculated as the difference between hydro availability and annual unmet demand. The ratio between excess energy and the domestic demand is used to estimate the annual energy margin (Eq. (28)). A low margin points to an adequacy problem.

$$Unmet\_demand_{sh} = \max\left(0, Demand_{sh} - \sum_{t \neq HS} Generation_{sht}\right) \tag{25}$$

[9] This approach could be extended to other storage technologies.

$$Storable\_excess_{sh} = \max\left(0, \sum_{t \neq HS} Generation_{sht} - Demand_{sh}\right) \tag{26}$$

$$Avail\_pumping_{sh} = \min(\mathrm{K}_{\mathrm{PSP}}, Storable\_excess_{sh}) \times \rho \tag{27}$$

$$Energy\_margin = \frac{\sum_{sh} Inflows_{s} + Avail\_pumping_{sh} - Unmet\_demand_{sh}}{\sum_{sh} Demand_{sh}} \tag{28}$$

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APPENDIX B.2

Arbitrage Opportunities for Pumped Storage Power Plants in Switzerland

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Abstract

Over the past decade Switzerland has invested significantly in pumped storage plants (PSP). They aim to exploit arbitrage opportunities by pumping water from a lower reservoir to an upper reservoir to store electricity in the form of hydraulic potential energy when prices are low and generating when prices are high. The changing generation-mix in Switzerland threatens these arbitrage opportunities in the long-term. To study this, we develop a heuristic to endogenise PSP bidding decisions, and integrate it in [1]'s simulation model of the Swiss electricity market. Our results show that initially the increase of photovoltaic capacity encourages pumping, but the nuclear phase-out and the expiration of long-term import contracts significantly decrease the available energy, leading to a decline in pumping. Although those changes in the capacity-mix increase the difference between peak and off-peak prices significantly, PSP are unable to exploit these because of the low availability of cheap energy to pump. This situation severely limits arbitrage opportunities in the long-term. We conclude that large scale arbitrage requires the availability of cheap excess energy. This can be achieved either by demand management or by supporting base load technologies.

Keywords

Energy storage, Swiss electricity market, Pumped storage power plants (PSP), Hydropower, Simulation

1. Introduction

Storage has recently gained major attention given the need to integrate non-dispatchable renewable energies (NDRES) into electricity systems. Unlike other energy sources, electricity demand needs to match power load in real time. Generation thus must adapt to the demand's daily and seasonal patterns. Historically, hydro-storage power plants have been used to cope with load and demand variations. While the largest allow storing water from one season to another, the smaller ones are useful to manage within-day load variations. These plants also provide flexibility to the system, i.e., they can adjust their supply in the very short term (minutes), contrary to base-load technologies.

Operability of conventional hydro-storage plants is nonetheless subject to the availability of water from natural inflows. The integration of pumping systems allows enhancing the utilisation of these plants as they can absorb excess energy by pumping water from a lower reservoir to an upper reservoir to store electric energy in the form of hydraulic potential energy. This was of paramount importance for integrating nuclear plants into electricity systems as these cannot modify their output to follow demand in the short-term [2].

Worldwide, the largest contingent of pumped-storage plants (PSP) was built in the 1970s, in parallel with the development of nuclear energy, following the significant increase in oil and gas prices, and the resulting concerns about security of supply (SoS). In those days, the energy-mix composition led to highly correlated price and demand patterns. This, together with the existence of excess base-load supply allowed PSP not only to balance the load but also to play an arbitrage role in the system by pumping when prices and demand were low (off-peak) and producing when they were high (peak). Arbitrage opportunities depend on price differences and the cycle performance (ratio between energy produced and energy consumed, 75% to 80%) [3].

Pumped hydroelectric energy storage is currently by far the most widely used technology for large-scale energy storage (>100 MW) [4,5]. Very specific site conditions are needed to ensure the technical feasibility of a PSP project; these include high head, favourable topography, good geotechnical conditions, access to the electricity transmission network, and water availability. Switzerland's topography and the expansion of nuclear power have favoured the development of the pumping business. In the 1990s few facilities were built due to the saturation of available locations and limited nuclear development, but with electricity markets across Europe being increasingly interconnected, Switzerland has over the past decade aimed to exploit its hydro potential to become the electricity hub of Europe: major investments in PSP will more than double their capacity (from 1560 MW to 3716 MW) by 2018.

However, electricity markets have evolved since those decisions were taken. Not only have electricity prices dropped across Europe, but daily price patterns have changed significantly: peak prices are lower and their time of occurrence is increasingly variable [6]. These elements threaten the profitability of both conventional hydro-storage and PSP. Additionally, three major changes are expected to impact PSP operation: the government's decision to decommission all nuclear plants in the medium-term, the expiration of long-term contracts (cheap off-peak imports) and the expected larger penetration of PV. While the first two will considerably reduce the availability of energy to pump, the impact of the increasing share of PV remains unknown. Large amounts of PV could provide cheap energy for PSP to pump, but they simultaneously decrease the difference between peak and off-peak prices. Therefore, the interaction of these three elements is expected to affect PSP operation and their economic viability.

In this paper we study the future of PSP arbitrage opportunities in Switzerland and identify under what conditions these could be enhanced. We build on [1], who develop a system dynamics (SD) model calibrated for the Swiss market. We endogenise PSP decisions regarding volumes and timing of pumping and generation. This is essential to capture how the changes in the energy-mix of the Swiss electricity market affect the operation of PSP.

Pumping and generating generally follow a daily cycle, but weekly and seasonal cycles occur for larger PSP. This load-shifting puts upward pressure on off-peak prices and downward pressure on peak prices, thus decreasing price differences [7]. Although this can stabilise prices over time [8], flatter prices affect PSP's business. There thus is a natural limit to PSP operation; because the value of energy storage decreases as storage capacity increases. This counterproductive effect of expansion is similar to the problem faced by investors in new transmission: these power lines alleviate congestion, eliminating the congestion rents that were expected to finance them. Consequently, PSP overcapacity would prevent these plants from recovering the capital costs if their main source of income was energy arbitrage [9]. Large scale PSP might thus need incentives that provide financial support and a more stable income [10].

Besides the impact of PSP's price-smoothing on its own profitability, PSP affect the whole market: they allow a more efficient utilisation of resources, avoiding expensive peak generators. This can lead to large net increases in consumer surplus, as shown by [7] for the PJM market. PSP can also reduce needs for grid expansion as storage can relieve grid congestion [7,11]. But in less competitive markets large producers could use PSP to exercise market power [12]. For instance, companies with both conventional thermal plants and PSP in their portfolio might want to underutilise their PSP to limit the price-smoothing effect [13].

While our focus is on PSP's role as merchant in the market, PSP also provide ancillary services. These are expected to gain in importance as NDRES, particularly wind energy, increase their penetration. This has indeed been the main motivation of most previous research [11,14–16]. By focusing only on their participation in electricity arbitrage regardless their load-levelling role through ancillary services, we provide a conservative estimate of PSP profitability. However, in Switzerland, we expect profits from ancillary services to be limited given the already large hydro-storage installed capacity, which provides enough flexibility and the limited potential of wind energy in Switzerland. Consequently, the profitability of energy arbitrage in the long-term is essential for Swiss PSP.

This paper is structured as follows: in Section 2 we present the main characteristics of the Swiss electricity market, in Section 3 describe the model and discuss its main assumptions. Then, we present the results of our model in Section 4. In Section 5 we discuss the policy implications.

2. The Swiss electricity market

As Figure 1 shows, electricity consumption in Switzerland has remained fairly stable since 2000. Electricity is mainly generated by nuclear (38%) and hydropower (57%). About 60% of hydropower generation comes from hydro-storage and the remaining from run-of river plants. The former have an aggregated storage capacity of 8.8 TWh, i.e., approximately 15% of demand. The remaining local production is generated by other sources such as cogeneration plants.

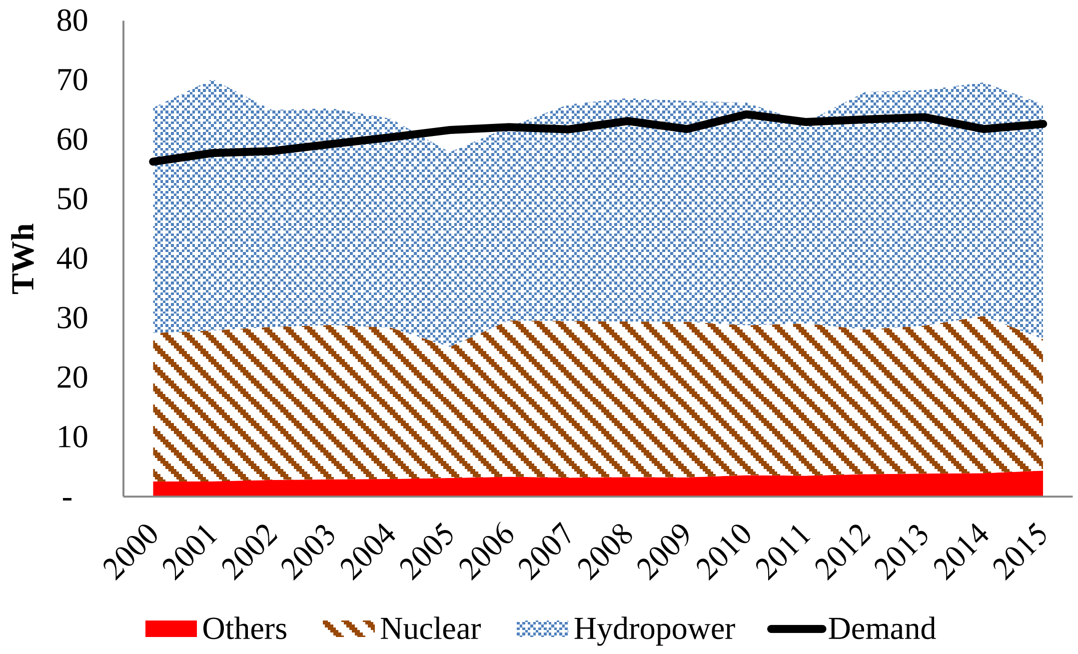

Figure 1. Generation by type of source and consumption in Switzerland since 2000. Data from [17].

After the Fukushima accident in March 2011, the Swiss Federal Council announced the phase-out of nuclear plants after 50 years of operation, i.e., between 2019 and 2034 [18]. This was a major commitment because nuclear capacity equalled 3,278 MW in December 2013, accounting for 18% of total capacity and 40% of generation. There is currently a heated debate about the future of nuclear energy in the country and only the decommissioning of Mühleberg is certain (373 MW in 2019). The parliament is currently considering an extension of at least 10 years for the remaining nuclear plants.

Although non-hydro renewable energy production currently represents less than 1%, this might change in the medium-term. Switzerland is strongly encouraging investments in renewable energies so as to enhance SoS by diversifying the production sources. Efforts were significantly stepped up when the country decided to phase out nuclear power, to avoid replacing this capacity with polluting sources, e.g., CCGT. For instance, both PV and wind energy receive a compensatory feed-in remuneration (CFR) of up to 250 CHF/MWh during 20 years [19]. It is noticeable that PV capacity has increased by a factor of almost 10 between

2009 and 2013, from 79 MW to 756 MW [17], while wind energy has only increased from 18 to 69 MW over the same period. This is due to the larger estimated potential of the former (18 vs. 4 TWh/year [20]) and the opposition from local communities to wind projects, i.e., NIMBY phenomena [21].

Historically Switzerland has been a net exporter (Figure 1) and the country plays an important role in European interconnection. The following numbers illustrate the magnitude of electricity flows to and from Switzerland: around 10% of EU-28 exports transit through Switzerland, while Swiss consumption is equivalent to 2% of these countries' final consumption [17,22]. These flows generate a surplus for local generators due to the difference between export and import prices. For instance, in 2014 exports exceeded imports by 5,389 GWh, generating a profit of CHF 442 million [17]. In 2011, despite imports exceeding exports by 2,587 GWh, net revenues were even higher (CHF 1,018 millions). PSP typically use cheap off-peak electricity from France and generate at peak hours to export to Italy.

As shown in Figure 2, most pumping capacity started operating between the 1960s and the 1980s, following the development of nuclear power: the entire current capacity, 3,278 MW, was installed in that period. Generation capacity of PSP has followed a similar development. But recently, major investments have been undertaken: 140 MW were installed in 2010 and three large projects are currently under construction (see Table 1). These will increase pumping capacity by 2,156 MW and generation capacity by 2,140 MW. At the end of 2013, total hydro-storage generation capacity equalled 9,920 MW, and PSP had a pumping and generation capacity of 1,561 MW and 1,977 MW, respectively[10], which allowed them to generate about 1.7 TWh that year [23]. This expansion represents respectively a 20% and 138% increase in generation and pumping capacity.

[10] Only pure and mixed pumped-storage plants are considered. Generation capacity from adjacent plants, using the same reservoirs is not considered.

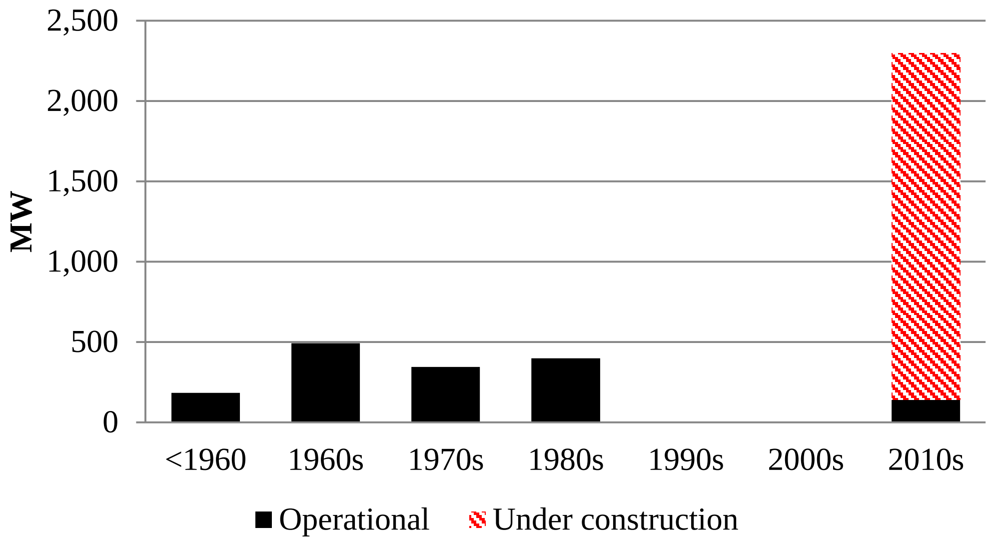

Figure 2. Evolution of pumping capacity in Switzerland. Data from [23].

The next section presents the methodology used to model the Swiss electricity market and, particularly, PSP decisions.

Table 1. PSP under construction. Information from [23–25]

Plants	Generation / Pumping Capacity (MW)	Published cost (million CHF)	Project developer	Construction start	Starting date (first published date)
Nant de Drance	900/900	1,900	Nant de Drance SA (Alpiq 39%, CFF 36%, IWB 15% and FMV 10%)	2008	2018 (2014)
Limmern*	1,000/1,000	2,100	Linth-Limmern AG (Canton of Glarus 15% and Axpo 85%)	2009	2016 (2015)
Veyteaux (extension)	240/256	331	Forces Motrices Hongrin-Léman (Romande Energie 41.13%, Alpiq 39,31%, Groupe E 13.13% and the municipality of Lausanne 6.43%)	2011	2015 (2014)

CHF: Swiss francs. Average exchange rate in 2015: 1.07 CHF = 1 EUR

*The cost of Limmern includes the costs of additional facilities such as the expansion of two plants in Tierfehd, where a 140 MW pumped/turbine was installed and already commissioned.

