Nuclear in the Mix: A Scenario Analysis of Swiss Electricity Supply and Demand at the Horizon 2050

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Master Thesis

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Abstract

In light of the pressing public demand for clean energy, we develop a model for generating electricity supply and demand time series for the years 2030 and 2050. Our goal is to compare the electricity system that would result from the Swiss Energy Strategy 2050 with systems preserving nuclear electricity production, under various assumptions relating to electricity demand. We start be reconstructing an hourly time series for nuclear, hydro dam, run-of-river, thermal, wind and solar power for the year 2017 based on available data. We then develop several models for projecting this reconstructed data in the future and analyze the hourly, daily, weekly and seasonal variation in the supply of different energy mixes. On the demand side, we combine the effects of the development of demand per capita and of the adoption of Electric Vehicles (EVs) on electricity demand by relying on an EV adoption and charging model. We find that the electricity mix resulting from the Swiss Energy Strategy 2050, which is dominated by solar power, leads to large seasonal imbalances, which will increase the dependency on Europe for meeting electricity demand, and thereby reduce Switzerland's ability to control its greenhouse gases emissions alone compared to electricity mixes including nuclear power.

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I must finally express my very profound gratitude to my family, friends and girlfriend Irina for providing me with unfailing support and continuous encouragement throughout this thesis.

This has been quite a ride.

List of Abbreviations

ABB	Asea Brown Bovery
ATOL	Aare-Tessin AG
BBC	Brown Bovery & Cie
BEV	Battery Electric Vehicle
BWR	Boiling Water Reactor
BKW	Berner Kraftwerke (utility company of the city of Bern)
CCGT	Combined Cycle Gas Turbines
CKW	Centralschweizerische Kraftwerke (utility company of Central Switzerland)
COP	Conference of Parties
DETEC	Department of the Environment, Transport, Energy and Communications
EES	Electrical Energy Storage
ENTSO-E	European Network of Transmission System Operators for Electricity
EOS	Energie de l'Ouest (utility company in Western Switzerland)
EPA	Environment Protection Agency
ETS	Emission Trading System
EV	Electric Vehicle
FOEN	Federal Office of Environment
GHG	Greenhouse Gas
ICE	Internal Combustion Engine
IPCC	Intergovernmental Panel on Climate Change
kWh	Kilowatt-hour
MAPE	Mean Absolute Percentage Error
MC	Marginal Cost
MWh	Megawatt-hour
MPE	Mean Percentage Error
NOK	Nordostschweizerische Kraftwerke AG, (utility company of northeast Switzerland)
NPP	Nuclear Power Plant
PV	Photovoltaics
PWR	Pressurized Water Reactor
RES	Renewable Energy Source
ROR	Run-of-River
SBB	The Swiss railroad company
SES	Stationary Electricity Storage
SFOE	Swiss Federal Office of Energy
SFOS	Swiss Federal Office of Statistics
TWh	Terawatt-hour
UNFCCC	United Nations Framework Convention on Climate Change
VSE	Verband Schweizerischer Elektrizitätsunternehmen (association of Swiss electricity companies)

Executive Summary

On May 21st 2017, the Swiss people accepted the revisions to the Energy Law incorporating the first set of measures of the Energy Strategy 2050. The Energy Strategy's focus point is the development of renewable energies, the increase of energy efficiency, the modernization of the transmission grid and the gradual phasing out of nuclear power. In this project, we compare the effects on electricity supply, demand, imports, exports and greenhouse gas (GHG) emissions of the electricity mix arising from the Energy Strategy 2050 with two electricity mixes in which nuclear power is preserved. In order to do so, we develop a model for simulating supply and demand in 2030 and 2050 and perform a scenario analysis.

As a base for the analysis of the future electricity system, we first turn to the year 2017. The Swiss Federal Office of Energy (SFOE) does not make time series data of electricity production over the whole year publicly available. We hence begin with the reconstruction of electricity supply data by generating technology in 2017 based on time series from the European Network of Transmission Operators of Electricity's (ENTSO-E) transparency platform. In order to correct for the sometimes-bad quality of the ENTSO-E data, we arithmetically scale up the time series to match production aggregates from the SFOE. This scaling is done monthly for nuclear, run-of-river and hydro dam and yearly for solar and wind, as constrained by data availability. For consumption, detailed hourly time series are available through the Swiss grid operator Swissgrid.

Based on the 2017 data, we develop a model for simulating supply and demand in the future. We consider two components for future demand: the evolution of population and demand per capita excluding electrical vehicle charging and separately demand from electrical vehicle charging. The future demand is simulated through an arithmetic scaling of the 2017 demand. After scaling, the annual demand without EV matches the aggregate arising from the population size and demand per capita assumptions. The contribution of EV charging is then added to the simulated demand.

On the supply side, the non-dispatchable supply sources (nuclear, waste incineration, run-of-river, solar photovoltaics and wind) are set first. Run-of-river, wind and solar are simulated by scaling their 2017 time series of production. Nuclear is simulated by scaling a modified version of the 2017 nuclear production time series, correcting for the comparatively bad year 2017 was for nuclear production. Finally, waste incineration is assumed to run as a baseload with a 75% capacity factor. The hydro dam production, with merit order two follows a profit maximization strategy. It depends on the evolution of the bid price of electricity in the market. The bid price of electricity in the future is assumed to differ from the 2017 price only through a price diminution at times where solar production peaks. After the hydro dam production is set, the thermal dispatchable supply sources fill the remaining deficit up to their installed capacity. The technologies included in the thermal dispatchable electricity sources are: biomass, biogas and combined cycle gas turbines (CCGT). The storage model follows a daily load shift strategy. Its goal is to minimize the surpluses and deficits. Both pumped hydro and lithium ion batteries perform the daily load shift. Finally, the remaining deficits and surpluses are respectively imported and exported.

We use the model to study the Swiss electricity system in the future by developing three supply and three demand scenarios. The three demand scenarios differ by their demand per capita and electric vehicle fleet size assumptions shown in Table 1. In the three demand scenarios the population size in Switzerland is assumed to be 9.5 million in 2030 and 10.2 million in 2050.

Demand Scenario	*Demand per Capita [MWh/a]*	*Electric Vehicle Fleet [million cars]*	*Demand in 2050 [TWh]*
Low	5.8	0.5	60
Middle	7.0	2.1	75
High	8.3	3.9	93

Table 1: Demand per capita, electric vehicle fleet assumptions and resulting total demand for the demand scenarios in 2050

The three supply scenarios are: Green Wave, Back to the Atom and Resilience. The Green Wave supply scenario presents a mix compatible with the Swiss Energy Strategy 2050. The nuclear power plants are progressively shut down and solar photovoltaics and wind capacities grow steeply. In the Back to the Atom supply scenario, the nuclear capacity increases over time compared to 2017 while renewable electricity sources grow moderately. The Resilience supply scenario puts the emphasis on security of supply. The nuclear capacity stays identical to 2017 while the CCGT capacity, a dispatchable electricity source, increases.

We find that the Green Wave scenario exacerbates the already existing seasonal imbalance in production of the Swiss electricity system. It exhibits large deficits in the winter and large surpluses in the summer which need to be respectively exported and imported. This translates into a larger reliance on imports of electricity than the Back to the Atom and Resilience scenarios as shown in Table 2 for the middle demand scenario in 2050.

Annual Imports in 2050	*[TWh]*	*[% of demand]*
Green Wave	11.2	15%
Back to the Atom	3.8	5%
Resilience	0.5	1%

Table 2: Annual imports in 2050 in TWh and percent of demand in the middle demand scenario where total demand is 75 TWh in 2050.

GHG Emissions of Consumption [$MtCO_2$-eq]	*2050*
Green Wave	2.1
Back to the Atom	1.7
Resilience	3.6

Table 3: Annual GHG emissions of consumption in 2050 in the middle demand conditions. The average GHG emissions of imports are assumed to be 41 gCO_2-eq/kWh in 2050.

The Green Wave scenario does not minimize GHG emissions of electricity consumption. The GHG emissions of the Green Wave scenario are sensitive to the European electricity mix since 15 % of Swiss electricity needs to be imported in the middle demand scenario in 2050. The lower import dependency of Back to the Atom and Resilience means Switzerland has greater control over its CO_2 emissions and leads the Back to the Atom scenario to having the lowest GHG emissions of consumption thanks to the important and low carbon nuclear production and the low reliance on electricity imports for meeting demand.

Introduction

It wasn't until the 1990s that awareness of the environmental effects of the energy sector reached the global scene. International actions aimed at addressing climate change began in 1992 with the United Nations Framework Convention on Climate Change (UNFCCC) treaty. Its objective was to "stabilize greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system" (United Nations, 1992). The UNFCCC treaty was extended in 1997 through the Kyoto Protocol under which State parties committed to not only stabilizing but also reducing greenhouse gas (GHG) emissions. Following the Kyoto Protocol's failure to reduce worldwide emissions, a more ambitious agreement, the Paris Agreement, was adopted in 2015. It differs from the Kyoto Protocol in its bottom-up approach, leaving the capacity to its signatories to decide the amount of emissions they aim to reduce.

In Switzerland, the concretization of the Swiss UNFCCC, Kyoto's and Paris' pledges took the form of numerous revisions of the Energy Law (LEne). After the nuclear accident of Fukushima in 2011, the public perception of nuclear energy changed dramatically. As a result, the Federal Department of the Environment, Transport, Energy and Communications (DETEC) started to develop a new Energy Strategy to be implemented by 2050, aiming to exclude nuclear power from the future electricity mix (SFOE, 2018, a). The Energy Strategy 2050 features four main measures: the development of renewable energies, the reduction of GHG emissions, the expansion of the transmission grid and the gradual phaseout of nuclear energy. Its first set of measures was incorporated into the Energy Law by popular vote on the 17th May 2017.

In this project, we compare the effects on GHG emissions of the electricity mix arising from the Energy Strategy 2050 with those arising from two electricity mixes in which nuclear power is preserved. In order to do so, we develop a model for simulating supply and demand in 2030 and 2050 and perform a scenario analysis.

The work is structured as follows: Chapter 1 contains a brief history of power generation in Switzerland; chapter 2 features the reconstruction of historic data and provides an analysis of the 2017 Swiss electricity system; chapter 3 presents our model for simulating supply and demand in the future; and chapter 4 sets out a scenario analysis and our results.

1 A Brief History of Power Generation in Switzerland

Before diving into the analysis of the 2017 and future Swiss electricity grid, we start by looking back at the evolution of the Swiss electricity sector, starting with the drivers of electrification.

1.1 Drivers of Electrification

1.1.1 Public Lighting

In the middle of the 19th century, the Swiss energy landscape was dominated by coal. Due to the modest indigenous production capacity, Switzerland relied on imported coal transported to Switzerland via the newly built train tracks linking Germany, France and Switzerland through the city of Basel (Marek, Energie, 2014).
Manufactured gas quickly emerged as a primary energy source. Made by reacting coal (and sometimes wood) with steam to produce a mixture of hydrogen, carbon monoxide and methane, it enabled since the middle of the 19th century, a network of privately-owned gas plants which were responsible for powering public gas lights in large Swiss cities (Mages & Gardiol, 2007). The city of Bern paved the way in 1843, followed by Geneva in 1844, Lausanne in 1848, Basel in 1852 and Zurich in 1856. The use of gas for powering gas lanterns necessitated the installation of the first local distribution networks.

Picture 1: Gas Lantern. Source: Archives of the city of Bern

Picture 2: Kramgasse in Bern, captured in 1984. Gas lanterns in the middle of the picture. Source: Archives from the city of Bern

As one for the first network-based energy systems, lighting accelerated for the development of energy and later electricity in Switzerland. Electrical lighting emerged in the 1880s. Enabled by the discovery of Heinrich Goebel and Thomas Edison, the incandescent electric lamp saw the light of day in 1879. Electric public lighting was installed in Saint-Moritz in 1879 and in Luzern in 1886, mainly as a mark of prestige. It benefited from great publicity in the international exposition of Paris between 1878 and 1880 where Edison's electric lighting was presented and dazzled the visitors (Paquier, Industrie électrique, 2008).

In the course of the 1890s, the growing use of electricity saw the use of gas for lighting go into decline, representing a classical energy substitution where a new source has clear advantage over the old. Gas, however, became increasingly popular for thermal applications like cooking or heating (boilers) (Mages & Gardiol, 2007). Lighting was first considered as a luxury, it is only during the 20th century that it became a basic necessity.

With electrical lighting established, industrial-scale electricity production had to start in Switzerland. Due to its unique position in the middle of the Alps, Switzerland possesses a large potential for hydroelectric production, which it exploited first.

1.1.2 Powering Electrical Lighting

Switzerland is today one of the worldwide leaders in hydro power technologies and expertise, with hydro power accounting for 60% of the electricity generation in 2017 (SFOE, 2017, a). The history of power generation in Switzerland starts in 1879 with the construction of Europe's first hydroelectric power plant in St-Moritz (Gobet, 2013). This enabled the installation of electric public lights in St-Moritz and paved the way for the birth of the Swiss hydro sector. Shortly after, in 1892, another hydroelectric plant started its operation in Switzerland with two 20 horse power (2*14.7 kW) turbines in Couvaloup in Lausanne (Dubois, 1938). The plant of Couvaloup powered the lights of the cantonal hospital of Lausanne. The engineer responsible for building the plant was later named president of the new Swiss Electrical Society (Dubois, 1938).

Picture 3: Political campaign poster from 1936

The first hydroelectric dams in Switzerland trace back to the end of the 19th century. Europe's first hydro dam made of concrete was built by the Swiss city of Fribourg in 1872: The dam of "la Maigrauge" (570 kW). It enabled the distribution of drinkable water for the canton of Fribourg as well as later, the distribution of electricity to industries (Barrage de la Maigrauge).

As electricity was gaining popularity by the end of the 19th century, a lively debate was taking place about which standard should be adopted for electrical current. There were proponents of continuous current (DC) and alternative current (AC) which presented different advantages. The AC current emerged as the winner in 1891 after a demonstration of the transmission of a 200-horsepower supply over 174km with a 75% efficiency in Frankfurt-am-Main (Paquier, Electrotechnique, 2016).

1.1.3 Mobility

A second important driver of electrification in Switzerland was the transport sector. It started in 1896 with the construction of tramways in large Swiss cities, starting with Zurich (Kurz, 2013). In 1909 389km out of 390km of all the Swiss tramways tracks were electrified (Paquier, Electrification, 2010).

Tramways were followed by the birth of the Swiss national railroad company: the Schweizerische Bundesbahnen (SBB). The SBB arose after a referendum in 1898, where the Swiss people accepted a law creating a nationalized train company, allowing the merging of smaller cantonal and regional companies (Bärtschi, 2017). The SBB contributed greatly to electrification efforts in Switzerland, and was a pioneer worldwide for electric trains. The steam engines suffered many disadvantages compared to electrical trains, ranging from easiness of exploitation, cost to cleanliness and maintenance needs. It pushed the SBB to encourage the development of electric railways in Switzerland. In 1899 the SBB finished electrifying the first complete railroad track in Europe between Berthoud and Thun, that is 40km with 750 V and 40 Hz lines (Gobet, 2013).

1.2 Electrical Companies: The Birth of an Industry

As public lighting got installed in more and more cities and train tracks were equipped with power lines over the SBB network, electrical companies emerged as a result of public and private investment.

On the private side, the chemical companies, flagships of the Swiss industry, developed at the end of the 19^{th} century their own energy and were responsible for about 50% of the electricity production in 1900 (Paquier, Electrification, 2010). Enabled by steam generators based on the principle of Siemens' dynamo, chemical companies were able to produce cheap power in reasonable quantities dedicated to their own use (Hansen, 2008).

On the side of the manufacturing industry, the long economic depression of 1875 to 1895 pushed firms to innovate and to rely on new processes. For example, in 1891 the specialized construction company Brown Boveri & Cie (BBC, ancestor of the ABB group) was formed. Through one of its daughter firms, BBC constructed the first parts of the Swiss electricity transmission system which would later be sold to electrical companies between 1910 and 1920 (Steigmeier, 2009).

Starting in 1880, private electrical and gas companies started being bought by municipalities to form publicly owned electrical companies. It began with the creation of the so-called Industrial Services ("Services Industriels") in Geneva, Bern and Zurich. First specialized in the distribution of drinkable water in the cities, the industrial services incorporated electricity at the end of the 19^{th} century as they discovered the potential of hydroelectric power plants. The rationale behind the purchase of gas and electrical companies was the realization that there were too many foreign funds in those companies, and public powers wanted to ensure a reasonable level of independence (Paquier, Sociétés électriques, 2016).

As electrical companies passed into public hands, the first law on electricity was formulated in 1902. Electricity was indeed a new field of action for energy policy, and in response to the dangers associated with this nascent industry, the "safety measures in the execution and operation of electrical installations" law laid down safety measures for the exploitation of electrical power plants. The second aim of the law was to subject the "establishment and operation of the low and high-current electrical installations [...] to the strict supervision of the confederation" leading to a harmonization of standards (Loi fédérale concernant les installations électriques à faible et à fort courant, 1902).

1.2.1 World War 1 and the Coal Crisis

During the first world war, Switzerland faced difficulties to import coal from France and Germany (Marek, Politique énergétique, 2011). The shortage of coal, which was still a widely used energy source, boosted the electrification projects in Switzerland (Paquier, Electrification, 2010). Enabled by the exploitation of the Swiss hydro potential and the growing rate of construction of hydro dams, the hydro power capacity grew by 45% between 1910 and 1920.

In order to further facilitate the needed growth of the electrical sector, a law enabling the use of hydrological resources was passed in 1916. This law can be summed up in three points: First it gave the confederation the power to supervise the use of hydro power from public or private watercourses, second it forced the electricity produced by Swiss hydro forces to be used in Switzerland, unless authorized not to do so, finally, it facilitated the electrification of the railroad tracks by authorizing the SBB to expropriate concessions needed to develop their power network (Loi fédérale sur l'utilisation des forces hydrauliques, 1916).

The difficult times of WW1 also lead to the fostering of cooperation within Switzerland, in order to not waste hydro power. The first step towards cooperation was the needed harmonization of the electrical standards. The Swiss Water Development Association (SWDA) greatly contributed to the uniformization of current standards, suggesting three-phase 50 Hz as the preferred option, which enabled the creation of nation-wide interconnexion grids. Moreover, the choice of 50kV for big lines and 220/380 V for the distribution to households was confirmed (Paquier, Electrotechnique, 2016). With a common standard for transmission and distribution, electricity could be efficiently shared and rationed within the country, as it got linked into a single network.

1.2.2 Electrical Companies

During those times (1910 to 1930), numerous electrical companies were founded. They played a major role in the development of the electricity sector in Switzerland in the 20th century. Their role was to produce electricity and sell it to consumers.

As an example, one may mention the advent in 1919 of the Energie de l'Ouest Suisse (EOS) electric company. Its purpose was to "ensure the rational and intensive use of the hydropower resources of Western Switzerland, [...] to buy energy from and sell it to the participating electricity power stations or to other companies, and to that end [...] to construct and operate a major electricity transmission and distribution grid" (Alpiq). Similarly, companies like the Forces Motrices from Bern (later BKW), the Aare-Tessin AG (ATEL), the "Nordostschweizerischen Kraftwerke AG" (NOK) or the Centralschweizerische Kraftwerke AG (CKW) operated similarly and arose in the start of the 20th century as private companies acting as intermediaries.

Later in the early 2000s EOS and ATOS merged to create Alpiq, NOK and CKW merged to create Axpo Holdings. Together with BKW, Alpiq and Axpo Holdings own the majority of the power plants in Switzerland.

1.3 Expanding Swiss' Power Capacity

1.3.1 From Small Hydro to Big Plants

Between the two world wars, the shortage of coal in Switzerland combined with the new rights allocated to the SBB allowed the Swiss railroad network to reach 74% of electrification in 1939 when the European mean was 5%. Additionally, the continued growth of the electricity sector required new production plants. The growth of hydroelectric power between the two wars was 126%, with 1.4 GW of hydro power installed in this time span, reaching a total installed capacity of 2.5 GW in 1939. The general trend was the construction of bigger plants, the mean size of new plants between 1920 and 1940 was 25.6 MW compared to 10.4 MW between 1900 and 1920 (SFOE, 2018, b).

The general strategy was to build big plants in partnerships and mix of private and public funding and to make those investments profitable by exporting large quantities of electricity (Paquier, Sociétés électriques, 2016). For example, the hydro plants of Amsteg (1922, 120 MW), Wägital Siebnen (1924, 48 MW) and Etzel (1937, 135 MW) were constructed respectively in 1931 and 1937 in a partnership: Amsteg was developed in a partnership between SBB and the canton of Uri, the Etzel plant between SBB and NOK and the Wägital Siebnen Pump Hydro power plant between NOK and the electric company of Zürich (EZK) (SBB).

The 1930s also witnessed the advent of petroleum as an industrial energy source. Already in use since the start of the century in the nascent automobile sector, its proportion in primary energy consumption grew from 1% in 1910 to 11% in 1939 (Marek, Pétrole, 2011).

During World War 2 (WW2), the dependence of Switzerland on imported energy sources became a problematic issue. The reliance of gas plants on imported coal became a serious issue as imports of coal declined (Marek, Energie, 2014). But Switzerland also suffered a shortage of petrol which was the last setback before the slow replacement of coal and wood for transport and households uses (Marek, Pétrole, 2011). These circumstances further contributed to the increasing development of the electrical sector in Switzerland.

1.3.2 Big Hydro Dams

After WW2, households and services intervened with new needs for electricity. Households got equipped with washing machines, electrical stove, fridges, freezers and other appliances (Mutzner, 1995). The increased need for electricity in services reflects the growth of the tertiary sector (restaurants, hospitals, cinemas, offices) in the second half of the 20^{th} century (Paquier, Electrification, 2010). The demand hence grew greatly and once again bigger power plants were needed. In 1945 began the time of the construction of the big hydro dams in Switzerland. The Mauvoisin dam (2110 thousand m3 dam volume), the highest arch dam in the world when constructed with 237m was completed in 1957 and the Grande Dixence (5960 thousand m^3 dam volume), the highest Swiss dam with 285m height and the world's highest gravity dam, was completed in 1961. Due to the Swiss' peculiar alpine topography, some dams necessitated international cooperation with neighboring countries, this was notably the case for the Emosson dam in 1967 given the situation of the Emosson lake between France and Switzerland (Kaiser, 2017). Until the end of the 1960s the Swiss hydroelectric infrastructure grew until a total installed capacity of 11 GW in 1970.

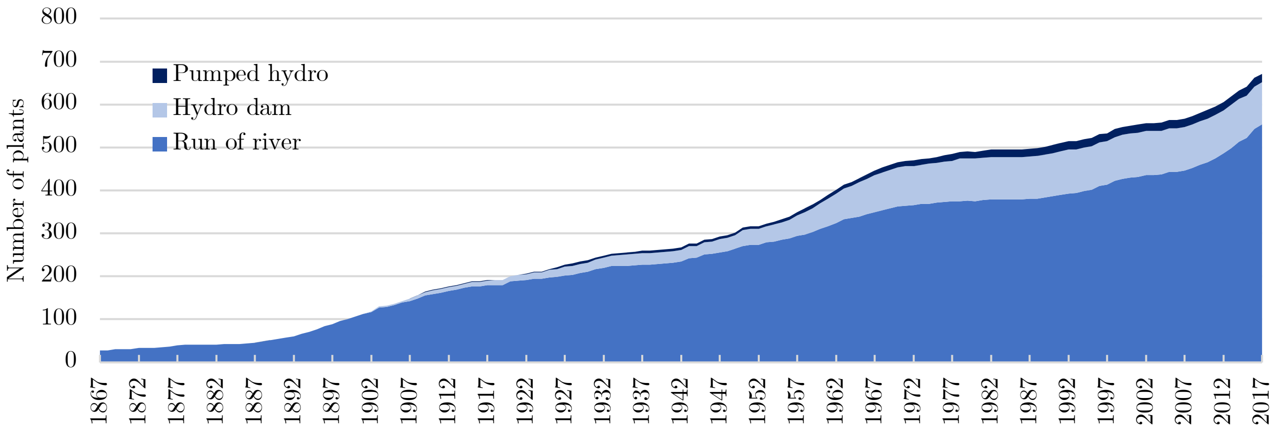


Figure 1: Number of hydroelectric power plants in Switzerland from 1867 to 2017, data from (SFOE, 2018, b)

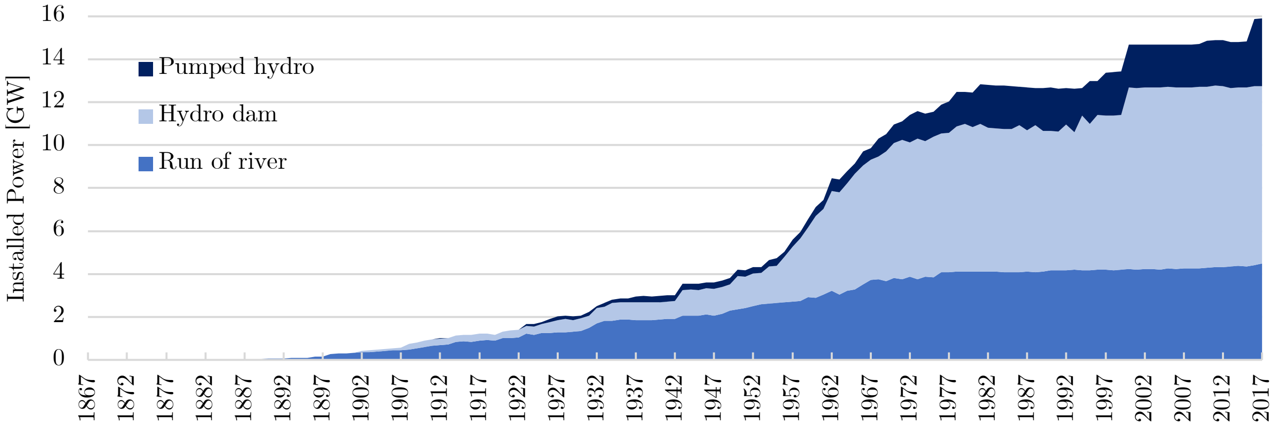


Figure 2: Evolution of installed hydropower in Switzerland from 1867 to 2017, data from (SFOE, 2018, b)

The construction of big hydro dams also had opponents, notably the Swiss Protection of Scenery Association (also known as the Heimatschutz). Since the 1920s the Heimatschutz undertook protests and measures in order to preserve the Swiss scenery, and that often translated into the opposition to the construction of big hydro infrastructure. In Switzerland with its direct democracy tools like the popular initiative or referenda, a well-organized association can have a significant impact on the realization of such projects. This was notably the case in 1951 when the protests against a new dam in the canton of Uri lead to the abandonment of the new dam project. Or more recently in 1980 and 1999 where the protests lead to the non-realization of the Greina and West Grimsel dams (Kaiser, 2017).

Despite the efforts of the protection of the scenery, the hydroelectric potential significantly increased in the 1950s and 1960s. Figure 1 shows the evolution of the number of hydroelectric plants in Switzerland. The growth appears to linear starting 1880 until 2017. The evolution of the hydroelectric power capacity in Figure 2 however exhibits a larger growth between 1950 and 1970, which directly attests of this tendency of building larger hydroelectric plants in this period.

1.3.3 The Nuclear Age

After world war two, the second big development in the Swiss energy landscape was the development of nuclear electricity production. In 1945, the Swiss Military Department (SMD) created a commission to study nuclear energy, whose president was a scientist from ETH Zurich called Paul Scherrer. The commission, together with the newly formed company Reaktor AG, worked on experimental reactors in Würenlingen, not far from Zurich. Reaktor AG was a conglomerate formed by a partnership between 125 companies, led by Director Walter Boveri, founder of BBC (former ABB). Reaktor AG's goal was to explore the use of nuclear technology for electricity generation, it also received high subventions from government and from the private sector for its operation. Following a faulty estimation of costs of operation, Reaktor AG had to leave its installations to the confederation. The confederation transformed it into a research institute on nuclear reactors who took the name of Paul Scherrer Institute in 1988 (Hug, 2009).

The electrical industry was at first cautious about the use of nuclear energy, preferring first to invest in hydroelectric installations. The newly passed law on nuclear energy in 1959 also put strict regulations in place for the construction of nuclear power plants. It said that “A license from the Confederation is required (...) for the construction and operation of an atomic installation, as well as for any change in the purpose, nature and scale of such an installation” (Loi fédérale sur l'utilisation pacifique de l'énergie atomique et la protection contre les radiations, 1959). Moreover, the authorization itself was to be given by the confederation only under the fulfilment of appropriate conditions or obligations if necessary to safeguard Switzerland’s external security, or to respect the international commitments to protect persons, property of others or important rights (Mueller, 2017). The final points of the nuclear law were to ensure the peaceful use of nuclear energy as well as the protection of the public against accidental release of radioactive materials.

In 1961, the national society for promoting industrial atomic energy was founded, and lead to the construction in Lucens of an experimental heavy water reactor with enriched uranium as fuel. It started operation in 1968 but had to be closed in 1969 due to partial core meltdown.

In 1964, the Swiss nuclear era truly began with Elektrowatt, the German and Swiss financing company, buying terrain for building the nuclear power plant of Leibstadt. Additionally, the Forces motrices du Nord-Est (NOK) decided to construct in Beznau a pressured water nuclear reactor (Beznau 1, 365 MWe) which triggered the “forces motrices” from Bern to plan the construction of their own reactor in Mühleberg (465 MWe) in 1964. A number of projects for nuclear power plants were filed to the confederation: Verbois in Geneva in 1965, Kaiseraugst in 1965, Beznau 2 in 1967, Graben in 1968, Gösgen in 1969, Rüthi in 1971 and Inwill in 1972. Only Beznau 1 (1969, 350 MWe) and 2 (1972, 350 MWe), Mühleberg (1972, 320 MWe), Gösgen (1979, 940 MWe) and Leibstadt (1984, 990 MWe) were approved and built.

Beznau 1 and 2 are pressurized water reactors (PWR), the plants are located on an artificial island on the Aar river in the canton of Aargau as the water of the river is used for cooling the reactor. The Mühleberg NPP consists of a single boiling water reactor (BWR) of type 4. As for Beznau 1 and 2, the thermal power passes through steam turbines to produce electrical energy. Mühleberg is located in the canton of Bern, along the river Aar. The cooling down of the reactors results in an increase of temperature of the river of about 1.3 degree Celsius. As a measure to protect the fish population, the utilization of the plant must be reduced when the river temperature exceeds 18°C. (Bernet, 2000). The Gösgen nuclear power plant is located in the canton of Solothurn along the Aar. It has a pressurized water reactor (PWR). Worried about the overexploitation of the Aar, the authorities forbade the Gösgen NPP to use the Aar for cooling. This resulted in the construction of a big cooling tower (Kernkraftwerk Gösgen-Däniken AG). Finally, the Leibstadt NPP’s reactor is a BWR, the plant is located in the canton of Aargau along the river Rhine. The water from the Rhine as well as a cooling tower are used to cool the NPP.

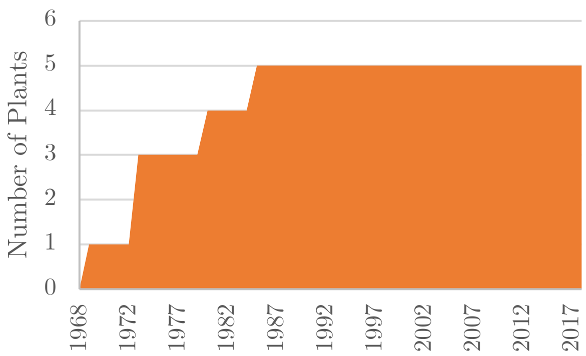


Figure 3: Number of operational nuclear power plants in Switzerland from 1968 to 2017

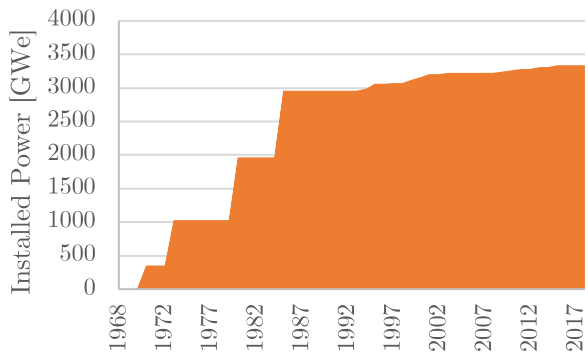


Figure 4: Installed nuclear power capacity in Switzerland from 1968 to 2017

In Figure 3 and Figure 4 we can observe the evolution of the number of nuclear power plants as well of the nuclear power capacity in Switzerland. The gradual increase in installed power observed from 1984 on is mainly due upgrades in the steam turbines (KKG). Finally, the 1970s also witnessed the appearance of natural gas in Switzerland (Mages & Gardiol, 2007), used for space heating and in a small extent, power production.