3. Methods

System dynamics (SD) is a simulation methodology that has been widely used over the past 20 years to study electricity systems due to its ability to capture the long-time delays and the feedback mechanisms in this industry [26]. Also, unlike traditional economic equilibrium models, SD adequately address the issues faced by recently liberalised industries [27]. Among the seminal papers addressing the consequences of liberalisation in investments, we find [28] and [29]. A survey of SD models of energy systems can be found in [30]. [1] propose an SD model of the Swiss electricity market to gain understanding of long-term SoS. Here we extend this model in order to endogenise pumping decisions. We next present a brief description of the [1]'s model, before explaining how PSP strategic decisions are simulated. The model is divided into three modules. The first two, investment decisions and market operation, are based on [1] and are summarised in Section 3.1. The third module, the simulation of PSP decisions, is explained in Section 3.2. Section 3.3 gives the main assumptions of the model.

3.1. Investments and market operation

In [1], investments are made in each technology according to expected profitability. Capacity construction is thus encouraged by high profits, which increases the future supply. A higher expected supply increases the expected reserve margin. As electricity prices reflect the scarcity of supply, a higher reserve margin leads to lower prices and, in turn, to lower expected profits.

As NDRES' marginal costs are very close to zero, a larger share of these technologies leads to lower prices and a lower residual demand. This implies lower revenues for the other technologies, discouraging new investments, except for NDRES, which are typically subsidised by feed-in tariffs (FiTs). These are expected to cover all the plant's costs and are allocated regardless of the market price. Therefore, prices do not affect the expected profits of those plants, so investments in NDRES are not subject to market dynamics. There is thus a distortion in investments, which is captured by the model.

Installed capacity defines the available supply, while total demand results from the local demand and the net flow of electricity exchange. Since the market is cleared by merit order dispatch, higher total demand leads to higher prices. The wholesale price is compared to the price abroad to determine whether the country will import or export. Next, we explain the heuristic used for simulating the pumping/generation decisions.

3.2. PSP arbitrage

We only consider PSP operation as a merchant unit in the wholesale market, i.e., bidding and buying in the day-ahead market. Hence, we assume that PSP do not pump and generate at the same time; this would not be profitable taking into account the efficiency losses. As our analysis is based on a long-term model, the impact of NDRES on grid stability (very short-term) is beyond the scope of this paper.

PSP profit from arbitrage opportunities by pumping typically at off-peak hours (buying energy at low prices) and using this energy to generate at peak hours (expecting to receive high prices). We assume a daily cycle for PSP. Before the ‘green revolution’ of NDRES, planning was easy as were highly predictable daily price patterns. Currently, these patterns change from day to day and peak prices are less and less correlated with peak demand. This justifies the need to endogenise pumping decisions in the model. The process used to make this strategic decision is described in the flow diagram presented in Figure 3. A detailed description of the heuristic is given in Appendix.

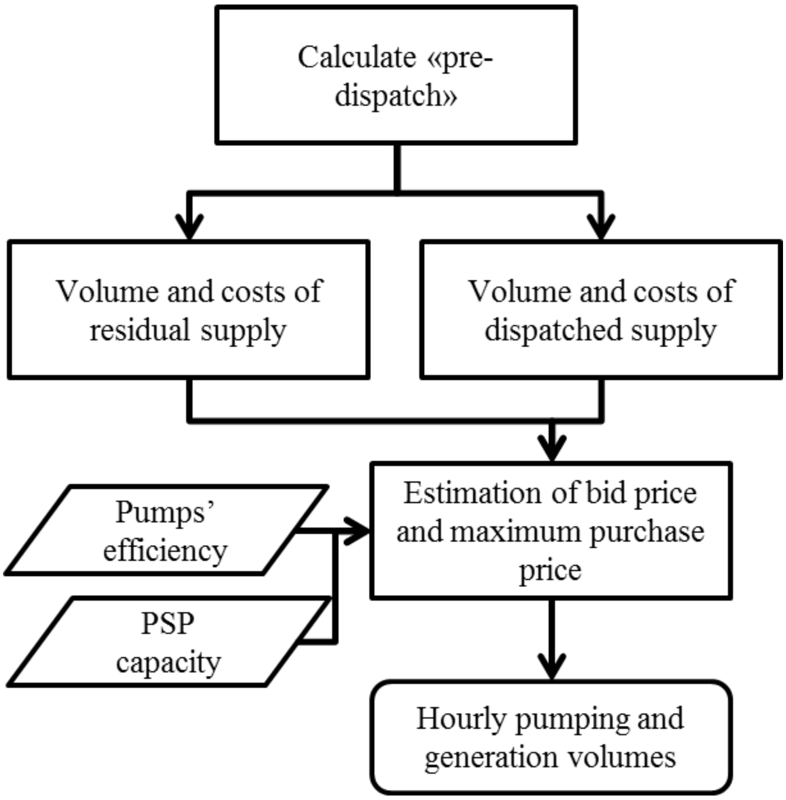

Figure 3. Flow diagram of arbitrage heuristic.

We assume PSP have perfect information about other technologies' bid prices and bid-offers. PSP thus assess a "pre-dispatch", which allows them to calculate the volumes of allocated and unallocated supply of each technology. Figure 4 shows a numerical example of a daily "pre-dispatch", which consists of the aggregation of hourly bids according to their bid price. The stacked bars in Figure 4 correspond to the bids, with the cheapest at the bottom and the most expensive ones at the top, so as to represent a merit order dispatch. Different fill pattern are used to illustrate the prices at which these volumes are bid. The areas below (black) and above (green) demand correspond respectively to the allocated and unallocated volumes.

Then, we aggregate the hourly allocated volumes (those below the demand in black in Figure 4) on a daily basis according to their prices. This allows defining what we call the daily curve of allocated energy (Ac in Figure 5), i.e., the amount of electricity to be dispatched at each price. This curve thus shows the volumes that can be displaced by PSP when bidding at a certain price. For instance, a plant bidding at a price of $0 displaces all allocated volumes, while a plant bidding at a price of $20 displaces only those bidding at higher prices than $20. In Figure 5 we use linear functions to simplify the presentation. The negative slope indicates that few high-bid producers are “pre-dispatched”.

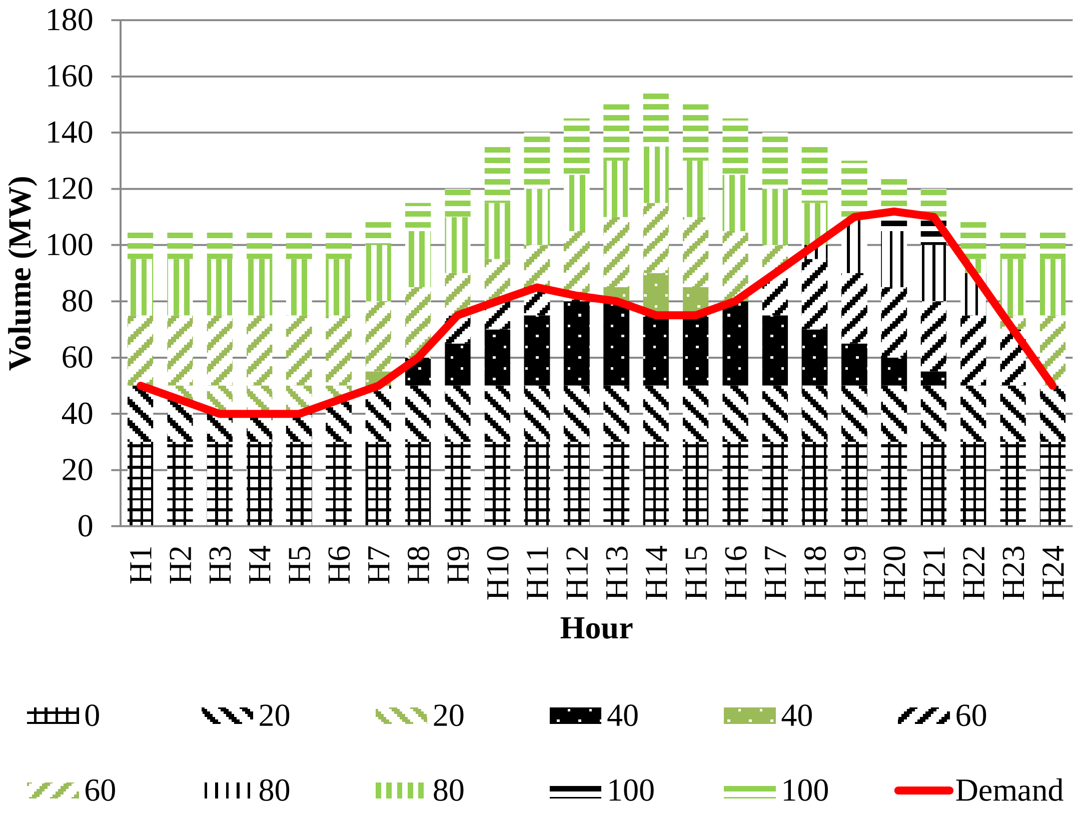

Figure 4. Example of a daily pre-dispatch.

Likewise, volumes of unused supply (above the demand curve, in green in Figure 4) are aggregated over a day so as to build the curve of unallocated energy (Uc in Figure 5), i.e., the amount of electricity that could be bought by PSP at different purchase prices for pumping. This curve has a positive slope, indicating that the higher the price PSP are willing to pay, the more energy they can pump. The amounts that can effectively be pumped each hour are constrained by the pumping capacity. These amounts are multiplied by the efficiency factor of the pumps, to obtain the volumes of energy available after pumping. We assume an efficiency factor α of 80%.

The price at which PSP buy energy to pump should not exceed 80% of that at which they bid in order to ensure profitability of operation. For instance, to buy 10 MWh at 80 CHF/MWh, a PSP must expect to sell the resulting 8 MWh of generation (after discounting losses) at a price above 100 CHF/MWh.

Next we estimate the hourly volumes pumped for each day. To enable comparison of the two curves, we replace the purchase prices of the Unallocated curve by the equivalent bid price. Recall that *Purchase price* = α**Bid price*, i.e., a bid price of 100 CHF/MWh requires a maximum purchase price of 80 CHF/MWh. The point at which both curves intersect thus gives the volume V^* that PSP expect to allocate in the market in one day, as well as the bid price P^* (the minimum price PSP expects to receive for the energy generated). The corresponding purchase price (the maximum price PSP is willing to pay for energy to pump), equals αP^*, and the amount of energy that has to be pumped in one day is V^*/α.

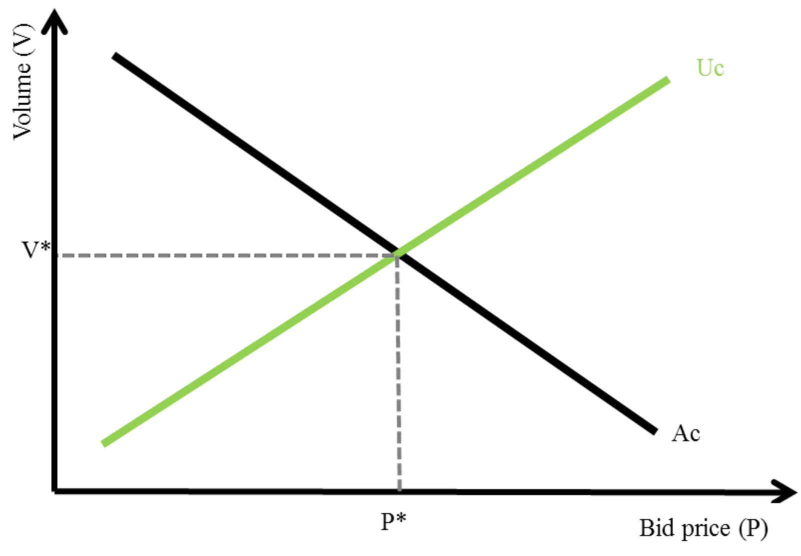

Figure 5. Simplified representation of Allocated and Unallocated volumes.

Finally, we use the data from the "pre-dispatch" to identify the volumes from the Allocated curve that are displaced by PSP. This allows determining the PSP hourly bids. Likewise, we use the data from the "pre-dispatch" to identify the volumes from the Unallocated curve that provide PSP energy to pump, i.e., the hourly pumping. PSP's hourly pumping and hourly bid-offer are used to run the market dispatch. We do not consider any other additional cost for PSP when bidding. Our formulation ensures that PSP will always sell at prices at least 25% above their costs to guarantee that they recover the efficiency losses.

A capacity-mix change impacts both curves, which in turn affects pumping. For instance, the replacement of a nuclear power plant by a more expensive unit leads to more expensive allocated energy. PSP bids at a certain price could displace a larger amount of generation, resulting in Ac to shift to the right. But the dismantling of a nuclear plant reduces the cheap unused energy, which results in Uc to also shift to the right. The net effect on pumping of such an event depends on the shape and slopes of the two curves. This highlights the complexity of analysing the effect of changes in the energy mix on PSP arbitrage opportunities, and the need to integrate the arbitrage heuristic into a dynamic model of the Swiss electricity market.

3.3. Simulation setup

The simulation runs from 2014 to 2050 with a quarterly time step. For each quarter (season) we consider a representative day with hourly demand curves and hourly availability factors for the different technologies, so as to capture the seasonal and hourly effects of production and demand. The eight technologies considered are: conventional hydro-storage (HS), run-of-river (RR), nuclear power (NUC), wind energy (WI), photovoltaics (PV), combined cycle gas turbines (CCGT), conventional thermal (TH) and pumped-storage plants (PSP). Three additional sources are considered: long-term import contracts, short-term imports from France and Germany[11] and short-term imports from Italy. Capturing seasonal and hourly patterns is important given the increasing role of PV and wind energy. To fit the Swiss hydrological pattern, seasons are defined as follows: January-March (winter), April-June (spring), July-September (summer) and October-December (autumn). We run our simulation in Vensim ® DSS 6.3.

We assume PSP bid separately from conventional hydro storage, yet both might use the same reservoirs and generation units. This implies a strict separation of the pumping business. Generation from pumped water is bid as explained in Section 3.2, while generation from natural inflows is bid at the water opportunity cost. Indeed, HS has three decisions to make: how to allocate water between this season and the next, how much to bid each hour and the prices at which to bid those volumes (water opportunity cost). The price at which they bid depends on the price of substitutes (other producers).

The expansion potential of pumping capacity is limited by economic conditions and topographical suitability, among others. This potential has not been estimated, contrary to the expansion potential of overall hydropower generation (and the other technologies considered), which has been assessed by [20]. Since PSP potential is strictly linked to the expansion potential of hydropower generation, we assume that PSP capacity growth is proportional to the increase of hydro-storage generation capacity. Hence, in addition to the 2,156 MW of pumping capacity expansion projects under construction mentioned in Table 1, we assume that PSP capacity increases proportionally to HS generation capacity expansion. To simulate investments in hydro-storage, we assess the aggregated profitability of HS and PSP.

Exogenous expansion is assumed for PV and wind energy during the first 20 years of the simulation as we hypothesise that the country will keep FiTs so as to achieve the 2035

[11] We aggregate export capacity of the two countries to Switzerland as some of those exports transit through the other country and their prices tend to converge.

NDRES production target set by the government. Expansion of these technologies is assumed to be 13,600 MW for PV and 845 MW for wind. Endogenous expansion is assumed afterwards, while for the other technologies endogenous expansion is assumed during the entire simulation period.

In our base case scenario (*BAU*) we assume what currently seems to be the most likely scenario for nuclear power: Muhleberg being decommissioned in 2019 and the others plants[12] being decommissioned after 60 years of operation. We also assume that hydro projects currently under construction will come online at their scheduled start of operation [23].

4. Results

We analyse the impact of different policies on the economic viability of PSP arbitrage and identify conditions under which arbitrage opportunities are enhanced. The business as usual (*BAU*) capacity-mix is as discussed in [1].