1.4 The Renewable Era

Capitalizing in the 1950s on the successful actions of the protection of scenery, a new ecological movement arose (Skenderovic, 2012). Until the start of the 1970s, this movement focused mainly on the protection of scenery and of nature, it then focused more and more on the concept of ecology. In Switzerland, the awareness that human action affected the environment and the climate began in 1970. The constitutional article on the protection of nature in 1970 and the first report on the Club of Rome in 1972 contributed to this realization. The oil crisis of 1974 finally confirmed the growing skepticism of the May 1968 generation and coincided with the birth of a global ecological movement. In response to this, the Swiss government created a global energy commission (GEC) in 1974 whose mandate was to deliver an energy policy based on three pillars: energy savings, energy research and diversification. The emphasis changed from profitability and security of supply to reducing the impact on nature by encouraging non-polluting sources. Out of the GEC emerged a constitutional article, which, after two defeats in front of the Swiss people, was accepted in 1991. This article enabled the confederation to encourage energy savings as well as renewable energy development (Marek, Politique énergétique, 2011).

The new federal office of environment (FOEN) was created in 1971 under the name of Federal Office for Environmental Protection at a time where Switzerland was gaining awareness of the effects of the Swiss way of life on the environment. Its objectives are the long-term conservation and sustainable use of natural resources and the rectification of existing damage and the protection of human life against natural hazards and environmental impacts (FOEN).

1.4.1 The Beginning of the End for Nuclear?

The ecological movement used direct democracy tools between 1977 and 2003 in order to promote its agenda. 19 popular initiatives on energy and transport were submitted to the people, and all of them except the moratorium on nuclear energy and the Alps initiative in 1994 were rejected (Skenderovic, 2012). Despite the failures in the ballot boxes, the influence of the ecological movement was growing. It successfully provoked the beginning of the end of nuclear power production. In 1975, the project of nuclear power plant in Kaiseraugst was stopped after the occupation of the site of the future plant by activists. The ecological movement also put pressure on the government and occupied the public space, pleading for what was going to become the 1978 federal decree on nuclear energy.

In 1978 the federal decree on nuclear energy specified that the authorization for new plants should be refused if the installations do not meet an actual need in the country, effectively preventing Switzerland from being, like France now, a net electricity exporter by relying on nuclear electricity. Moreover, the authorization should be granted only if "the safe and long-term disposal and final disposal of radioactive waste from the facility is ensured and that if the decommissioning and possible dismantling of decommissioned facilities is addressed". Finally, it specified that the federal council as well as the federal assembly have to give their approval for every new nuclear project.

The next step was to launch a popular initiative in order to write into the constitution a moratorium of 10 years on the construction of new nuclear power plants. This moratorium, under the name of "stop the construction of nuclear power plants" was accepted by the Swiss people in 1990. In 2003, the Swiss people were to vote on giving up nuclear energy, but the Federal Council suggested a counter-proposal, arguing for the extension of the moratorium rather than the elimination of nuclear power (Hug, 2009). In 2008, new projects for the construction of nuclear power plants were submitted to the government but after the Fukushima accident in 2011, they never got approved.

1.4.2 From Energy to Climate Policy

In the 1970s the government realized that the new energy challenges had to be addressed by means of policy. A change in energy policy was observed with from 1991 with a new energy initiative encouraging the construction of solar photovoltaic (PV) installation by means of tax cuts (Paquier, Sociétés électriques, 2016).

Switzerland is not unique in this matter. In the end of the 20th century more and more countries around the world became concerned about climate change. The Intergovernmental Panel on Climate Change (IPCC) was founded in 1988 as a body of the United Nations. It is dedicated to delivering objective scientific knowledge about climate change, its risks, impacts and mitigations options (IPCC). This marks the start of a worldwide raise in awareness about the changing world climate.

In 1992, the UN Conference on the Environment and Development in Rio de Janeiro results in a Framework Convention on Climate Change (UNFCCC). The signatories are referred to as parties. Three years later, in 1995, the first Conference of the Parties (COP) takes place in Berlin, where specific targets on emissions are discussed. It is only in 1997 in Kyoto that the emission reduction targets are included in an international agreement linked to the UNFCCC: the Kyoto Protocol. The goal of the Kyoto protocol is to control and limit human greenhouse gas (GHG) emissions in a way that would "stop dangerous anthropogenic interference with the climate system" (UNFCCC, What is the Kyoto Protocol?). Switzerland ratified the Kyoto Protocol in 1997 and its specific GHG emission reduction target was an 8% reduction by 2012 compared to 1990 levels (UNFCCC, Kyoto Protocol - Targets for the first commitment period). Meeting the GHG emissions reduction targets was facilitated by flexibility mechanisms including an international emissions trading system.

In the year 2000, the new Swiss CO_2 law was passed, putting restrictions on CO_2 emissions in Switzerland. The CO_2 law was the first milestone of Swiss climate policy. The commitment of 8% reduction compared to 1990 made in the Kyoto protocol was extended to a more ambitious 10% in the law. The law planned two phases for reaching the objective: In the first phase, the reduction of GHG emissions should happen through measures of energy, transportation and fiscal policy. If that proved not efficient enough, in the second phase Switzerland would introduce a CO_2 a steering tax on fossil fuels (Epiney, 2010).

One of the important tools towards the reduction of GHG emissions in Switzerland was the creation of a country-wide emission trading scheme (ETS) for companies. The advantage of such a scheme is that it allows to reduce emissions where the costs are the lowest (FOEN, 2018). Following the integration of the Swiss energy and climate policy in Europe, the Swiss ETS was linked to the European one in 2017 (Euromean Commission, 2017).

After the hard realization that the CO_2 law had very limited effects on the reduction of carbon emissions in the thermal fuel sector, the planned CO_2 levy was put into place. The levy would be collected by the federal custom administration at the boarder when the primary energy sources are imported. The levy was a key instrument in order to achieve statutory CO_2 emissions targets of the Kyoto Protocol. This tax on fossil fuels such as heating oil and natural gas, has been levied since 2008. In making fossil fuels more expensive, it creates an incentive to use them more economically and choose more carbon-neutral or low carbon energy sources (FOEN, 2018). Note that large companies which were part of the Swiss ETS can be exempted from the CO_2 levy, if they commit to reduce their CO_2 emissions. The initial CO_2 levy was 12 CHF/tCO_2 in 2008 but has since been increased to 96 CHF/tCO_2 in 2018 (FOEN, 02.2018). The effects of the CO_2 levy have been underlined in two studies financed by the Swiss Federal Office of Environment (Müller, et al., 2015) (FOEN, 2016). The CO_2 levy has proven to be effective as emissions reduction has been estimated to lie between 4.1 and 8.6 million of tons of CO_2. We show the evolution of GHG emissions in Switzerland in Figure 5. It shows all GHG emissions of the energy sector, not only CO_2, but the decrease observed from 2008 (54.01 tCO_2-eq) to 2017 (48.29 tCO_2-eq) can be attributed, to a certain extent to the effects of the CO_2 levy. The reduction have been driven mainly by households, which are the most affected by the combustibles being taxed. The replacement of heating oil by natural gas or renewable sources has been the principal driver of the observed decrease (FOEN, 02.2018).

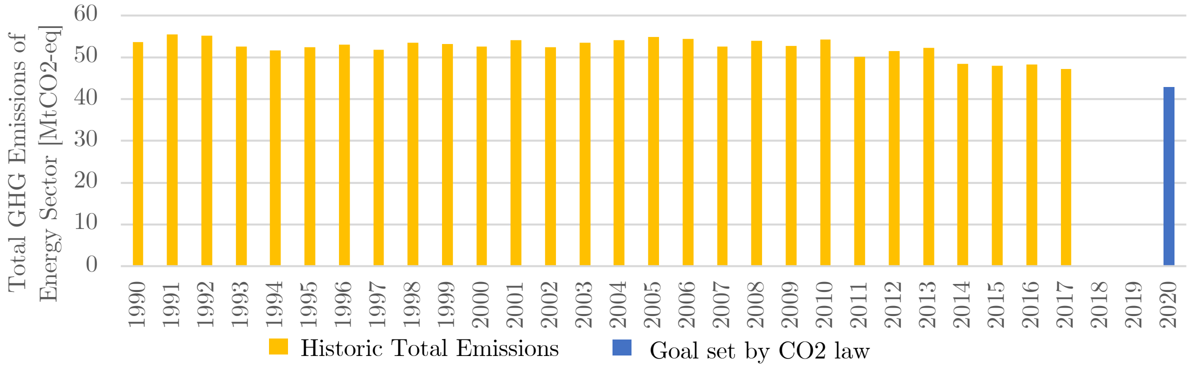


Figure 5: Historic Swiss GHG emissions of the energy sector. Source: (FOEN, 07.2018)

The ecological movement which triggered these new policies has two focus points: the reduction of GHG emissions and the reliance on renewable energy sources. The CO_2 levy directly addresses the first point, being technology-neutral it simply penalizes the use of CO_2 intensive processes. The second focus point is addressed in the 2009 modification of the Law on Energy with the following objective stated in Article 1: an increase in the production of renewable electricity of 5.4 TWh in 2030, compared to year 2000 (LEne). This objective is to be reached primarily thanks to a newly introduced feed-in tariff.

In 2009 the Swiss system of feed in tariffs for small hydro, biomass, solar PV, wind and geothermal energy emerged. The payments for a single installation are limited in time, to a maximum of 15 to 20 years and have in average been oscillating between 19 and 20 cents per kilowatt-hour (Pronovo, 2018). They are financed by the electricity consumers by an increase in the price of electricity at consumption. In 2017, 12'600 installations benefited from the feed-in tariff. They produced 2.6 TWh of electricity, that is about 5% of the total Swiss consumption in 2017 (Swissgrid, 2017). The rates are updated periodically, in order to allow the SFOE to stir the renewable electricity production in the direction it wishes. The breakdown per technology shown in Figure 6 shows that solar PV has benefitted from above average feed-in tariffs, starting at 71 cents/kWh and reaching 34 cents/kWh in 2016, compared to the fairly constant tariff for small hydro, between 15 and 16.5 cents/kWh.

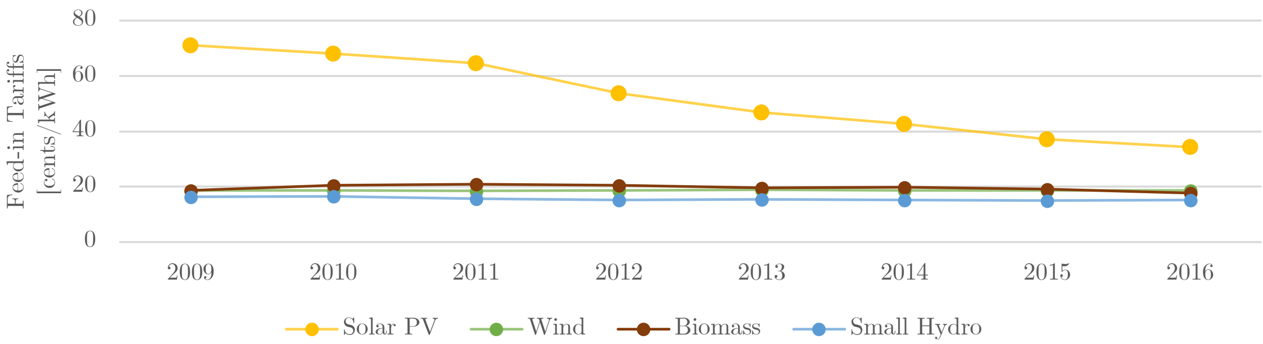


Figure 6: Feed-in tariffs for renewable electricity in Switzerland, source: (Pronovo, 2018)

In addition to the feed-in tariff, the promotion of renewable electricity production was further developed in the 2014 revision of the Energy Law with a new one-time investment grant for solar PV installations (Pronovo, 2018). This investment grant aimed solely at solar PV installations can cover up to 30% of the investment cost.

Looking at Figure 7, it is no surprise to see the increase in solar PV installed capacity starting in 2009. This further illustrates that the incitation mechanisms embedded in the revisions of the Energy Law are efficient.

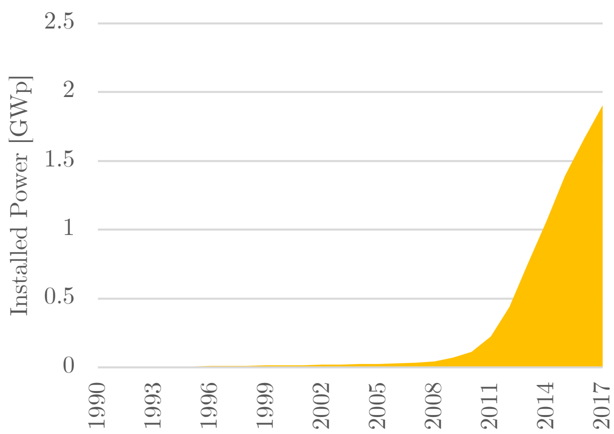


Figure 7: Installed power of solar PV in Switzerland from 1990 to 2017.

Following the nuclear accident of Fukushima in 2011, the Federal Council and Parliament decided on Switzerland's progressive withdrawal from nuclear energy production. This decision, together with further far-reaching changes in the international energy environment, require an upgrading of the Swiss energy system. For this purpose, the Federal Council developed the Energy Strategy 2050 whose first package of measures was adopted to law through popular vote in 2015. The strategy can be summed up in five main measures: energy efficiency, renewable energy development, withdrawal from the use of nuclear energy and upgrade of electricity grids. By following the Energy Strategy 2050, the evolution of the Swiss electricity mix, as seen in Figure 8, will follow a new trend: Renewable electricity sources are to replace the lost nuclear capacity.

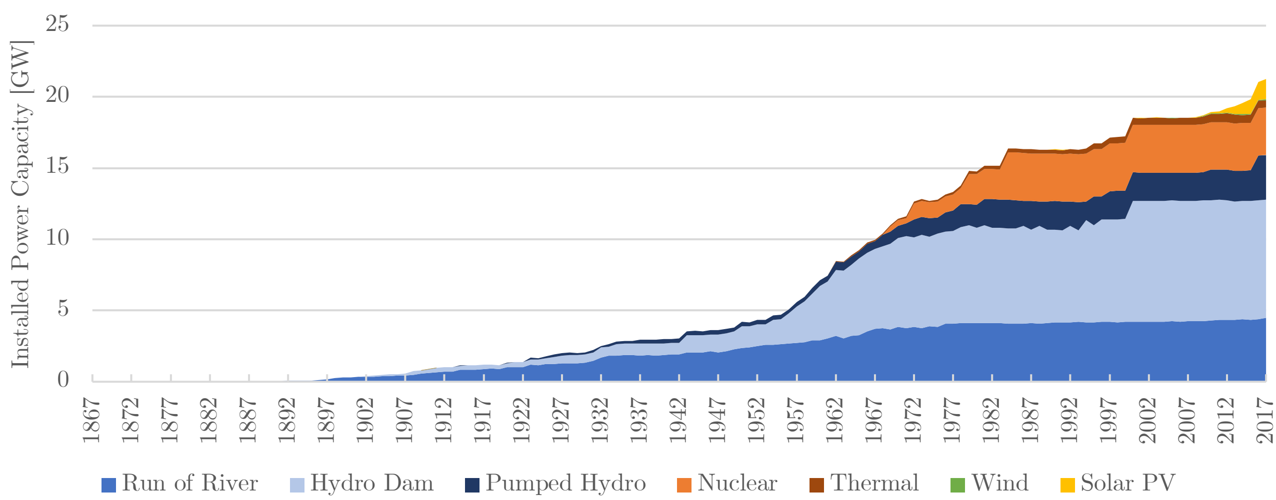


Figure 8: Installed capacity of electricity sources in Switzerland from 1867 to 2017

2 The Swiss Electricity System in 2017

As a base for the analysis of the future electricity system, we first turn to the year 2017. In this section we start by reconstructing time series of power supply by technology and analyze the specificities of the Swiss electricity system in 2017 in section 2.2. We finish by investing the consequences of replacing nuclear power with solar and wind thanks to an illustrative example in section 2.3.

2.1 Reconstructing 2017 Time Series of Power Supply

Our goal is to obtain hourly time series of electricity imports, exports, consumption and generation by technology, for the whole year. Switzerland does not have publicly available time series of electricity generation per technology, we hence reconstruct time series based on the best available data which we present in the next section.

2.1.1 The Data at Hand

Detailed time series data for total consumption, imports and exports are available through the Swiss electricity grid operator Swissgrid. They make key data about production, consumption and transmission at a 15min resolution publicly available (Swissgrid, 2017).

Regarding production, unfortunately, the Swiss Federal Office of Energy (SFOE) does not systematically collect time series data of electricity production over the whole year. The only available time series are those of the 3rd Wednesday of each month, which they summarize in a yearly report (SFOE, 2017, a). The categories of power generation in the report are nuclear, hydro dam, run-of-river, conventional thermal and others. Additionally, the SFOE gives information about consumption, imports, exports and pumping.

Completing the Wednesday time series, the SFOE releases every year a report called "Total Production and Consumption of Electrical Energy in Switzerland" (SFOE, 2017, b), where the monthly aggregated production data for run-of-river, hydro dam, nuclear and classical and renewable thermal production are given.

Since public data from the SFOE are not archived or at least not publicly available, we reconstruct a time series from available data. The key source on which our reconstruct historic time series comes from is the European Network of Transmission System Operators for Electricity's (ENTSO-E) transparency platform[1]. Hourly time series for nuclear, hydro pumped storage, hydro run-of-river and poundage, hydro water reservoir, solar and onshore wind can be found on the transparency platform.

[1] https://transparency.entsoe.eu

Transmission system operators as well as individual plants provide generation data to the transparency platform on a voluntary basis. In Switzerland for example, Swissgrid collaborates closely with ENTSO-E, and shares some of its data with the transparency platform. However, the platform does not have agreements with all the power generation plants in Switzerland. This leads to underreporting and thus bad data quality, especially for sectors with many small power plants, like in the hydroelectric sector.

2.1.2 Methodology

In order to cope with the varying quality of the ENTSO-E data, the time series of individual generation types were scaled to fit the SFOE's monthly aggregated production. As the SFOE and ENTSO-E do not use the same categories and category names, we mapped the ENTSO-E categories to the SFOE's. The mapping is presented in Table 4.

Category in this report	ENTSO-E Time Series	SFOE Equivalent Category
Hydro Dam	Hydro Reservoir and Hydro Pumped	Hydro Dam
Run-of-River	Run-of-river and Poundage	Run-of-river
Nuclear	Nuclear	Nuclear
Solar PV	Solar	Solar
Wind	Wind	Wind

Table 4: Mapping between ENTSO-E and SFOE electricity production technologies

Hydro Dam, Run-of-River and Nuclear:
For each month:
1. Calculate the aggregated monthly production from ENTSO-E
2. Divide the aggregated monthly production from SFOE by the ENTSO-E production to obtain a conversion factor for this month
3. Multiply the ENTSO-E time series by the monthly conversion factor

Append the monthly scaled time series to create a yearly time series.

Solar and Wind:
1. Calculate the aggregated yearly production from ENTSO-E
2. Divide the aggregated yearly production from SFOE by the ENTSO-E yearly production to obtain a conversion factor
3. Multiply the ENTSO-E time series by the yearly conversion factor.

Thermal:
For each month:
1. Deduct the Solar and Wind aggregated production from SFOE's Thermal and classical renewable production to obtain a monthly thermal and classical renewable production without wind and solar
2. Divide this production by the number of hours in the month

Box 1: Method for reconstructing the hourly time series of electricity supply in Switzerland for the year 2017

Note that we have pooled the time series from hydro reservoir and hydro pumped into a category we called hydro dam. The others category includes all the technologies not mentioned in the left column of Table 4, the most important sources which are waste incineration, gas and combined cycle gas turbines (CCGT), woody and non-woody biomass, biogas and other conventional thermal technologies.

With the mapping in place, we can proceed with the reconstruction of the historical time series. The method for this reconstruction is presented in Box 1. It consists of a simple scaling of the ENTSO-E data to match the smallest resolution of aggregated production from SFOE available, that is monthly for nuclear, run-of-river and hydro dam, and yearly for wind and solar PV and others.

In the method presented in Box 1, we implicitly assumed that the production from the "others" category is non-controllable by making it a baseload technology. After scaling, the monthly (except for wind and solar) and yearly aggregated production quantities of the reconstruction agree perfectly with the SFOE data from (SFOE, 2017, b).

2.1.3 Measures of Fit

From the methodology presented in Box 1 we obtain 12 monthly conversion factors for Nuclear, ROR and Hydro Dam but only one annual factor for Solar PV and Wind which we present in Table 5.

Conversion Factors	*Nuclear*	*ROR*	*Hydro Dam*	*Solar PV*	*Wind*
January	1.0	25.6	1.3	-	-
February	1.0	17.7	1.4	-	-
March	1.0	21.6	1.4	-	-
April	1.0	22.7	1.4	-	-
May	1.0	29.7	1.4	-	-
June	1.0	37.5	1.3	-	-
July	1.0	33.1	1.3	-	-
August	1.0	32.4	1.2	-	-
September	1.0	25.8	1.4	-	-
October	1.0	14.4	1.5	-	-
November	1.0	12.5	1.4	-	-
December	1.0	13.2	1.4	-	-
Year	-	-	-	1.67	4.01

Table 5: Conversion Factors to scale up the ENTSO-E time series to correct aggregated production

The conversion factors presented in Table 5 show the ratio of the SFOE aggregates and the ENTSO-E ones. The closer the conversion factor to one is, the better quality of the data is. We immediately see that the nuclear data is of very good quality. This is most probably due to the simplicity of the data. There are only five nuclear power plants in Switzerland, compared to the 548 run-of-river plants bigger than 300 kW, this makes the reporting far easier for nuclear, and our hypothesis is that this is the reason of the underreporting of run-of-river to ENTSO-E. The fact that the hydro dam conversion factors are not too far from unity further confirm this hypothesis, as there are 96 hydro dam plants in Switzerland and 23 of them produce about 65% of the electricity (SFOE, 2018, b).

We however have to keep in mind that the analysis of the conversion factors only give us information about aggregates, and nothing about the daily pattern of the production curves. In order to analyze the reliability of the daily trends, we calculate the Mean Absolute Percentage Error (MAPE) between the reconstructed historic data and the time series for the 3rd Wednesday of the month from SFOE as well as with the total production data from Swissgrid. The MAPE measures the difference between two vectors ($\mathbf{x}$ and $\mathbf{y}$) and is calculated as follows:

$$MAPE(\boldsymbol{x}, \boldsymbol{y}) = \frac{1}{n}\sum_{i}^{n}\left|\frac{x_i - y_i}{x_i}\right|$$

A MAPE of 0% means that the two vectors are identical in every point. By definition, the MAPE is positive and reflects how different two vectors are. It however says nothing about whether the error is positive or negative.

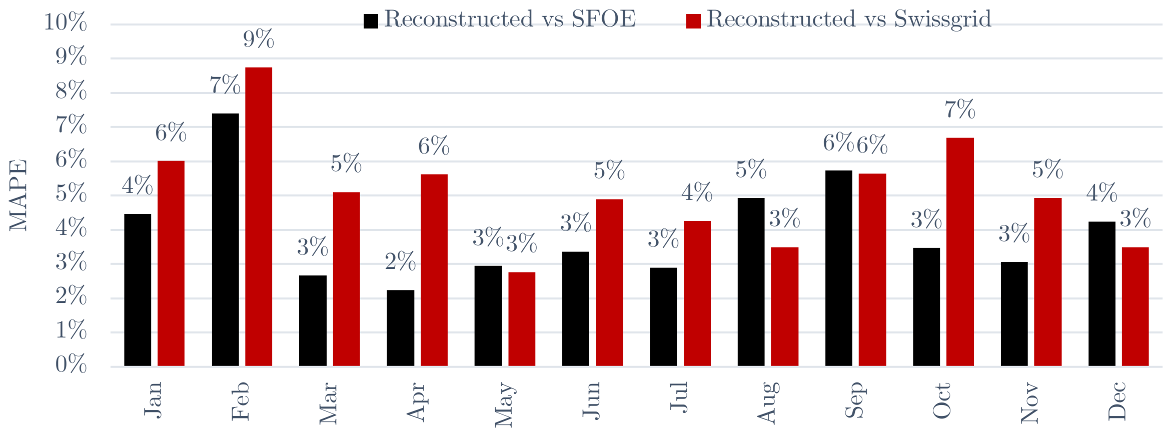


Figure 9: Mean Absolute Percentage Error between the total production of the reconstructed data and the total production from SFOE and Swissgrid for the 3rd Wednesday of each month of 2017.

In Figure 9, we compare the reconstructed data with the total production from SFOE and Swissgrid on the 3rd Wednesday of the month. The first observation is that the total production from SFOE and Swissgrid do not agree completely as the MAPE between the reconstructed data and the reference SFOE and Swissgrid are not identical. The reliability of the reconstructed production curves depends on the studied month. For example, in February, September or October the error is far higher than in May, where it stays under 3%.

Those discrepancies are mainly driven by the bad quality of the run-of-river and hydro dam time series on the ENTSO-E transparency platform. We recognize a significant underreporting when looking at the conversion factors in Table 5 and the adjustment to the correct aggregated production may amplify errors.

When looking at Figure 10 where the MAPE for ROR and hydro dam are given, still for the 3rd Wednesday of the month, we can see that certain months are more critical than others. The reconstruction for the months of February and September for example have large values of MAPE for hydro dam. We should keep in mind that these are percentages, and in the special case of September, the discrepancy is mainly driven by the early morning where the hydro dam production is around 1 GW. At those hours, a 300 MW error will lead to a 30% MAPE value.

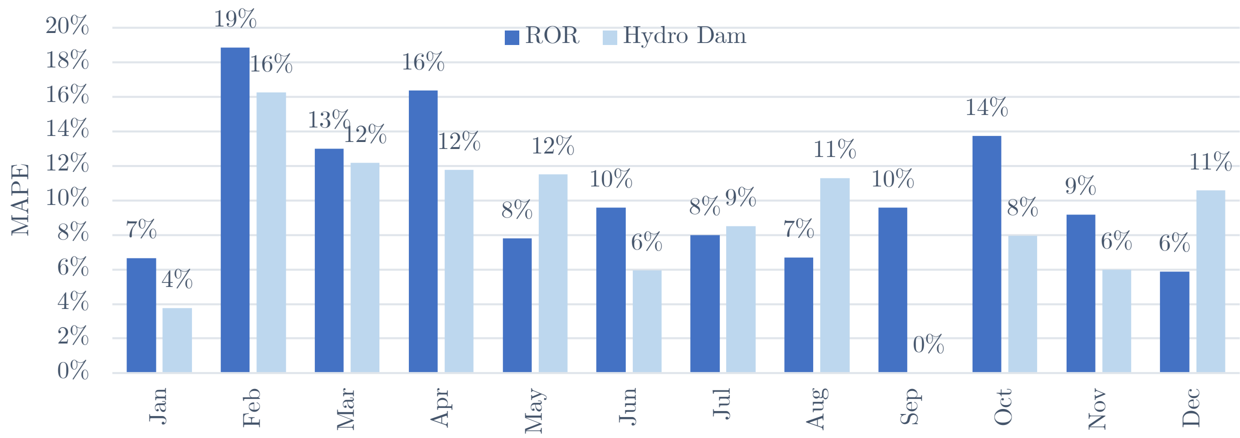


Figure 10: Mean Absolute Percentage Error for hydro dam and run-of-river production between the reconstructed data and the SFOE's time series for the 3rd Wednesday of each month.

But regardless of this weakness in the indicator, the MAPE gives a good idea of how closely the reconstructed data fits the available SFOE's time series. Note that Figure 9 and Figure 10 show errors for the third Wednesday of each month, which is the constraint inherited from the data availability from SFOE. Wednesdays are not necessarily representative of a typical day, there are generally differences between weekdays and weekends but also within weekdays, and the data above describe only the third Wednesday of each month.

Looking more into depth into the reconstructed data, we show in Figure 11 the average error between the total production derived from the reconstructed data and the time series from Swissgrid. We show, for each hour, what the average error is, and plot as well the standard deviation. By error we mean the Swissgrid production deducted from the reconstructed total production. Each point is an average of 365 points, one for each day. By doing so we are able to recognize at which hour the reconstructed data is the closest to the true time series. A positive value should be interpreted as an overproduction compared to the Swissgrid time series, a negative value as underproduction.

The general pattern is the following: In average, the reconstructed total production is superior to the true values from Swissgrid, except in the evening. The maximum of the error is at 8 in the morning where the reconstructed data lies in average at 0.6 GW too high. At the contrary at 10 pm, the overall production is in average 0.2 GW too low.

Note that over the whole year 2017, the reconstructed historic time series for 2017 fits the total production given by Swissgrid with a MAPE of 6.05%.

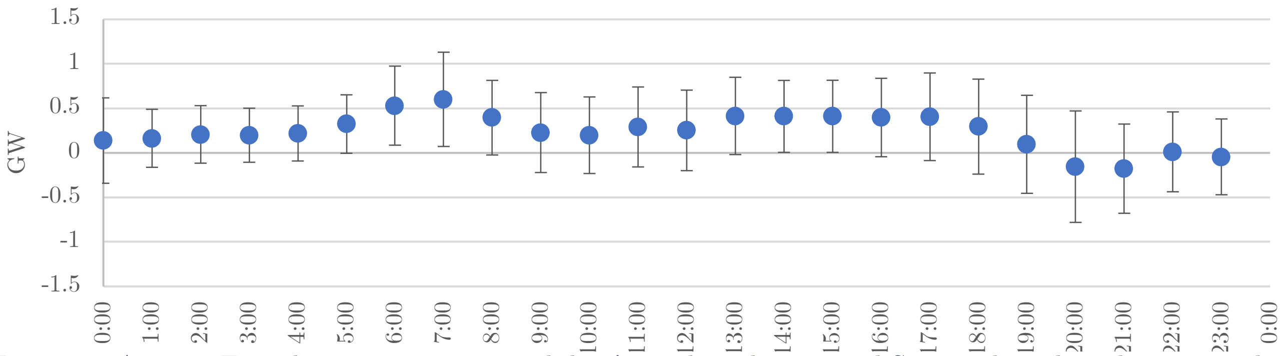


Figure 11: Average Error between reconstructed data's total production and Swissgrid total production, pooled by hour

2.2 Lessons from the 2017 Swiss Electricity System

In this section, we analyze the Swiss electricity production, consumption imports and exports based on the reconstructed time series of production per technology and the 2017 imports, exports and demand time series from Swissgrid (Swissgrid, 2017).

2.2.1 Electricity Production and Consumption

We begin by presenting the installed capacities, electricity production and annual capacity factor of each technology in 2017 in Table 6.

	Installed Capacity [MW]	*Electricity Production [TWh]*	*Annual Capacity Factor*
Nuclear	3333	19.5	67%
Run-of-River	4053	15.9	48%
Hydro Dam	8152	14.3	20%
Pumped Hydro	3089	6.4	24%
Thermal Fossil	750	1.6	24%
Thermal Renewable	211	1.2	65%
Solar	1906	1.6	10%
Wind	75	0.1	20%

Table 6: 2017 installed capacity, electricity production and annual capacity factor per electricity generation source

Comparing the share in installed capacity with the share in electricity production in Figure 12, we directly see the influence of annual capacity factors[2]. Nuclear power accounts for 16% of the installed capacity but 32% of the electricity produced, this is because the nuclear capacity factor is the highest among the electricity generating technologies. On the other hand, Solar PV accounts for 9% of the installed capacity but only 2% of the electricity production, this is directly linked with its low capacity factor.

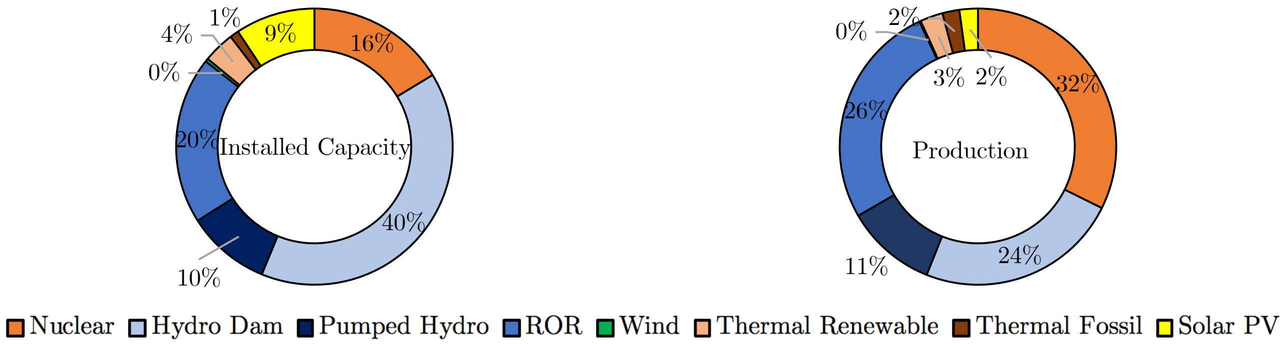


Figure 12: 2017 technology-specific shares in installed capacity and electricity production

The reconstructed historic data helps us recognize the specific patterns in power generation. Figure 13 and Figure 14 show the stacked production for the months of January and July. The supply data come from the method presented above, the demand, imports and demand from Swissgrid (Swissgrid, 2017).

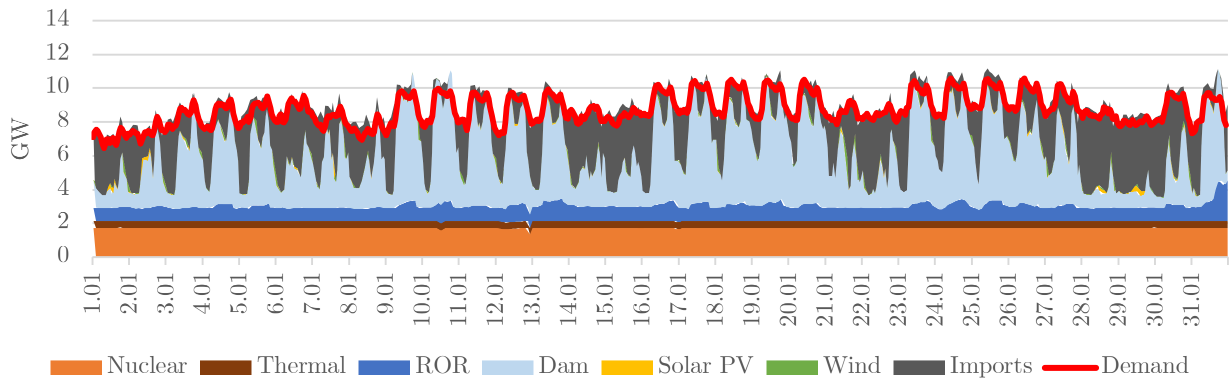


Figure 13: Reconstruction of historic production for January 2017. Historic demand from Swissgrid.

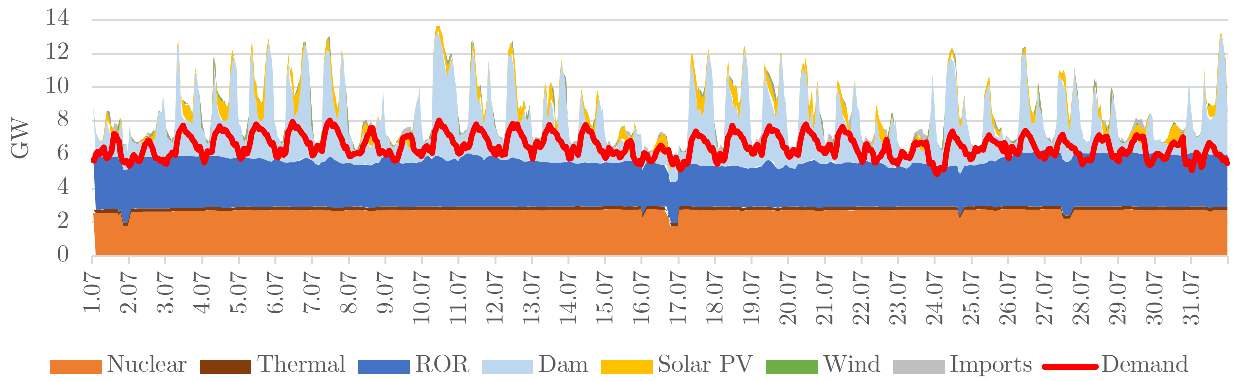


Figure 14: Reconstruction of historic production for July 2017. Historic demand from Swissgrid.

[2] For an explanation of what capacity factors are, see appendix A.

It appears clearly that the patterns and strategies are different in summer and winter months. Nuclear, run-of-river and thermal act as baseload electricity generation. The hydro dam production however is dispatchable and provides load-following capability. Solar PV peaks in summer in the middle of the day when the hydro dam production slows down. The deficits are filled with imports and the surpluses are exported.

2.2.1.1 Demand

Electricity demand is higher in January than in July. The aggregated demand are respectively 6.5 and 4.9 TWh, which makes the consumption in January 33% higher than in July. A driver of this higher consumption in winter is heating. Switzerland residential buildings are heated mainly with heating oil (40%) and Gas (21%), but electricity comes third with 7% (SFOS, 2017). In addition to electrical heating, other drivers for the higher demand in Winter include public and private lighting, due to the fact that the days are shorter and that people tend to spend more time inside in Winter, as well as the increased use of electrical equipment like boilers or the television in Winter.

2.2.1.2 Nuclear Production

Nuclear power runs as baseload throughout the year with occasional gaps due to maintenance or incidents. We also see that the nuclear production was higher in July than January. This is due to the unexpected closing of two nuclear power plants: Beznau 1 and Leibstadt. Leibstadt had to be closed down for 6 months between August 2016 and February 2017 because of dryouts on fuel rods. Oxide deposits were found and caused the yearly main maintenance to be extended (Tages Anzeiger, 17.02.2017). The Beznau 1 nuclear power plant was closed in March 2015 for a planned maintenance, after having found numerous cavities in the reactor. A rigorous documentation of each cavity was required before putting the reactor back on. The reactor started generating electricity again in March 2018 (Tages Anzeiger, 08.10.2015).

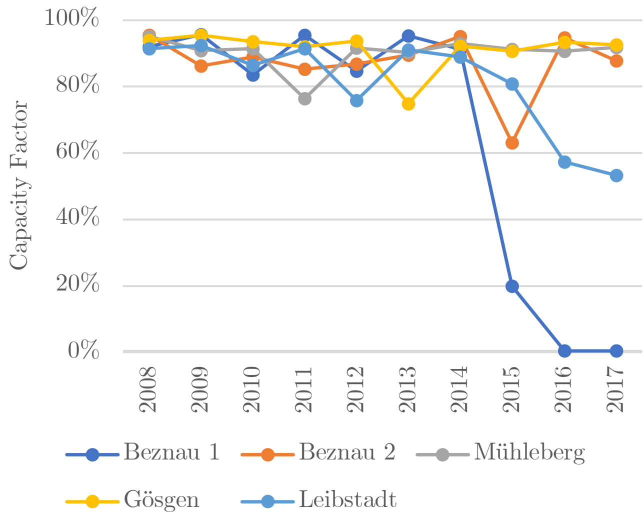


Figure 15: Nuclear yearly capacity factors from single power plants from 2008 to 2017. Source: (Swissnuclear)

Over the year 2017, nuclear power plants were responsible for 19.5 TWh of electricity, with 3333 MW installed, that means a capacity factor of 67%, which is low for nuclear. Typical values for Switzerland lie between 85% and 95%, as shown in Figure 15. As explained above, the reasons behind it were the unexpected extension of the closing of Leibstadt (1220 MW) until the end of February as well as the maintenance of the Beznau 1 (345 MW) reactor until March.

2.2.1.3 Renewable Electricity

The run-of-river production tends also to run as baseload, but production is higher in summer than winter when the snow and ice from the glaciers are melting and the flows in the rivers are high. We see this clearly in Figure 13 and Figure 14 where the hourly average production in January was 896 MW, versus 2789 MW in July[3].

The electricity production from wind turbines is not visible on the two Figures. With only 75 MW of installed capacity, the role of wind in Switzerland in 2017 was negligible. The generated wind electricity was 132.6 GWh (SFOE, 2017, c) which amounts to a 20.2% capacity factor.

Over the year the 1905.8 MWp of solar capacity produced 1.7 TWh of electricity. This corresponds to a 10.2% capacity factor (SFOE, 2017, c). 2017 was a very sunny year, the amount of sunshine reached 110% to 145% of the 1981-2010 averages measured from Meteoswiss (Meteoswiss, 2017). The solar production is noticeably different in Summer and Winter. Due to the weather cycle and sunlight difference between those seasons, it is to be expected that solar production peaks around June or July. We observe here this difference, as solar PV sums up to 19 GWh production in January and 230 GWh in July, that is twelve times more in July. Figure 16 shows the reconstructed time series of solar PV production for January and July 2017 and Figure 17 the average solar production during these months. It is interesting to notice the inter-daily variation which is directly linked to the weather conditions, namely cloud cover. In January, the highest peak is at 429 MW and the lowest at 8 MW. In July, the highest peak is at 1212 MW and the lowest at 425 MW. We must however be careful in analyzing the solar PV reconstructed time series. Due to the large number of solar panels, the solar PV data was underreported to the ENTSO-E transparency platform. We thus scaled the ENTSO-E data up according to the lowest resolution available aggregates for solar PV: yearly. It is hence not possible to exclude that the underreporting is correlated with some specific months. In our case, the January solar PV production is 12 times lower than the July one, but it cannot be excluded that the data is more underreported to ENTSO-E in January than July. Using satellite and reanalysis data, Pfenninger and Staffel calculated historical capacity factors for Solar PV from 1985 to 2016 (Pfenninger & Staffell, 2016). According to their data on Switzerland, the average capacity factor in July has been 4.14 times higher than the capacity factor in January over the past 30 years. If this data is correct, it would mean that the underreporting of solar PV is correlated with certain months, suggesting that the winter months are more underreported than the summer months.

We finish by looking at the hydro dam production in greater details. We plot in Figure 18 and Figure 19, the reconstructed hydro dam production and the intraday electricity spot price from EPEX SPOT SE, the operator of physical short-term electricity markets in central western Europe[4] overlaid.

[3] These numbers come from our own calculations from the 2017 reconstructed data
[4] https://www.epexspot.com/en/market-data/elix

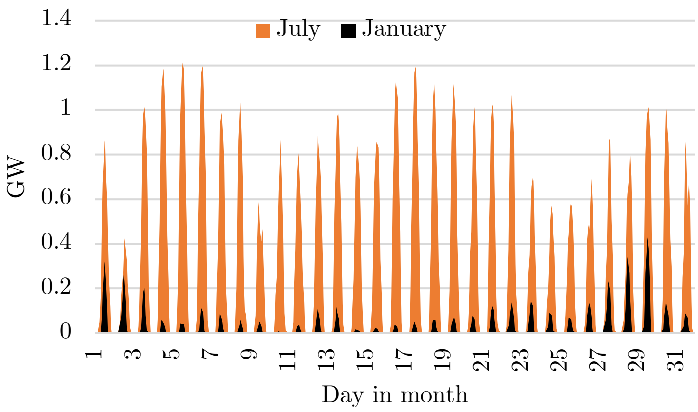


Figure 16: Reconstructed Solar PV time series for January and July

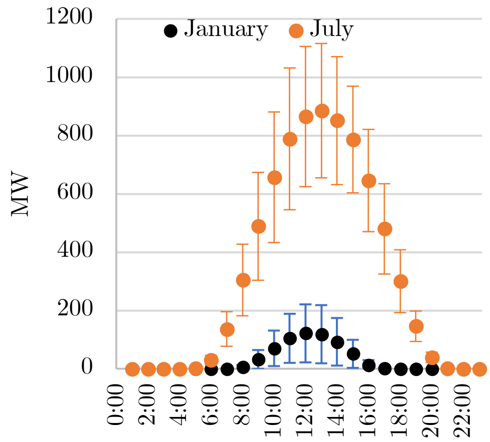


Figure 17: Average solar PV production in January and July. Calculations based on reconstructed data

The correlation between the time series of the reconstructed hydro dam production and the intraday spot price is 0.59 in January, 0.8 in July and 0.55 over the whole year. We clearly see in Figure 18 and Figure 19 that the patterns of price and hydro dam production are similar. It suggests that an important driver of hydro dam production is the price of electricity.

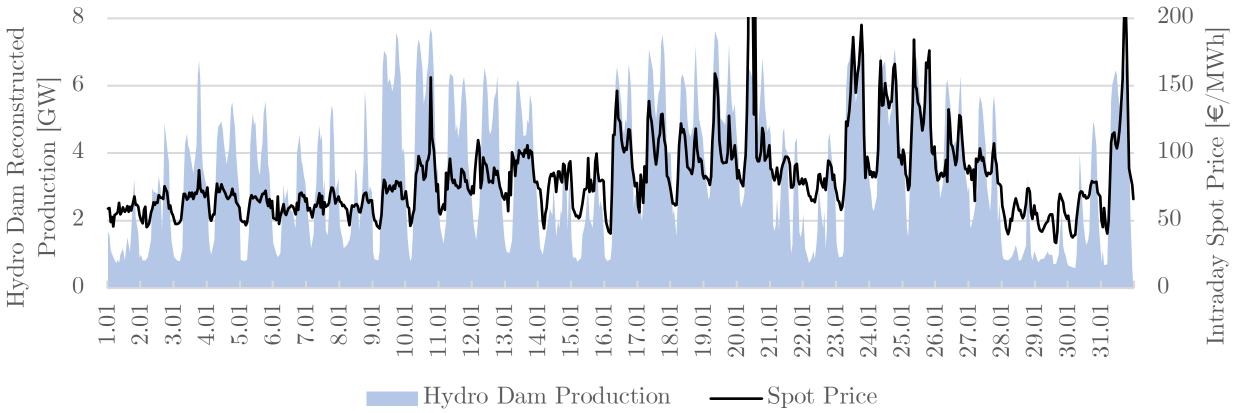


Figure 18: Reconstructed hydro dam production and intraday spot price for January 2017

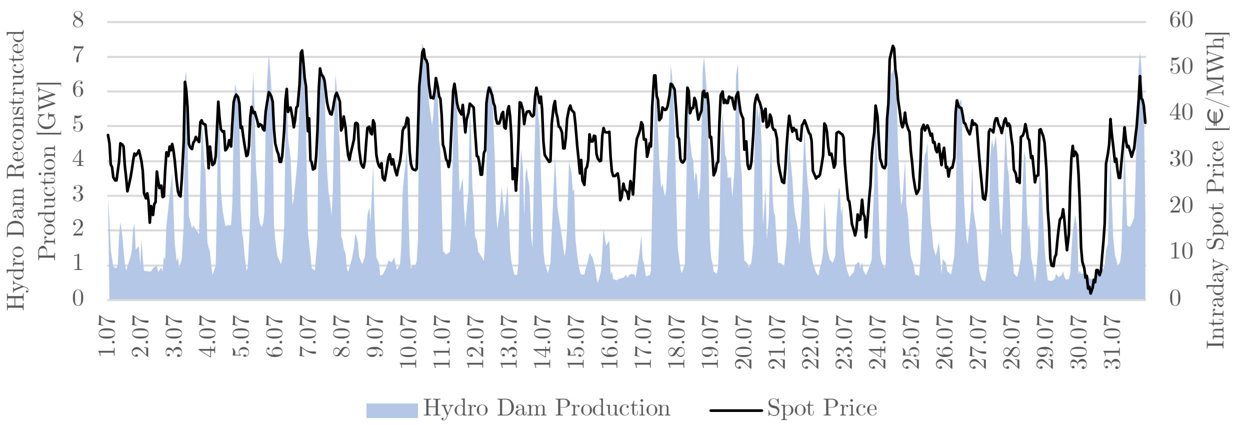


Figure 19: Reconstructed hydro dam production and to intraday spot price for July 2017

2.2.2 Imports and Exports

Switzerland is a net importer in January and net exporter in July. In January, 1.9 TWh of electricity is imported, it represents 29% of the January consumption, whereas there are almost no imports in July (only 0.1 TWh) which accounts for barely 1% of the consumption. The imports reflect the presence of surpluses and deficits in the Swiss local electricity production and consumption. The deficits are filled with imports and the surpluses are exported. Over the year 2017, 17% of demand was covered by imports in 2017 and 8% of the electricity production was exported. On the monthly breakdowns in Figure 20 and Figure 21 we see that the exports are concentrated in the winter and fall seasons with as much as 40% of the demand covered by imports in February. On the exports side, the excess production generated by the high run-of-river and solar production in the summer leads to exports, which peak in July with 20% of the production exported.

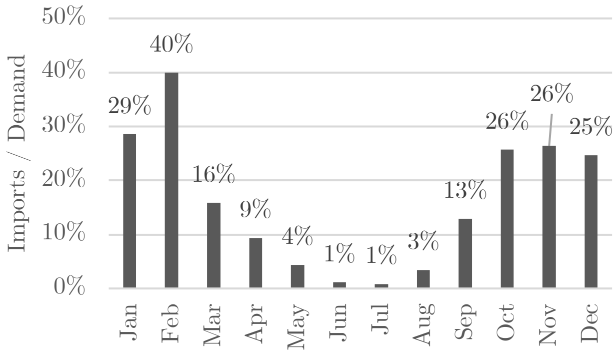


Figure 20: Share of demand covered by imports in each month in Switzerland in 2017.

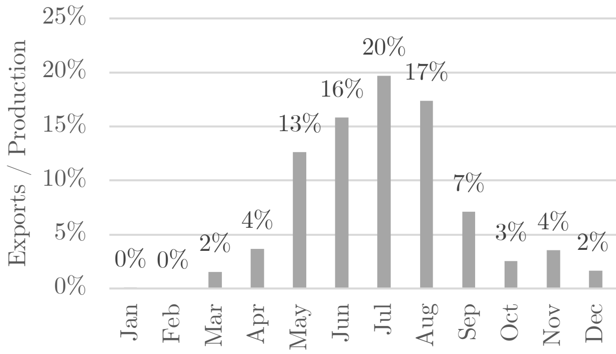


Figure 21: Share of production exported in each month in Switzerland in 2017

Looking more closely at the hourly average imports in Figure 22 and Figure 23, we see that there are two very clear imports peaks in January, namely early in the day between 03:00 and 05:00 am and one in the afternoon, between 14:00 and 16:00 pm. In July, there are almost no imports, which we recognize by looking at the Y-axis scale. A similar pattern as for the month of January can be observed with two peaks, one early in the morning between 2:00 and 6:00 am and one in the afternoon around 16:00 pm.

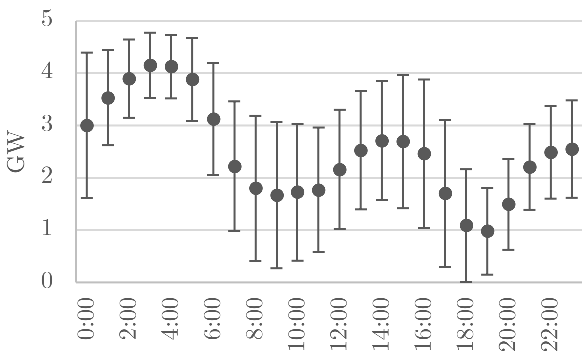


Figure 22: Hourly average net imports in January 2017. Source (Swissgrid, 2017)

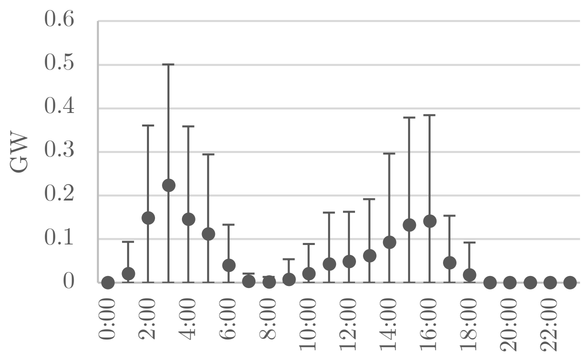


Figure 23: Hourly average net imports in July 2017. Source (Swissgrid, 2017)

Figure 24 and Figure 25 show the hourly average exports in January and July 2017. We illustrate here the phenomenon observed on stacked graphs, namely that the exports are higher in July than January. As for imports, the daily exports peak twice in the day but late in the morning, between 8:00 and 11:00 am and late in the evening, between 19:00 and 23:00 pm. This also coincides with periods of high demand.

Switzerland acts as an electricity hub in the middle of Europe as a large share of electricity transiting through the country is not consumed in Switzerland. Figure 27 shows the difference in net and gross exports of electricity in Switzerland in 2017. The gross exchanges are about 25 TWh higher than the net imports and exports. The countries of origin and destination are shown in Figure 26. Most of the electricity is imported from Germany France and Austria while Italy and France are the destination of the majority of Swiss' exports.

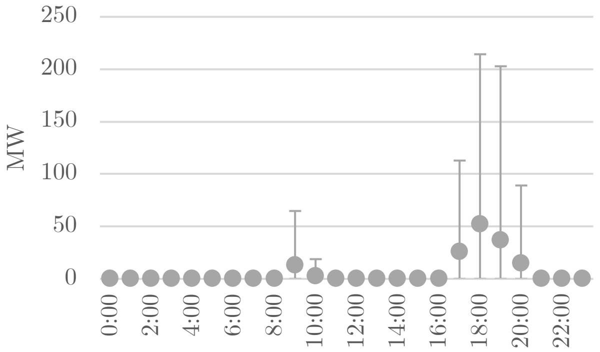


Figure 24: Hourly average net exports in January 2017. Source (Swissgrid, 2017)

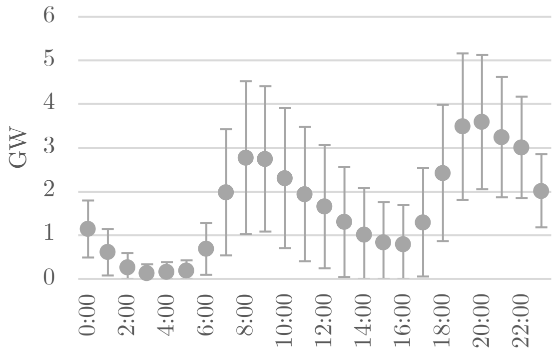


Figure 25: Hourly average net exports in July 2017. Source (Swissgrid, 2017)

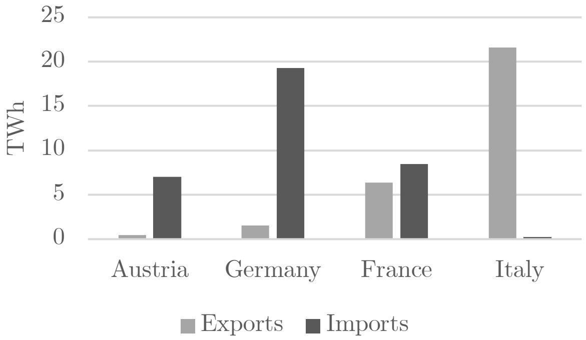


Figure 26: Country of origin and destination of Swiss imports and exports in 2017. Source (Swissgrid, 2017)

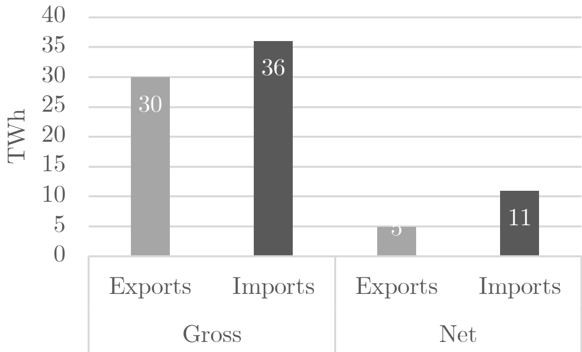


Figure 27: Swiss gross and net imports and exports in 2017. Source (Swissgrid, 2017)

2.3 Replacing Nuclear by Wind and Solar: An illustrative example

The Energy Strategy 2050 excludes the construction of new nuclear power plants. Each nuclear plant should be taken off the grid after 50 years of operation. The nuclear power lost from energy is planned to be replaced locally mainly by wind and solar electricity, as well as biogas, biomass and small hydro. In this section we analyze the challenges arising from replacing nuclear with solely local solar and wind production in Switzerland

In this section, we use the hourly reconstructed time series to address the two following questions: "What are the consequences on electricity supply of the replacement of the nuclear power production by an equivalent amount of solar and wind in Switzerland?" and "What are the storage size requirements for performing seasonal storage in Switzerland". In order to do so, we consider two electricity mixes which we present in Table 7.

	Yearly Nuclear Production [TWh]	*Yearly Solar & Wind Additional Production [TWh]*
Nuclear Mix	19.5	0
Solar & Wind Mix	0	19.5

Table 7: Illustrative example: Nuclear and Solar & Wind electricity mixes. The Nuclear mix is identical to the 2017 electricity mix, the Solar & Wind mix replaces the nuclear production by solar and wind. The additional solar and wind capacities are added to and the nuclear capacity removed from the 2017 mix to reach the Solar & Wind mix.

The nuclear mix corresponds to the 2017 electricity mix presented in Table 6. The solar & Wind electricity mix corresponds to a mix where the nuclear capacity is set to zero and replaced by additional solar and wind capacity which produce the same amount of electricity over the year as nuclear in 2017. In this illustrative example, the other electricity generating sources (hydroelectric, other renewables and thermal) are assumed to produce the same amount of electricity as in 2017 and at the same times as in 2017. There is hence no endogenous effect of the change of production mix on electricity generation.

In order to calculate how much local renewable electricity capacity is necessary in Switzerland for to compensating the loss of baseload production from nuclear, we use the solar and wind capacity factors of 2017. Generating 19.5 TWh of electricity with solely PV and wind, using the capacity factors of the year 2017 as calculated from the reconstructed data, would necessitate 2.4 GW of Wind power and 17.2 GW of solar PV.

We reach those numbers by considering the maximal power generation potentials as calculated by Bauer and Hirschberg in (Bauer & Hirschberg, 2017) namely 19 TW/a for solar PV and 4.3 TWh/a for wind and calculated the necessary installed power for generating this electricity, based on the 2017 conversion factors. As the capacity factor of wind is higher than solar, the wind potential is first set to its maximal before turning to solar PV. Generating 4.3 TWh/a with the 20.2% capacity factor of wind electricity necessitates 2.4 GW of power installed. Generating the remaining 15.2 TWh/a with solar PV's 10.2% capacity factor necessitates 17.2 GW of power installed. We obtain adjusted time series of solar PV and wind generation corresponding to these new capacities by scaling up the reconstructed time series. The ratio of the calculated and historic capacities is taken as a multiplicative factor by which the whole 2017 reconstructed time series is calculated.

2.3.1 Production, Surpluses and Deficits

We start by looking at the differences of the two mixes on electricity production over the year. We focus our analysis on their only differing point: On one side the nuclear production, and on the other side the additional solar and wind production. Figure 28 and Figure 29 show the nuclear production of the Nuclear mix and the solar PV and wind production of the Solar & Wind mix for the months of January and July.

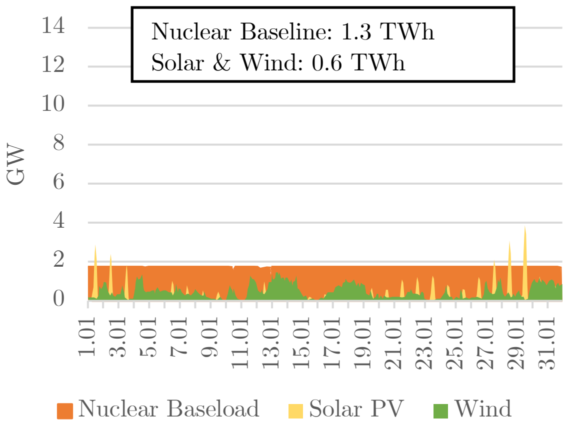


Figure 28: Illustrative example, solar PV and wind production of the Solar & Wind mix, nuclear production of Nuclear mix for January 2017

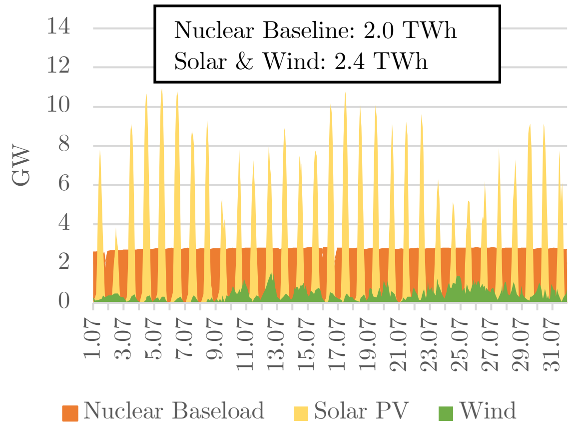


Figure 29: Illustrative example, solar PV and wind production of the Solar & Wind mix, nuclear production of Nuclear mix for July 2017

The main difference lies in the variability of the renewable electricity sources. In this example, local wind and solar electricity are set to generate as much electricity as nuclear in 2017. The monthly aggregates of production however differ as we show for January and July in Figure 28 and Figure 29. In January, nuclear electricity generates 1.3 TWh and the additional wind and solar production only 0.6 TWh. In July, nuclear generates 2.0 TWh and the additional wind and solar 2.4 TWh. The renewable generation is about four times higher in July than January. The consequence is that the deficits and the surpluses are higher in the Solar & Wind than in the Nuclear mix.

	Deficit [TWh]	*Surplus [TWh]*	*Deficit – Surplus [TWh]*
Nuclear	10.9	4.9	6.0
Solar & Wind	20.0	14.0	6.0
Nuclear – Solar & Wind	9.1	9.1	0.0

Table 8: Illustrative example, yearly deficit and surplus arising from replacing nuclear by solar and wind in 2017

Table 8 shows the yearly deficits and surpluses arising from both mixes. The difference between deficit and surplus is identical in both mixes as the amount of electricity generated is identical. However, both the surplus and the deficit increase by 9.1 TWh over the year for the Solar & Wind mix. The monthly deficits and surpluses of both mixes are shown in Figure 30. In the Wind & Solar mix, the surpluses get larger in the summer when solar production peaks but due to the diurnal cycle of solar electricity, the deficits in the summer months increase too.

The limitations of this approach lie in the fact that electricity production from other sources from nuclear, wind and solar are taken as exogenous. In reality the change of electricity mix would have an effect on electricity prices and hence on electricity production, especially of hydro dam. This example is limited to the case where every other electricity generation technology is kept constant at its 2017 level. Moreover, the reliance on 2017 data conditions this analysis to a year with similar weather conditions as 2017, through the use of the wind and solar 2017 capacity factors.