A threatening future for PSP

Changes in the availability of energy sources resulting mainly from nuclear plant decommissioning, expiration of long-term contracts and PV deployment affect pumping patterns. Figure 6 shows how long-term contracts progressively expire by 2040, while last nuclear plant closes down in 2044. PV increases to a maximum of 14,000 MW by 2035, and then starts decreasing as a consequence of the discontinuation of FiTs. Recall that we consider that FiTs are not renewed after 2035; therefore investments after this date are endogenous.

We assume that capital costs for PV decrease from 3,300 CHF/MW in 2015 to 1,500 CHF/MW in 2050 [31]. Despite this decrease, investments in PV are not profitable under market conditions. Consequently, in the absence of subsidies, PV capacity will decrease after

[12] Beznau I and II (365 MW each) in 2029 and 2032, respectively; Gösgen (985 MW) in 2039 and Leibstadt (1190 MW) in 2044.

2035 due to obsolescence after the assumed lifetime of 20 years. Current government policies aim at encouraging PV in the middle term seeking to achieve the 2035 target, but longer-term support remains uncertain. However, if large PV capacity becomes obsolete and market prices are inadequate to trigger their replacement, the government is likely to intervene.

One of the main reasons to encourage investments in NDRES is the nuclear phase-out. Even if the 2035 PV objective is achieved, this will not be sufficient to replace the nuclear power and expiring long term contracts. While the annual availability factors of those long-term imports and nuclear power are up to 90%, PV's is only 13%. However, the PV availability factor at noon in summer reaches 50%.

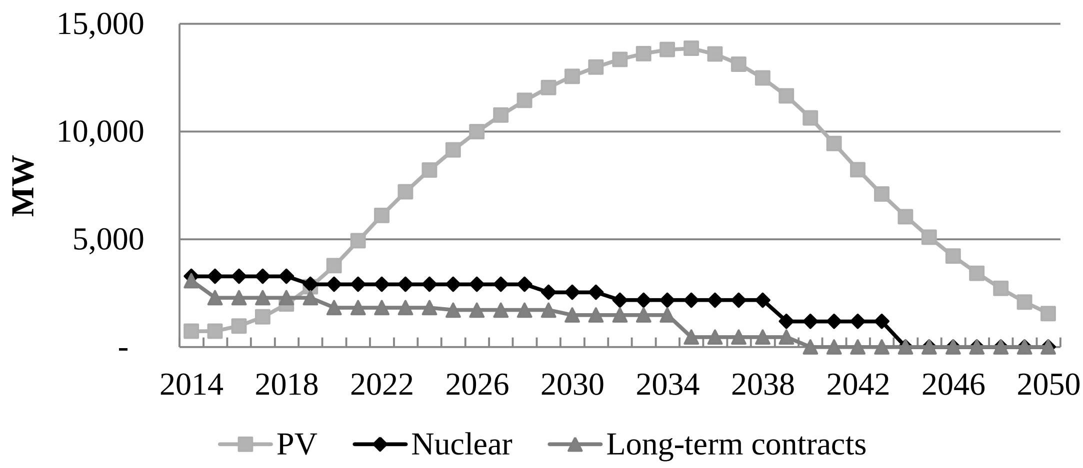

Figure 6. Evolution of PV and nuclear capacity, and long-term contracts availability.

Changes in capacity-mix affect the difference between peak and off-peak prices and the amount of cheap energy available for pumping. We present the 10^{th} and 90^{th} percentiles (P10 and P90) of prices, respectively in Figure 7(a) and (b). According to our results, the average cost of energy pumped by PSP is below the 20^{th} percentile of prices, while the average price received by PSP is above the 80^{th} percentile. We thus use P10 as a reference for the price of "cheap energy" and P90 as reference for the revenues of PSP. Figure 7(c) shows the difference between the P90 and P10 for each quarter. We work on a quarterly basis with a representative day for each one. PSP patterns vary across seasons. Hence, we need to look at the differences between peak and off-peak prices on a quarterly basis. As shown in Figure 7(a) and (b), both these percentiles have and increasing trend. Therefore, sudden increases or drops in Figure 7 (c) are caused respectively by large increases of P90 or P10. For instance, the complete decommissioning of nuclear leads to a significant increase of P10 in the summer of 2044 and consequent decrease in the difference between P90 and P10.

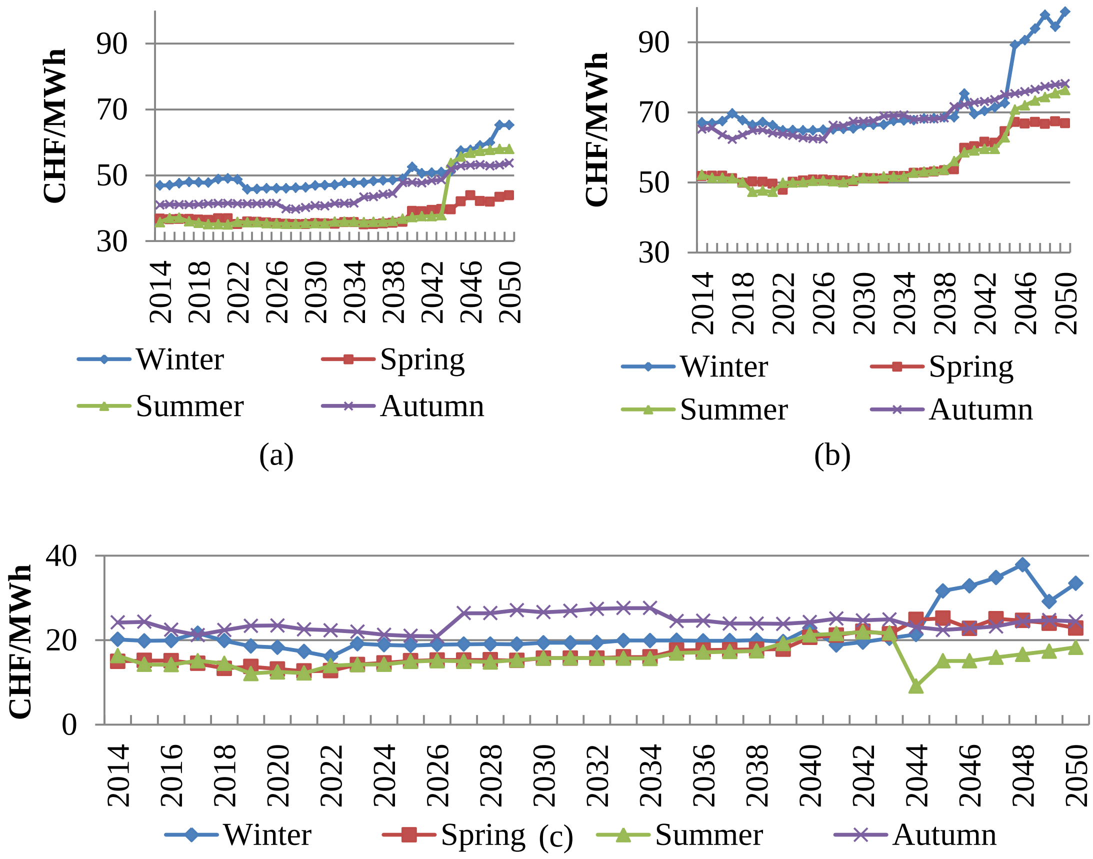

Figure 7. Simulated prices. (a) 10th percentile (P10) of prices per season. (b) 90th percentile (P90) of prices per season. (c) Difference between P90 and P10.

The cheap energy available for pumping in a given year can be approximated by the aggregation of seasonal volumes of energy available after meeting local demand and exports, at a price equivalent to the 10th percentile (see Figure 8). Note that large drops in cheap energy volumes occur when long-term contracts expire, e.g., in 2015 and 2040, and when nuclear plants are decommissioned, e.g., in 2019. Cheap excess energy remains fairly stable until 2034. After this date cheap excess energy availability decreases rapidly because of the expiration of long-term import contracts equalling 1 GW/hour, the dismantling of Gösgen (the fourth decommissioned plant) in 2039 and the increasing obsolescence of PV panels. By 2050 cheap excess energy is only a quarter of its 2014 value.

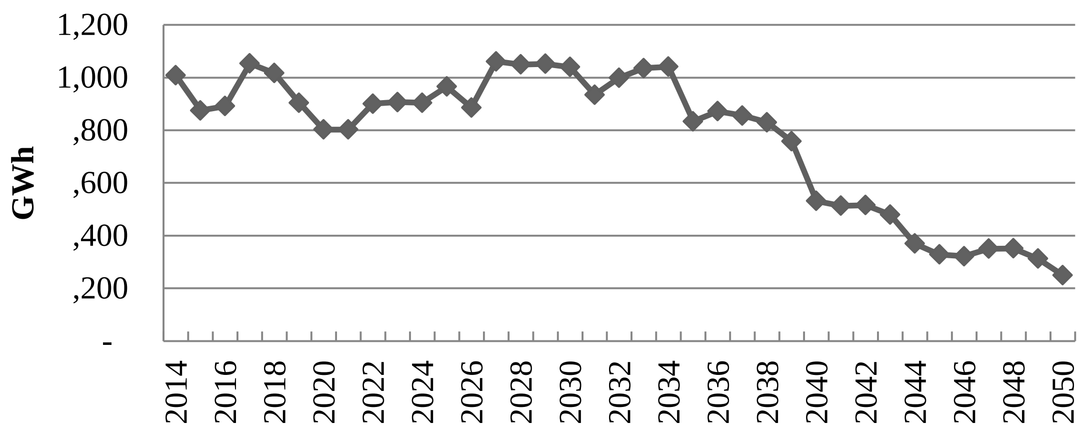

Figure 8. Excess energy available at P10.

The evolution of the generation-mix thus triggers significant changes in pumping patterns. We can distinguish two periods in the pumping behaviour: before and after 2020. As Figure 9 shows, pumping exhibits a first peak in 2017 at 1,925 GWh. This increase results from the expansion of PSP pumping and generation capacity from 1,560 MW in 2013 to 3,716 MW by 2017. This allows PSP to pump more as pumping capacity was fully used at certain hours before the expansion. In 2019, the first nuclear plant decommissioning reduces excess energy, which decreases pumping.

In the second period (2021-2050) pumping increases to a maximum of 2,258 GWh in 2034 and then decreases rapidly. Pumping is particularly high in the period 2026-2034 due to the following factors. First, the decommissioning of Beznau I and II increase the difference between peak and off-peak prices, especially in autumn. Note in Figure 9 pumping increases significantly in that season. Second, new PV capacity partially fills the gap left by contract expirations and decomissionings, keeping excess energy at around 900 GWh. PV thus provides excess energy to PSP. Hence, there is a joint effect of nuclear decommissioning and PV expansion before 2034.

Note that the impact of the first decommissioning (373 MW in 2019) has an opposite impact compared to the second and third decommissionings (730 MW in 2029 and 2033). In the former case, dismantling was preceded by hydro-storage expansion, which leads to lower differences between peak and off-peak prices. In the latter case, decommissioning occurs simultaneously with a large PV expansion, which can only produce during daylight hours. This implies a higher utilisation of expensive sources in the evening. As a consequence peak prices in the evening are higher, which leads to higher differences between peak and off-peak prices (see Figure 7(c)). Note that the difference between P90 and P10 is higher in the 2029-2033 period than in the 2019-2020 period, leading to more pumping in the latter case. In both cases, excess energy is quite similar. Consequently, pumping decreases in the former despite the nuclear capacity is higher than in the latter.

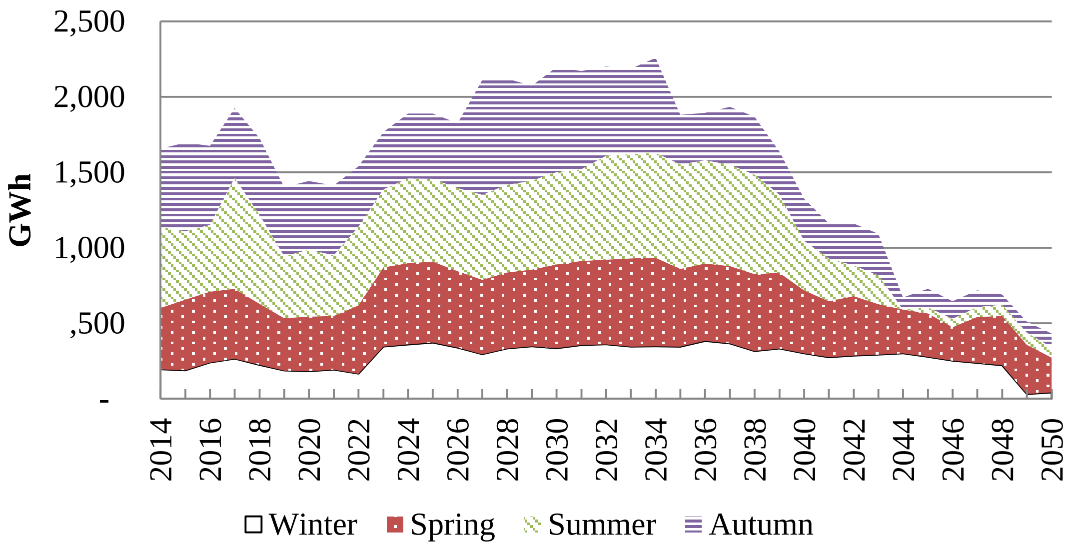

Figure 9. Simulated seasonal pumping.

After 2034, pumping decreases significantly. Despite the higher difference between peak and off-peak prices in all seasons except autumn, the lack of cheap energy pushes down pumping. As shown in Figure 7, differences between prices are higher after 2034 in all seasons, except autumn. The only exception occurs in summer 2044, when difference between prices is not enough to cover pumps' losses, which leads to zero pumping that season. In autumn difference between peak and off-peak prices decreases by up to 20% after 2034, which discourages further pumping. At the end of the simulation period, in 2050, pumping is down to 432 GWh.

Although pumping increases in the medium-term (2025-2035), profitability of PSP is threatened even in this period. As Figure 10 shows, pumping does not increase in the same proportion as pumping capacity. PSP pump the equivalent of 912 hours at full capacity in 2014 and of 116 hours in 2050, i.e., PSP utilisation for arbitrage opportunities decreases from 10.5% to 1.3%. Even when pumping peaks (2,258 GWh in 2034), pumps only run the equivalent of 608 hours per year. Pumps never run more than the equivalent of 935 hours at full capacity (in 2015).

Pumping for arbitrage should not be expected to occur 24 hours per day given technical and economic limits. Additionally, there are PSP capacity needs for ancillary services. Still, the observed values of capacity utilisation are too low for investments to be amortised.

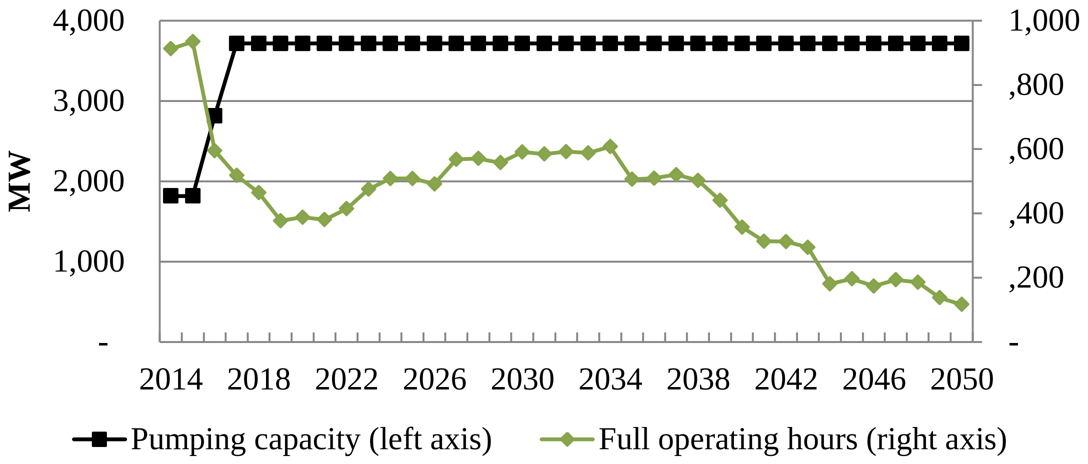

Figure 10. Pumping capacity and full operating hours of PSP.

Now we turn to evaluating the impact of different scenarios on arbitrage opportunities. Given the strong decrease of pumping in the long-term, we first evaluate scenarios aimed at encouraging PSP operation. Then, as our results so far show that the nuclear phase-out significantly decrease the energy excess, we focus on analysing the impact on PSP of alternative dismantling schedules. Finally, we investigate which scenarios provide favourable long-term conditions for PSP.

Encouraging PSP operation

As mentioned above, several events affect PSP operation. Although we cannot point to a unique cause for the decrease in pumping, our results show that the financial viability, especially of the new projects, is seriously threatened. Therefore we first analyse different policies aimed at improving the profitability of PSP and evaluate their consequences for the market and the country’s SoS.

We evaluate two approaches. The first, focused entirely on PSP operation, is the implementation of a premium for PSP generation. The government is aware of the current financial problems faced by some hydro-storage plants, e.g., Alpiq [32]. We model two scenarios of premiums for PSP generation, which artificially increase the price difference in those periods in which excess energy is still available, but the price difference is too low to cover efficiency losses. Such a mechanism addresses one of the key issues of PSP operation: the difference between sale and purchase price. In these scenarios, labelled *Premium5* and *Premium10*, PSP receive a premium of respectively 5 and 10 CHF per MWh generated. This implies that PSP would receive the wholesale price plus this payment for each MWh generated. These values are much lower than the incentive currently given to NDRES. For instance, PV and wind producers currently receive a CFR exceeding 200 CHF/MWh, which is more than 100 CHF/MWh above the wholesale price.

The second approach, focusing on improving SoS and providing favourable conditions for PSP, is the extension of FiTs for NDRES. This would allow owners of obsolete plants to refurbish their PV and wind energy facilities after their initial lifespan. This not only increases the total available capacity but also indirectly encourages PSP operation by providing cheap energy to pump. More precisely, the large penetration of PV leads to lower prices at noon, from which PSP could profit. We label this scenario *ExtFiT*.

Figure 11 shows that supporting PSP directly achieves the objective of increasing pumping significantly (on average by 37% in *Premium5* and 77% in *Premium10*), while the extension of FiTs (*ExtFiT*) only shows a slight improvement after 2040. The four scenarios exhibit very similar patterns: pumping increases slightly until 2034 and then decreases rapidly. Unlike *BAU*, in *ExtFiT* pumping remains steady after 2045 and thus the income of PSP stabilizes in that period. If premiums are implemented, policy makers should define their values carefully because a value exceeding 20% of purchase price would make it profitable to pump and to generate simultaneously, transforming PSP into money printing machines.

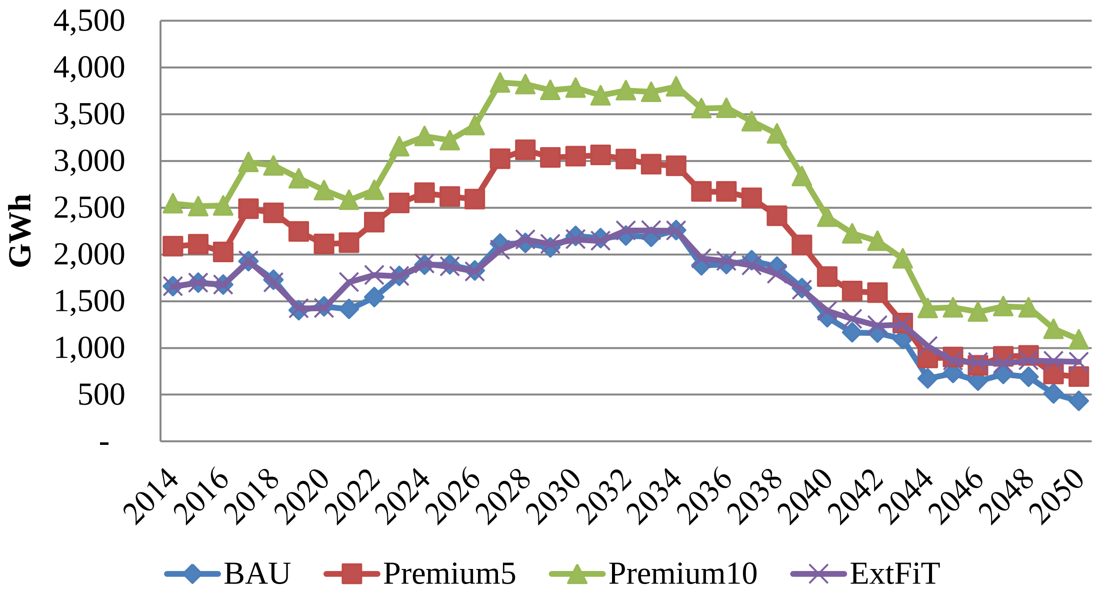

Figure 11. Simulated pumping under different schemes aimed at increasing PSP operation.

As expected, PSP achieve better results in scenarios with a premium (see Table 2). Profits are respectively 45% and 102% higher in *Premium5* and in *Premium10* than in *BAU*. Net income is significantly higher in these two scenarios compared to *BAU*: 74% in *Premium5* and 169% in *Premium10*. Operational margins are also higher than in *BAU* and *ExtFiT*. Still, the warning message remains as pumping from 2034 onwards decreases severely and full operating hours are far below their 2014 level.

Table 2. Simulated financial results of PSP under scenarios aimed to encourage pumping (numbers in parentheses are relative changes with respect to BAU).

	BAU	Premium5	Premium10	ExtFiT
(1) Average pumping (GWh/year)	1,554	2,138 (37%)	2,765 (77%)	1,627 (5%)
(2) PSP income (Millions CHF)	2,740	3,995 (45%)	5,537 (102%)	2,868 (5%)

	BAU	Premium5	Premium10	ExtFiT
(3) Cost of electricity used by PSP (Millions CHF)	2,283	3,200 (40%)	4,304 (88%)	2,385 (4%)
(4) Net income of PSP (Millions CHF) [(2) - (3)]	457	795 (74%)	1,233 (169%)	483 (6%)
(6) Change in net income of PSP with respect to the base scenario (Millions CHF)	--	338	776	26
(7) Operational margin [(2) - (3)]/(3)	17%	20%	22%	17%

We perform a welfare analysis to assess the impact on the whole market (Table 3). The four scenarios are comparable as they have the same pumping capacity. We calculate the change in consumer surplus with respect to *BAU* as the difference in consumers' costs. A rise in consumers' costs is a reduction in consumer surplus. Wholesale prices are lower when FiTs are extended (cost of electricity, line (8)) because there is larger NDRES penetration after 2035. However, higher fees are paid by consumers in order to support the extension of FiTs (*ExtFiT*) than in other scenarios (line (9)), and this cost is not offset by the drop in wholesale prices. As a consequence consumers' costs increase by 10% (line (11)). While extending FiTs significantly decreases consumers' surplus, the premiums for PSP have a negligible impact (line (12)). However, note that premiums leading to more pumping do not lower average wholesale prices (line (8)). Although at certain hours very expensive peak producers are avoided, the resulting reduction in peak prices is offset by the rise in off-peak prices when PSP pump.

Prices in *ExtFiT* lead to lower producer surplus (cost of electricity in line (13) in Table 3) compared to *BAU*, *Premium5* and *Premium10*. This result is coherent with the change in consumer surplus as the highest producer surplus occurs when premiums are implemented, and the lowest when FiTs for renewable are extended. Still, the surplus of local producers is very similar in the four scenarios (a maximum difference of 2.5% with respect to *BAU*, line (14)). The Swiss producers' surplus (line (15)) follows also the same pattern: highest loss in *ExtFiT* and increased surplus when premiums are implemented. These increases nonetheless do not offset the loss in consumers' surplus and thus total welfare in Switzerland (line (17)) decreases in the three alternatives.

Table 3. Simulated results of market welfare analysis.

	BAU	Premium5	Premium10	ExtFiT
Consumer surplus				
(8) Cost of electricity (Billions CHF)	143.3	144.0	144.9	140.3
(9) Cost of subsidising NDRES (Billions CHF)	93.2	93.2	93.2	116.9
(10) Cost of subsidising PSP (Billions CHF)	--	0.3	0.8	--
(11) Cost electricity + subsidies (Billions CHF) [(8) + (9) + (10)]	236.4	237.5	238.9	257.1
(12) Change in consumer surplus with respect to *BAU* (Billions CHF)	--	-1.1	-2.5	-20.7
Producer surplus				
(13) Producer surplus (Billions CHF)	106.6	107.4	108.0	100.8
(14) Change in producer surplus with respect to *BAU* (Billions CHF)	--	0.8	1.4	-5.8
(15) Swiss producer surplus (Billions CHF)	94.0	94.8	95.3	91.7
(16) Change in Swiss producer surplus with	--	0.8	1.3	-2.7

	BAU	Premium5	Premium10	ExtFiT
respect to *BAU* (Billions CHF)				
Total welfare				
(17) Change in Swiss market welfare with respect to *BAU* (Billions CHF) [(12) + (16)]	--	-0.3	-1.2	-23.4

Impact of the timing of the nuclear phase-out on PSP

The Parliament is currently reconsidering its decision to decommission nuclear plants. A position in which these plants should only be decommissioned based on security measures is gaining support. Consequently, the only plant that will certainly be decommissioned is Mühleberg (373 MW) in 2019 as the investments needed to improve its security are too high. The debate on the extension of the lifespan of the remaining four plants continues.

We consider two scenarios besides *BAU*. In both Mühleberg (373 MW) closes in 2019, while Gösgen (985 MW) and Leibstadt (1190 MW) continue operating until at least 2050. While in the first scenario (labelled *Nuc3Out*) Beznau I and II (365 MW each) are decommissioned after 60 years of operation, in 2029 and 2032, respectively, in the second (labelled *Nuc1Out*) these plants are also allowed to operate until at least 2050.

PSP operation is similar in the three scenarios (see Figure 12). Pumping achieves its highest level in the mid to late 30s before decreasing sharply, despite the higher generation capacity in *Nuc1Out* and *Nuc3Out* compared to *BAU*. As expected, in the scenarios where some nuclear power plants remain operational (*Nuc1Out* and *Nuc3Out*), pumping is higher than in *BAU* as more excess supply is available. This leads not only to more income, but also to higher operational margins. However, the situation in the 2040-2050 period remains critical. Even the availability of 90% of current nuclear capacity cannot avoid the drop in pumping. This highlights the importance of an ample supply of cheap energy.

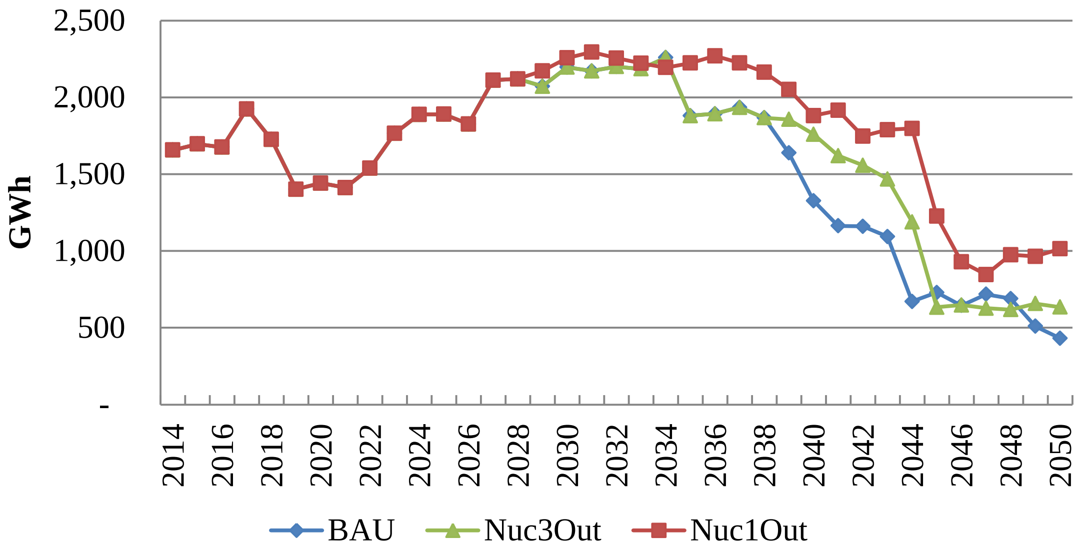

Figure 12. Simulated pumping under different nuclear power phase-out scenarios.

In the three scenarios total generation capacity decreases as obsolete PV plants are not replaced as investments are not profitable; this leads to lower SoS. We thus evaluated three additional scenarios in which government provides incentives to build CCGT of the same capacity as the dismantled nuclear plants. The results are very similar to the previous scenarios; therefore we do not discuss them. This highlights that while the replacement of a base-load technology (nuclear) by a mid-peak technology (CCGT) improves SoS, it does not improve arbitrage opportunities for PSP because the fundamental problem of lack of cheap energy is not solved. Also, spot imports are still most of the time the marginal producer, so peak prices remain unchanged.

Is there a future for PSP arbitrage?

Results presented so far show that even when keeping most of the nuclear capacity, arbitrage opportunities decrease significantly in the long-term and direct incentives cannot reverse the downward trend after 2035. We thus turn the question around: is there a plausible evolution in which PSP arbitrage would be profitable?

In a first scenario we consider the evolution of the German electricity market. We assume that once the German nuclear phase-out is completed by 2022, its prices will increase and its export capability will decrease, particularly in the evening, leading to lower competition for PSP at peak hours. This would also increase the possibilities of exporting to Germany in the evening as the difference between German peak prices and Swiss off-peak prices would increase. We thus consider a scenario in which prices increase by 35% and exports availability decreases by 50% between 5 p.m. and 9 p.m. in Germany. Given that we assume an aggregated export capacity from France and Germany to Switzerland, and that exports from Germany to Switzerland are about two thirds of the volume that Switzerland imports from the two countries, we reduce the joint net transfer capacity (NTC) by 35%. We label this scenario *HighPriceDE*. NTC and prices are season dependents. We acknowledge this is an stylised scenario as there is huge uncertainty about the impact of the German nuclear phase-out on prices in that country, but we aim to illustrate the extent to which these conditions could affect operation of Swiss PSP. As an example, Figure 13 shows the daily German prices and France/Germany NTC for exports to Switzerland in winter.

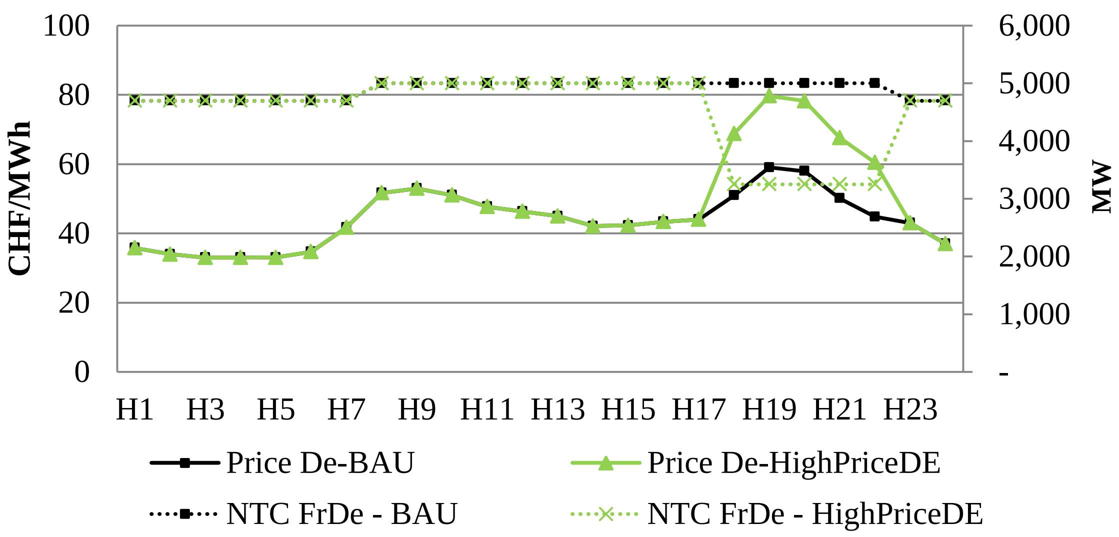

Figure 13. Assumptions of scenarios BAU and HighPriceDE. Left axis : prices in Germany in winter. Right axis : NTC of imports from France and Germany (in MW) in winter.