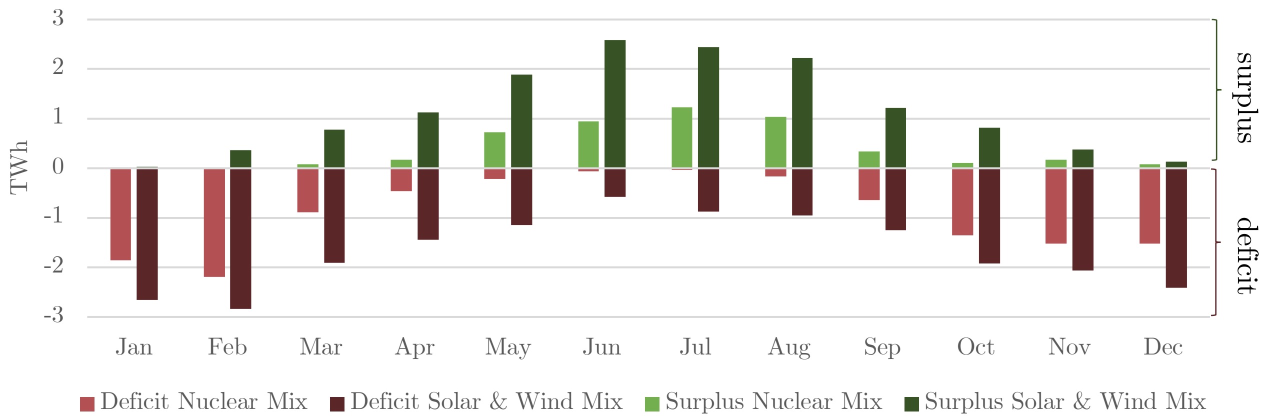


Figure 30: Illustrative example, deficit and surplus for the Nuclear and Wind & Solar mixes based on the 2017 reconstructed time series of electricity production in Switzerland

In sum, the Solar & Wind mix exhibits a larger seasonality imbalance in production as the Nuclear mix. Its production peaks in the summer when demand is usually low, and slows down in the winter when demand is usually high. It leads, when other electricity producing sources are taken as exogenous at the level of 2017, to an increase in deficits and of surpluses over the year compared to the Nuclear mix. The surpluses' increases lie mainly in the summer and the deficits in the winter. Additionally, replacing a baseload technology with a variable, non-controllable one brings up technical challenges, notably in how to smoothen the electricity production curve in order for it to match demand. Electricity storage systems are often mentioned as solution to those challenges. We study in next section the physical requirements of a storage system performing seasonal load shift in Switzerland based on the 2017 reconstructed data.

2.3.2 Seasonal Electricity Storage

The increasing penetration of intermittent renewable electricity in the European electricity mix, and especially of solar PV, calls for new tools for ensuring network stability and reliability as well as for matching the seasonally peaking electricity production to demand. One of the most promising approaches for addressing this problem is Electrical Energy Storage (EES) (Chen, 2009).

In Switzerland, electricity demand peaks in winter, whereas production peaks in Summer. The increase of solar PV capacity in the Swiss mix will further increase this difference and calls for technological solutions.

Switzerland is already a leader in EES, thanks to its large hydro dam and pumped hydro capacity. Swiss pumped hydro is noticeably dominated by open-loop pumped hydro storage (US Department Of Energy), that means that the upper reservoir is continually filled with natural inflows. For simplicity we assume throughout this example that the pumped hydro power plants have no natural inflows. The total power capacity of the Swiss pumped hydro power plants in 2017 was 3089 MW (SFOE, 2018, b) and the storage capacity was estimated to be 240 GWh in 2017 by Piot (Piot, 2014). The average efficiency of a pumped hydro power plant in Switzerland is about 80% (SFOE, 2017, a).

In this section, we calculate storage sizes necessary for Switzerland to perform seasonal load shift. We first look at the requirements for Switzerland to eliminate all surpluses with storage and then turn to the requirements for Switzerland to eliminate all deficits. The assumptions presented in Box 2 are made for modelling the electricity storage system.

Assumption 1:	The technology is pumped-hydro only
Assumption 2:	The round-trip efficiency is 80% (SFOE, 2017, a)
Assumption 3:	There are no natural inflows in the reservoirs
Assumption 4:	The charging and discharging power are unconstrained

Box 2: Illustrative example, assumptions for modelling electricity storage

There are three possibilities for simulating the evolution of the storage level, we name them method 1 to 3 and present them in Equation 1, Equation 2 and Equation 3.

$$storage\ level_t = storage\ level_{t-1} - {}^{imports_{t-1}}/_{80\%} + exports_{t-1}$$
$$charged\ electricity_t = exports_t$$
$$discharged\ electricity_t = imports_t$$

Equation 1: Illustrative example, method 1 for calculating the storage level at each time t

$$storage\ level_t = storage\ level_{t-1} - imports_{t-1} + {}^{exports_{t-1}}/_{80\%}$$
$$charged\ electricity_t = exports_t$$
$$discharged\ electricity_t = imports_t$$

Equation 2: Illustrative example, method 2 for calculating the storage level at each time t

$$storage\ level_t = storage\ level_{t-1} - \frac{imports_{t-1}}{\sqrt{80\%}} + \frac{exports_{t-1}}{\sqrt{80\%}}$$
$$charged\ electricity_t = exports_t$$
$$discharged\ electricity_t = imports_t$$
Equation 3: Illustrative example, method 3 for calculating the storage level at each time t

The minimal storage size necessary is found through a minimization. The initial storage level is minimized under the constraint that the minimal storage level over the year is larger than zero. The minimal storage size is given by the maximal storage level over the simulated year.

2.3.2.1 A Storage Model Charging all Surpluses

Charging all surpluses will allow to fill only a fraction of the deficits. As Table 8 shows, the deficits are larger than the surpluses for both mixes. The percentage of deficit filled by the storage model is respectively 36% and 46% for the Nuclear and Solar & Wind mixes. These numbers are obtained by dividing the total surplus by the total deficit and then multiplying by the round-trip efficiency. In this section, we have to decide when the deficits get filled. We assume that in each hour where there is a deficit, the deficit is uniformly reduced by respectively 36% and 46% in the Nuclear and Solar & Wind mix.

Minimal Storage Size Necessary	*Nuclear Mix*	*Solar & Wind Mix*
Method 1 (Equation 1)	4.0 TWh	7.3 TWh
Method 2 (Equation 2)	3.2 TWh	5.8 TWh
Method 3 (Equation 3)	3.6 TWh	6.5 TWh

Table 9: Illustrative example, calculated minimal pumped hydro storage size necessary for being able to shift all surpluses in deficit hours for the Nuclear and Solar & Wind mixes.

The minimal storage sizes necessary for performing the seasonal load shift, constrained by the size of the surplus are shown in Table 9. The necessary storage size for the Nuclear mix varies between 3.2 TWh and 4.0 TWh, for the Solar & Wind mix it lies between 5.1 TWh and 7.3 TWh. Note that both mixes charge and discharge different amounts of electricity (see Table 10).

Minimal Storage Size Necessary	*Nuclear Mix*	*Solar & Wind Mix*
Charged Electricity [TWh]	4.9	14.0
Discharged Electricity [TWh]	3.9	11.2
Necessary Charging Power [MW]	6927	11743
Necessary Discharging Power [MW]	1912	3805

Table 10: Illustrative example, calculated charging and discharging power, charged and discharged electricity necessary for being able to shift all surpluses in deficit hours for the Nuclear and Solar & Wind mixes.

Finally, we show the evolution of the storage model for both mixes in Figure 31 and Figure 32. Both mixes show the same tendency, the model discharges in winter until spring where it stays at a constant level until the start of summer, meaning that the share of deficits filled and surpluses charged are similar in spring. In summer, the surpluses are larger than the share of deficits filled and the storage level increases and peaks at the end of September before coming down to its initial level. The main difference between the two Figures is that the Nuclear mix leads to less variation of the storage level, due to the fact that the surpluses and deficits are both lower than for the Solar & Wind mix, as shown in Figure 30.

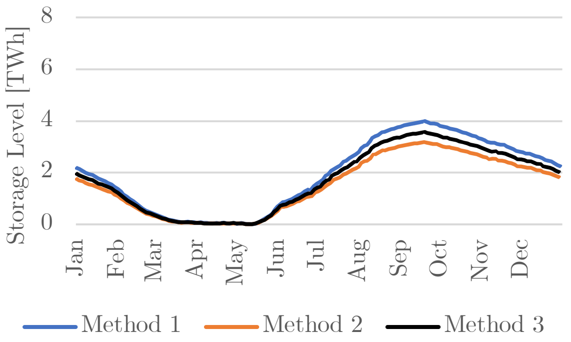


Figure 31: Illustrative example, Nuclear mix, evolution of the storage level over the year. The storage model shifts all surpluses uniformly in deficits hours.

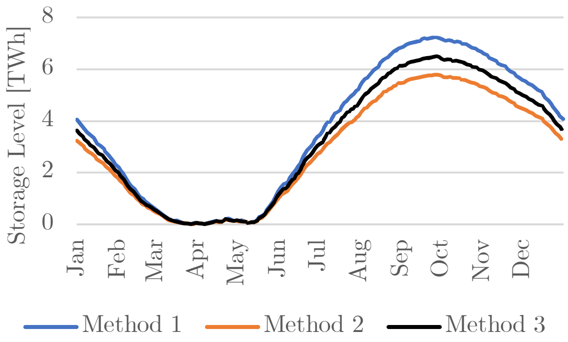


Figure 32: Illustrative example, Solar & Wind mix, evolution of the storage level over the year. The storage model shifts all surpluses uniformly in deficits hours.

2.3.2.2 A Storage Model Filling all Deficits

We study in this section the requirements for eliminating all deficits of an electrical storage infrastructure in Switzerland. The idea is to replace the needs for imports by local electrical storage.

The necessary storage level for performing seasonal storage in the Nuclear mix (which corresponds to Switzerland in 2017) and for completely replacing imports varies between 7.02 TWh and 8.77 TWh, depending where the efficiency intervenes in the storage level calculation. For the Solar & Wind mix these storage sizes vary between 8.84 TWh and 11.05 TWh. The results are summarized in Table 11.

Minimal Storage Size Necessary	*Nuclear Mix*	*Solar & Wind Mix*
Method 1 (Equation 1)	8.77 TWh	11.05 TWh
Method 2 (Equation 2)	7.02 TWh	8.84 TWh
Method 3 (Equation 3)	7.85 TWh	9.88 TWh

Table 11: Illustrative example, Nuclear mix, calculated minimal pumped hydro storage size necessary for being able to charge all surpluses and fill all deficits.

Compared to the estimated 240 GWh storage size in Switzerland in 2017, the estimates of Table 11 are high: between 33 and 37 times higher in the Nuclear mix and between 37 and 46 higher in the Solar & Wind mix. The seasonality imbalance of the renewable electricity sources necessitate a larger storage size for performing a seasonal storage. This should be traced back to the results of Figure 30 where we see that the surpluses are more concentrated in the summer and the deficits more concentrated in the winter for the Solar & Wind mix. Also note that the amounts of electricity charged and discharged are different for the two mixes.

The necessary charging and discharging powers for filling all deficits are shown in Table 12. In 2017 the pumped hydro plants had a 3089 MW turbine (discharging) power and a 2696 MW pumping (charging) power (SFOE, 2018, b). The Nuclear and Solar & Wind mixes would necessitate a charging power 2.6 and 4.4 superior to 2017 and discharging power 1.7 and 2.0 superior to 2017 for filling all deficits with storage.

Minimal Storage Size Necessary	*Nuclear Mix*	*Solar & Wind Mix*
Charged Electricity [TWh]	4.9	14.0
Discharged Electricity [TWh]	10.9	20.0
Necessary Charging Power [MW]	6927	11743
Necessary Discharging Power [MW]	5340	6808

Table 12: Illustrative example, calculated necessary charging and discharging power, charged and discharged electricity for the Nuclear and Solar & Wind mixes in order to able to charge all surpluses and fill all deficits

We finally look at the evolution of storage level for the two electricity mixes in Figure 33 and Figure 34. The storage level curves reflect the evolution of surpluses and deficits over the year. When the storage level decreases, it means that there is more deficit than surplus, when the storage increases, it is because there is more surplus to charge as deficits. Note that for both mixes and all methods, the storage starts full and finishes empty. In order to operate seasonal storage over more than one year one would have to either produce or import more electricity, creating surplus which could be charged by the storage model, or fill less of the deficit and still rely on imports for meeting demand.

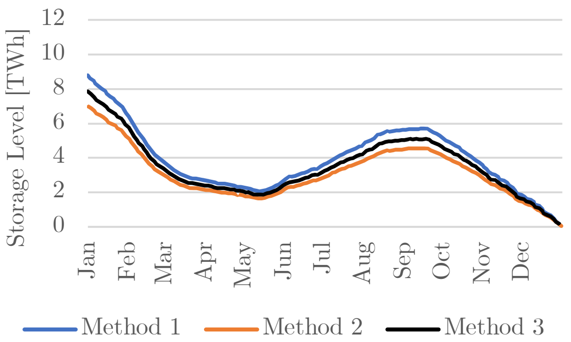


Figure 33: Illustrative example, Nuclear variant, evolution of the storage level over the year

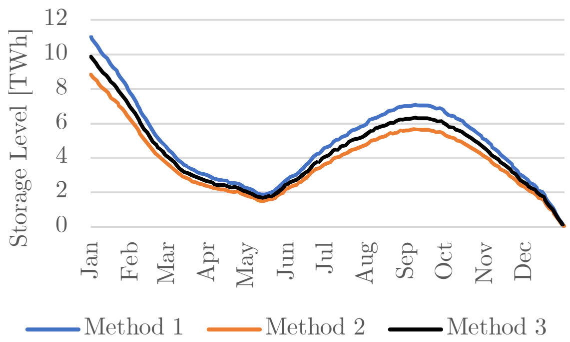


Figure 34: Illustrative example, Solar & Wind variant, evolution of the storage level over the year

2.3.2.3 Summary

Provided that the time series electricity of electricity production from the hydroelectric and thermal sources are exogenous and kept at their 2017 level, the storage size necessary for filling all deficits varies between 7.02 TWh and 8.77 TWh in the Nuclear mix and between 8.84 and 11.05 TWh in the Solar & Wind mix. This is compared to the estimated 240 GWh of storage size in 2017 between 33 and 46 times higher than the current reservoir capacity. The necessary charging and discharging powers associated with this seasonal load shift strategy are around twice superior to the 2017 installed capacities.

The storage size necessary for shifting all excess production in deficit hours is lower, it varies between 3.2 TWh and 4.0 TWh for the Nuclear mix and between 5.8 TWh and 7.3 TWh for the Solar & Wind mix. The differences lie in the distinct sizes and repartition of surpluses and deficits over the year, depending on the mix.

These two seasonal load shift models require an important expansion of the storage infrastructure in Switzerland, in terms of storage size but also charging and discharging powers. Seasonal storage models would also require a transformation of the current storage operation model from daily to yearly cycles with the the consequences it can have on profitability.

3 A Model for Simulating the future Swiss Electricity Supply and Demand

Having a reconstructed version of the 2017 time series of electricity production and having historic time series for consumption, we turn to developing a model for simulating electricity production, consumption, imports and exports in the future.

3.1 Simulating Demand

We consider two components for future demand: the evolution of population and demand per capita excluding Electrical Vehicle (EV) charging and demand from EV charging. We differentiate between these two components as the EV charging demand is predicted to change the demand curve in the future (Meng, et al., 2013; Mu, Wu, Jenkins, Jia, & Wang, 2014).

3.1.1 Simulating Demand without EV charging

The simulation of demand without EV charging is performed by making assumptions about population growth and demand per capita in the future in order to scale the 2017 demand accordingly A schematic view of the methodology can be seen in Figure 35. Note, that "demand" and "consumption" are used as synonyms in the case of electricity.

In reality, there are many factors contributing to the determination of the demand curve and the total electricity demand. In this model, we focus on two: population size and demand per capita. We rely on the population forecast from the Swiss Federal Office of Statistics (SFOS, 2015, a) for predicting the population size in Switzerland in the future. The SFOS present three scenarios, which give possible developments that depend on the realization of proposed assumptions, like GDP growth, immigration and natality rates. In our project, we use the SFOS' reference scenario which predicts respectively 9.5 and 10.2 million Swiss residents in 2030 and 2045. We consider the 2045 population forecast to be valid in 2050 and base the model on a 9.5 million population in 2030 and 10.2 million in 2050.

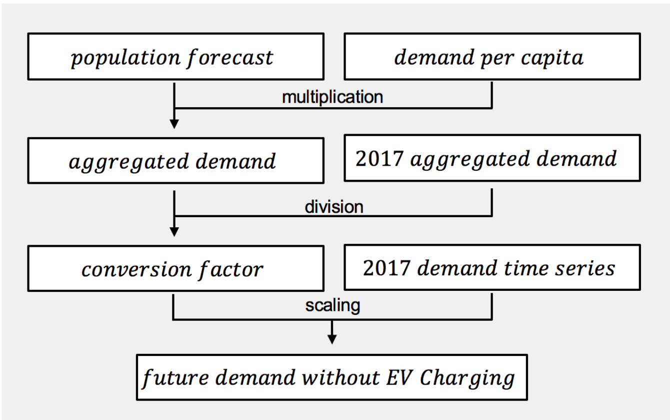


Figure 35: Method for simulating demand time series without EV charging

Once we have an estimation for the population size, we make assumptions for demand per capita excluding the contribution from EV charging in order to obtain a number for yearly aggregated electricity demand without EV charging. We obtain the aggregated demand by multiplying the population forecast by the demand per capita assumption.

We then scale the Swissgrid 2017 time series of electricity demand for the Swiss control-block such that it leads to the modelled yearly electricity consumption. We use a unique correction factor for the whole year, the correction factor is the ratio of the predicted and 2017 historic aggregated yearly demand. An example of this scaling procedure is shown in Figure 36.

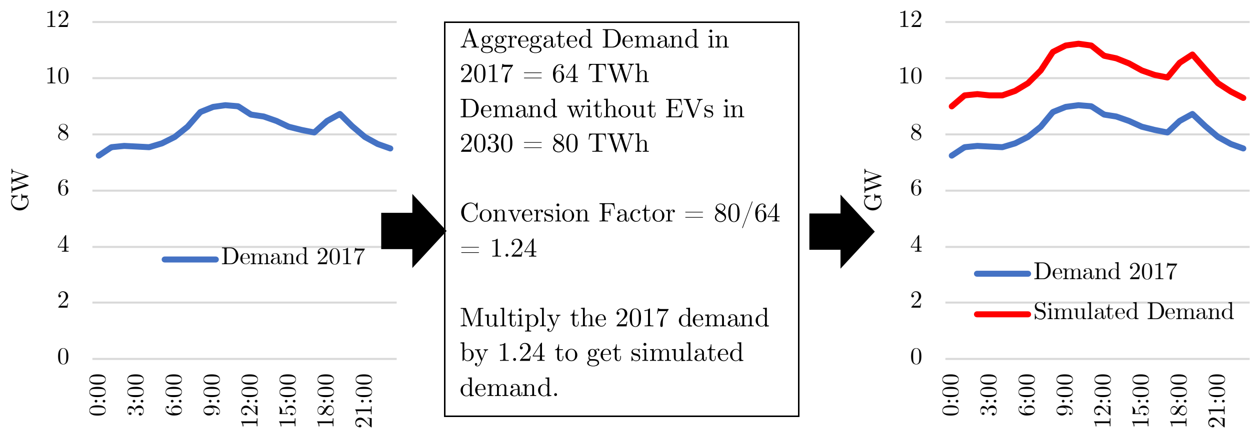


Figure 36: Example of scaling the 2017 demand according to the annual aggregated demand without EV charging in 2030. In this example the wished aggregated demand without EV charging is 80 TWh. The conversion factor multiplies the historic demand to reach the simulated demand in 2030.

3.1.1.1 Limitations

The main limitation of this approach for simulating demand without EV charging in the future is that we implicitly assume that the shape of the demand curve stays similar in the future compared to 2017. Scaling the demand by multiplying the time series by a single conversion factor acts on yearly aggregates and does not change the hourly patterns of demand: The maxima and minima in 2017 will stay respectively maxima and minima after scaling.

This method thus does not include potential changes in the shape of the demand curve. It is reasonable to consider that the increases or decreases in demand per capita will not simply shift the demand curve but also modify the daily patterns of demand. Our methodology reflects the shift of the demand curve but any source of change of the shape of the demand curve like the modification of electricity consumption habits or demand management systems are not considered. To sum up, our method is valid as long as we consider that the electricity consumption curve without EV charging in the simulated year is similar to the consumption curve in 2017.

What we consider to be the biggest contributor in the change of the shape of the demand curve in the future is the effect of Electrical Vehicle charging.

3.1.2 Demand from Electrical Vehicle Charging

Electric vehicles are more and more popular in Europe, in the USA and China. They are promoted as a potentially clean mode of transportation, provided the source of electricity is low in carbon emissions. The statistics show that the share of EV in new registrations and in car fleets are on the rise (Bloomberg New Energy Finance, 2017; McKinsey, 2017). In addition to revolutionizing an industry, electric vehicles are going to greatly impact electricity systems (Carlos & Morcos, 2003; Lopes, 2011). The electric demand from EV charging will not only generally increase overall demand, but also pose new challenges for transmission systems and modify the demand curve, as one could witness peaks of demand due to recharging of the batteries (Meng, et al., 2013; Mu, Wu, Jenkins, Jia, & Wang, 2014). We therefore include predictions for EV penetration and its effect on the demand curve in our simulation of demand.

The EV charging load curve is obtained in the following way: First, we determine the future size of the EV fleet in Switzerland. Based on this EV fleet size, we then simulate the charging load following closely the procedure described in (Meng, et al., 2013).

3.1.2.1 Simulating the Size of the future Electrical Vehicle Fleet

The determination of the size of the future EV fleet is based on a simple stock flow model for passenger cars (Fridstrøm, 2016). It relies on two main components: the evolution of the size of the total car fleet and the share of EVs in new registrations.

In this project we consider solely Battery Electrical Vehicles (BEVs) and non-Battery Electrical Vehicles. Plug-in Hybrids and Hybrid Electrical Vehicles are considered as non-BEVs and hence do not contribute to electricity demand in the model.

Evolution of the total car fleet size

For determining the total car fleet size in Switzerland in the future, we multiply the population forecast from the SFOS (SFOS, 2015, a) by the average number of cars per person in Switzerland in 2017. We obtain this second number by dividing the size of the car fleet from the SFOS (SFOS, 2019) by the population size in 2017. The number of cars per persons in 2017 was 0.54. Looking at the evolution of the average number of cars per person in Switzerland in Figure 37 we observe a slowing in the growth rate starting in year 2013. We assume that the development of public transports as well as the population and resulting urbanization growth will lead to a stabilization of the number of cars per persons and therefore consider the number of cars per persons in 2017 to stay unchanged until 2050. The results of the simulation of the total car fleet can be seen in Figure 38.

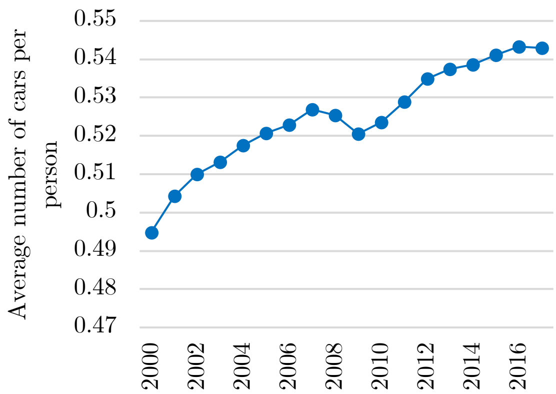


Figure 37: Evolution of the average number of cars per persons in Switzerland. Data from total car fleet and population size obtained from the SFOS

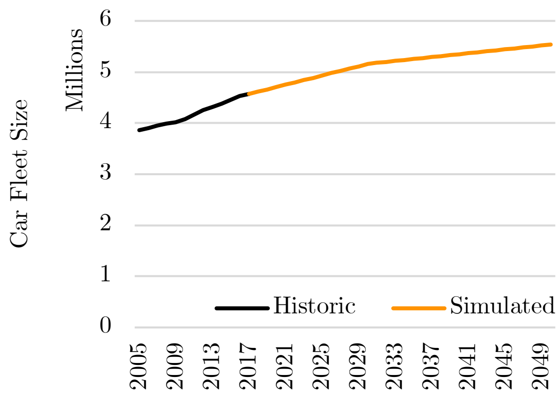


Figure 38: Historic and simulated total car fleet in Switzerland

After obtaining total car fleet sizes every year, we derive the BEV fleet size for the year of interest by making assumptions on the evolution of the share of BEVs in new registrations (the assumptions are presented in Chapter 3). The estimation for the number of BEVs over the years follows a simple car stock flow model (Fridstrøm, 2016). Each year, the BEV and non-BEV (that is Internal Combustion Engine cars (ICE) and others) car stocks are equal to the previous year's one plus the newly registered vehicles, minus the retired vehicles on the current year (see Equation 4).

$$Fleet_{BEV,t} = Fleet_{BEV,t-1} + Registrations_{BEV,t} - Retired_{BEV,t}$$
$$Registrations_{BEV,t} = 7\% \times Fleet_{Total,t} \times Share\ in\ New\ Registration_{\boldsymbol{BEV},t}$$
$$Retired_{BEV,t} = Share\ in\ Fleet_{BEV,t-1} \times (Fleet_{Total,t} + Registrations_{Total,t} - Fleet_{Total,t-1})$$

Equation 4: Car stock flow model for simulating the size of the BEV car fleet. t is the year, t-1 means the previous year.

It is assumed that every year 7.1% of the fleet is renewed. This corresponds to the average renewal numbers for the period 2005-2017 as given by the SFOS (SFOS, 2015, b). No difference in lifetime between BEV and non-BEV is considered.

Each year, the number of retired cars is calculated in order for the total stock, after adding the new registrations, to be equal to the simulated total stock given in section 3.1.2.1. A gross number for retired cars is calculated, it oscillates between 5 and 7% of the car fleet. This number is then split into BEV and non-BEV retired cars. The share of retired BEVs and non-BEVs is proportional to the share in the previous year's car fleet.

This simple method gives us estimation for BEV and non-BEV shares in the total fleet every year. A summary of the method is shown in Equation 4. With the size of the BEV fleet, we can calculate the charging load due to EV charging.

Sensitivity Analysis

The next step is to analyze how much the simulated BEV fleet depends on our assumptions. We perform a sensitivity analysis, where we vary three main assumed quantities: the number of cars per capita after 2017, the population size until 2050 and the renewal rate, i.e. the percentage of the total car fleet renewed each year. We analyze how much their variation affects the size of the BEV fleet in 2030 and 2050. The results can be seen on the tornado diagrams in Figure 39 and Figure 40. A tornado diagram should be understood as follows: For instance, for a fixed variation of the number of cars per capita (plus 20% in green or minus 20% in red), the top bars shows the corresponding variation in BEV fleet in 2050.

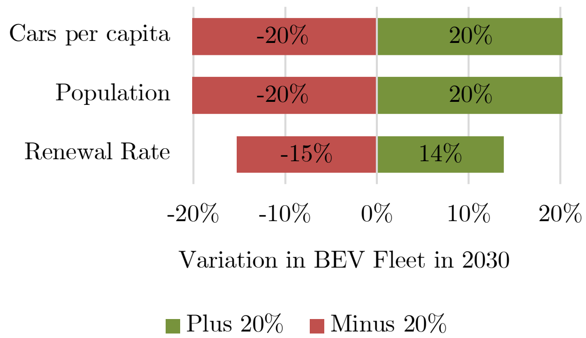


Figure 39: Tornado diagram presenting the sensitivity of the BEV simulated fleet in 2030 to variations of the cars per capita, population and renewal rate.

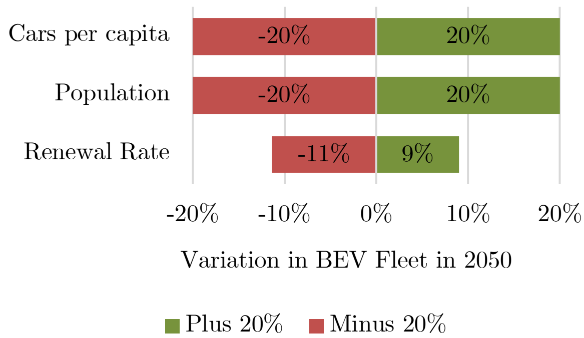


Figure 40: Tornado diagram presenting the sensitivity of the BEV simulated fleet in 2050 to variations of the cars per capita, population and renewal rate.

We observe that the assumptions of average number of cars per capita and population size are determinant of the BEV fleet in 2030 and 2050 as varying them by plus or minus 20% results in a variation of the BEV fleet of exactly plus or minus 20%. Additionally, the annual fleet renewal rate assumption plays an important role. If the rate is high, we witness the effects of the increasing BEV share in new registration on the total car fleet quicker than when the car renewal rate is low.

Limitations

The stock flow model gives estimations of the number of passenger-BEVs and non-BEVs over time. It relies on three main assumptions, whose effect we looked at in the previous section. The sensitivity analysis tells us that the population, average number of cars per capita and the renewal rate assumptions can all have a large and direct impact on the simulated BEV car fleet model.

By keeping the average number of cars per capita constant at 0.54, we are restricting the model to a future in which individual habits for mobility are similar to 2017. Moreover, considering a constant renewal rate as we do does not encompass a potential difference in lifetime between BEVs and non-BEVs. Finally, by excluding Plug-in Hybrids EVs and Hybrid Electrical Vehicles from the penetration model, we take a shortcut. The obtained BEV car fleet should be interpreted as a BEV-equivalent car fleet. The number of BEV-equivalent cars would in reality correspond to only a share of BEVs with some PHEVs and HEVs that, in sum, would correspond to the simulated BEV car fleet in terms of electricity consumption. A disambiguation between BEV, PHEV and HEV would allow us to refine the penetration model.

3.1.2.2 Simulating the Charging Load

After having obtained a size of the BEV car fleet, we generate charging load for BEV based on the method described in (Meng, et al., 2013). A fleet of the correct size is created, then, for each car in the fleet an individual driving pattern and daily charging load are simulated. The charging load is copied 365 times in order to obtain a yearly time series. These are then aggregated in order to obtain a charging load for the complete BEV fleet.

We start with the determination of characteristics of the car, namely its electric efficiency. Instead of specifically implementing different vehicle types, we randomly pick, for each EV, an electric efficiency, which is uniformly distributed between 4.88 and 6.59 km per kWh. Those numbers come from test performed by the American Environmental Protection Agency (EPA) for the labelling of newly registered EVs in 2017 (EPA, 2019). All the registered vehicles have electric efficiencies in the range of4.88 and 6.59 km per kWh. For this model, we assume that future BEV will have efficiencies within this range.

$$electric\ efficiency \sim \mathcal{U}(4.88\,\frac{km}{kWh}, 6.59\,\frac{km}{kWh})$$

We continue with the simulation of a daily travel range, which follows a normal distribution. The mean of the normal distribution is 23.8 km, which is the average distance driven by Swiss people per day in 2015 (SFOS, 2015, b). The standard deviation is chosen to be 10km.

$$daily\ range \sim \mathcal{N}(24km, 10km)$$

The number of kilometers travelled are divided by the electric efficiency of the car in order to obtain a daily electricity consumption. It is assumed that the battery discharges linearly with the number of kilometers travelled.

The BEVs are charged daily and in one stretch as in (Mu, Wu, Jenkins, Jia, & Wang, 2014; Meng, et al., 2013). The amount of electricity charged is equal to the electricity consumed during the day. The charging power is equal to the maximal BEV power acceptance rate of 7.2 kW. This value of 7.2 kW is the median of the EV power acceptance rate of the available BEV models in the US in 2017[5]. This quantity is considered to remain constant in the future.

We can now obtain a daily charging duration by dividing the daily consumption by the maximum EV power acceptance rate (the maximal power at which BEVs can be charged).

$$charging\ duration\ [h] = {}^{daily\ consumption\ [kWh]}\!\Big/_{EV\ power\ acceptance\ rate\ [kW]}$$

[5] : https://www.clippercreek.com/, extracted data from manufacturer's websites

Note that the lowest time resolution is hourly. The charging duration is rounded to the closest integer (always rounded to one in case the duration is lower than one hour).

Finally, we need to choose the moment at which each car starts to be charged. This is done by choosing one of the two charging strategies: "evening" or "night" charging. The probability of using either strategy is 50% for each car.

The strategies differ in the following way: The evening charging describes a charging strategy where drivers start charging their car at the end of the day. The starting time in the evening charging strategy follows a normal distribution centered around 18:00 with standard deviation of 4 hours. The night charging strategy is similar to the evening one, the only difference is that the starting time of charging is centered around 1:00 in the morning with a 5 hours standard deviation.

$$\begin{cases} starting\ time_{evening} \sim \mathcal{N}(18{:}00, 4\ hours) \\ starting\ time_{\mathrm{night}} \sim \mathcal{N}(1{:}00, 5\ hours) \end{cases}$$

After having randomly picked a charging strategy for each EV, the starting time of charging is randomly generated according to the corresponding normal distribution. The finishing time is obtained by adding the charging duration to the starting time.