In a second scenario we focus on local policies. We combine the scenarios *ExtFiT* and *Nuc1Out*, i.e., we assume that FiTs for NDRES are extended after 2035 and that all nuclear plants except Muhleberg operate during the entire simulation horizon. We label this scenario *FiT&Nuc*. Finally, we propose a variation of this scenario, with lower demand. For this we assume the demand scenario "new policies" proposed in [33], which implies stronger efficiency measures. The remaining conditions are as in *FiT&Nuc*. We label this scenario *FiT&Nuc&Dem.* Finally, we have also run the BAU scenario with this more conservative demand hypothesis. As results are very similar to those of *BAU*, we do not present them here.

Figure 14 shows that in these three scenarios pumping is higher than in *BAU*. While in *HighPriceDE* the highest pumping volumes are achieved, the pattern is similar to the one of *BAU*: a peak in 2037 (3,988 GWh), followed by a rapid decrease. This occurs because of the expiration of the long-term contracts. In the other two scenarios, *FiT&Nuc* and *FiT&Nuc&Dem,* the higher availability of energy results in pumping remaining stable in the long-term. It even increases in *FiT&Nuc&Dem* because there is a higher availability of cheap energy due to the lower demand. Although on average pumping in *HighPriceDE* is respectively 33% and 45% higher than in *FiT&Nuc* and *FiT&Nuc&Dem* (line (18) in Table 4), pumping in the 2041-2050 period is respectively 13% and 45% higher in *FiT&Nuc* and in *FiT&Nuc&Dem* than in *HighPriceDE.* This leads to a higher utilisation of pumps in the 2041-2050 period. Therefore, although conditions assumed for the German market in *HighPriceDE* are favourable for PSP in the medium term, they do not address the lack of cheap energy available; the extension of FiTs and nuclear plants provide more favourable conditions to exploit arbitrage opportunities in the long term.

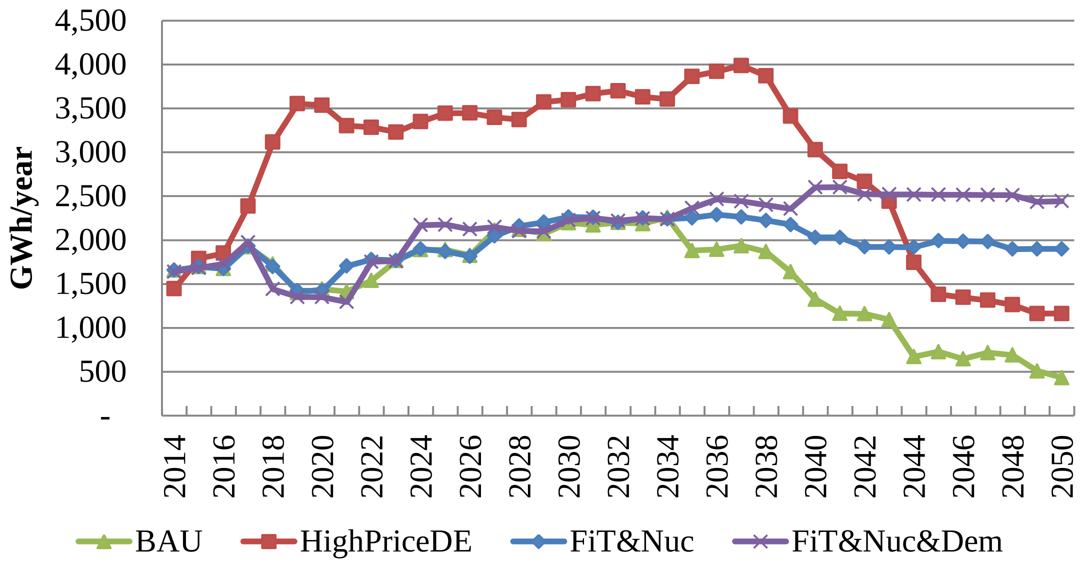

Figure 14. Comparison between simulated pumping in BAU and under scenarios with more favourable conditions.

Prices, daily pumping patterns and electricity exchange in *HighPriceDE* differ from those of the other scenarios. Wholesale prices are higher due to exports to Germany in the evening, making pumping significantly more profitable. An operational margin of 42% is achieved compared to a maximum of 20% for the other three scenarios (line (23) in Table 4).

Pumping increases in the three scenarios during daylight hours. The highest increase occurs in *HighPriceDE*, because of the higher difference between evening and noon prices. This not only renders arbitrage more profitable but also allows accessing larger energy volumes for pumping. Therefore, imports during daylight hours are used not only to meet local demand, but also to pump. This energy is then used to generate in the evening, which reduces imports from Germany, and even allows increasing exports to Germany and Italy, yielding higher operational margins. Overall imports and exports decrease: the rise of imports at noon does not compensate the imports drop in the evening. After 2038, pumping decreases significantly in *HighPriceDE*: like in *BAU*, arbitrage opportunities are considerably limited due to the lack of excess energy PSP despite the even larger difference between evening and noon prices. While better than *BAU*, pumping in *HighPriceDE* in 2050 is still below the 2014 level.

Although the impact of such conditions in Germany appears to be positive for PSP, the lower exchange could affect profits of the system operator because of lower income from grid utilisation and congestion rents. In such a scenario, cross-border expansion projects could be endangered. Also, there seems to be a trade-off between PSP and conventional HS. While the former's surplus increases by 1.5 CHF billion (line (21) in Table 4), the latter's surplus decreases by 2.2 CHF billion (line (24) in Table 4) in *HighPriceDE* compared to *BAU*. More pumping increases competition during evening hours, which relegates conventional HS generation to hours when prices are lower.

Table 4. Simulated results under scenarios with favourable conditions for PSP.

	BAU	**HighPriceDE**	**FiT&Nuc**	**FiT&Nuc&Dem**
(18) Average pumping (GWh/year)	1,554	2,855	1,963	2,155
(19) PSP income (Millions CHF)	2,740	6,168	3,332	3,612
(20) Cost of electricity used by PSP (Millions CHF)	2,283	4,333	2,788	2,998
(21) Net income of PSP (Millions CHF) [(2) - (3)]	457	1835	544	614
(22) Change in net income of PSP with respect to the base scenario (Millions CHF)	--	1378	87	157
(23) Operational margin (21) /(20)	17%	42%	20%	20%
(24) HS surplus (Billions CHF)	28.9	26.7	26.9	24.4
(25) Cost of electricity (Billion	143.3	152.1	137.7	119.7

	BAU	HighPriceDE	FiT&Nuc	FiT&Nuc&Dem
CHF)				
(26) Cost of subsidies to NDRES (Billions CHF)	93.2	93.0	117.9	118.6
(27) Cost electricity + subsidies to NDRES (Billions CHF) [(8) + (9) + (10)]	236.4	245.1	251.7	238.2
(28) Change in consumer surplus with respect to BAU (Billions CHF)	--	-8.7	-15.3	-1.8

Although to a lower extent, PSP also profit from excess energy produced by PV in *FiT&Nuc* and *FiT&Nuc&Dem*, allowing them to pump during daylight hours. Unlike in *BAU* and *HighPriceDE*, this pattern continues through the entire simulation period because of the larger penetration of PV after 2034. Financial results are also better than in *BAU*, not only in terms of higher income but also in terms of a larger operational margin. Although average wholesale prices in *FiT&Nuc* and *FiT&Nuc&Dem* are respectively 7% and 10% lower than in *BAU* (line (25) in Table 4), net profits of PSP are not affected because both off-peak and peak prices decrease in the same proportion. However, the cost of supporting the extension of FiT are the highest (line (26) in Table 4), not only because of the larger investments in these technologies, but also because the average prices being lower, the difference between the levelised investment cost and prices increases. Hence, for consumers, these two scenarios have higher costs than in *BAU* as the cost of supporting the extension of FiTs offsets the lower wholesale prices (line (28) in Table 4). Overall SoS is improved since profitability of PSP is enhanced, prices are more stable and capacity adequacy is higher.

5. Conclusion

Our model simulates the strategic behaviour of PSP and allows evaluating their long-term arbitrage opportunities. PSP decide simultaneously the volume and time of generation and pumping. Their decisions depend on price differences and on the available energy to pump, which is due to decrease significantly in the long-term because of the major changes in the Swiss electricity market: the nuclear phase-out, expiration of long-term import contracts and obsolescence of PV.

Our results show that pumping peaks in 2034 following the rise in PV production. From there onwards, pumping decreases rapidly due to tighter capacity margins resulting from the expiration of long-term contracts and the nuclear phase-out. There is thus a significant decrease of excess energy which, despite the higher difference between peak and off-peak prices, severely limits pumping. Neither a premium for PSP generation, nor the decrease of demand, nor the extension of FiTs appear to have a significant long-term impact. But the combination of certain of these policies could significantly encourage PSP operation.

The scenarios with alternative timings for the nuclear phase-out and/or an extension of FiTs for NDRES show that pumping increases under large penetration of both PV and nuclear. Still, we cannot conclude that PV and PSP complement each other; such complementarity depends on the size of PV capacity. On the one hand, PV and PSP compete as they both bid during the summer and spring noon peak. Therefore, a limited installed capacity of PV displaces PSP generation and decreases noon prices. On the other hand, a large penetration of PV makes the noon peak disappear and decreases prices significantly, which is an opportunity for PSP: they pump at midday, and produce in the evening. This limits the price-lowering effect of PV, which is particularly important if the technology is no longer subsidised by FiTs, but by a market-dependent mechanism, e.g., market premiums, as currently being considered in Switzerland's "Energy strategy 2050". These mechanisms provide a premium in addition to a strike price, e.g., the average monthly price. In this case, PSP could help PV limit the price drop when there is excess PV supply, while PV still provides cheap energy to pump.

Nonetheless, conclusions about such complementarity (or lack of it) are limited by the characteristics of our model, which assumes a representative daily pattern for PV availability in each season. Variations from one day to another are thus not captured. On the one hand, these could provide an opportunity for PSP, as they could pump more water on a sunny day (with lower expected prices) and use it for generation on a cloudy day (with higher expected prices). On the other hand, these variations dramatically change the timing of daily price patterns and significantly limit the occurrence of peak prices at noon, as highlighted recently in Germany [6], which could affect PSP operation. Accurate models and transparent information are thus needed for PSP operation economic efficient.

As mentioned before, our results only concern arbitrage related PSP operations. Any assessment about PSP profitability is thus a conservative estimate as PSP also provide ancillary services. However, the expected scale of ancillary services needs is small compared to the size of the PSP under construction. Although PV output is subject to variations, these are significantly lower than those of wind energy. Because of limited potential and the NIMBY phenomenon, wind energy is expected to have a lower development than PV in Switzerland. The potential to provide ancillary services to foreign markets is limited. Germany is the only neighbouring country with a significant share of wind energy, but most of its facilities are located in the north and there is significant congestion between north and south. This prevents a potentially active participation of Swiss PSP in the German market. The increase of the value of ancillary services in Switzerland might thus be limited and is unlikely to compensate the lack of arbitrage opportunities.

Our results thus show that PSP currently under construction will face conditions totally different from those forecasted 10 years ago, when investments were committed. If the regulator is keen to guarantee PSP profitability, support is needed. Not only incentives such as the premiums proposed in this work, but also policies aimed at enhancing capacity adequacy, e.g., supporting technologies with low variable costs such as NDRES and nuclear power. This is not only important for investors of PSP currently under construction, whose major motivation was exploiting arbitrage opportunities, but also for the country as the drop in pumping limits the potential benefits PSP can bring in terms of SoS, through reduction of peak imports, peak demand shaving, prices stabilisation and higher system reliability.

6. Acknowledgement

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7. Appendix: arbitrage heuristic

We assume that PSP have perfect information about other technologies[13] concerning their available hourly supply and marginal costs (bidding prices). We run a dispatch (including the electricity exchange) excluding PSP and calculate the hourly prices and the volumes dispatched. We call this a “pre-dispatch”. Let A_{th} denote the available supply from technology t for hour h. Technologies bid these volumes at their marginal costs C_{th} and the market is cleared by merit-order dispatch; Q_{th} denotes the quantity dispatched and S_{th} is the unallocated supply (Eq. (1)). The unallocated supply of each technology is associated with the respective marginal costs at which it can be dispatched. This allows us to calculate the volumes available for pumping at a purchase price P, i.e., $S^*_{th}(P)$ (Eq. (2)). We calculate the

[13] These are conventional hydro-storage, run-of-river, nuclear power, wind energy, PV, CCGT and conventional thermal.

maximum pumping for each hour at each price $S_h^*(P)$ taking into account that pumping is constrained by the pumping capacity K (Eq. (3)). Next we build the Unallocated curve *S(P)* from hourly unused supply volumes and considering the pumps' efficiency α so as to obtain the effective available energy (Eq. (4)).

$$S_{th} = A_{th} - Q_{th} \; \forall t \neq PSP \tag{1}$$

$$S_{th}^*(P) = \begin{cases} S_{th} & \text{if } P \geq C_{th} \\ 0 & else \end{cases} \tag{2}$$

$$S_h^*(P) = min\left(\sum_t S_{th}^*(P)\,, K\right) \tag{3}$$

$$S(P) = \alpha \sum_h S_h^*(P) \tag{4}$$

We follow a similar process to build the Allocated curve. First, we calculate the volumes that can be supplied by PSP at a bid price *B*, $X_{th}^*(B)$, i.e., the allocated volumes that PSP would displace at that price (Eq. (5)). These are the volumes that can be supplied by PSP if they bid at *B*. Then, we calculate the maximum volumes that can be supplied per hour considering that generation is constrained by the generation capacity *G* (Eq. (6)). Finally, we build the Allocated curve *X(B)* as a function of the bid price *B* (Eq. (7)).

$$X_{th}^*(B) = \begin{cases} Q_{th} & \text{if } B \leq C_{th} \\ 0 & else \end{cases} \tag{5}$$

$$X_h^*(B) = min\left(\sum_t X_{th}^*(B)\,, G\right) \tag{6}$$

$$X(B) = \sum_h X_h^*(B) \tag{7}$$

Since *B* = *P/α*, both the Unallocated curve *S* and the Allocated curve *X* can be written as a function of the purchase price *P*. The energy available for PSP to generate, *V**, can be calculated from the intersection of *S(P)* and *X(P)*. *V** is thus the energy available after subtracting the pumps' efficiency losses, while *P** the maximum price that PSP is willing to pay for energy to pump. Therefore, for a purchase price P^*, V^* is the energy obtained after pumping (Eq. (8)). Finally, the energy PSP have to buy, i.e., their pumping, is calculated as $Y^* = V^*/\alpha$.

$$V^* = X(P^*) = S(P^*) \qquad (8)$$

Next we calculate PSP hourly pumping Y_h and hourly bids $A_{PSP,h}$, which are used for the "real" dispatch. The former are calculated from the cheapest unallocated volumes R_{th} (see Eq. (9)), while the latter is calculated from the most expensive allocated volumes Z_{th} (see Eq. (10)).

$$\min_{R_{th}} \sum_{th} C_{th} R_{th} \qquad (9)$$

Subject to

$R_{th} \leq S_{th}$ (availability of unallocated energy)

$Y_h = \sum_t R_{th}$ (hourly pumping)

$Y^* = \sum_h Y_h$ (daily pumping)

$$\max_{Z_{th}} \sum_{th} C_{th} Z_{th} \qquad (10)$$

Subject to

$Z_{th} \leq Q_{th}$ (generation of expensive producers)

$A_{PSP,h} = \sum_t Z_{th}$ (PSP hourly bids)

$V^* = \sum_h A_{PSP,h}$ (PSP daily generation)

When PSP is incentivised, the heuristic changes slightly. Suppose PSP receive a premium M for each unit generated. We thus modify Eq. (2). Now PSP can purchase energy to store at a higher price, while considering the pumps efficiency α. This payment causes an upward displacement on $S(P)$: Eq. (11) replaces Eq. (2). The other equations remain unchanged.

$$S_{th}^{*}(P) = \begin{cases} S_{th} & \text{if } P \geq C_{th} + \alpha M \\ 0 & else \end{cases} \tag{11}$$

In this case the Unallocated curve *Uc* will shift to the left (*Ucl* in Figure A1) as more energy can be bought by PSP at a given price. Since the allocated volumes remain unchanged, *Ac* does not shift. Consequently, more pumping is profitable (*Vc* > *V**). The bid price decreases, but the incentive for PSP covers the difference between P^* and P_C.

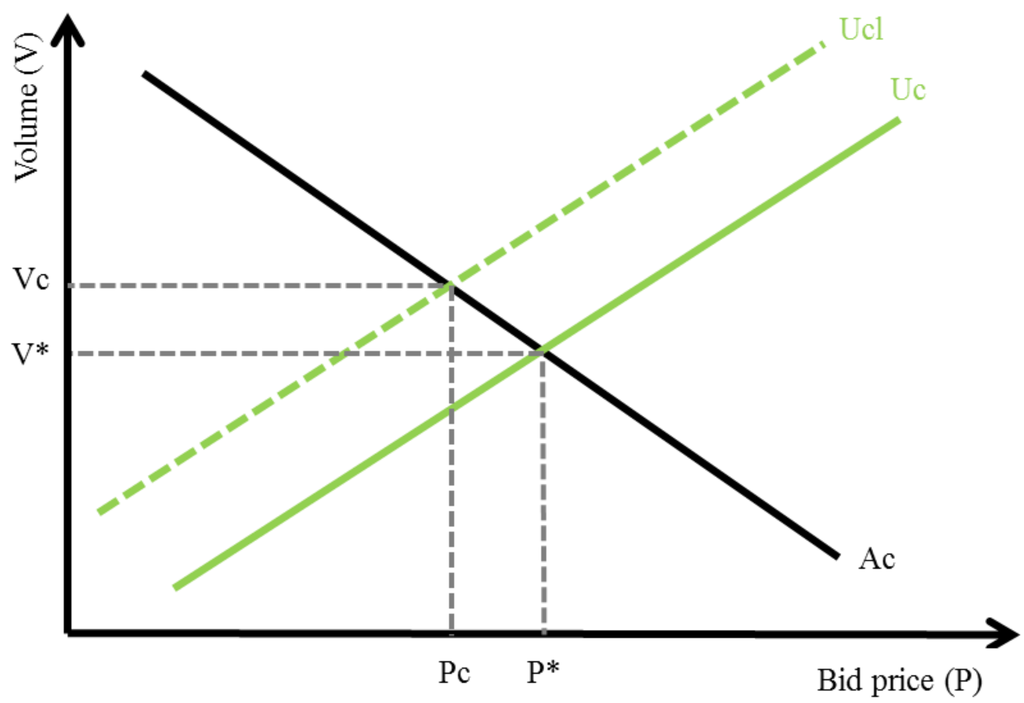

Figure A1. Impact of a premium for PSP on daily Allocated and Unallocated curves.

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APPENDIX B.3

A Framework to Evaluate Security of Supply in the Electricity Sector

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Abstract

Security of Electricity Supply (SoES) has become a major concern for regulators and policymakers over the last decade. However, most work focusses either more generally on energy security or on a single fuel. We develop a comprehensive but flexible framework to assess the SoES for a single jurisdiction, taking into the account the specificities of electricity. This framework has two aims: (i) provide a snapshot of the situation to understand current weaknesses and determine what actions are required; (ii) capture the evolution over time to evaluate progress and identify potential problems before they materialise. The framework, based on an extensive literature review, consists of twelve dimensions that are critical for SoES. We develop metrics that capture the state and evolution of each dimension. This framework is intended to be a management information tool for all stakeholders, aimed at organising data and structuring its analysis, to enable monitoring the evolution of the SoES, while also functioning as an early-warning system by flagging potential future problems.

Keywords:

Security of supply, electricity, energy security, framework

1. Introduction

Energy security (ES) has been a concern for regulators and policymakers since the oil crisis in the seventies [1]. However, security of electricity supply (SoES) has only recently become a major issue. Over the last two decades many countries around the world have developed competitive electricity markets [2], and regional markets are emerging [3], implying an increase in cross-border transmission and trade. Research has thus focussed on the consequences of the deregulation [4] and privatisation of the electricity sector [5], including market design [6,7], market regulation, and providing the right incentives [8].

Over the last few years electricity markets have undergone major changes: decisions to close down nuclear capacity, a shift to renewable energies, insufficient new investments in thermal generation, and the decreasing profitability of utility companies. This has resulted in security of supply becoming a central issue for all the actors of the electricity industry, from consumers, through utility companies to regulators and policymakers; several national regulators have expressed concerns about long-term SoES, e.g., in the UK [9] and in Belgium [10].

The particularities of electricity systems, the changes in the market structure, and the pressure resulting from environmentally driven policies, together with technological innovations over the last thirty years, have also led to a notable change in the technologies used for electricity generation. The significant shift towards gas-fired turbines as the main technology for newly installed conventional generation capacity [8] has, among others, made the European electricity market increasingly dependent on gas imports [11]. Recently, renewable energy technologies have reached a significant share of new installed capacity [12,13]. Regional issues further complicate the situation. For instance, a significant share of Europe's existing generation capacity will soon become obsolete, and thus needs to be replaced [14]. Several countries intend to phase-out nuclear plants, which often represent a non-trivial share of their generation; this will affect future capacity adequacy [15].

These issues need to be understood in the context of environmental factors. For instance, while a move from old generation plants to new gas fired plants typically reduces emissions, the opposite is true when gas fired plants replace nuclear ones [16]. This raises the question of the degree to which renewables can play a role in this replacement. Furthermore, in many countries the grid is more fragile than anticipated, as illustrated by several large blackouts in Europe and the USA [17]. Finally, there is the question of whether consumers are able to understand these issues, and will accept to pay what might be significantly higher tariffs to ensure SoES, generally considered a “non-issue” until blackouts start occurring [18,19]. The magnitude of the economic impact of such events is huge. For instance, the blackout in the U.S.A in 2003 costed between 4 and 10 billion U.S. dollars [20], and according to a study of the Swiss Federal Office of Energy, the cost of a blackout in Switzerland varies between 8 and 30 million CHF per minute [21]. Such estimates do not include less tangible consequences, such as loss of reputation.

Finally, there is the question of time horizon. Investment planning in the electricity system is a long-term process: building new thermal capacity requires at least three years, large hydro might take up to ten years, and the expected lifetime of investments ranges from twenty to more than fifty years. While disruptions to the electricity supply are often attributed to sudden, short term, events (e.g., grid failure, unscheduled plant outage, unexpected demand peak), the true underlying cause is a lack of long-term planning. These disruptions force the regulators to become reactive rather than proactive, preventing them from taking a long-term perspective.

In this paper we develop a framework to assess the level of security of supply of the electricity sector, and its evolution over time, for a single jurisdiction. The term framework refers to a set of principles, ideas, etc., used to form a judgement and reach a decision. Our aim is to provide a framework for regulators, policy makers, utilities and other stakeholders to understand, asses and act on the state of the security of supply of an electricity system.

In legal terms, a jurisdiction is formally defined as "the limits or territory within which authority may be exercised" [22]. In our context, the electricity sector, this refers to a geographical area under the authority of a single regulator, governed by a common set of rules. A jurisdiction may or may not coincide with national borders or with the area under the control of a single system operator. For instance, despite being divided into different areas, each with its own system operator, Germany is considered as a single jurisdiction, because the legislation of its market is determined at the national level [23]. On the contrary, while in the USA the Federal Energy Regulatory Commission (FERC) provides general guidelines and directives to the regional markets, there are well-established, autonomous, regional markets (e.g., PJM, NYISO and ERCOT), each with its own independent system operator and public utilities commission, resulting in very different regulatory frameworks; we therefore consider these regional markets to be jurisdictions. We thus use the term jurisdiction to refer to an area under the control of a single regulator or policy maker.

The paper is organised as follows: first we review the existing literature and outline our framework. Then we develop our framework and the metrics necessary for its evaluation. Next we elaborate on how this framework can be used, and conclude with a more general discussion, including the limitations of the proposed framework.

2. Literature review

Jewell et al. [24] define energy security as low vulnerability of vital energy systems. More concretely, according to the IEA [25], energy security refers to the uninterrupted availability of energy sources at an affordable price. The IEA [26] emphasises the importance of the time-frame: while in the short-term energy security focuses on the ability of the energy system to react promptly to sudden changes within the supply-demand balance, in the long-term it mainly deals with timely investments to supply energy in line with economic developments and sustainable environmental needs. A similar definition is provided by Chester [27], who suggests that the concept is based on 'reliability' and 'adequacy' at 'reasonable' market-determined energy prices. Likewise, Sovacool et al. [28] define energy security as "how to equitably provide available, affordable, reliable, efficient, environmentally benign, proactively governed and socially acceptable energy services to end-users" (p. 5846). An extensive review of energy security definitions is presented in Winzer [29]. These definitions illustrate that SoES is a complex concept, with a very broad scope.

Previous work has focused on the conceptualisation of the multiple factors affecting ES, using different approaches depending on the specific fuels analysed, the geographic dimension and the time-horizon under consideration. Other work has focused on specific energy sectors or primary energy sources, (mainly oil, and to a lesser degree gas). Examples include [30–33]. Studies regarding security of oil supply tend to take a global view, while those concerning the gas industry, due to the network aspects, take a regional view [34].

One of the most widely used frameworks, proposed by the APERC [35], defines ES using the four A's: availability, accessibility, affordability and acceptability. Several authors have built on this framework. For instance, Jonsson et al. [36] base their work on the first three A's, focusing on whether energy systems are exposed to insecurity (e.g., infrastructural disturbances), or whether they create insecurity, (e.g., energy used as a "weapon" in geopolitics). Cherp and Jewell [37] build on this definition by discussing whether the four A's deal with the fundamentals of security in the broadest sense. Likewise, Gracceva and Zeniewski [38] propose five properties, strongly related to the four A's, that energy systems should have to ensure supply: stability, flexibility, resilience, market adequacy and robustness. They also identify potential threats to those properties and classify them according to the time-horizon of their impact and the segment of the supply chain that they affect.

Other authors focus on defining the different dimensions of ES, and indicators to assess these, rather than on conceptualising a definition for ES. For instance, Von Hippel et al. [39] propose four major elements that should be included in a definition of energy security: the environment, technology, demand-side management and domestic socio-cultural and political factors. Cherp et al. [40] insist on the need to include environmental factors given the tangible impact of climate change on energy systems. Vivoda [41] adds three further dimensions: human security, international issues and policy aspects. This work [39,41] is closely related to that based on the APERC's four A's [35]. For instance, an environmentally friendly electricity system will gain acceptability from society. Likewise, Kruyt et al. [42] argue that their four dimensions of ES (globalisation, regionalisation, economic efficiency and environmental acceptability) are strongly linked to the four A's. For instance, political embargoes (regionalisation dimension) endanger the accessibility (property) of energy resources.

Several authors focus on evaluating the multiple dimensions of ES. Kruyt et al. [42] provide a review of the available indicators to assess ES in the long-term, while Löschel et al. [43] elaborate on two indicators proposed by the IEA for evaluating the risk of price disturbances and physical availability of fossil fuels. Others develop a single metric for ES by aggregating the indicators used to measure the different dimensions. For instance, Sovaccol [28] and Vivoda [41] both calculate a global index to assess the level of energy security in the Asia-

Pacific region. The very different nature of the dimensions of ES casts doubts on the usefulness of aggregate indicators: a good performance on one dimension will not necessarily compensate a poor performance on another one; worse, a reasonable overall performance could hide critical situation on one dimension. Several authors, including [38], are very critical towards the use of indicators due to the simplifications required for their calculation.

Two of the more comprehensive ES frameworks found in the literature are the Model of Short-term Energy Security (MOSES) [44] and the General Energy Assessment (GEA) [40]. The main difference between these two studies is the time frame. While the former focusses on issues affecting ES in the short-term, the latter considers the short- to medium-term. The former considers how an energy system's resilience could mitigate the risks of energy disruptions related to domestic and foreign external factors. The latter proposes three main perspectives (robustness, sovereignty and resilience) to classify threats and mitigation strategies. Thus, while these studies incorporate some aspects of the electricity system, we consider the level of detail insufficient to evaluate the security of electricity supply.

Although the electricity sector and the generation technologies (e.g., hydropower and nuclear power) are included as one element of the ES frameworks previously mentioned [40,44], there is relatively little work focusing specifically on the SoES. In particular, while the Cherp et al. framework [40] includes a wide range of potential threats to energy systems, it only provides a very narrow set of indicators for electricity systems. Furthermore, the impact of renewable energies, which are leading the electricity markets' transition and reshaping their dynamics, is not analysed in detail. Overall, studies analysing the SoES focus on the supply-side view of the problem, dismissing the increasingly active role of demand.

Several frameworks focused on the electricity sector have been developed [45,46]. In both papers, the frameworks are tailored to national specificities. Consequently, they ignore important dimensions, such as the environmental impact and the profitability of peak generators, which hinders their adaptability to other regions. The framework developed by Nepal and Jamasb [20] focusses on the network risks, and proposes an aggregated risk measure.

Finally, there is a significant amount of work on estimating the value of SoES. For instance, de Nooij et al. [47] compute estimates for different economic sectors in the Netherlands, based on the opportunity cost resulting from an interruption of the electricity supply. A similar analysis has been performed for Spain [48].

We can thus conclude that, although most studies acknowledge the multidimensional nature of security of supply, they focus on energy systems as a whole. The few studies that specifically analyse SoES, do not attempt to provide a comprehensive and general framework; they are context-dependant, tailored to the particular features of a country or adapted to specific scenarios [38,45]. Assessing the SoES of a jurisdiction requires a sound understanding of its particularities, and the conclusions and policy implications are necessarily context dependant. Still, we believe that an appropriate framework should be comprehensive and sufficiently flexible to be adaptable to the electricity sector of any jurisdiction.

3. Framework development: objective and boundaries

Electricity markets deserve particular attention due to their specific characteristics. These include non-storability of electricity (thus requiring real-time balancing of demand and supply), long construction delays and life-times for generation and transmission infrastructure, low demand elasticity, rigidity of the transport infrastructure and the regional nature of markets [49]. These elements differentiate electricity from other energy markets, such as oil or gas, which can be stored and transported over long distances. Also, oil and gas are traded in global markets, with a global price, while electricity is priced locally; several prices can co-exist inside a single country, e.g., in Norway [50]. Furthermore, the infrastructure and the regulation differ significantly from most other energy forms. Therefore there is a need for a framework designed specifically for electricity.