This methodology allows us to create a BEV charging load depending on the BEV stock for a typical day. The simulated typical day is repeated 365 times in order to create the BEV charging load for the year as illustrated in Figure 41.

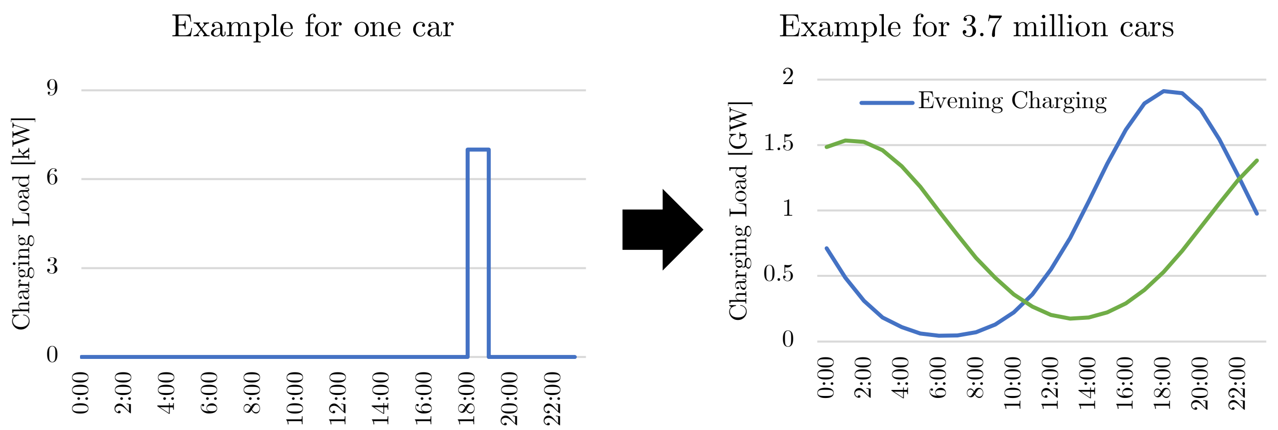


Figure 41: Example of the working of the EV charging model. A charging load for each car is created and then aggregated.

3.1.2.3 Sensitivity Analysis

We continue with a sensitivity analysis of the BEV charging model. For a given BEV stock, we analyze the contribution of our five main parameters on the maximum BEV charging load and the aggregate BEV charging load. The five parameters are the maximum and minimum electric efficiencies, the average daily range, the maximum charging power and the probability of each EV to use the evening charging strategy. We here assume that the parameters are independent.

We vary each parameter, while the others are kept constant, and run the charging load simulation, from which we extract the aggregate charging load (in TWh) and the maximum charging load (in MW). We then compare these two quantities to the reference case with all parameters having their initial values, and obtain the deviation from reference, in percent. We choose run the model with a BEV stock of 2.1 million. The results are shown in Figure 42 for the maximal and in Figure 43 for the aggregate charging load.

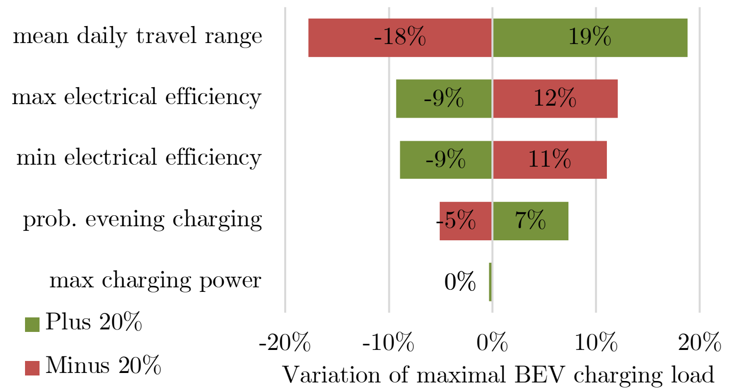


Figure 42: Tornado diagram presenting the sensitivity of the maximal BEV charging load on the model parameters. The simulation was run for 2.1 million BEVs.

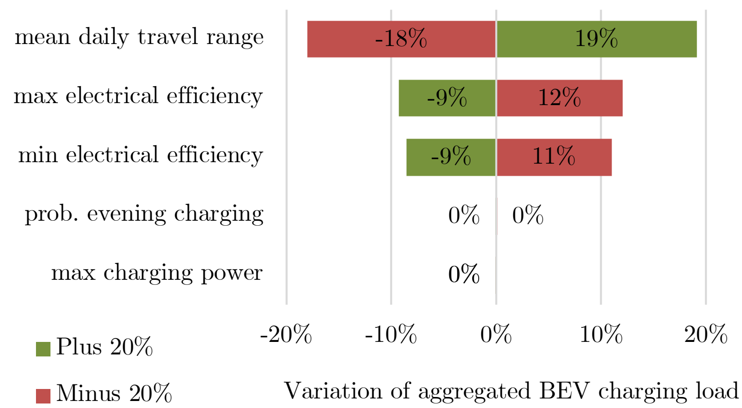


Figure 43: Tornado diagram presenting the sensitivity of the aggregate BEV charging load on the model parameters. The simulation was run for 2.1 million BEVs.

The main determinant of the maximal and aggregate EV charging load is the average daily travel range. A 20% increase in mean daily travel range leads to a 19% increase in the maximal EV charging load and 19% increase of the aggregate charging load. Conversely, a 20% decrease leads to a 18% decrease in the maximal load and a 18% decrease in the aggregate load.

Increasing the maximal electrical efficiency, the maximal number of km that each kWh allows to drive, will decrease the maximal charging load as well as the aggregate load, as it influences the electricity consumption. The higher the electrical efficiency, the lower the consumption, in this case, a 20% increase in the maximal efficiency leads to a decrease of

9% of the maximal and aggregate load. Note that it is only 9% and not 20% because, the electrical efficiency of each EV is randomly drawn between the minimum and the maximum, increasing the maximum by 20% in our case increases the average electrical efficiency by only 4%. The same reasoning can be applied to the minimal electrical efficiency, whose effect is similar to the maximal electrical efficiency.

The probability to use the evening strategy unsurprisingly has no effect on the aggregate charging load as it only influences when EVs are charged and not by how much. As the evening strategy has a smaller standard deviation than the night strategy, increasing the probability to use the evening strategy will increase the maximal load, as more EVs will be charging at the same times. An increase of the probability from 50% to 60% (that is indeed 20% more in relative terms), leads to a 7% increase in the maximal charging load. A decrease from 50% to 40%, which means there is about 60% night charging and 40% evening charging decreases the maximal load by 5%.

It is surprising to observe that the maximal charging power does not influence the maximal charging load. This is due to the fact that the maximal charging power's original value is 7 kW and that the average daily consumption of EVs that arises from the daily traveled range and the electrical efficiency is in average between 4 and 5 kWh. As long as the maximal charging power stays above this average, its effect on the maximal load will stay almost zero, as the lowest resolution of the model is hourly.

We should keep in mind that, as the model is probabilistic, we observe small deviations when running the same simulation several times, and it explains a part of the asymmetries observed on the two above Figures. However, as we chose an EV stock of two million, there are enough EVs in order for the law of large numbers to play its role in making the differences between two simulations small.

3.1.2.4 Limitations

We address here the main limitations of the methodology used for simulating the BEV charging load. First of all, all of the parameters used in section 3.1.2.2 stay constant over time, that is we use the same parameters for 2030 and 2050 as in 2017. By keeping the electric efficiency range and the power acceptance rate constant, we exclude the effect of the evolution of the current technology on the EV charging load. Secondly, we consider only two charging strategy with none of those having an average starting time of charging in the middle of the day, which might be an optimal strategy in a future with a lot of solar PV power generation. Thirdly, the charging load for a typical day is simulated and repeated every day of the year, no difference is made between week days and weekends. Finally, the model would gain in accuracy by reducing the time resolution from hourly to a lower one.

3.2 Simulating Supply

After simulating demand, we turn to supply. The supply model does not contain feedback loops. The non-dispatchable supply sources are set first, then, the hydro dam production, followed by the thermal controllable supply sources, the storage model, and finally imports. The resulting merit order is shown in Table 13.

	Merit Order	*Strategy*
Nuclear	1	Non-Dispatchable
Waste Incineration		
Run-of-River		
Solar		
Wind		
Hydro Dam	2	Profit Maximizing
Thermal Dispatchable	3	Deficit Minimizing
Storage	4	
Imports	5	Fill Deficit

Table 13: Merit order for the simulation of electricity supply. In the thermal dispatchable sources we include biomass, biogas and combined-cycle gas turbines.

The leading constraints of the model are chosen to be physical rather than economic. In all of the technologies except hydro dam, the cost does not intervene. The supply model gives insights about what is physically feasible when one aims to minimize imports.

3.2.1 Non-dispatchable Supply Sources

The electricity production arising from run-of-river, solar PV, wind, waste incineration and nuclear are considered to be non-dispatchable. For solar PV, wind, run-of-river and nuclear, we simulate the future production by scaling up or down the 2017 reconstructed time series. The whole time series is multiplied by a single, annual correction factor. This correction factor is either the ratio of installed capacities or the ratio of yearly production. As an example, assume we predict the solar capacity to double by 2030. In order to obtain the time series of solar electricity production in 2030, we would multiply the 2017 reconstructed time series of solar production by two.

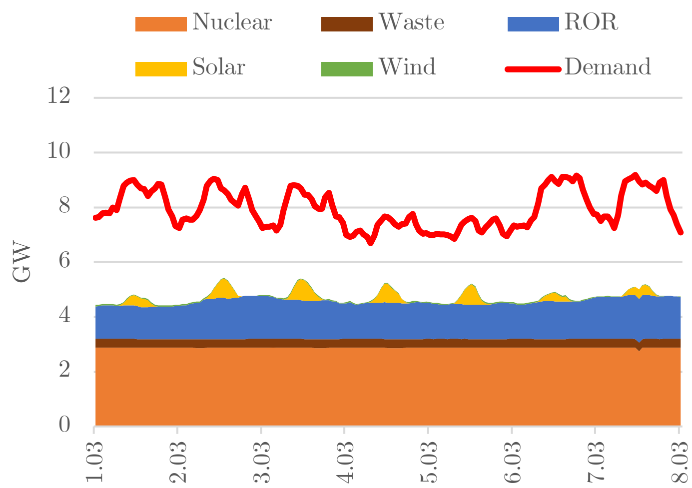


Figure 44: Supply model running example for the first week of march 2017. The power capacities for this example are those of 2017.

For waste incineration, due to the absence of time series for this technology in the ENTSO-E database and consequently in our reconstructed data, we generate a baseload based on the installed capacity and assumed a capacity factor of 75%.

Figure 44 shows an example of the workings of the supply model for the first week of March 2017. The demand is simulated first, then, the non-dispatchable electricity sources are stacked.

3.2.1.1 Reference Year for Nuclear, Run-of-River, Solar and Wind

For non-dispatchable supply sources we choose to scale reference time series. For run-of-river, solar and wind the reference time series are those of production in 2017.

The year 2017 benefitted from above average exposure to sunlight. The amount of sunshine reached 110% to 145% of the 1981-2010 averages measured from Meteoswiss (Meteoswiss, 2017). This translated into the 10% annual solar PV capacity factor in 2017, while the 2010-2016 average was 9% (SFOE, 2017, c). 2017 was also a comparatively good year for wind production, the average annual capacity factor between 2010 and 2017 was 17%, compared to 20% in 2017 (SFOE, 2017, c). Run-of-river production was however slightly under average in 2017, with a capacity factor of only 45% compared to the average 49% between 2010 and 2017 (SFOE, 2017, c). The biggest discrepancy between the year 2017 and the averages lies in the nuclear production.

The Swiss nuclear power plants have produced 19.5 TWh electricity in 2017, with 3333 MW of electric power installed (SFOE, 2018, b). It corresponds to a capacity factor of 67% which is low for nuclear compared to the previous years. The exceptional shutdown of Beznau 1 during the whole year, as well as the extended maintenance of Leibstadt during several months are responsible for this reduced activity in 2017. As a point of comparison, in the previous 9 years (from 2008 to 2016), the average capacity factor was 86%.

Before scaling the 2017 nuclear production curve, we create an average nuclear production curve which consists in the 2017 curve to which we add a baseload of 1220 MW (the capacity of Leibstadt) for the months of January, October and November, when Leibstadt was off, and a baseload of 220 (60% of the capacity of Beznau 1) for the whole year. In doing so, the annual nuclear capacity factor is 86%. This is to adjust for the exceptional circumstances that existed in 2017 for Swiss nuclear supply.

3.2.1.2 Limitations

In scaling up and down the production time series of 2017, we are constraining our analysis to future years which are similar to 2017, especially in terms of weather conditions. Moreover, by calculating the conversion factor, solely with a ratio of installed capacities or annual aggregated production, we also assume that the capacity factors of the technologies are going to stay identical in the future compared to 2017.

3.2.2 Hydro Dam Model

After having set the non-dispatchable supply sources, we turn to hydro dam production which is dispatchable. Electricity production from hydro dam is assumed to follow a profit maximization strategy.

Our model relies on the spot prices of electricity from the intraday power market as reported by EPEX SPOT SE, the operator of physical short-term electricity markets in Central Western Europe[6].

The hydro dam production is set to follow the price of electricity, under the physical constraints of the system. The hourly production should be lower than the maximal power capacity, but also higher than the lower operating limit of 500 MW (determined empirically from the 2017 reconstructed hydro dam time series). Finally, the electricity production should be lower than the amount of energy stored in the water reservoirs.

In a first step, an artificial bid price is created by deducting 5€ from the EPEX spot price of electricity in Switzerland.

$$bid\ price_{t,2017} = EPEX\ intraday\ continuous\ spot\ price_t - 5€$$

Equation 5: Assumption for 2017 bid price of electricity in Switzerland

Following a profit maximization strategy from a producer point of view means that when the marginal cost (MC) of hydro dam production is lower than the bid price of electricity in the market, the hydro dams produce electricity, under the aforementioned constraints. The marginal cost of hydro production we use is 9.1 €/MWh (EIA, 2017)[7]. In order to determine how much electricity is generated when the MC is lower than the bid price, we rely on a linear response function with parameters (A, β). The quantity of electricity produced at time t and month M when the MC is lower than the bid price is shown in Equation 6.

$$quantity\ of\ electricity\ produced_{t,M} = A_{t,M} \times (bid\ price - MC)^{\beta_{t,M}}$$

Equation 6: Quantity of electricity produced when the MC is lower than the bid price at time t and month M.

3.2.2.1 Determining the Parameters (A, β)

We choose to generate a parameter pair for each month, in order to grasp the monthly and seasonal differences of the production curves. We therefore have 12 parameter pairs (A, β), one pair for each month. The determination of the parameters of the linear response function works as follows: For each month, the Euclidean distance between the simulated production and the reconstructed hydro dam production is minimized by changing the parameter pair (A, β), under the constraint that the simulated aggregated monthly

[6] https://www.epexspot.com/en/market-data/elix

[7] The quantity given by EIA is corresponds to Operation and Maintenance costs in USD per kWh, we applied the 2017 average exchange rate between USD and EUR to obtain a quantity in EUR per kWh.

production is higher or equal to the historic hydro dam production. minimization is carried out with the 2017 power capacity.

The resulting parameter pairs (A, β) minimize the difference between the simulated and the reconstructed hydro dam productions for the year 2017. The values for the parameter pairs (A, β) are given in appendix C.

3.2.2.2 Simulating Future Production

The parameters of the model are the twelve pairs (A, β), the time series of bid price, a marginal cost of hydro dam electricity production, the minimal operating capacity, the reservoir size and the turbine capacity. The twelve pairs (A, β), the marginal cost and the minimal operating capacity are assumed to stay constant over time.

In order to simulate future hydro dam generation, we give future reservoir size and turbine capacity as inputs to the model as well as a modified time series of bid price. We modify the time series of bid price in order to account for the increasing future production of solar electricity and its effect on electricity price. The effect of solar generation on the bid price follows a simple heuristic: In the future, the bid price is assumed to decrease proportionally to the solar generation, but not more than 10€ compared to 2017. The assumed future bid price at time t and year Y is given in Equation 7.

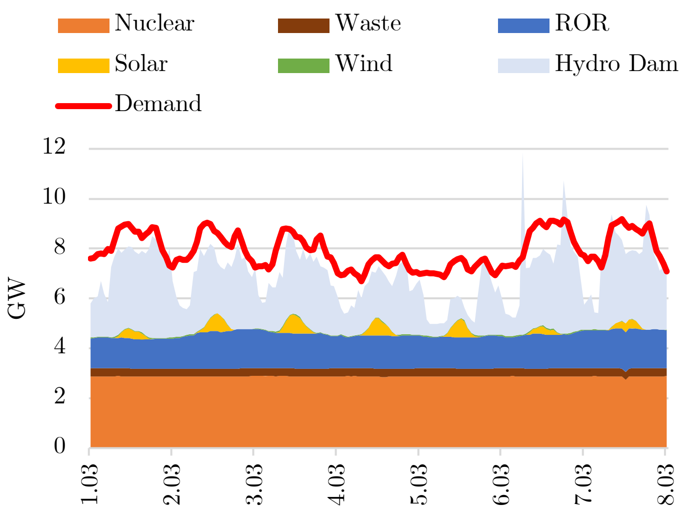


Figure 45: Supply model running example for the first week of march 2017. The power capacities for this example are those of 2017. The hydro dam production, with merit order 2, is stacked on the dispatchable supply sources.

$$future\ bid\ price_{t,Y} = bid\ price_{t,2017} - \left(10\ € \times \frac{solar\ generation_{t,Y}}{\max solar\ generation\ in\ year\ Y}\right)$$

Equation 7: Future bid price of electricity in Switzerland

The resulting production from the hydro dam model is shown in Figure 45 where the hydro dam production is stacked on the non-dispatchable production.

3.2.2.3 Measures of fit

We quantify how reliable the simulated hydro dam production is by looking at measures of fit between the 2017 simulated and reconstructed time series. We ran the simulation with the 2017 input parameters given in appendix C. The Mean Absolute Percentage Error (MAPE) between the simulated and the reconstructed hydro dam production is 40%. The Mean Percentage Error (MPE) is however lower at 8%. This suggests that the errors tend to average out over the year with some overproduction and some underproduction. The hourly breakdown of the error is displayed in Figure 46 where the average difference between the simulated and the reconstructed hydro dam production is shown.

The simulated data is on average higher than the reconstructed data early in the morning (between midnight and 6 am.) and in the middle of the day (between 12 am and 16 pm). Those are moments of the day where demand was generally low in 2017. The simulated data leads to underproduction at the demand peak times, that is between 7 am and 11 am and between 17 pm and 20 pm, but this is also when the standard deviations are the biggest.

The simulated aggregated annual production is equal to the reconstructed one, as it is one of the constraints of the model. Without this constraint, it is possible to reach values for the MAPE between reconstructed and simulated production as low as 34% but this leads to a general underproduction in the simulated data.

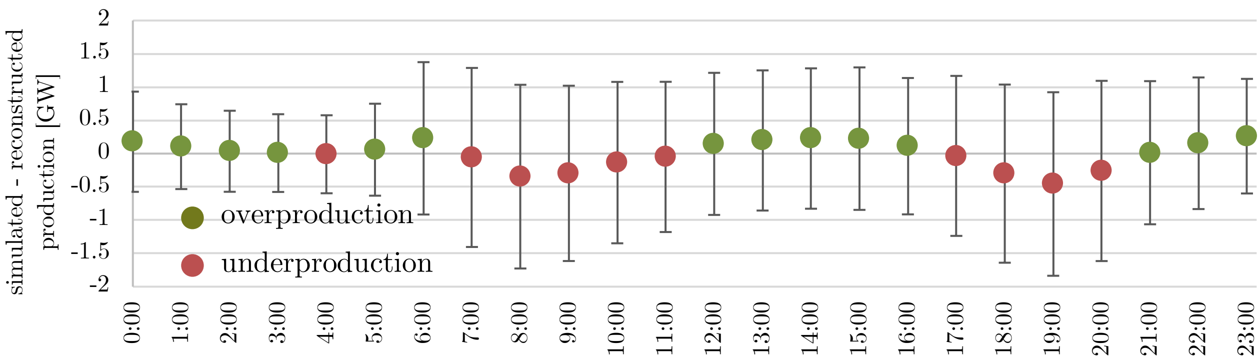


Figure 46: Difference between simulated and reconstructed hydro dam production, averaged over the whole year 2017, shown in an hourly resolution. Positive values mean that the simulated production is in average above the reconstructed one.

3.2.2.4 Sensitivity Analysis

We continue by outlining how sensitive the model is to three main assumptions: the marginal cost, the bid price and the minimal operational capacity. The sensitivity of the model to the parameters (A, β) is shown in appendix C.

Figure 47 shows the effect of the marginal cost, bid price and minimal operational capacity on the total production of electricity in 2017. The bid price has unsurprisingly the largest effect, as the time and quantity of the production is determined by its value. The marginal cost comes only second and we see that our assumption of 9.1€/MWh is determinant as it also directly affects the time and quantity of electricity produced.

Figure 48 shows the effect of those three assumptions on the MAPE between the 2017 simulated and reconstructed hydro dam production. We see similar sensitivities to the bid price and marginal cost. Note that increasing the marginal cost or the minimal capacity also decreases the MAPE which shows that our choice of parameter pairs (A, β) is suboptimal.

This is due to the fact that by reducing the marginal cost or the minimal capacity the yearly simulated production decreases, which our minimization does not allow as we have as constraint that the aggregated simulated production should not be lower than the reconstructed one.

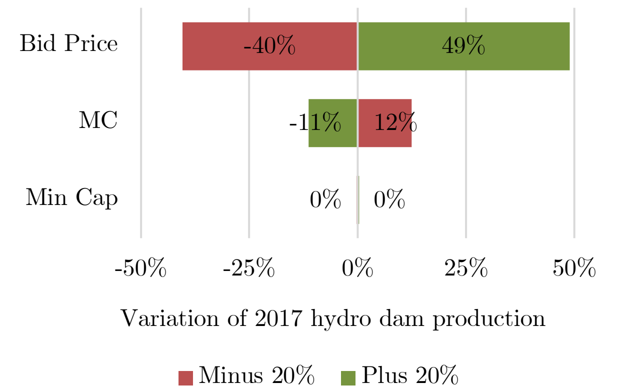


Figure 47: Tornado diagram presenting the sensitivity of the yearly aggregated simulated production on variations of the bid price, marginal cost and minimal operational capacity. MC stands for Marginal Cost, and Min Cap for Minimal operational capacity.

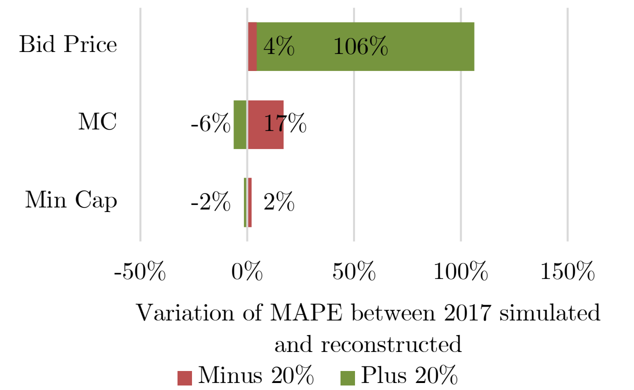


Figure 48: Tornado diagram presenting the sensitivity of the MAPE between the 2017 simulated and reconstructed hydro dam time series on the bid price, marginal cost and minimal operational capacity. MC stands for marginal cost, and min cap for minimal operational capacity

3.2.2.5 Limitations

We finish the description of the hydro dam model by mentioning its main limitations. First of all, the reliance on a linear response function with parameters is a simplification. In reality, the quantities of electricity produced by the hydro dam producers are dictated by the market structure and the market power of each operator. With the linear response function, we bypass the market power considerations and fit our model to a 2017 template. By keeping the twelve pairs (A, β) constant over time we are assuming that the market power structure in the future is identical to 2017. Additionally, we are assuming that the weather conditions leading to the 2017 production stay constant as the parameters are fitted to match the 2017 production and are then kept constant.

Furthermore, we do not update the marginal cost of hydro dam production over time. Also, apart from the effect of solar production on bid price, we keep the time series of bid price constant over the years.

Finally, endogenous effects of the change of electricity mix and hence of production curves on the bid price of electricity are restricted to a simple adjustment accounting for the growth of solar PV. This is the main limitation of the hydro dam model as the bid price of electricity as the biggest determinant of hydro dam production in our model.

3.2.3 Dispatchable Thermal

After having set the dispatchable supply sources and the hydro dam production we turn to the first of two dispatchable supply categories: the dispatchable thermal production which has merit order 3. In the dispatchable thermal category, we consider biomass, biogas, and combined-cycle gas turbines (CCGT).

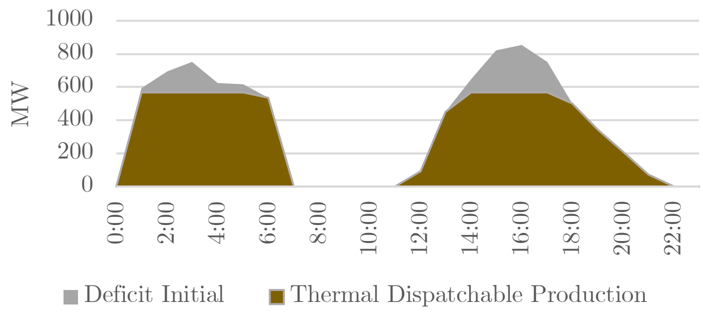


Figure 49: Example of the working of the dispatchable thermal model with 568 MW of installed capacity

The strategy for electricity generation is deficit minimizing[8]. The difference between the demand and the production from the non-dispatchable sources and the hydro dam power plants is calculated, and a time series of electricity deficit is created. The thermal controllable production aims to fill the deficit constrained by its available power capacity. An example of the functioning of the thermal dispatchable model is shown in Figure 49.

The thermal production matches the deficit as long as the deficit is lower than the installed thermal capacity. When the deficit is larger, the thermal dispatchable supply sources work at full capacity. In Figure 50, the dispatchable thermal production is stacked on the non-dispatchable and hydro dam production. It fills the deficit between demand and production sources with a lower merit order up to the dispatchable installed capacity. When there is no deficit, there is no dispatchable thermal production (see on the 6.03).

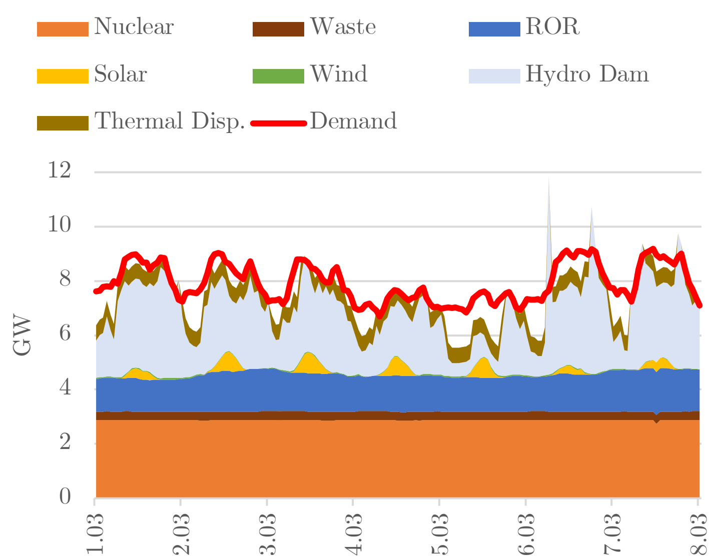


Figure 50: Supply model running example for the first week of march 2017. The power capacities for this example are those of 2017. The dispatchable thermal production fills the deficit left after the hydro dam production.

3.2.3.1 Limitations

In making the production match the deficit, we assume that dispatchable thermal technologies have a sufficiently high flexibility and response rate in order to match the deficit, i.e. that the ramp rate is high enough in order not to be a limiting factor. Finally,

[8] There is a deficit when the electricity production is lower than the demand.

there are no cost considerations in this method, it could be that this production profile leads to monetary losses for the power producer.

3.2.4 Stationary Electricity Storage

We now turn to the electricity storage model which is fourth in the merit order. The surpluses and deficits remaining after setting the non- dispatchable supply sources, the hydro dam production and the dispatchable thermal sources are used as inputs for the storage model. The electrical storage strategy is to minimize the deficits and the surpluses. It does so by using a load shifting strategy. We go over other potential strategies in appendix D.

In our load shifting strategy, the storage capacities are cycled on daily basis. The application is similar to the "Renewable energy integration application" described in (Malhotra, Battke, Beuse, Stephan, & Schmidt, 2016). The idea is to store excess generation and discharge the storage during deficit hours. By doing so, the storage model effectively minimizes exports and imports and helps avoid curtailment in case of large excess of production. A schematic view of this strategy can be seen in Figure 51. Note that Figure 51 illustrates a situation where the installed power and storage capacity is sufficient to shift the whole surplus.

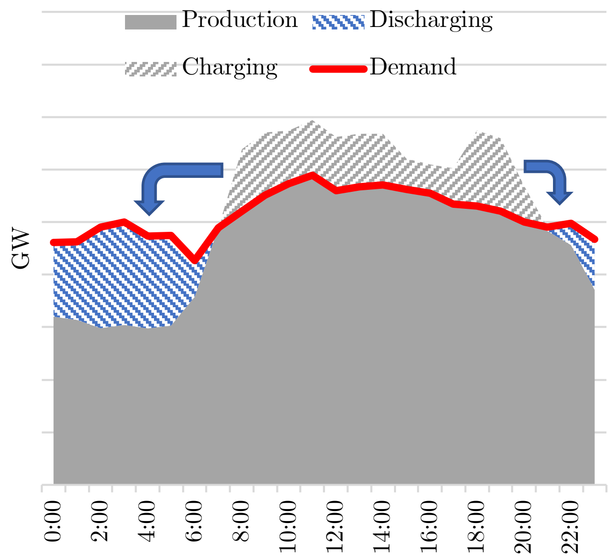


Figure 51: Load shifting strategy for electricity storage

We consider two storage technologies: pumped hydro and lithium ion batteries. Both technologies are simulated individually and both are adequate for a daily load shift strategy (Abdon, et al., 2017). For simplification, we model the Swiss pumped hydro plants as one large plant and the swiss lithium ion batteries as only one large battery. It means that we rely on one charging power, one discharging power and one storage size per technology.

We present the model through its constraints in Box 3. The goal of the storage model is to shift as much surplus in the deficit hours as possible (Constraint 1). It does so on a daily basis without creating new surpluses or deficits, but by minimizing the existing ones (Constraint 2). In order to maximize utilization of the model, the storage level at the end of the day lies between 15% and 85% of the total storage capacity (Constraint 3). This is imposed to make sure that there is always enough electricity in storage and enough storage available in order to perform a load shift on the upcoming day. Note that the storage level during the day can be under 15% and higher than 85% of the storage capacity, it is only its level at the end of the day which is constrained.

Constraint 1: Minimize surplus and deficit

- Charge if and only if there is a surplus
- Discharge if and only if there is a deficit

Constraint 2: Daily load shift

- The daily charged quantity is lower or equal to the total daily surplus
- The daily discharged quantity is lower than or equal to the total daily deficit

Constraint 3: Storage at the end of the day is neither full nor empty

- The storage level at the end of the day is lower or equal to 85% of the maximal storage capacity
- The storage level at the end of the day is higher or equal to 15% of the maximal storage capacity

Constraint 4: Minimize maximal surplus and deficit

- The charging time series minimizes the maximal surplus
- The discharging time series minimizes the maximal deficit

Constraint 5: Charging and discharging powers

- The hourly charged quantity is lower or equal to the available charging power
- The hourly discharged quantity is lower or equal to the available discharging power

Constraint 6: Storage level

- The hourly charged quantity is lower or equal to the storage available
- The hourly discharged quantity is lower or equal to the storage level

Constraint 7: Round-trip efficiency

- 1 MW charged during an hour leads to an increase of 1 MWh of the storage level
- 1 MW discharged during an hour leads to a decrease of $1/\eta$ MWh of the storage level

Box 3: Constraints of the daily load shift storage model

The model works on a daily rhythm. At the beginning of each day a quantity to charge and to discharge is set such that it meets the requirements of the first three constraints. After having set how much electricity should be charged and discharged, the model chooses the hours within the day at which it is going to charge and discharge. The hours and powers are chosen such that the maximal surplus and the maximal deficit during the day is minimized (Constraint 4). It means that the model will charge in priority when the surplus is the biggest. The hourly charging and discharging powers are constrained by the available powers (Constraint 5) and the storage level (Constraint 6). Note that the variations of the storage level depend on the round-trip efficiency of the storage technology (Constraint 7). A mathematical formulation of the algorithm is presented in appendix E.