We develop a framework focused on the electricity sector of a single jurisdiction. This framework is comprehensive enough to ensure that the central elements determining SoES are taken into account, while being sufficiently flexible to be adaptable to the specificities of most jurisdictions. Our framework enables the various stakeholders to monitor the changes in the industry. We do not make any attempt to prioritise the different dimensions, as this would induce users to focus on a (small) subset of measures. We believe all are important and need to be monitored, allowing policy makers and regulators to act on the appropriate parts of the system to ensure SoES.

Our framework differs from previous work in the area of energy security in the following respects:

- Given its specificities, we consider only the electricity sector, not the energy sector as a whole.
- We aim to develop a set of measures that can be used to evaluate the current state of SoES, using a multi-dimensional view; we do not try to aggregate these measures into one single indicator.
- We aim to develop a framework that will allow decision makers to follow the development of SoES over time, enabling them to observe the changes that take place in the different dimensions.
- We focus on a single jurisdiction, because the ability of regulators and policy makers to act on signals indicating potential problems is limited to their jurisdiction.

- The framework is not intended to compare jurisdictions; we do not prioritise the dimensions, nor do we provide a single measure that would enable such a comparison. The framework could be used to make comparisons between jurisdictions but, given the specificities of each jurisdiction, we do not believe that this would provide any useful insights for a regulator attempting to solve problems in the jurisdiction he is in charge of. Furthermore, the disaggregated nature of the framework makes a comparison across jurisdictions difficult.

Based on an extensive literature review of work analysing security of supply in energy systems, we have identified twelve dimensions that influence the performance of an electricity system. This review included a wide variety of approaches, ranging from quantitative frameworks to policy papers. It covered different aspects such as the primary energy sources and potential energy-uses. We considered studies that took a disaggregated, as well as an aggregated approach to evaluating security of supply.

For each dimension we either suggest an existing metric or develop a new one. The metrics we propose can be calculated using data that is (usually) publicly available, as this enables a wider use. While more accurate measures exist, their calculation requires more sophisticated tools, e.g., operational models of electricity systems. These cases will be discussed in detail in the next section.

Another important aspect of the framework is its longitudinal nature. Drawing a comparison with accounting, numbers for a single year are not particular useful to understand the development of a company. Similarly, to valuate an electricity system, it is necessary to monitor the evolution of the indicators over several years, focussing on those that worsen, and taking action when an indicator points to a potential threat to SoES in the near- or medium-term. Given the long investment delays in this sector, the framework should function as an early-warning system, aimed at preventing future SoES problems.

In this paper we have chosen to focus on a detailed motivation of the framework, its dimensions, and their measures, at the expense of providing a numerical example or a case study. Indeed, applying our framework to a specific jurisdiction is a major undertaking; the outcome of such an endeavour would be a 100-page policy report.

4. Dimensions of the framework

In this section we discuss the twelve key dimensions policymakers should considered when assessing security of supply in an electricity market. For each dimension we develop one or more indicators to evaluate the current state of the system.

4.1 Generation adequacy

This dimension refers to a jurisdiction's capability to meet domestic demand in the short- and medium-term with its own generation capacity. SoES has mostly been approached as a capacity adequacy problem [49,51–53], which is appropriate as demand has to be matched in real-time; capacity should thus be available in the right amount at the right time. Capacity adequacy has traditionally been measured by the reserve margin, the ratio between installed capacity and peak-demand. The increasing role of renewable intermittent resources makes the reserve margin less informative: while their long-term average production level is known, their actual availability at a given point in time is difficult to predict. This has led to an increasing use of the de-rated capacity margin to measure a system’s capacity to meet annual peak-demand [54,55].

Rather than considering peak-demand, we suggest focussing on the hour that exhibits the lowest de-rated margin within a year. For systems with, for instance, a significant share of hydro and annual peak-demand occurring during summer afternoons, this measure may be more representative as the tightest margin does not necessarily occur when demand peaks. One example is California, where in 2009 the de-rated margin was lower in winter (10%) than in summer (14%), when demand peaked [56].

Still, this measure could overestimate capacity adequacy in countries with a significant share of hydro-storage generation, as this technology's de-rating factor is generally assumed to exceed 80%, ignoring the constraint created by a limited water supply. In such a situation the energy margin, which estimates the ratio between the surplus (or lack of) energy and demand, might be more appropriate [57]. Depending on the generation mix of a country, we thus propose the de-rated capacity margin or the energy margin as indicator of generation capacity adequacy.

4.2 Resilience

This concept is defined as "the ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event" [58]. While capacity adequacy captures energy availability under normal conditions, resilience refers to the capacity of electricity systems to maintain an uninterrupted electricity supply in the face of sudden changes in resource availability.

Causes of disruption can be environmental, technological or political factors, human error or deliberate actions. One example of an environmental factor is the ENSO phenomenon in South American countries, which can result in reservoir inflows being 30% lower than normal for periods lasting from 6 months to over a year. The consequences can be devastating as illustrated by the programmed blackouts in Colombia in the 1990s [4]. Turning to political factors, a country without gas reserves, relying mainly on CCGT generation (e.g., Ukraine) might be seriously affected by a disruption in the gas supply [59]. This dimension is thus about ensuring that available capacity can actually be used, so the jurisdiction is able to meet demand in the short-term under changing supply availability.

Measuring the intrinsic ability of a country to adapt to sudden change is quite abstract; running "real" experiments to establish this capability is inconceivable, and simulation experiments only provide limited insights. This makes it necessary to rely on proxies to track the evolution of resilience. It has been argued that geographical expansion through the interconnection of electricity markets reduces vulnerability, as a larger entity is more likely to be able to absorb short-term disruptions [60]. However, there is no clear empirical evidence yet for how strong these effects are [61].

Dependence on one or a few technologies endangers resilience as the system becomes more vulnerable to changes in the availability of the resource used by that technology (e.g., sudden gas cuts in a country highly dependent on CCGT). A more diversified country will be in a better position to prevent shortages resulting from external events. Resilience can thus be measured as the concentration of generation technologies, using an approach similar to the Herfindahl - Hirschman index (HHI): the higher the value of this index, the higher the dependency on a limited number of technologies.

4.3 Reliability

This concept is related to the quality of the service, i.e., electricity supply. Since electricity is a non-differentiated product, quality refers exclusively to being uninterrupted. While the metrics used above to assess capacity adequacy and resilience show a trend in SoES, they are not as such a measure of the risk of interruption. Nor do they provide any information on how large an outage event may be. Reliability thus refers to the capability of the system to provide an uninterrupted supply. The most commonly used metric is the System Average Interruption Duration Index (SAIDI), i.e., the ratio between the total annual customer-minutes without service and the total number of customers in the system [20]. This data is typically provided by the Transmission system operator (TSO), based on information from the utilities, and is used as a benchmark in reliability improvement programmes.

4.4 Supply flexibility

Electricity systems must be able to deal with sudden imbalances, whether due to inaccurate demand forecasts, technical problems or, more recently the inherent variability of intermittent renewable generation sources. Events like a solar eclipse or an unexpected thunderstorm suddenly become of major concern when photovoltaic plays a significant part in the production [62]. Generators with fast response times, e.g., hydro-storage plants and CCGT, can meet sudden fluctuations in demand or help compensate for the loss of other power supply options [63].

While variable renewable energies (VRES), i.e., wind and solar (PV), create short-term problems, countries with a large share of hydro, but limited reservoirs, face medium-term problems as they also need sufficient non-hydro capacity to withstand longer periods of drought caused by local weather systems [4]. As metric for flexibility, we use the ratio between, on the one hand, the available flexible load (hydro-storage and CCGT) and, on the other hand, the maximal load supplied by VRES over the last year.

4.5 Condition of the grid

This dimension refers to grid performance and adequacy. The degree to which both transport capacity adequacy and grid ageing affect the reliability of the system depends on grid topology, which in turn depends on the geographical distribution of the demand/supply nodes. The locational constraints of PV and wind lead to a much more decentralised generation system, which increases topological complexity. In the presence of congested power-lines, the reorganisation of electricity flows in a highly decentralised system, following either an ageing failure or a power loss, becomes increasingly complicated and might lead to disruption [64]. Older systems operating close to their saturation level are more likely to suffer cascade events, as occurred in the USA in 2003 and in Europe in 2003 and 2006 [17,65].

Grid capacity adequacy

While capacity adequacy assessments tend to focus exclusively on the generation segment, the adequacy of power-grid capacity also deserves attention, as transportation of electricity depends on the transmission and distribution grid. Some work has focused on the impact of different congestion management mechanisms on investments in cross-border interconnectors [66,67] and on the TSO costs within a jurisdiction.

Grid congestion leads to deterioration of service quality due to frequent power outages [20]. It can also lead to higher prices and to an inefficient allocation of resources, highlighted by significant price differences among pricing zones within a single market. For instance, in 2012 average prices in Norway differed by more than 8% across regions [50]. In Germany, curtailment of wind power plants due to network congestion has increased in recent years [68].There are several mechanisms to deal with congestion management within a market; the two most widely used are market splitting and redispatch. In the former a market is split into different zones, leading to zonal prices. This mechanism is used among others in Nordpool and Italy. In the latter some generators, whose power contributes to congestion, are asked to produce less while others are requested to increase production. This mechanism is used for instance in Germany and some markets in the USA. Kumar et al. [69] provide a detailed review of the different mechanisms. According to the type of mechanism, Alomoush [70] proposes different indicators to measure congestion and its severity. With zonal prices, he proposes an “index of locational marginal prices” as measure of the differences between zonal prices and the unconstrained marginal price. The unconstrained marginal price might be difficult to calculate, or not publicly available; one could instead use the weighted average of zonal prices. When there is redispatching, [70] proposes the “Index of Total Congestion Charge”, which is the ratio between the total congestion charge (TCC) and the total system generation. TCC expresses the difference between what consumers pay (strictly for the electricity, i.e., excluding any other fees) and what generators are paid. Since TCC data can be unavailable, an alternative could be the number of hours with redispatching, such as reported for Germany [71]. Alternatively, congestion might be measured in just a single critical power line. This can be done using the power transfer distribution factor, which is the physical flow on the transmission line in question as a fraction of the flow between the two points connected by the power line.

Grid ageing

A significant share of grid infrastructure in western countries was developed after the Second World War. For instance, two thirds of Swiss transmission capacity was built in the 1950s and the 1960s [72] and 70% of the transmission lines and power transformers of the USA's grid are now over 25 years old [73]. Unplanned interruptions due to system breakdowns and increased planned outages due to maintenance and upgrades are more frequent in old and/or poorly maintained networks [20]. The share of ageing failures grows significantly when components age [74]. Operating conditions such as bad weather may also increase a component’s failure rate, particularly in the presence of ageing components [75]. As a result, the age of the grid’s components contributes to the incidence of weather-related power outages.

Investments in transmission should aim not only at relieving congestion by adding transmission capacity, but also at modernising and increasing the resilience of the grid. The amounts invested, while a useful indicator of the state of the network, are not a satisfactory measure as a component is not restored to an as good as new condition from a reliability perspective [76]. The age of the grid seems a more appropriate indicator of current performance and potential problems. In particular, it provides an indication of the investments that will be required in the medium- to long-term to maintain reliable transmission.

4.6 Demand management

Security of supply can also be improved by influencing demand, referred to as demand side management (DSM); this includes demand conservation, consumer efficiency, and load-shifting.

Conservation

Conservation is the reduction in energy demand resulting from users foregoing certain services. This can be achieved, among others, by direct load control, demand bidding and industrial/commercial programmes, such as interruptible contracts [77]. Conservation usually provides only a temporary demand reduction in response to either higher prices or other external pressures [78]. We do not propose a specific metric for this aspect as it can be measured by subtracting interruptible demand from peak demand when calculating the de-rated margin. For instance, the California ISO accounts for demand response and interruptible load programmes when assessing capacity adequacy [79].

Efficiency

Consumer efficiency is the ratio of energy service to the energy required to deliver that service. Improving consumer efficiency decreases demand [78], leading to higher margins of available capacity and a higher level of SoES. This dimension thus focuses on the impact of energy efficiency measures, e.g., white certificates, energy efficiency obligations, and electricity savings trusts [80]. A successful demand side management programme focussing on efficiency gains (e.g., electricity saving light bulbs or improved insulation) will also reduce electricity intensity. To measure efficiency we use electricity intensity (adapted from Sovacool [28]), which represents the economic activity of a country (GDP) per unit of electricity consumed. This metric is preferable to the electricity consumption to avoid interpreting a decrease in consumption due to an economic recession as improved efficiency [81,82].

Demand flexibility

Unlike conservation and efficiency measures, load-shifting does not imply a demand reduction, but it relieves the stress on the electricity systems during demand spikes, or more generally, when demand/supply imbalances occur. The more flexible the demand, the more load can be shifted when needed. Consequently, increasing demand flexibility also contributes to the SoES. A TSO might be interested in "load shifting" or "load shaping" to fill a load valley, allowing for more efficient energy scheduling. This can be done either to increase demand when there is excess production, e.g., wind at night, or to dampen demand when prices are high [83]. Demand flexibility is thus strongly linked to capacity adequacy: for a given energy margin, SoES is higher when demand is more flexible.

As metric, we use estimates of flexible demand relative to total demand. As explained above, shifted load is not necessarily peak-demand but rather demand that can be 'allocated' in a more efficient way to match the generation profile, which usually leads to a more cost-effective allocation of resources. As meeting annual peak-demand tends to remains the main challenge of electricity system planners, load shifts generally lead to flatter load curves. On the positive side, these flatter load curves avoid price spikes and decrease generators' uncertainty regarding their operating hours. On the negative side, they may result in the highest cost producers no longer being profitable and withdrawing from the market, thus creating an availability problem [84]. Therefore, the long-term effects of such measures need to be monitored carefully, as the benefit in terms of SoES from a higher de-rated margin resulting from a flatter load curve could be more than off-set by the closure of a peak unit due to decreased profitability.

4.7 Regulatory efficiency

Regulation should aim at ensuring well-functioning electricity markets; this includes sending the right signals to investors at the right time, without need for repeated regulatory interventions. Here we focus specifically on market performance and the need to provide incentives to conventional generators; environmental regulations are included in the sustainability dimension. There is also a link with the socio-cultural dimension, e.g., the main barriers to building new high-voltage lines in the U.S.A and optimizing the grid are not so much technical or economic, as bureaucratic [85].

Market performance

This dimension focuses mainly on the prevention of market power, which could lead to market distortions, such as artificially high prices [86]. For instance, reform failures in the 90s in Norway and California, leading to uncertainty, created transmission congestion and a capacity shortage. This resulted in market power, leading to high prices [87]. Market power is generally more likely when there are fewer companies, i.e., competition is positively correlated with the number of competitors [88]. Regulation aimed at preventing market concentration has been one of the main issues for regulators after market liberalisation. For instance, it is recognised by most experts that there were too few companies in the England and Wales market in the early nineties, resulting in relatively high prices, until the regulator intervened [89]. Concentration is often measured by the HHI, using the market share of the five largest companies in the sector [90]. A high value indicates a high concentration, which is likely to lead to higher prices, thus decreasing affordability.

Incentives for conventional generators

Environmental pressures, combined with the current uncompetitive cost-level of VRES, have induced policy-makers to provide incentives for these technologies. However, this support leads to a lower residual demand for thermal generators, who become economically unviable. Still, thermal units are required for balancing and as backup during adverse weather conditions, when output from renewables is low, leading to regulatory concerns [84]. This has resulted in the implementation of different forms of support for thermal generation, such as capacity markets, capacity payments and strategic reserves [91,92]. While supporting VRES can be considered a long-term investment, aimed at allowing the technology to mature and achieve grid parity, supporting conventional generators indicates a market failure. The percentage of the tariff allocated to supporting conventional generators, i.e., hydro, nuclear and thermal generators, measures the support needed to keep these technologies online.

4.8 Sustainability

In the literature, the term "sustainability" is usually found to refer solely to the environmental implications of energy use: a sustainable system is unlikely to damage the environment. This aspect increasingly dominates current energy policy decisions at national and EU levels [93]. Furthermore, environmental commitments are acknowledged to have a considerable impact on security of supply because of the significant transformations and investments required to reduce the environmental impact of energy systems.

However, the concept of sustainability goes beyond the environmental aspect: it includes longer-term economic viability as well as the long-term physical availability of resources. While most studies addressing the economic aspect of sustainability focus on the fact that energy should be affordable for consumers, little attention has been given to the supply-side: energy production should be profitable so as to ensure the availability of facilities to produce and transport energy.

Finally, energy availability is one of the dimensions receiving major attention in studies concerning energy security. This dimension refers mainly to the existence of resources, which is particularly important in fossil fuel markets. Still, fossil fuels are used not only to generate electricity, but also for, among others, transportation and heating. Therefore their availability specifically for electricity generation is hard to quantify. However, given the exhaustible character of fossil fuels, relying on these to generate electricity endangers the future availability of electricity. We next discuss in more depth these four aspects of sustainability: environmental sustainability, affordability, profitability, and fossil fuel dependency.

Environmental sustainability

Discussion persists on whether environmental sustainability should be considered as one of the dimensions of SoES; for instance [93] and [38] implicitly split environmental sustainability and energy security. However, environmental consequences of energy production and consumption affect energy systems; e.g., climate change has an effect on water patterns and availability [40]. According to van Vliet et al. [94] over two thirds of hydropower plants will face a reduction in their capacity due to reduced inflows and increased sedimentation. Thermoelectric plants will also be affected as they use large amount of water for their cooling systems. Given that 98% of world generation comes from the two sources, this impact cannot be ignored [94]. Climate change is also expected to affect the demand-side;

for instance, Eskeland and Mideksa [95] show that in Europe an increase in temperature will result in significantly higher demand.

Given the complexity of measuring to what extent electricity-related environmental impacts affect the electricity sector, we focus on the driver of climate change, emissions, a directly measurable environmental aspect. We propose the annual carbon emissions per unit of production, e.g., TWh. Depending on a country's characteristics, other emissions, such as sulphur, particles or NOx, may need to be considered.

Affordability

There exist many approaches to measuring affordability. Some authors address the issue of high costs in energy markets by considering fuel prices as a metric [28,42,43]. Other metrics depend on very detailed information that is not always available, e.g., energy systems' internal costs [96]. However, these metrics do not take into account the purchasing power of consumers. A suitable metric should thus relate costs and income, e.g., by calculating the ratio between fuel costs and GDP [41] or fuel expenses as a share of household revenues [97]. A measure for the affordability of electricity tariffs should specifically incorporate consumers' income [27]; we therefore adapt the approach of [97] and define the metric as the ratio between the average cost of electricity cost per household and the median household wage.

The validity of this measure depends on the electricity grid coverage. Developing countries often have high income inequality and/or low coverage. Therefore, comparing the cost of electricity to the median income in a country with high income inequality might provide a misleading view of affordability, as the indicator hides the real cost of electricity for the poorest part of the population. Likewise, a high level of affordability in a country with low coverage is a poor indicator as it does not capture access to electricity. Furthermore, in some situations there can be a trade-off between electricity tariffs and the electricity coverage policy, when the income from high tariffs is dedicated to improving coverage. If countries have differentiated tariffs depending on household income (e.g., the Ontario Electricity Support Program [98]), this should be taken into account when evaluating this measure.

Profitability

On the supply side, a measure of the economic sustainability of the system should reflect the adequacy of generators' revenues. A price decrease does not necessarily reduce generators' profitability as it can result from technological progress, such as a more efficient use of fuel [89]. Similarly, a price increase resulting from changing oil and gas prices or exchange rates does not necessarily affect the generators' profitability.

We focus on generators because the transmission and retail segments usually have regulated tariffs that ensure their economic viability. This is not the case of the generators, who are increasingly facing very difficult market conditions due to the larger penetration of subsidised VRES [99]. Consequently, not only are prices decreasing, but so is the residual load.

It is important to distinguish between base-load and peak-load generators. Base-load generators are likely to be profitable as the price mostly exceeds their marginal costs. Marginal producers, i.e., peak units, have relatively short production hours and may at times only recover their marginal costs, leaving them without a margin to cover their fixed costs. The profitability of these generators, who are the most affected by large VRES penetration, is important: prolonged periods of insufficient profitability result in few or no investments in new capacity, and may even cause mothballing or early closures, leading to a shortage.

Data about individual plants' profitability is rarely publicly available, and mostly unknown even to TSOs; we thus suggest as alternative metric the load factor of conventional and peak generators. A significant decrease of their load factor should act as an early-warning, signalling potential future problems. For instance, the Belgian gas-power plant Drogenbos used to operate on average 8,000 hours/year, but in the first quarter of 2014 it only operated 100 hours [100]; likewise, the German plants Irsching 4 and 5 supplied no merchant power at all in 2014 and were only dispatched when they were needed to stabilize the network [101]. The resulting lack of profitability is endangering their availability; these and other plants are being mothballed across Europe [102].

Fossil fuel dependency

Although dependency on fossil-fuels is included by [41] in the measurement of the environmental impact, the explicit inclusion in our framework is not redundant. This is indeed tightly related to the economic and environmental aspects: fossil-fuels are expected to become more expensive not only because of the environmental commitments, but also because of their depletion.

The finite nature of fossil fuels will require the eventual replacement of fossil-based generation. While this can partly be achieved through a decrease in demand, a shift to renewable generation technologies, existing or new, will be necessary in the long-term. This might be possible with technological progress in electricity generation and storage [103], but future technological breakthroughs are difficult to predict. As a measure we propose the ratio between current fossil-based generation and the expansion potential of generation by renewable sources.

4.9 Geopolitics

Yergin [104] recognises that energy security is affected by international relations. Import dependency has attracted major attention, in particular in the oil and gas markets, as non-competitive pricing could result from the exercise of market-power by fuel exporters, with adverse socio-economic implications for consumers [31]. Furthermore, import dependency is seen as a threat because of some suppliers' political instability [27,41]. There are numerous examples of countries using gas as a political instrument; examples include Russia [105] and Bolivia [106]. Dependency on imported gas for electricity is recognised as a threat to SoES.

While the increased interconnection of electricity markets has been seen as a major achievement of foreign policy to promote SoES, this exposes the system to threats of cascade failures [20]. Furthermore, reliance on imported electricity might decrease investment incentives in the long-term [52]. The degree to which a country is vulnerable depends on the concentration of imports. We distinguish two main sub-dimensions: dependency and vulnerability. The metrics we propose for these dimensions are adapted from Constantini et al. [107] to be applicable to single jurisdictions.

Dependency

This dimension captures to what extent imports are necessary to meet local demand. Imports include direct electricity imports, as well as imports of primary fuels used for electricity generation, e.g., gas, coal and oil. The higher the percentage, the more dependent the country is; particular attention should be given to the evolution over time. An analysis of the stability of the countries of origin, the relationships with exporters and the balance of trade are also essential. For instance, the EU is developing an integrated electricity market, and can be considered as politically stable, implying that significant exchanges between EU countries should not be seen as a threat from a geopolitical point of view. However, sudden shortages due to extreme weather conditions or significant price changes could threaten SoES in countries which are net importers, e.g., Italy.

Vulnerability

This dimension focuses on the concentration of imports, which depends on volumes imported and the number of jurisdictions where imports come from. As was the case for resilience of generation capacity, the aim is to highlight the risk of relying on a limited number of fuels, or on electricity from a few jurisdictions. The SoES in the importing jurisdiction could be seriously endangered in case of political problems or extreme weather conditions in the exporting jurisdictions. This was observed for instance during the Californian crisis in 2000 and 2001, which was caused among others by an excessive dependence on imports from the Northwest of the USA [108]. We suggest two metrics, similar to the HHI, to measure the concentration of import jurisdictions and of electricity and primary fuels respectively. In their analysis of oil trade, Cohen et al. [30] propose to adjust the metric for political risk. Their arguments also apply to electricity markets, as political factors in the exporting jurisdiction could lead to sudden disruptions. We thus propose the use of the "Government effectiveness" index, provided by the Global Risk Service and included in the Worldwide Governance Indicators – WGI [109], which measures how confident businesses can be of the continuity of economic policy.

4.10 Socio-cultural factors

Opposition caused by environmental concerns may result in investments in new transmission or generation capacity being delayed, suspended or even cancelled. For instance, a heated debate about wind energy and hydropower is taking place in Switzerland. Opponents of wind energy projects criticise the construction of wind farms, because of their impact on the landscape, birds, etc. These debates have led to the cancellation of several projects [110]. Likewise, hydropower expansion potential is severely limited because opponents criticise the impact of these projects on water flows and ecosystems [111]. The installation of new high-voltage transmission lines is often objected to by people living close-by. Recent examples include projects in Switzerland [112], Germany [113] and the USA [85]. Furthermore, several wind projects in the north of Germany have been suspended due to the resistance to a new north-south “super-grid” [114].

Opposition is not limited to new technologies. For instance, nuclear energy has faced political and grassroot pressure for many decades: a moratorium on new plants was launched in California in the 70s [115]. More recently, following the 2011 Fukushima accident, Germany closed several plants [116] and Switzerland plans to close at least a third of its nuclear capacity between 2019 and 2032 [117]. In these decisions, political arguments and fear often outweigh technical, economic and security arguments [118]. These decisions will have a significant influence on the capacity adequacy issue discussed above, and there is evidence that prices might increase as a result of nuclear plant shutdowns [119].

Although socio-cultural factors are rather subjective, they could be approximated by estimates of the total time required to implement a project (including the time for consultations and delays due to appeals). For instance, installing a new high voltage grid in Switzerland takes between 9 and 12 years [120], a multiple of the actual construction time.

4.11 Access

For many developing countries it is furthermore necessary to keep track of the share of the population who have the physical possibility of connecting to the grid and receive electricity, i.e., energy access; this can in some countries be less than half the population [121]. Indeed, there could be a trade-off between increasing the share of the population connected to the grid, and the degree of SoES for those who do have access. It is important to keep track of how this fraction evolves over time, yielding as metric the percentage of the population having access to the grid.

4.12 Terrorism

High voltage transmission systems, in particular overhead transmission lines, are vulnerable to sabotage. Simultaneous attacks at several places in an electricity system, including cyber-attacks, could leave a region without electricity for an extended period of time [122]. While the economic impact of such power outages would be significant, the long-term consequences are limited [63]. Since the costs of damages due to terrorist attacks in the electricity sector might not be publicly available, we propose using one of the measures of the World Economic Forum (WEF) Report: the business cost of terrorism.

5. The framework as policy tool

Our aim in this section is to outline how our framework can help stakeholders understand the opportunities and threats that will shape the future of the electricity industry. This framework will not provide a "silver bullet" for SoES; rather, it is a decision support tool aimed at helping to organise and present data, and structure the analysis. By providing an overview of the state of SoES, it will highlight potential future problems and help decision makers understand the challenges they face, putting them in a better position to optimally allocate their limited resources. The objective of the framework is to understand where, when and how to intervene to maintain the desired level of SoES. In this sense, the framework also works as a form of "early-warning system". By drawing attention to changes in the values of the different metrics while there is still time to intervene, decision-makers can take the necessary steps to prevent potential problems from materialising.

Each jurisdiction should aim to establish appropriate critical values for the various metrics. A metric approaching its critical value signals that this dimension could endanger SoES in the near future. It is also crucial to keep in mind a metric's time-scale when comparing its current and critical values. When a metric reaches its critical value, it is too late to react: there thus is a need for “lag-adjusted critical values”. An indicator getting close to its lag-adjusted critical value signals to decision makers that this is their last opportunity to act before the SoES becomes endangered.

While a simple graphical representation of the metrics' time-series is a useful way to visualise their evolution, other, more sophisticated charts, may be more informative. For instance, spider-web diagrams showing the evolution of (a subset of) the metrics over a number of years could provide an overview of the “dynamics” of SoES, identifying which metrics have improved and which have deteriorated.

As mentioned previously, we do not propose one single aggregate metric representing SoES, as such a metric would not provide insights for investors, regulators or policy makers to act on. Rather, the focus should be on the evolution over time of the metrics, as long time-scales are one of the key characteristics of the industry. Consequently, observing the evolution of the metrics over time is critical, as reversing a trend can take years, even decades. One should particularly be aware of the fact that each measure has its own time-frame. For instance, reversing a decreasing trend in the de-rated margin takes years due to construction delays, while strengthening the high-voltage grid requires decades.

6. Conclusion and policy implications

Ensuring the security of electricity supply is currently a matter of concern for regulators and policy makers. There is a need for a comprehensive framework that clearly maps out the dimensions of SoES in a way that allows decision makers to monitor the system's evolution and act before problems arise. Most of the previously proposed frameworks either address the entire energy sector or focus on selected fossil fuels. The few frameworks developed for the electricity sector are too specific to be generalised. This paper has developed a framework to evaluate security of supply in the electricity industry, acknowledging its multidimensional and inter-temporal nature, and the need for one or more accompanying metrics to assess each dimension.

Our framework enables regulators and policymakers to act timely as it offers the following advantages: (i) an exclusive focus on the electricity sector; (ii) a disaggregation of SoES into a series of key indicators that allow identification of specific potential problem areas; (iii) a temporal dimension that enables tracking the evolution of these indicators over time, highlighting emerging trends; (iv) a focus on a single jurisdiction within the decision makers remit and responsibility; (v) a reliance on publicly available data for most indicators.

The debate on SoES has often been very one-dimensional, focussing on the most critical issue at a given point in time, rather than on the bigger picture. Examples include the European dependence on Russian gas [123–125] and insufficient investments in the electricity sector [92,126,127]. Our framework aims to broaden the debate, by pointing to the need to focus not on one, but on a multitude of dimensions simultaneously, to achieve a true understanding of SoES. Focusing on one dimension removes attention for what might be the next issue, leading to a situation of constant firefighting: problems which could have been resolved easily and cheaply if addressed at an early stage become major issues. The framework developed here should induce stakeholders to keep the bigger picture in mind when analysing the situation, thus contributing to the quality and pertinence of the public debate about the priorities in the electricity industry.

This framework has a number of limitations one needs to be aware of. While it is comprehensive and covers the most important aspects of the electricity industry, it may require adaptation for use in jurisdictions with very atypical characteristics; some of the proposed dimensions or metrics may be irrelevant, while others may need to be added. For instance, for Norway, which is close to 100% hydro-based, CO2 is clearly not an issue, but climate change is an essential dimension.

A further complexity that we have not dealt with explicitly is the increasing interdependency of the many factors that determine security of supply, i.e., addressing problems in isolation is difficult as any action will have knock-on effects: an action might improve one dimension while adversely affecting others. Understanding these interdependencies, and their consequences across the whole electricity sector, is essential if we are to achieve a real understanding of the security of electricity supply. Although defining such interdependencies is beyond the scope of this paper, our work does point out some of these, increasing policy makers' awareness of the consequences and potential side effects of policy modifications. For instance, while regulators may tolerate a reasonable tariff increase to subsidise renewable energies, there is a limit to how much tariffs can rise before affecting the standard of living of the general population or industrial competitiveness.

Finally, one of the main obstacles to a successful implementation of this framework is data availability: while we have privileged measures requiring only publicly available data, required data may be unreliable (e.g., socio-cultural factors) or simply non-existent (e.g., congestion costs). A successful use of the framework will only be possible with the collaboration of all parties involved.

Future work will include the mapping of the interdependencies between the different dimensions, as well as the development of a number of cases for specific jurisdictions to illustrate the applicability of the framework.

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8. References

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