Three working regimes

The storage model has three different working regimes: one regime if the storage level oscillates at the higher limit (storage level at the end of day is 85% of the storage capacity) which we call the high regime, one regime if it oscillates around the lower limit (storage level at the end of day is 15% of the storage capacity) which we refer to as the low regime and one regime when the storage level at the end of the day lies in between.

In the high regime, the model is directly constrained by the storage available. During a day where there is a large surplus but no deficit, the storage model will stay idle, because of the impossibility to discharge electricity during the day, due to the absence of deficit (Constraint 1) and hence the impossibility to respect Constraint 3 if the model charges nevertheless. In the low regime, during a day where there is a deficit but no surplus, the storage model will also stay idle, as it won't be able to charge to compensate the discharged electricity (Constraint 1). It also doesn't discharge because of Constraint 3.

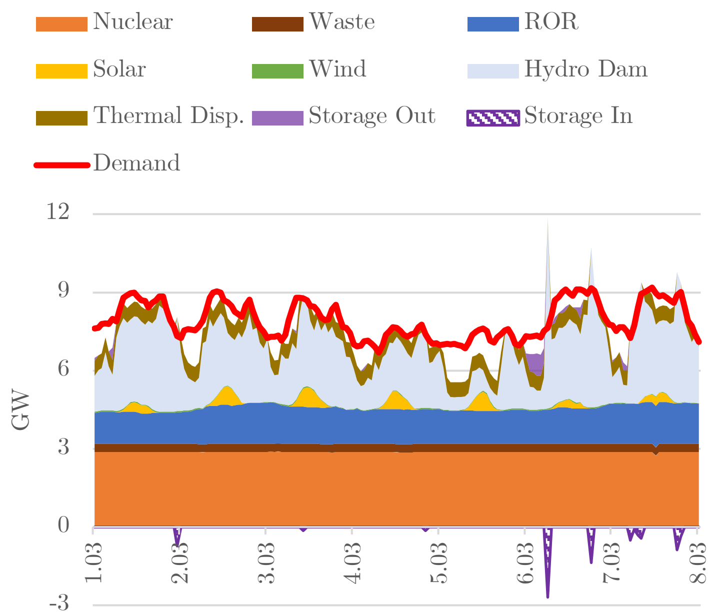


Figure 52: Supply model running example for the first week of march 2017. The power capacities for this example are those of 2017. The storage model charges the surplus and reduces the deficit.

Finally, the middle regime is the most unconstrained one. If the storage level at the end of day allows it, the model will eliminate all surpluses and deficits, provided the storage level as well as input and output power allow it (Constraints 4 and 5) until the model reaches the high or low regime.

These three regimes will typically correspond to three different times of the year. The high regime corresponds to summer, where Switzerland produces more electricity than it consumes, the low regime corresponds to winter, where Switzerland produces less than it consumes and finally the middle regime corresponds to Spring and Fall.

The storage model's workings for the running example of the first week of march can be seen in Figure 52. The model is in the low regime in March. It reduces the deficit before charging the surpluses on the 6th of March.

3.2.4.1 Example for 2017

We illustrate the functioning of the model by studying its effect on two days of the year 2017. The aggregated production and consumption time series taken to calculate the surpluses and deficits are from the 2017 reconstructed time series from Chapter 2.

In this section, only pumped hydro storage is used as we estimate the Swiss lithium ion battery capacity to be too small to be modelled in 2017. We show the results for two days, Monday the 9th of January where the aggregate deficit is higher than the aggregate surplus but neither is zero (Figure 53 and Figure 54), and the Monday August 21st where the aggregate deficit is lower than the aggregate surplus (Figure 55 and Figure 56).

In Figure 53 and Figure 54, the model is in the low regime. The maximal amount of stored electricity is constrained by the size of the surplus i.e. when the sum of the surplus over the day is lower than the sum of the deficit. The algorithm minimizes the surplus, effectively bringing it to zero in this case, and discharges the electricity at times where the gap is the largest, that is between midnight and 6 am. Before load shifting, the size of the gap is 29.1 GWh (with maximum 4.2 GW) and the size of the surplus 5.0 GWh (with maximum 1.2 GW). The model stores the whole 5.0 GWh and discharges 4.0 GWh at the peak gap hours. The difference between the stored and discharged quantities is explained by the 80% efficiency of pumped hydro storage (SFOE, 2018, b). After load shifting, the gap becomes 25.1 GWh (with maximum 3.2 GW) and the surplus 0 GWh.

In Figure 55 and Figure 56, the model is in the high regime. In this case, the maximal amount of stored electricity is constrained by the size of the deficit i.e. the daily deficit is lower than the daily surplus. The algorithm minimizes the surplus when it is maximal, that is between 6 am and 10 am, and 6 pm and 10 pm. The electricity stored is used to fill the deficit completely. Before load shifting the size of the deficit is 3.9 GWh (with maximum 0.8 GW) and the surplus is 24.8 GWh (with maximum 3.7 GW). The algorithm discharges 3.8 GWh to fill the deficit and charges 16.5 GWh, bringing the storage level at 79% at the end of the day. After load shifting, the daily deficit is 0 GWh and the daily surplus 8.2 GWh (with 0.6 GW maximum).

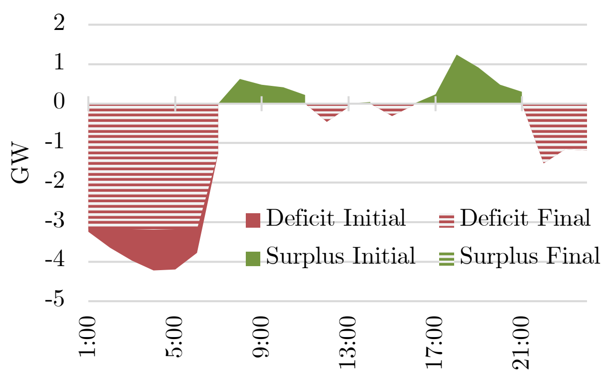


Figure 53: Effect of load shift on the 9th of January 2017, case where the aggregate surplus is lower than aggregate deficit

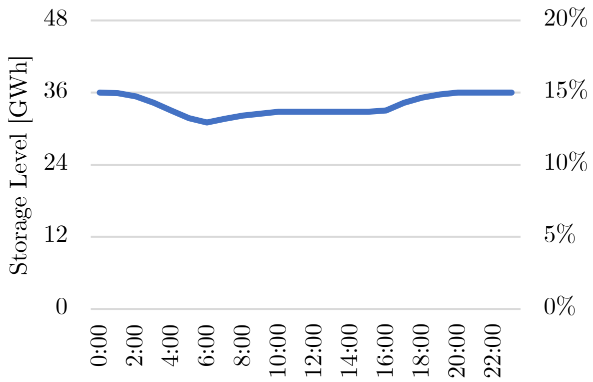


Figure 54: Storage level after load shift on the 9th of January 2017, case where the aggregate surplus is lower than the aggregate deficit

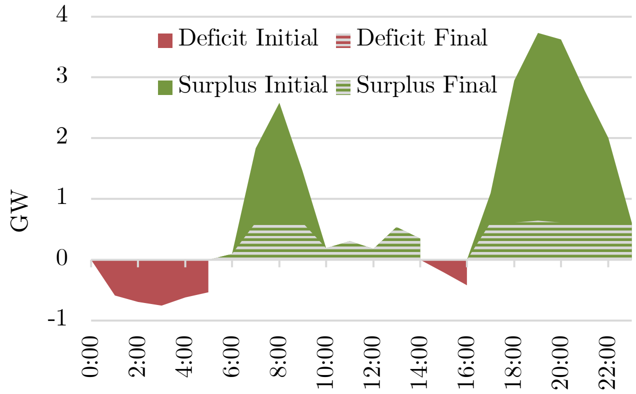


Figure 55: Effect of load shift on the 21st of August 2017, case where the aggregate surplus bigger than the aggregate deficit

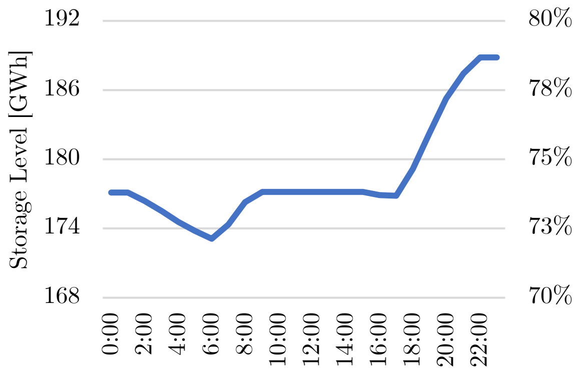


Figure 56: Storage level after load shift on the 21st of August 2017, case where the aggregate surplus is bigger than the aggregate deficit

We continue by looking at the whole year 2017. We show the evolution of storage level in Figure 57. The starting level of the accumulation lake was chosen to be 50.7% which is the average filling level of the whole reservoirs (hydro dam and pumped hydro) over the years 2017 and 2016 (SFOE, 2017, a).

The storage level takes value between 211 GWh (88% of max storage) and 17 GWh (7% of max storage). Over the whole year, 1.47 TWh are being charged and 1.24 TWh discharged, the inequality between the electricity charged and the electricity discharged is due to the round-trip efficiency, which in case of pumped hydro is 80% and to the different storage levels on the 1st of January and 31st of December.

In Figure 57, the storage level quickly drops to 15%, due to the presence of large deficits in electricity production in Switzerland in the Winter in 2017. It stays in the low regime until the end of April. At the end of spring, it charges up to 85% and evolves in the high regime. Finally, around the end of September, the Swiss production declines again leading to larger deficits than surpluses, and the storage level drops to 15%, going back to the low regime. Note that the pumped hydro reservoirs start 50.7% full on the first of January and finish 15% full on the 31st of December.

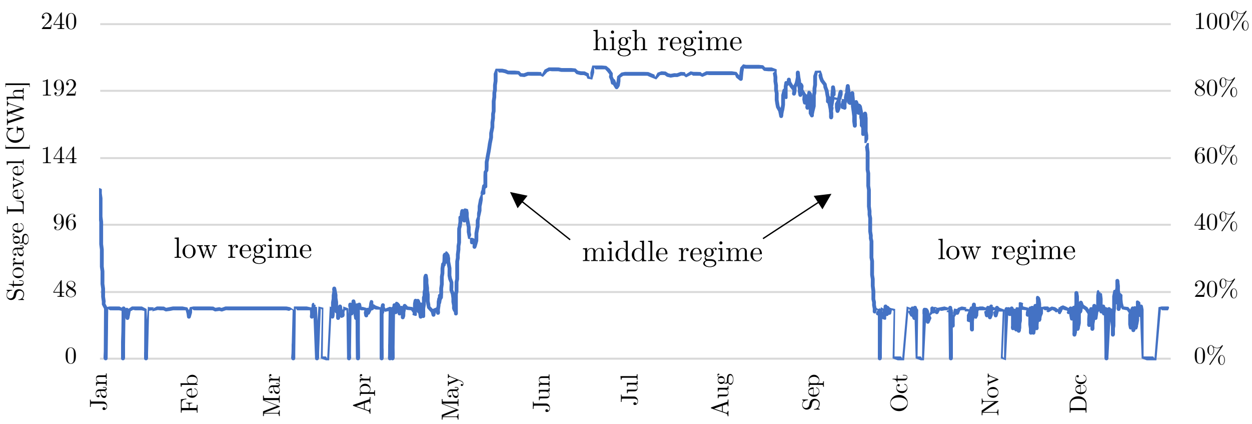


Figure 57: Storage level associated with load shift with production and consumption based on the 2017 reconstructed data.

We continue the analysis of the 2017 example by looking at the daily maximal and aggregated surplus and deficits before and after storage. Figure 58 shows the aggregated surplus and deficit before and after storage. The storage model has only a small effect on the total deficit and surpluses. It works best and shifts the most electricity between days 73 and 140 (14th of March and 20th of May) and between days 235 and 265 (23rd of August and 22nd of September). This corresponds to the middle regime where there are deficits and surpluses during the same day. At the end of the year starting at day 265, the model successfully eliminates all the surplus while also reducing the deficit. This is made possible because the daily surpluses are lower than the surpluses but not zero. The low regime is easily recognizable on the graph, it corresponds to days where there is only deficit and no surplus, in the beginning and end of the year. The model works in the high regime, as we observed in Figure 57, in the middle of the year between mid-May and mid-August.

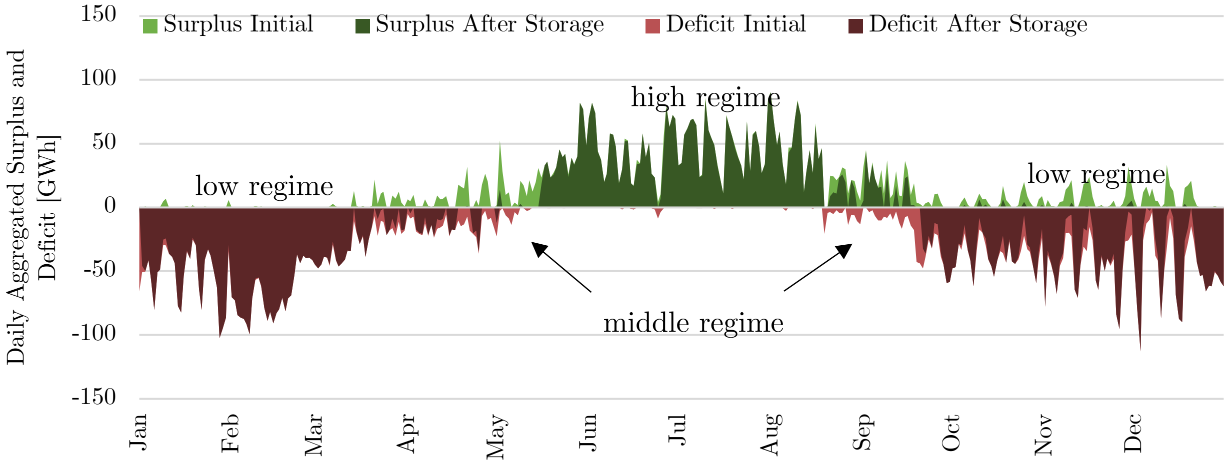


Figure 58: Daily aggregated surplus and deficit before and after storage based on the reconstructed data for the year 2017

We finish by looking at the effect of the storage model on the maximal surplus and deficit in Figure 59 where we see that the reduction in surpluses and deficit observed in Figure 58 were carried out by reducing (and minimizing) their maxima.

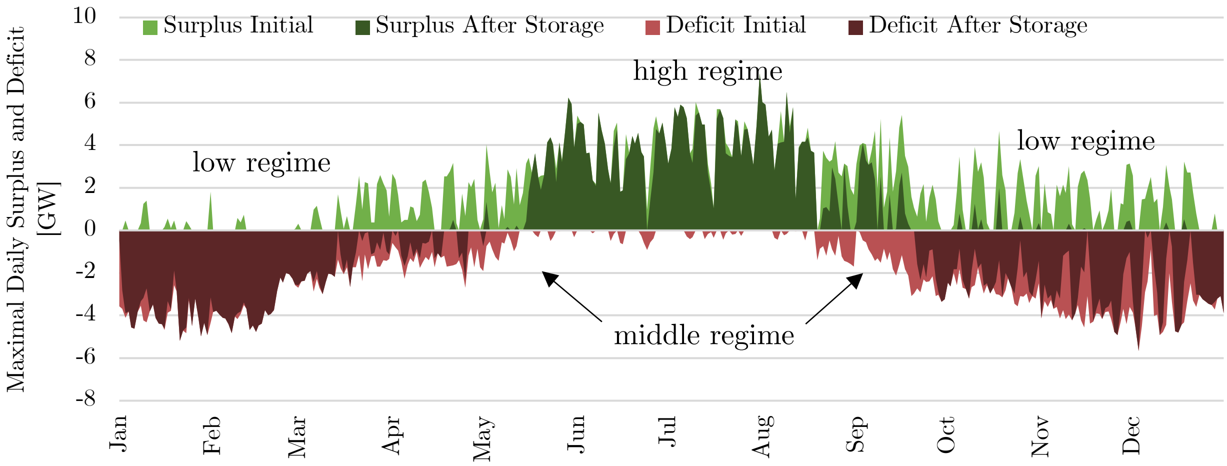


Figure 59: Daily maximal surplus and deficit before and after storage based on the reconstructed data for the year 2017

3.2.4.2 Sensitivity analysis

The storage model has seven input parameters: the charging and discharging powers, the storage size, the storage level at the start of the year, the round-trip efficiency, the end of day maximal storage level and the end of day minimal storage level. In this section we analyze the effect of these inputs on the total amount of electricity charged and discharged over the year 2017 as well as on the maximal surplus and deficit after charging, based on the 2017 reconstructed data. We calculate the deficits and surpluses from the historical demand and the reconstructed production time series without imports. The results are shown in Figure 60 and Figure 61.

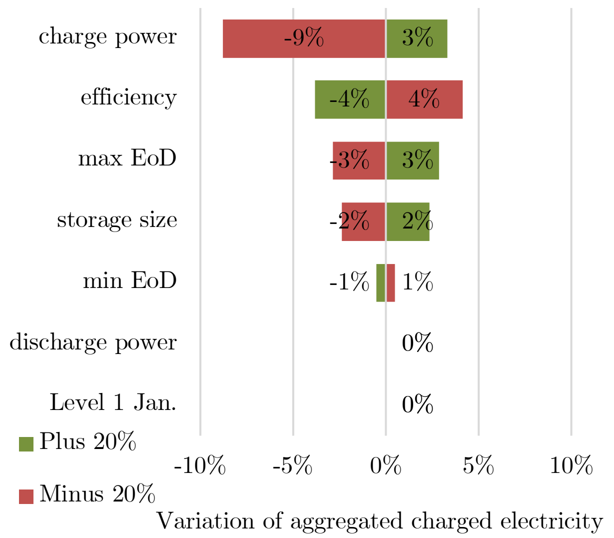


Figure 60: Tornado diagram presenting the sensitivity of the annual aggregated charged electricity on the model's input parameters. Efficiency refers to the round-trip efficiency η, EoD to the storage level at the End of the Day (85% in our example) and level 1 Jan. to the storage level on the first of January.

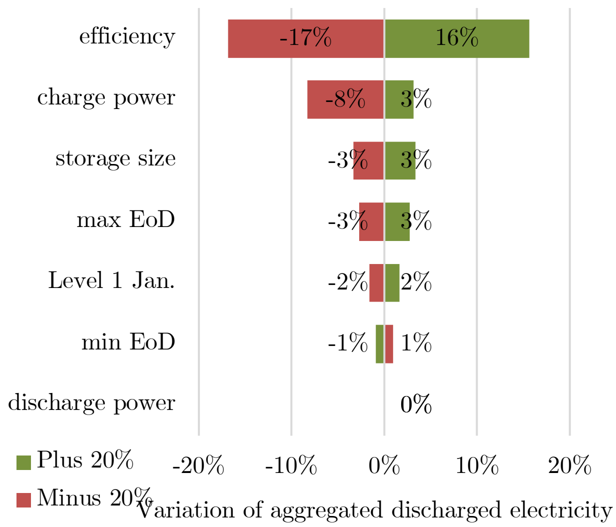


Figure 61: Tornado diagram presenting the sensitivity of the annual aggregated discharged electricity on the model's input parameters. Efficiency refers to the round-trip efficiency η, EoD to the storage level at the End of the Day (85% in our example) and level 1 Jan. to the storage level on the first of January.

The charging power has the largest effect on the aggregated charged electricity over the year. By increasing the charging power, the model is able to charge more electricity when the surpluses are narrow in time but large in size which will have most of its effects in summer.

Figure 61 shows that a variation of efficiency and charge power also have the largest effect on the amount of discharged electricity. The discharge power comes last also here. Increasing the efficiency will reduce the amount of electricity deducted from storage per MW of electricity discharged (remember Constraint 7). It hence translates almost directly in the aggregated discharged electricity as we see that increasing η by 20% leads to a 16% increase in discharged electricity. The charge power has the second largest effect on aggregated discharged electricity because it leads to more electricity charged and hence more electricity available for discharging. Note that a variation of the discharge power has effects neither for the charged nor for the discharge aggregate. This is due to the fact that the quantity of electricity discharged is mainly constrained by the quantity of electricity charged. As 2017 was a year where Switzerland was a net importer of electricity, the limiting factor for the discharge of electricity is the size of the surplus or how much of the surplus can be charged.

3.2.4.3 Limitations

Like the thermal dispatchable model, the daily load shift storage model does not incorporate cost considerations. The variations of electricity prices and the cost of storage are assumed not to play a role in the determination of the time series of charging and discharging. This is an important limitation because it could be the case that the cost of discharging electricity is higher than the price of electricity in the market at the times when the model discharges electricity.

We also need to mention that in practice, such a storage strategy would rely on day-ahead forecast of electricity production, as in some cases, the model discharges electricity first, before recharging. It is of course impossible to shift electricity back in time but the model can discharge electricity early in the day, knowing that it will be possible to recharge this electricity later. In reality, as the forecasts are imperfect, this could lead to further constraints on the possible amounts to charge and discharge.
As for the dispatchable thermal production, we assume that the ramp rate for charging and discharging is high enough to allow for any variation in charge and discharge necessary for the functioning of the model.

Finally, we model the pumped hydro storage system and lithium ion storage system each as one battery with one storage size, efficiency, charge and discharge power capacities each. In reality a pumped hydro power plant has at least two reservoirs of different sizes which add constraints to the model.

3.2.5 Imports and Exports

We now come to imports and exports. All the time series of supply from the Swiss supply sources have been set. The remaining deficits arising from the difference between the simulated demand and supply are filled by imports. Similarly, every surplus remaining is assumed to be exported. No constraints in imported and exported power are considered.

The consequences for the running example for the first week of march 2017 are shown in Figure 62 where we see that imports fill the deficit between the demand and the production.

3.2.5.1 Limitations

In 2017, the maximal power physically importable in Switzerland was 5 GW (Swissgrid, 2017). We do not constrain the imports or exports according to the available infrastructure. It is always assumed that the infrastructure is not a limiting factor for the imported and exported powers.

The price of electricity in the market is not considered and we also assume that there is always enough electricity to be imported and that there is always a market for the electricity needed to be exported.

3.3 Summary

On the demand side, the future demand is simulated by scaling up or down the 2017 demand and then adding the contribution of EV charging.

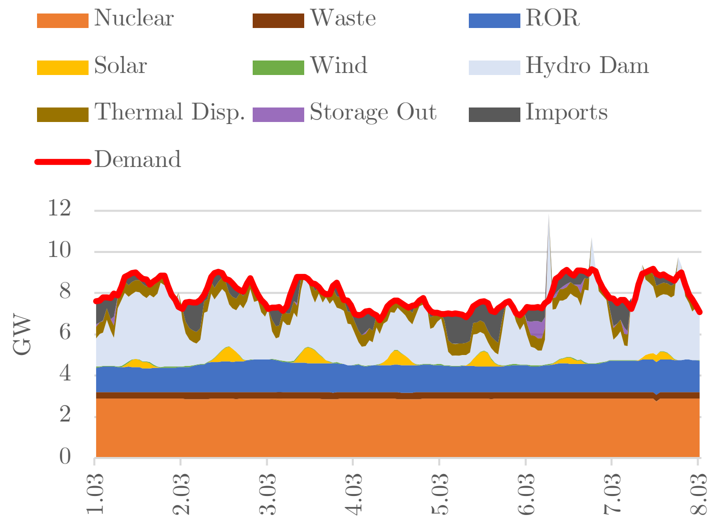


Figure 62: Supply model running example for the first week of march 2017. The power capacities for this example are those of 2017.

On the supply side, the non-dispatchable supply sources (nuclear, waste incineration, run-of-river, solar PV and wind) are set first. ROR, wind and solar are simulated by scaling their 2017 time series of production. Nuclear is simulated by scaling up a modified version of the 2017 nuclear production time series, in order to correct for the comparatively bad year 2017 was for nuclear production. Finally, waste incineration is assumed to run as a baseload with a 75% capacity factor. The hydro dam production, with merit order two, is set after the non-dispatchable supply sources. The simulated hydro dam production follows a profit maximization strategy and depends on the evolution of the bid price of electricity in the market. The bid price of electricity in the future is assumed to differ from the 2017 price only through a diminution of the price at times where solar production peaks. After the hydro dam production is set, the thermal dispatchable supply sources fill the remaining deficit up to the installed capacity. The technologies included in the thermal dispatchable electricity sources are: biomass, biogas and CCGT. The storage model is then set, following a daily load shift strategy whose goal is to minimize the surpluses and deficits. Both pumped hydro and lithium ion batteries perform the daily load shift. Finally, the remaining deficits and surpluses are respectively imported and exported.

By taking 2017 as base year for the renewable production, we constrain the model to years similar to 2017 with respect to weather conditions. Moreover, cost considerations intervene only in the hydro dam model. Neither the merit order nor the production from other sources from hydro dam are affected by the price of electricity or cost of production. The biggest limitation of the model is the partial integration of price in the hydro dam production without considering endogenous effects of a changing electricity mix on electricity market price other than a simplified update accounting for solar PV production peaks.

4 Scenario Analysis

After the adoption of the Energy Law by popular vote in May 2017, a first step in the direction of the realization of the Swiss Energy Strategy 2050 was made. The four main measures of the Energy Law were to reduce energy consumption, to increase energy efficiency, to promote renewable energies and to ban the construction of new nuclear power plants (LEne). In this section we look into the effects of the implementation of the Energy Strategy on the Swiss electricity sector and more precisely on imports and exports of electricity and GHG emissions of electricity in 2030 and 2050. Our goal is to compare the results with scenarios where nuclear electricity is not excluded from the electricity mix.

In order to do so we develop three supply scenarios, which we analyze under three demand conditions. The choice of scenario parameters are fed as inputs into the electricity model presented in chapter 3 and provide us with detailed hourly time series of electricity production, demand, imports and exports for the studied year.

4.1 Scenarios Formulation

4.1.1 Supply Scenarios

The three supply scenarios reflect different possible futures for the Swiss electricity system. They differ on four points: solar PV, wind, nuclear and combined thermal renewable and thermal fossil installed capacities. For these four technologies, we developed three variants each which we show in Table 14 and present in more detail in appendix F.

	Variants
Solar	Low, Middle, High
Wind	Low, Middle, High
Nuclear	Shutdown, Replacement, New Generation
Thermal (Renewable and Fossil)	Green, Constant, CCGT

Table 14: Variants for solar, wind, nuclear and thermal generation

These variants are combined to create three supply scenarios presented in Table 15: Green Wave, Back to the Atom and Resilience.

	Solar PV	*Wind*	*Nuclear*	*Thermal*
Green Wave	High	High	Shutdown	Green
Back to the Atom	Low	Low	New Gen.	Constant
Resilience	Middle	Middle	Replacement	CCGT

Table 15: Solar PV, wind, nuclear and thermal variants corresponding to each supply scenario

The supply scenarios differ only according to the variants shown in Table 15. For the other technologies (hydro dam, run-of-river and storage), they rely on the same assumptions.

In this section we present the three supply scenarios and outline their differences. The resulting parameters, which are fed to the model, are summarized in appendix G.

4.1.1.1 Green Wave

The first scenario, called Green Wave, results from the Swiss Energy Strategy 2050. It has a high share of renewable electricity with a rapid growth of solar and wind capacities, and a gradual nuclear shutdown. The electricity mixes of the Green Wave scenario in 2030 and 2050 are shown in Figure 63.

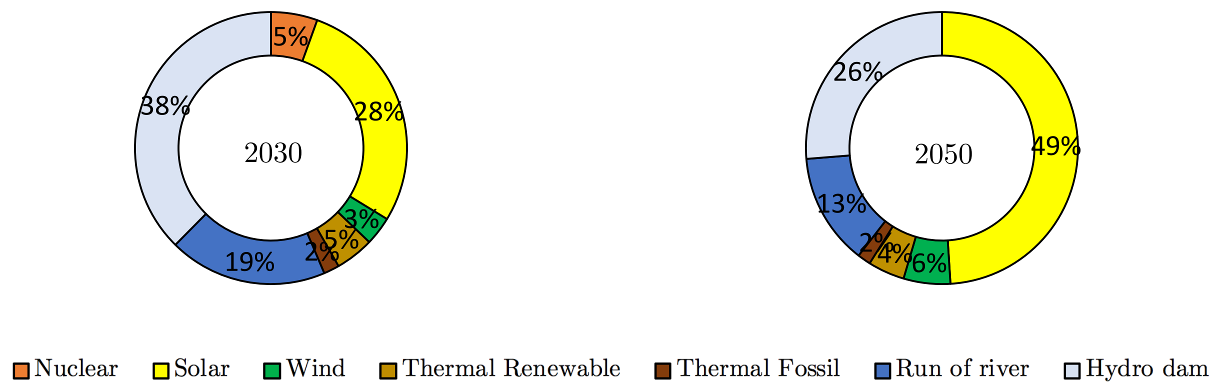


Figure 63: Green Wave scenario, electricity mixes in 2030 and 2050. The percentages refer to the share of installed capacity each category represents.

In 2030 and 2050, 93% and 98% of the power capacity in Switzerland would be renewable. In this scenario, nuclear power plants are shut down after 50 years of operation, in 2030 only the Leibstadt plant (1220 MW) would still be in activity.

Table 16 and Table 17 show the technology specific installed power capacities in 2030 and 2050. Solar PV grows from 1.9 GWp in 2017 to 6.2 GWp in 2030 and 15.9 GWp in 2050, representing a 327% and 832% growth by 2030 and 2050. The wind capacity also grows to its maximal potential as given by Bauer and Hirschberg (Bauer & Hirschberg, 2017) with 10 times the 2017 capacity in 2030 and 24 times in 2050.

	Nuclear	*Solar PV*	*Wind*	*Thermal Renewable*	*Thermal Fossil*
Capacity 2030 [MW]	1220	6229	753	1065	365
Capacity 2050 [MW]	0	15855	1798	1565	365

Table 16: Green Wave scenario, solar, wind, nuclear, and thermal installed capacities in 2030 and 2050

The thermal capacities in the Green Wave scenario are dominated by biomass and biogas. The CCGT and waste incineration installed powers stay similar to 2017.

	Biogas	*Biomass*	*CCGT*	*Waste*
Capacity 2030 [MW]	150	700	150	430
Capacity 2050 [MW]	300	1050	150	430

Table 17: Green Wave scenario, thermal fossil and renewable installed capacities in 2030 and 2050

4.1.1.2 Back to the Atom

The Fukushima nuclear accident of 2011 has been a turning point for nuclear power generation in Switzerland. Following the accident, the risk perception of nuclear has drastically changed, resulting in the exclusion of nuclear electricity by the Energy Strategy 2050. This scenario aims to analyze the consequences of a future electricity mix dominated by a nuclear power increase.

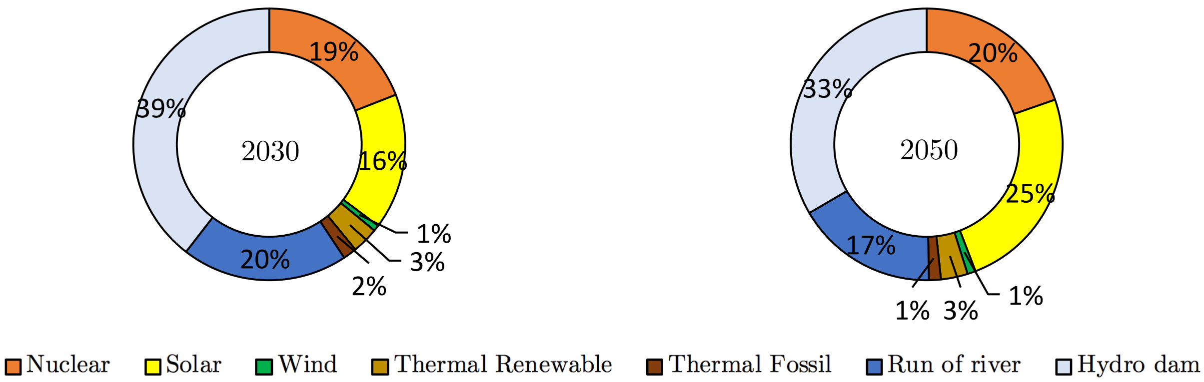


Figure 64: Back to the Atom scenario, electricity mixes in 2030 and 2050. The percentages refer to the share of installed capacity each category represents.

Figure 64 introduces the electricity mixes arising from this scenario for the years 2030 and 2050. Nuclear accounts for about 20% of the power capacity in the future. Solar PV and wind power capacities increase too but less than in the Green Wave scenario. The shares of renewable electricity in the installed capacities are of 79% in 2030 and 2050. The capacities in the Back to the Atom scenario are shown in Table 18 and Table 19.

	Nuclear	*Solar PV*	*Wind*	*Thermal Renewable*	*Thermal Fossil*
Capacity 2030 [MW]	4000	3398	150	715	365
Capacity 2050 [MW]	5000	6229	250	815	365

Table 18: Back to the Atom scenario, solar, wind, nuclear, and thermal power capacities in 2030 and 2050

The development of the thermal capacity is moderate in this scenario. Biomass and biogas grow but only up to half the power capacity of the Green Wave scenario. The CCGT and waste incineration installed capacities stay similar to 2017.

	Biogas	*Biomass*	*CCGT*	*Waste*
Capacity 2030 [MW]	85	415	150	430
Capacity 2050 [MW]	100	500	150	430

Table 19: Back to the Atom scenario, thermal fossil and renewable power capacities in 2030 and 2050

Back to the Atom describes an electricity future where the reduction of carbon emission and the electricity security are at the center of policymaker's priorities. In addition to the reliance on additional nuclear power plants, renewable energies as solar, wind, biomass and biogas steadily grow and the thermal fossil power capacity stays constant over time.

4.1.1.3 Resilience

Security of electricity supply stands at the heart of the third supply-side scenario. In the Resilience scenario, we study the effects of preserving the 2017 nuclear capacity over time and aggressively increasing the CCGT capacity. On the renewable side, the growths of solar, wind and renewable thermal are more moderate than in the Green Wave scenario but more important than in Back to the Atom. With the preservation of nuclear as a baseload generating technology and the increase of intermittent renewable generation from wind and solar, the increased controllable capacity coming from CCGT should increase the resilience of the Swiss electricity system.

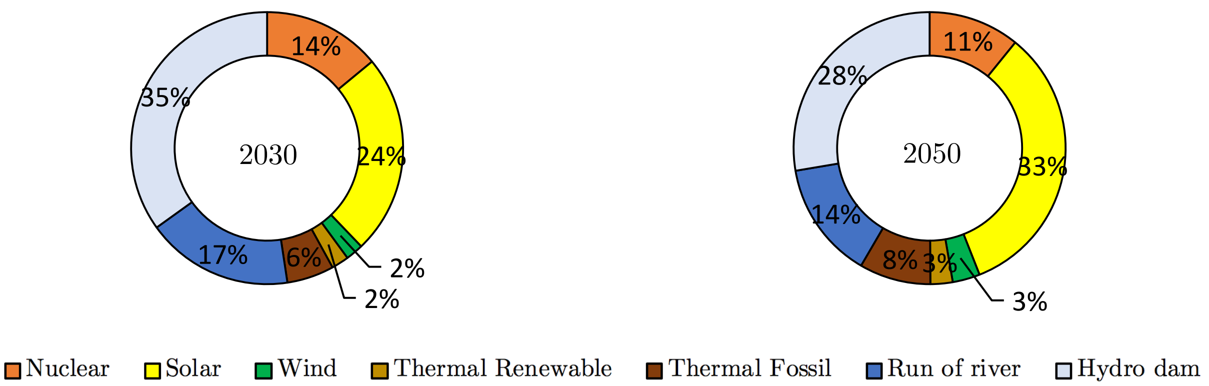


Figure 65: Resilience scenario, electricity mixes in 2030 and. The percentages refer to the share of installed capacity each category represents.

Figure 65 shows the electricity mixes for the Resilience scenario in 2030 and 2050. The thermal fossil share is the highest of the three supply side scenarios, this is due to the CCGT controllable power source. The share of renewable capacity installed are 80% and 81% in 2030 and 2050. Table 20 and Table 21 show the technology specific installed capacities in 2030 and 2050.

	Nuclear	*Solar PV*	*Wind*	*Thermal Renewable*	*Thermal Fossil*
Capacity 2030 [MW]	3333	5663	500	705	1335
Capacity 2050 [MW]	3333	10193	1000	815	2615

Table 20: Resilience scenario, solar, wind, nuclear, and thermal power capacities in 2030 and 2050

The solar, wind and thermal renewable capacities grow but slower than in the Green Wave scenario. The thermal fossil installed capacity increases significantly and is largely dominated by CCGT.

	Biogas	*Biomass*	*CCGT*	*Waste*
Capacity 2030 [MW]	100	390	1120	430
Capacity 2050 [MW]	150	450	2400	430

Table 21: Resilience scenario, thermal fossil and renewable power capacities in 2030 and 2050

4.1.1.4 Assumptions common to all Supply Scenarios

The supply scenarios differ by their reliance on nuclear, solar, wind and thermal electricity. For run-of-river, hydro dam, electricity storage and the future European electricity mix they are based on common assumptions.

Run-of-River

The large run-of-river plants (larger than 300 kW) produced 16.0 TWh of electricity with 4053 MW installed capacity in 2017 (SFOE, 2017, c). The electricity production from run-of-river is assumed to stay similar to 2017 in the future. The only difference lies in the effect of renovations and upgrades of the turbines that we assume to lead to the run-of-river production shown in Table 22. The 2030 and 2050 production represent respectively a 3% and 6% growth compared to the 2017 production.

	2017	*2030*	*2050*
Production [TWh]	16.0	16.4	16.9

Table 22: Run-of-river electricity production assumption for 2030 and 2050

Hydro Dam

In 2017, the storage capacity of hydro dams, pump-back hydroelectric dams and pumped hydro plants was 8.8 TWh and the installed capacity of hydro dams 8152 MW (SFOE, 2017, a).

	2017	*2030*	*2050*
Reservoirs size [TWh]	8.8	9.0	9.5
Capacity [MW]	8152	8300	8500

Table 23: Hydro dam reservoir size and power capacity assumptions for 2030 and 2050

Our assumptions for the evolution of hydro dam production in Switzerland are based on calculation by the laboratory of Hydraulics, Hydrology and Glaciology of ETH Zürich (Boes, 2019). Following the elevation of hydro dams, a growth of 1.7 to 2.8 TWh in reservoir size is possible (Felix, Leimgruber, & Boes, 2018). The construction of new large hydro plants could lead to an increase of 0.1 to 1 TWh per annum of produced electricity (SFOE, 2012).

The power capacity and reservoir size of hydro dams in 2030 and 2050 are shown in Table 23. The increase in reservoir size is associated with the aforementioned elevation and construction of new dams. The capacity increase is a consequence of new dam constructions.

Electricity Storage

Stationary electricity storage technologies (SES) are often mentioned as a complement to electricity mixes with high shares of intermittent renewable energy (Culver, 2010; Wimmler, Hejazi, De Oliveira Fernandes, Moreira, & Connors, 2017; IRENA, 2017). The strength of SES system is that they allow to shift electricity in time and hence decouple power generation and power consumption. Pumped hydro storage currently dominates the worldwide installed storage power with 96% of the total 176 GW installed in 2017 (IRENA, 2017). The second most popular storage technology is the electrical battery with 3.3 GW installed worldwide. According to a study from the International Renewable Energy Agency (IRENA), lithium ion batteries are the most common battery storage technology and have the largest installed capacity installed among chemical storage technologies worldwide. Additionally, large lithium ion batteries systems are being deployed in California (Spector, 2017) and south Australia (Gray, 2017) for grid support. For this reason, both pumped hydro and lithium ion batteries are both considered to be part of the future Swiss electricity system.

Pumped Hydro

Switzerland is one of the leaders in pumped hydro deployment, as it had in 2017 the worlds' 8th biggest installed turbine capacity with 3089 MW (IRENA, 2017; SFOE, 2018, b) with pumping capacity of 2696 MW (SFOE, 2018, b). The reservoir size of the pumped hydro dams were estimated by Piot to be 240 MWh in 2017 (Piot, 2014). With the projected constructions and renovations of hydro dams, the pumped hydro storage capacity is expected to rise to 404 GWh (5200 MW) by 2030 (Piot, 2014). We assume that it will then stay constant until 2050. The key input data used in the simulations are presented in Table 24 for pumped hydro.

Pumped Hydro	*2017*	*2030*	*2050*
Efficiency	80%	80%	80%
Storage Size [GWh]	240	404	404
Charging Power [MW]	2696	4800	4800
Discharging Power [MW]	3089	5200	5200
Generation Time at Capacity [h]	78	78	78

Table 24: Pumped hydro efficiency, storage size, charging and discharging power assumptions and resulting generation time at capacity for 2030 and 2050.

The 80% efficiency is an average estimate given by the SFOE (SFOE, 2017, a). The storage size and corresponding discharging powers are directly taken from the works of Piot (Piot, 2014).

Lithium Ion Batteries

Lithium ion batteries can be used in large stationary storage systems as well as in EVs (Malhotra, Battke, Beuse, Stephan, & Schmidt, 2016). In this project, lithium-titanate oxide (LTO) batteries with nickel cobalt aluminum (NCA) as cathode are considered. This choice is motivated by the long lifetime and great safety that this technology provides. The key data and projections given in Table 25 refer to this technology. LTO/NCA batteries are characterized by a discharge C-rate of 3C and a depth of discharge of around 90%, additionally these batteries have a lifetime of 15000 equivalent full cycles (Abdon, et al., 2017). A capacity of 5MWh is able to provide 1MW of power for 4.5 hours (due to the depth of discharge of 90%), we take this conversion as benchmark for the power/energy relationship of our assumption.

Lithium Ion Batteries	*2017*	*2030*	*2050*
Efficiency	90%	92%	94%
Storage Size [GWh]	-	5	10
Charge Power [MW]	-	1000	2000
Discharge Power [MW]	-	1000	2000
Generation Time at Capacity [h]	-	5	5

Table 25: Lithium ion batteries efficiency, storage size, charging and discharging power assumptions and resulting generation time at capacity for 2030 and 2050

Due to data unavailability, the storage size as well as charge and discharge power are not given for 2017. Our estimates for 2030 and 2050 are based on the work of (Abdon, et al., 2017).

European Electricity Production

Switzerland is deeply integrated in the European electricity system. Its geographical location between France, Germany, Austria and Italy gives Switzerland a role of electricity hub on the European continent with an important quantity of electricity transiting through the country. Consequently, Switzerland's imports and exports of electricity are dependent on the European electricity market. In order to be able to calculate GHG emissions of electricity consumption, we make assumptions about the future of electricity production in Europe.

We develop a scenario based on the European Commission's Energy Strategy 2050 (European Commission, 2018). The assumed shares of electricity production per technology in Europe in 2030 and 2050 are taken from the "Decarb. 2050" pathway.

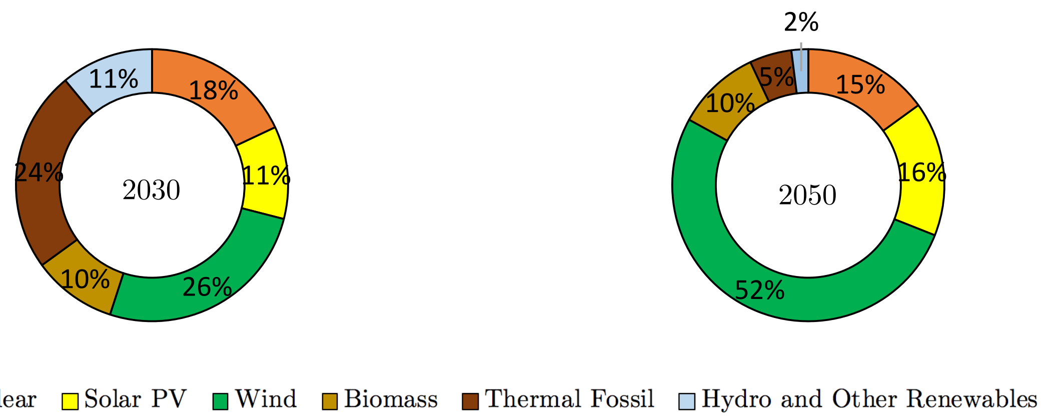


Figure 66: Share of electricity production per technology for the European decarbonization scenario.

The technology breakdown of European electricity production in 2030 and 2050 are shown in Figure 66. The share of fossil electricity production decreases while the wind and solar productions increase. Note that nuclear still plays a role in these scenarios as it is responsible for respectively 18% and 15% of the electricity produced in Europe in 2030 and 2050.

The resulting average GHG emissions of European electricity generation are shown in Table 26. The technology-specific emissions data are life cycle emissions and are taken from (Bauer & Hirschberg, 2017).

European Electricity Production	*2030*	*2050*
Average GHG emissions [gCO_2-eq/kWh]	108	41

Table 26: Average GHG emissions in 2030 and 2050 for the European electricity production assumption.

4.1.2 Demand Scenarios

The supply scenarios will be evaluated under different demand conditions. We develop three demand scenarios based on developments of demand per capita and the effect of electrical vehicle (EV) penetration on the charging load. The variants for demand per capita and EV penetration are presented in Table 27 and are further specified and justified in appendix H.

Contributor to Demand	*Variants*
Population	Increase
Demand per Capita	Decrease, Stabilization, Increase
EV Penetration	Low Linear, Middle Logistic, High Logistic

Table 27: Variants for demand per capita and EV penetration

Demand Scenario	*Demand per Capita*	*EV Penetration*
Low	Decrease	Low Linear
Middle	Stabilization	Middle Logistic
High	Increase	High Logistic

Table 28: Demand per capita and EV penetration variants corresponding to low, middle and high demand scenarios

The six variants and the population assumption are combined into three demand-side scenarios summarized in Table 28: Low Demand, Middle Demand and High Demand.

4.1.2.1 Low Demand

In the low demand scenario, the demand per capita decreases from 6.9 MWh per annum in 2017 to 6.5 in 2030 and 5.8 in 2050. In parallel, the share of electrical vehicles in new registrations increase linearly reaching a fleet size of 0.1 million in 2030 and 0.5 million in 2050. This corresponds to 3% and 8% of the total car fleet in 2030 and 2050. The resulting aggregated demand for 2030 and 2050 is shown in Figure 67.

The aggregate demand in 2030 is 62 TWh, of which 0.2 TWh from EV charging. In 2050 the demand decreases to 60 TWh with 0.6 TWh demand from EV charging.

4.1.2.2 Middle Demand

In the middle demand scenario, the demand per capita increases to 7.9 MWh per annum in 2030 and then stabilizes to 7.0 in 2050. In parallel, the share of electrical vehicles in new registrations grows following a logistic increase, reaching a fleet size of 0.3 million in 2030 and 2.1 million in 2050. This corresponds to 5% and 38% of the total car fleet in 2030 and 2050. The corresponding aggregate demands in Figure 68 show that the middle demand scenario corresponds to an overall demand increase compared to 2017.

In 2030, the aggregate demand is 70 TWh with 0.4 TWh of electrical consumption from EV charging. In 2050 the aggregate demand reaches 75 TWh with 3.6 TWh from EV charging.

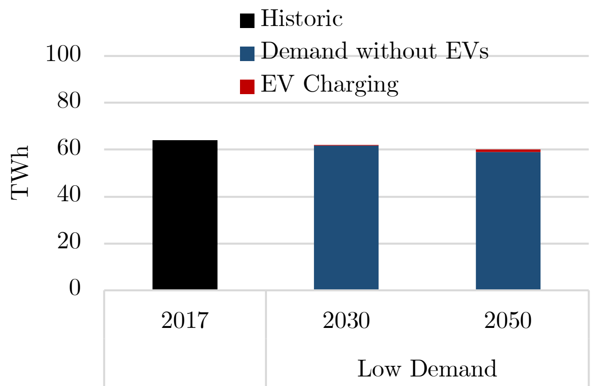


Figure 67: Low demand scenario, annual demand in 2030 and 2050

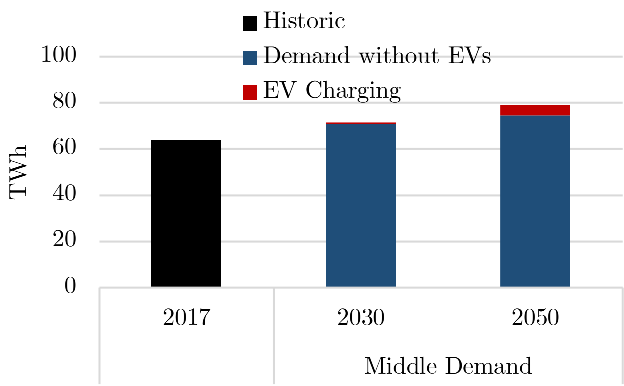


Figure 68: Middle demand scenario, annual demand in 2030 and 2050

4.1.2.3 High Demand

Finally, in the high demand scenario, the demand per capita increases to 7.9 MWh per annum in 2030 and to 8.3 MWh per annum in 2050. The share of electrical vehicles in new registrations grows following a steep logistic increase, reaching a fleet size of 0.8 million in 2030 and 3.9 million in 2050. This corresponds to 15% and 70% of the total car fleet in 2030 and 2050.

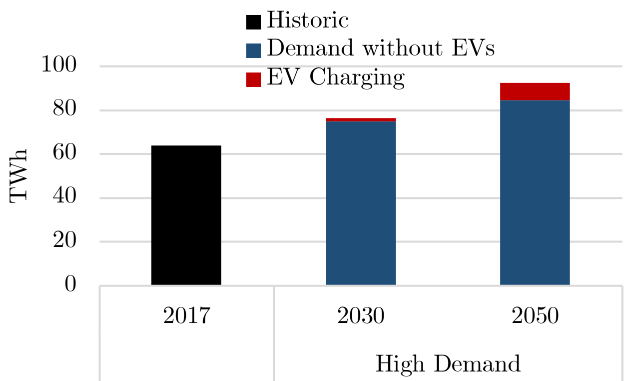


Figure 69: High demand scenario, yearly demand in 2030 and 2050

Figure 69 shows the aggregate electricity consumption arising from the high demand scenario. In 2030 and 2050, the aggregates are 76 TWh and 93 TWh with respectively 1.4 and 7.9 TWh arising from EV's electricity consumption.

4.1.2.4 Contributors to Demand per Capita Growth

In appendix I, we go over the relative contributions of the population size, demand per capita assumption and EV penetration on the total amount of electricity consumption predicted by the model. The key result is that the growth in population and demand per capita drive the increase of overall demand. In this section we discuss components which could contribute to a growth in demand per capita in the household, industry and transport sectors.

Within households, evidence shows that the electrification of heating systems through heat pumps has a significant impact on total demand and peak demand (Love, et al., 2017; Bossmann & Staffel, 2015). Their effect is estimated to increase peak demand by 14% if heat pumps are installed in 20% of UK's households (Love, et al., 2017).

The number of small appliances like phone tablets and connected devices has a positive effect on electricity demand (Sanquist, Orr, Shui, & Bittner, 2012). The increase of the number of connected devices per person is expected to be a contributor to demand per capita growth. Additionally, the announced development of the Internet of Things will lead not only to an increase in the number of connected devices which would consume more electricity in their production and use, but also to an increase in the number of datacenters, in data traffic and in the general consumption of communication technologies (Andrae & Edler, 2015; Ferreboeuf, et al., 2019). This general trend of digital overconsumption in individual use would be mirrored in industry, which would also be translated into demand per capita growth (Ferreboeuf, et al., 2019).

The third important contributor to demand per capita growth is the electrification transport sector which is still heavily dependent on fossil fuels in Switzerland. In our demand scenarios, we separated the contribution from personal electrical vehicles from the rest of the contributors to demand growth, but did not include goods and public transport. It is estimated that the electrification of truck goods transport in Switzerland would lead to an increase of demand of 5% compared to 2017 (Cabukoglu, Georges, Küng, Pareschi, & Boulouchos, 2018).

4.2 Results

In this section we present the results of the scenario analysis, using the model presented in chapter 3 and the supply and demand scenarios presented in section 4.1. We start by looking individually at each supply scenario and then compare their main results in section 4.2.4.

For analyzing electricity production and consumption of each scenario, we choose to show stacked production graphs only for the winter and summer extremes. We choose the last two weeks of January (January 16th to 31st) and the two first weeks of July (July 1st to 15th).

4.2.1 Green Wave

The Green Wave supply scenario is characterized by a large growth of renewable electricity production and a gradual shutdown of the nuclear capacity.

4.2.1.1 Electricity Production and Consumption

We start by looking at the aggregate production and consumption under the three demand variants for 2030 and 2050. Table 29 shows that the production is lower than the consumption for all cases except in the low demand scenario in 2050 where Switzerland would be a net exporter of electricity. The difference between production and consumption gets to 8.2 TWh and 17.8 TWh in 2030 and 2050 in the high demand scenario.

	2030			*2050*		
Demand Scenario	*Low*	*Middle*	*High*	*Low*	*Middle*	*High*
Production [TWh]	66.8	67.5	68.2	71.3	72.9	74.8
Consumption [TWh]	61.9	69.8	76.4	59.8	75.0	92.6
Surplus [TWh]	10.4	7.2	4.6	15.2	8.8	3.1
Deficit [TWh]	5.7	9.6	13.1	4.1	11.2	21.3

Table 29: Green Wave scenario, simulated aggregated production, consumption, surplus and deficit in 2030 and 2050 for the low, middle and high demand scenarios

In the rest of this section we look at the results for electricity production and consumption in the middle demand scenario. The results for the low and high demand scenarios are shown and discussed in appendix J.

Figure 70 and Figure 71 show the resulting time series of production and consumption for January 16th to 31st and July 1st to 15th 2030 and 2050 in the middle demand conditions.

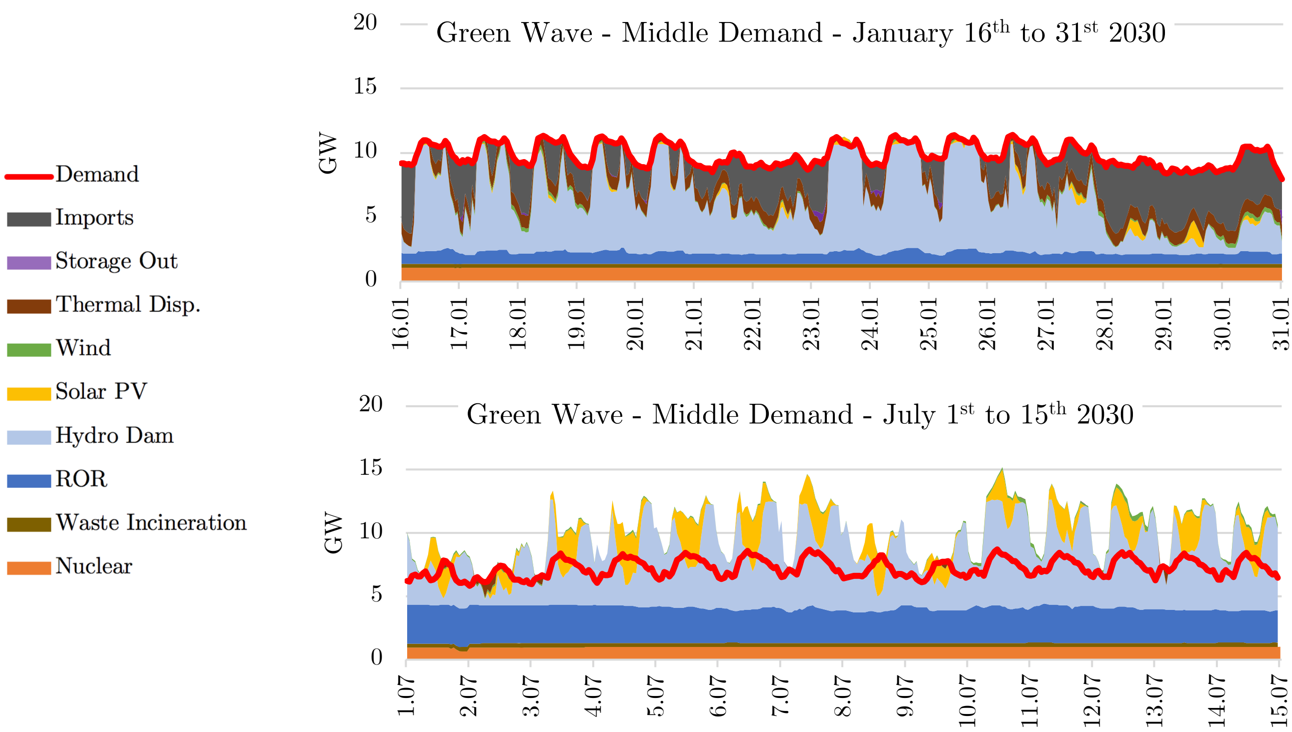


Figure 70: Green Wave scenario, simulated electrical production and consumption for January 16th to 31st and July 1st to 15th 2030 in the middle demand scenario

The nuclear baseload in 2030 is significantly lower than in 2017 with only about 1 MWh of hourly production. In winter, production is insufficient for meeting demand and in summer, as in 2017, the production exceeds the demand. Additionally, we can see the effect of the solar production on the hydro dam production which exhibits a decrease in production in the middle of the day when solar PV produces electricity.

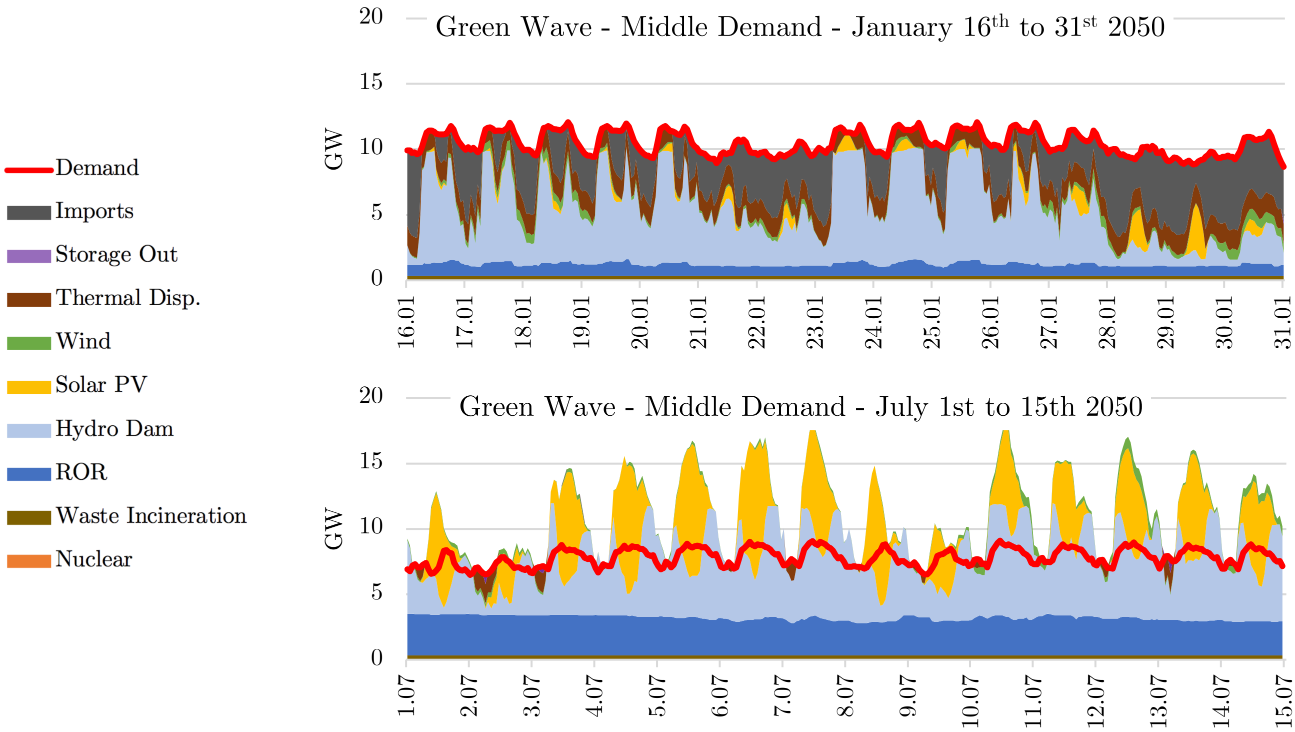


Figure 71: Green Wave scenario, simulated electrical production and consumption for January 16th to 31st and July 1st to 15th 2050 in the middle demand scenario

In 2050, the demand is higher than in 2030 but in the winter, the production stays at a level similar to 2030. The increase of solar and wind capacity contribute only little to the production in winter which directly translates in an increased share of imports in dark grey in Figure 71. In the summer, the high solar capacity leads to large peaks of production in the middle of sunny days, some of it help cover demand in the middle of the day and the rest needs to be exported.

Over the whole years 2030 and 2050, the Green Wave scenario leads to respectively 67.5 TWh and 72.9 TWh production of electricity respectively coming from 85% and 97% of renewable electricity sources (RES). The corresponding consumption in 2030 and 2050 for the middle scenario are 69.8 and 75.0 TWh.

Table 30 shows the simulated contribution of each electricity-producing source to the total production in 2030 and 2050. The solar PV share in electricity production grows from 8% in 2030 to 19% in 2050 while the nuclear share sinks from 12% to 0% in 2050. Even raised at its maximal potential, wind plays a minor role in the production, with 1.3 TWh in 2030 and 3.2 TWh in 2050.

	2030		2050	
	Production [TWh]	*Share [%]*	*Production [TWh]*	*Share [%]*
Total	67.5	100	72.9	100
Nuclear	8.1	12	0.0	0
Run-of-River	16.3	24	16.8	23
Hydro Dam	28.6	42	28.7	39
Wind	1.3	2	3.2	4
Solar PV	5.5	8	14.0	19
Thermal Ren.	5.5	8	8.0	11
Thermal Fossil	2.1	3	2.2	3
Renewable	57.3	85	70.7	97

Table 30: Green Wave scenario, simulated yearly production per technology in 2030 and 2050 in the middle demand scenario

	2030		2050	
	Consumption [TWh]	*Share [%]*	*Consumption [TWh]*	*Share [%]*
Total	69.8	100	75.0	100
Nuclear	9.2	13	1.7	2
Run-of-River	15.0	22	15.0	20
Hydro Dam	25.3	36	25.1	33
Wind	3.7	5	8.7	12
Solar PV	5.9	8	12.9	17
Thermal Ren.	6.4	9	9.0	12
Thermal Fossil	4.3	6	2.6	3
Renewable	56.3	81	70.7	94

Table 31: Green Wave scenario, simulated origin of electricity consumed in 2030 and 2050 in the middle demand scenario

Table 31 shows the simulated contribution of each electricity-producing source to the electricity consumed. The share in electricity consumption corresponds to the yearly production minus the exported electricity plus the imported electricity. The difference between the share in production and in consumption depends on the European electricity mix as well as on the share of exported power. We describe the method used to obtain these aggregates in more details in appendix M.

The biggest difference between the produced and consumed electricity lies in the importance of wind. A large share of the imported power comes from European wind turbines, which contribute to the increasing amount of wind electricity consumed in Switzerland to 3.7 TWh in 2030 and 8.7 TWh in 2050. In 2050, even though Switzerland does not produce nuclear electricity, the share of nuclear in consumed power is non-zero due to imports. Finally, by comparing Table 30 and Table 31 we notice that the amount of hydroelectricity consumed is lower than the hydroelectric production. This is due to the fact that most of the exported electricity is done so at hours where hydroelectric production is high.

4.2.1.2 Imports and Exports

The electricity production in 2030 and 2050 in the middle demand conditions is inferior to the electricity consumption. The difference is larger in the high demand and lower in the low demand conditions. The size of imports and exports is sensitive to the level of demand in the Green Wave scenario.

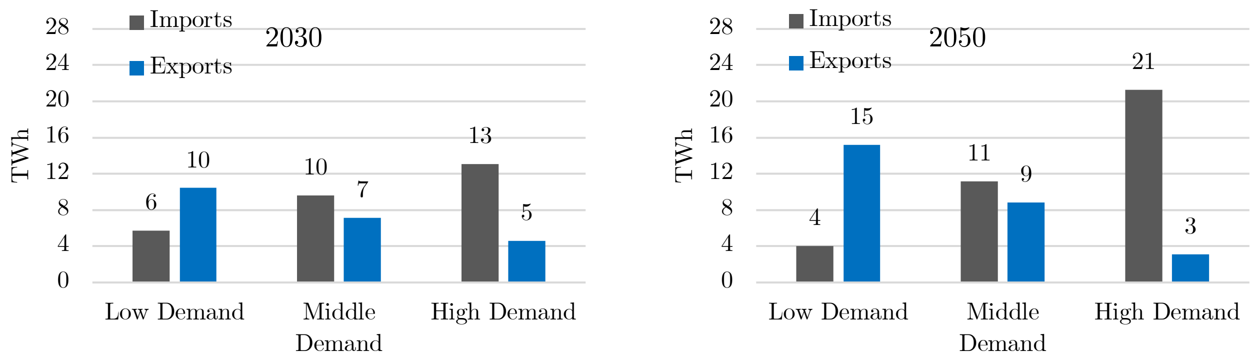


Figure 72: Green Wave scenario, simulated annual aggregated imports and exports in 2030 and 2050 for low, middle and high demand

We quantify this sensitivity in Figure 72 where the annual net imports and exports in 2030 and 2050 are shown. In the low demand scenario, the yearly exports are higher than the imports, making Switzerland a net exporter of electricity over the year. In the middle and high demand scenarios however, Switzerland is a net importer with 10 TWh (14% of demand) and 13 TWh (17% of demand) of imports in the middle and high demand scenarios in 2030 and 11 TWh (15% of demand) and 21 TWh (23% of demand) in 2050.

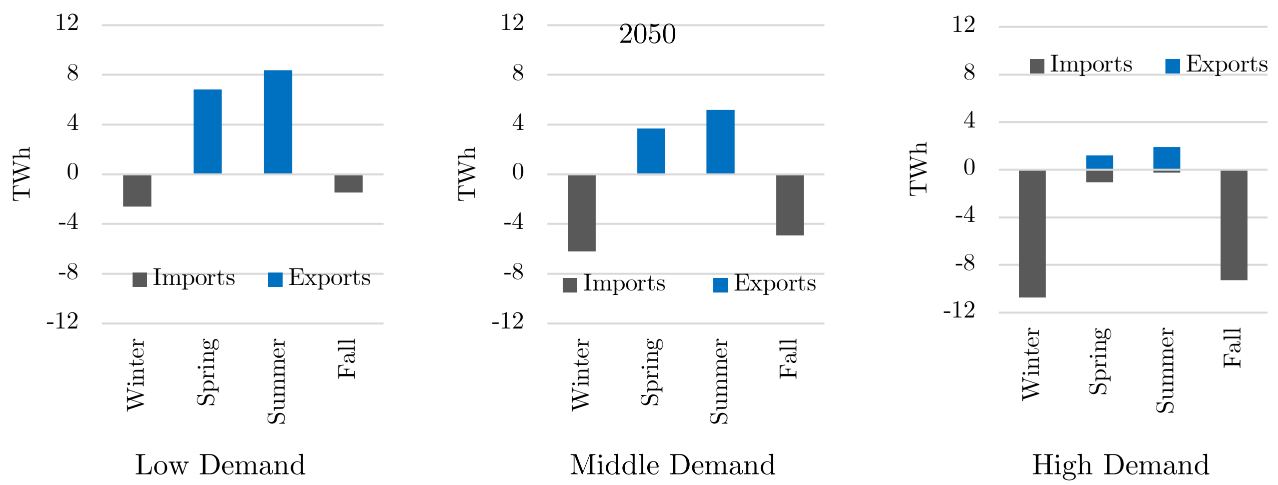


Figure 73: Green Wave scenario, simulated seasonal imports and exports in 2050 for low, middle and high demand. Imports are plotted as negative values and exports as positive values.

The imports are mainly driven by deficits in the winter and fall seasons. As Figure 73 shows, there is no need for importing electricity in the spring or summer in the low and middle demand scenarios and only a small amount of imports in the high demand conditions. The exports are decreasing as demand grows, and are concentrated in the spring and summer seasons, mainly due to the high hydro and solar production. In the Green Wave scenario, Switzerland would stay a net importer of electricity in the winter and a net exporter in the summer in the three demand conditions.

Finally, Figure 74 tells an interesting story about the mismatch between the production and consumption. The Green Wave scenario leads to high production in summer with large peaks in the middle of the day due to solar PV production. These peaks must be exported to a large extent, which leads to the significant share of exported production. On the other hand, in the winter, the solar PV has a low capacity factor which leads to deficits filled by imports. The consequence of this seasonality imbalance is the need of both imports and exports illustrated by the presence of non-zero share of demand covered by imports and share or production exported on the same year in Figure 74. Monthly breakdowns of imports and exports are given in appendix J.

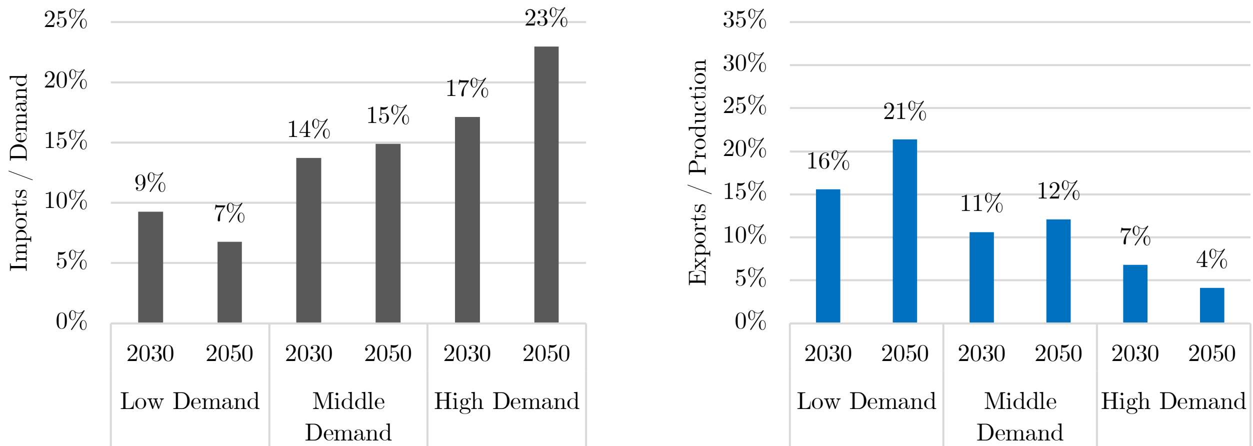


Figure 74: Green Wave scenario, share of demand covered by imports and share of production exported in 2030 and 2050 for the low, middle and high demand scenarios

4.2.1.3 Greenhouse Gas Emissions

We finish the analysis of the Green Wave scenario by looking at greenhouse gas emissions. The method for calculating the GHG emissions is presented in appendix N.

Annual GHG emissions [kt CO_2-eq]	*2030*			*2050*		
Demand Scenario	*Low*	*Middle*	*High*	*Low*	*Middle*	*High*
Of electricity production	1496	1579	1653	1579	1750	1944
Of electricity consumption	1952	2501	2989	1496	2056	2748

Table 32: Green Wave Scenario, simulated total annual GHG emissions of electricity production and consumption in 2030 and 2050 for the low, middle and high demand scenarios

In 2017 the GHG emissions of the electricity production was 1339 kt CO_2-eq[9]. The GHG emissions of production in 2030 and 2050 are higher than in 2017, regardless of the demand scenario, this is driven by the higher level of production in 2030 and 2050 compared to

[9] Calculation based on the aggregates from (SFOE, 2017, b) and the methodology described in appendix N.

2017. The annual GHG emissions of consumption are also consistently higher than those of production except for the low demand scenario in 2050. This is because in the low demand scenario in 2050, the production is higher than the consumption (see Table 29). In the other cases, the increase of the GHG emissions in the consumption should be traced back to the European electricity mix, which in this case, is more carbon intensive than Swiss production. We can observe this in Figure 75 where the average GHG emissions of production are systematically lower than the average GHG emissions of consumption, regardless of the demand scenario. Note that the average GHG emissions of production stay similar to their 2017 level (22 gCO_2-eq/kWh in 2017[10]).

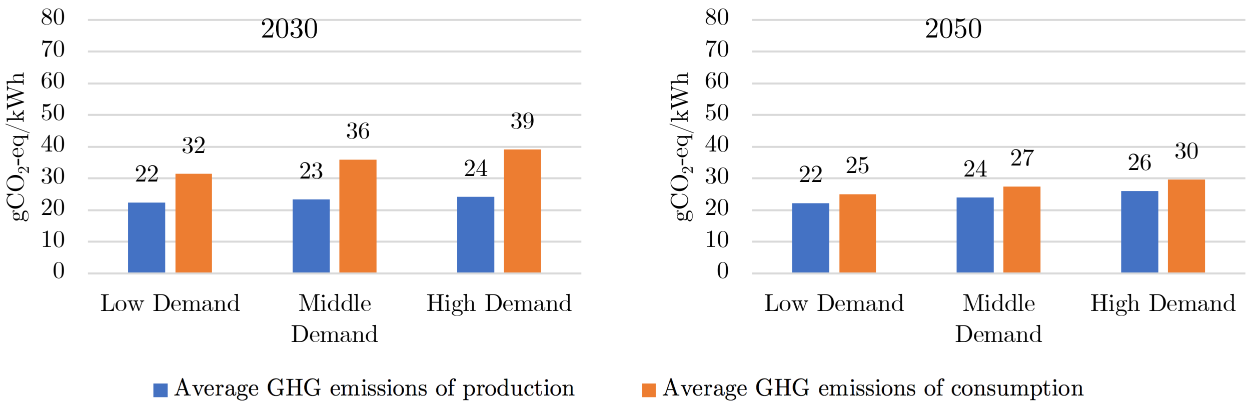


Figure 75: Green Wave scenario, simulated average greenhouse gas emissions of electricity production and consumption in 2030 and 2050 for the low, middle and high demand scenarios

The average GHG emissions are generally low in the Green Wave scenario with maximally 39 gCO_2-eq/kWh in 2030 and 30 gCO_2-eq/kWh in 2050 in the high demand scenario. The emissions are sensitive to demand: the higher the demand, the higher the GHG emissions. This is again due to the higher average carbon intensity of imports compared to production (108 gCO_2-eq/kWh in 2030 and 41 gCO_2-eq/kWh in 2050 for imports).

4.2.1.4 Summary

A high share of the produced and consumed electricity is renewable in the Green Wave scenario. The seasonal imbalances lead to a significant need for imports, mainly in the winter and fall seasons, and the GHG emissions of electricity consumption are low but increase with demand, as the assumed average emissions of imports are higher than those of production.

4.2.2 Back to the Atom

The Back to the Atom scenario describes a future in which nuclear power generation keeps a prominent role in the Swiss electricity system. Additionally, this scenario is characterized by a low share of dispatchable electricity supply sources.

[10] Calculation based on the aggregates from (SFOE, 2017, b) and the methodology described in appendix N.

4.2.2.1 Electricity Production and Consumption

The size of demand has little impact on the yearly production of electricity in this scenario. As we see in Table 33, the differences in production between the high and low demand scenarios are 1.2 TWh in 2030 and 2.6 TWh in 2050 while the differences in demand are large with 14.5 TWh (80.3 TWh – 79.1 TWh) in 2030 and 32.8 TWh (90.9 TWh – 88.3 TWh) in 2050. This low variation of production is explained by the high level of production due to the growing nuclear baseload, and by the low share of dispatchable supply sources.

	2030			*2050*		
Demand Scenario	*Low*	*Middle*	*High*	*Low*	*Middle*	*High*
Production [TWh]	79.1	79.8	80.3	88.3	89.7	90.9
Consumption [TWh]	61.9	69.8	76.4	59.8	75.0	92.6
Surplus [TWh]	18.2	13.3	10.1	18.1	6.9	8.1
Deficit [TWh]	1.2	3.5	6.5	0.2	3.8	9.9

Table 33: Back to the Atom scenario, simulated aggregated production, consumption, surplus and deficit in 2030 and 2050 for the low, middle and high demand scenarios

In the rest of this section we show the results for electricity production and consumption in the middle demand scenario. The results for the low and high demand scenarios are shown and discussed in appendix K.

We continue by showing the simulated production and consumption for January and July 2030 and 2050 in Figure 76 and Figure 77.

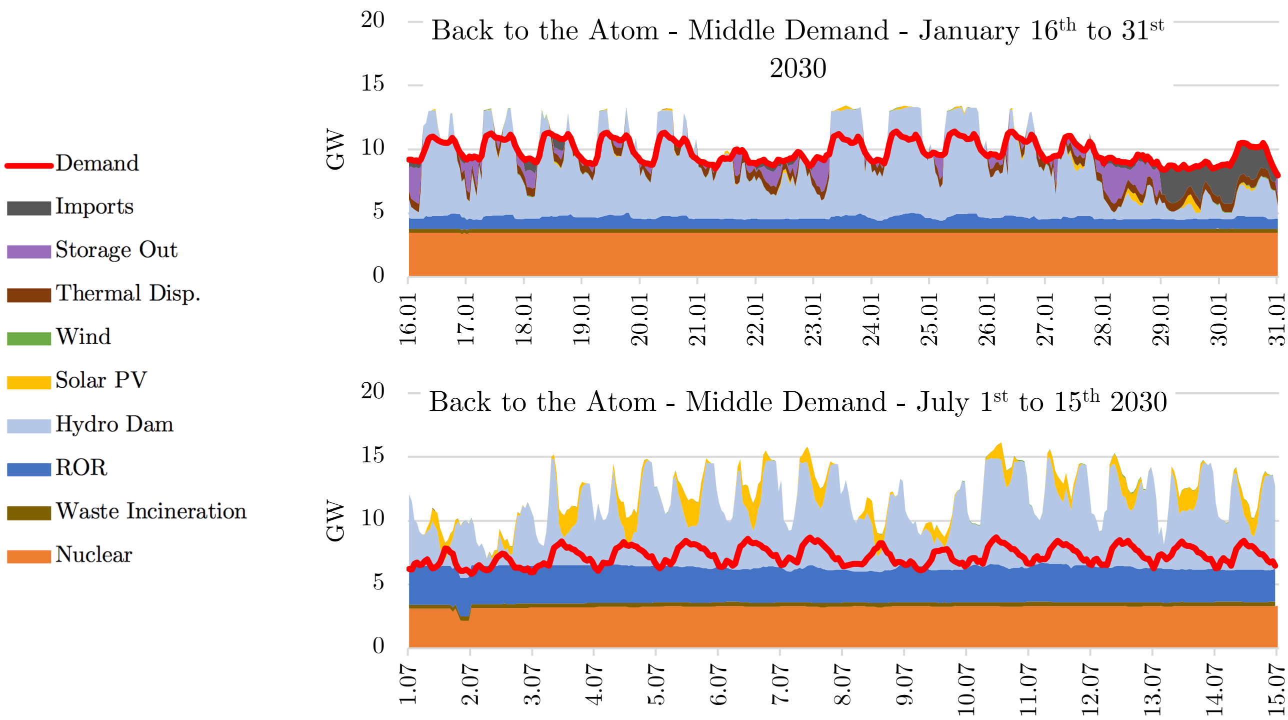


Figure 76: Back to the Atom scenario, simulated electrical production and consumption for January 16th to 31st and July 1st to 15th 2030 in the middle demand scenario

In January 2030, the 4 GW of nuclear power provide a large baseload which has as consequence that the hydro dam production creates surpluses. It allows the storage model to shift the surplus in hours of deficit and hence reduce the quantity of imported power. In the summer, the nuclear and hydro sources meet the demand completely.

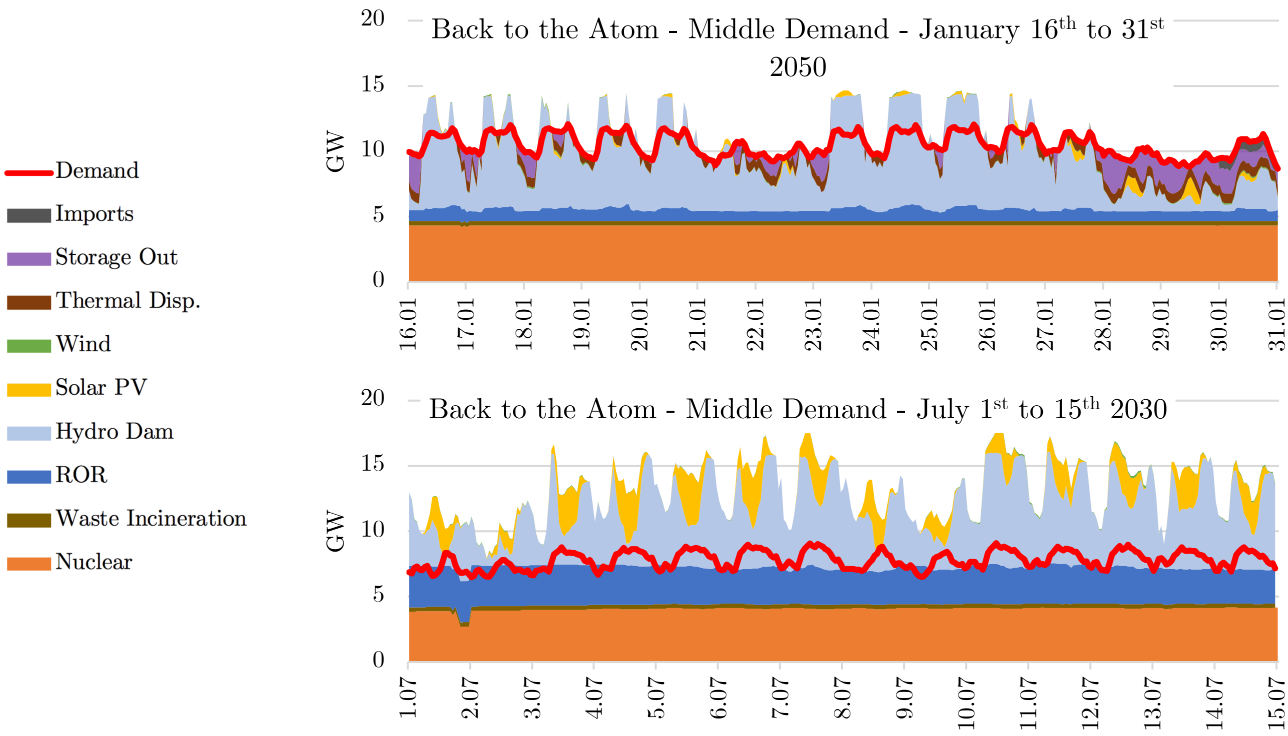


Figure 77: Back to the Atom scenario, simulated electrical production and consumption for January 16th to 31st and July 1st to 15th 2050 in the middle demand scenario

In 2050, the tendency is similar as in 2030: In winter, the large nuclear baseload and hydro sources lead to an overproduction which allows storage to shift the excess production. In the end of January 2050, the storage allows to almost completely eliminate imports of electricity. In July 2050, the Back to the Atom scenario leads to a large overproduction and a significant part of the electricity needs to be exported.

In the Back to the Atom scenario, electricity production is dominated by nuclear and hydroelectric power. Over the whole year, nuclear is responsible for 33% and 37% of electricity production in 2030 and 2050 (see Table 34).

The difference between the contribution of each technology in production is small for the Back to the Atom supply scenario. The difference lies again mainly in the share of wind, solar and thermal fossil generation. Note that the share of Solar PV is smaller in consumption than in production, this is due to the fact that most solar PV produce electricity at times where the overall production is already high and a large share of its production hence needs to be exported. Finally, the higher share of wind and thermal fossil generation in consumption than production in 2030 reflects the electricity mix of the imported power.

	2030		2050	
	Production [TWh]	*Share [%]*	*Production [TWh]*	*Share [%]*
Total	79.8	100	89.7	100
Nuclear	26.5	33	33.1	37
Run-of-River	16.3	20	16.8	19
Hydro Dam	28.6	36	28.7	32
Wind	0.3	0	0.4	0
Solar PV	3.0	4	5.5	6
Thermal Ren.	3.2	4	3.2	4
Thermal Fossil	1.9	2	1.9	2
Renewable	51.4	64	54.7	61

Table 34: Back to the Atom scenario, simulated yearly production per technology in 2030 and 2050 in the middle demand scenario

	2030		2050	
	Consumption [TWh]	*Share [%]*	*Consumption [TWh]*	*Share [%]*
Total	69.8	100	75.0	100
Nuclear	23.7	34	28.4	38
Run-of-River	13.6	19	13.4	18
Hydro Dam	22.7	33	22.0	29
Wind	1.1	2	1.7	2
Solar PV	2.8	4	4.5	6
Thermal Ren.	3.3	5	3.2	4
Thermal Fossil	2.6	4	1.8	2
Renewable	43.5	62	44.7	60

Table 35: Back to the Atom scenario, simulated origin of electricity consumed in 2030 and 2050 in the middle demand scenario

4.2.2.2 Imports and Exports

The Back to the Atom scenario is characterized by a high level of electricity production. We saw in Table 33 that the aggregated production is higher than demand in all demand scenarios except in 2050 for the high demand. This is directly reflected in imports and exports.

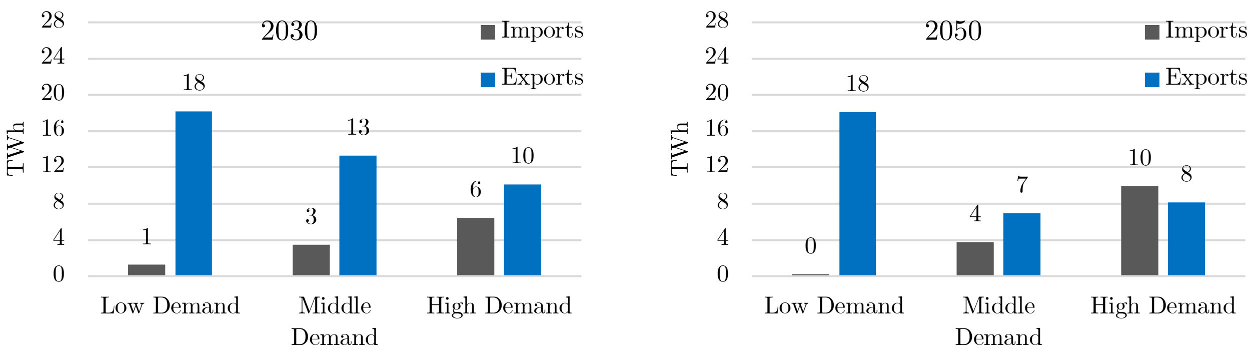


Figure 78: Back to the Atom scenario, simulated annual aggregated imports and exports in 2030 and 2050 for low, middle and high demand

Figure 78 shows the annual values of imports and exports in 2030 and 2050 for the three demand scenarios. In the Back to the Atom scenario, Switzerland would be a net exporter of electricity in 2030 and in 2050 except in the high demand conditions in 2050. The imports once again are concentrated in the winter and fall season and exports mainly in spring and summer even though, when the demand is low, some electricity needs to be exported in winter and fall too (see Figure 79).

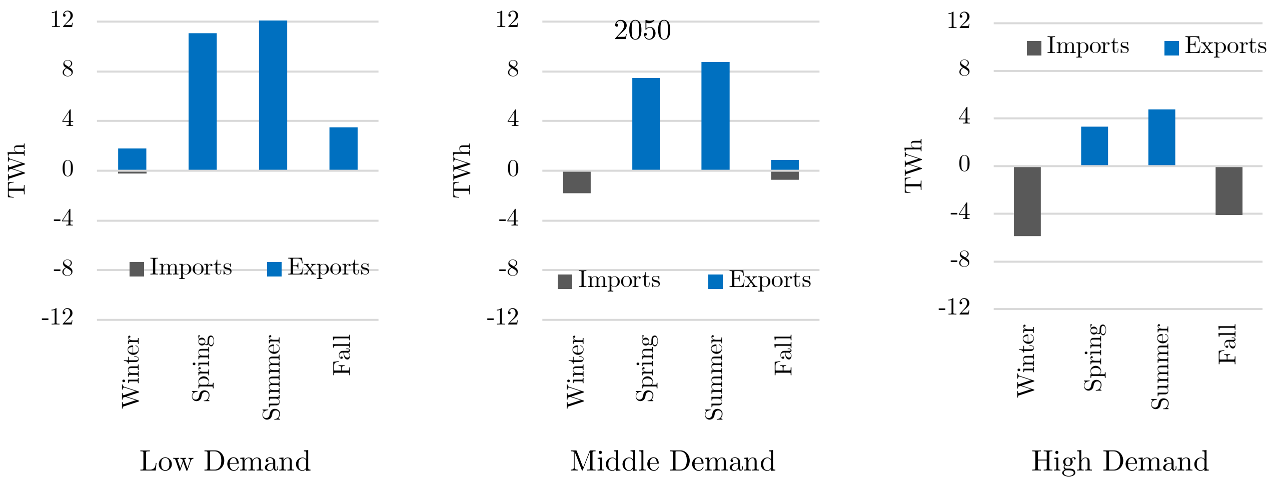


Figure 79: Back to the Atom scenario, simulated seasonal imports and exports in 2050 for low, middle and high demand

We finally turn to the share of demand covered by imports over the year and the percentage of production exported which are shown in Figure 80. Imports play a relatively small role in the Back to the Atom scenario as they cover maximally 11% of the demand in the high demand scenario in 2050. By looking at the share of production exported we clearly see the overproduction tendency exhibited in this supply scenario. In the low demand conditions, as much as 32% of electricity produced would be exported in 2050, and still 19% in 2050 in the middle demand scenario. The monthly breakdowns of imports and exports are given in appendix K.

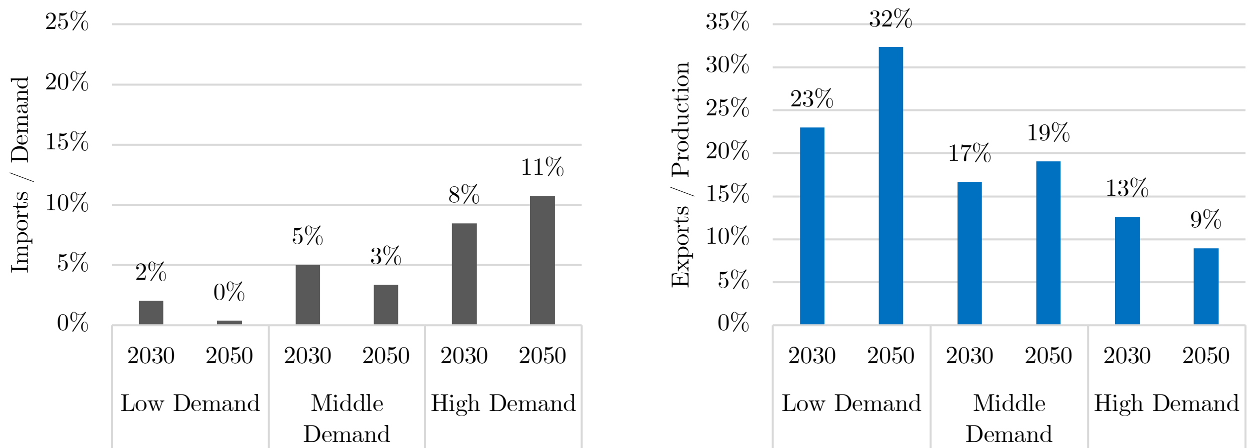


Figure 80: Back to the Atom scenario, share of demand covered by imports and share of imports exported in 2030 and 2050 for the low, middle and high demand scenarios

4.2.2.3 Greenhouse Gas Emissions

We finish by looking at the GHG emissions emanating from the production and consumption of electricity. We notice in Table 36 that the emissions of production increase with demand, this should be traced back to two factors: First, the production of electricity increases as consumption increases, as we showed in Table 33; second of all, the higher the demand, the higher the contribution of controllable supply sources, which happen to be the most carbon intensive.

Annual GHG emissions [kt CO_2-eq]	*2030*			*2050*		
Demand Scenario	*Low*	*Middle*	*High*	*Low*	*Middle*	*High*
Of electricity production	1626	1731	1793	1742	1915	2074
Of electricity consumption	1453	1882	2320	1242	1719	2337

Table 36: Back to the Atom Scenario, simulated total annual GHG emissions of electricity production and consumption in 2030 and 2050 for the low, middle and high demand scenarios

We can also note that the emissions of consumption are sometimes lower than the emissions from production, for example in 2030 in the low demand conditions and in 2050 in the low and middle demand scenarios. This is driven by the large overproduction of electricity. By looking at the average GHG emissions of the electricity produced and consumed in Figure 81, we see that the average emissions are systematically higher for consumption than for production, which confirms that the lower total emission of production in Table 36 are to be traced back to the overproduction. The reason for the higher average emissions of consumption is the higher carbon intensity of imports compared to production (108 gCO_2-eq/kWh in 2030 and 41 gCO_2-eq/kWh in 2050). In the Back to the Atom scenario, the average emissions of production stay in the range of 2017, where they were 22 gCO_2-eq/kWh[11].

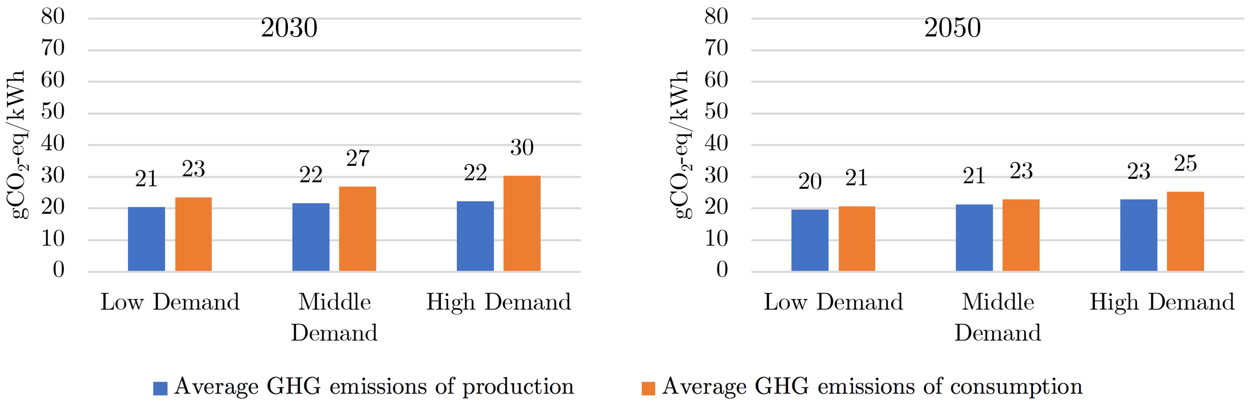


Figure 81: Back to the Atom scenario, simulated average greenhouse gas emissions of electricity production and consumption in 2030 and 2050 for the low, middle and high demand scenarios

[11] This number is obtained by using the method described in appendix N with technology specific production aggregates from the SFOE for 2017 (SFOE, 2017, b).

4.2.2.4 Summary

In the Back to the Atom scenario, the level of electrical production is high and varies only little when demand increases. The production in winter is however still insufficient to meet demand in the middle and high demand scenarios, with imports bridging the deficit. In the spring and summer seasons, the excess production is exported. The GHG emissions of electricity production and consumption are both low and less sensitive to demand variations than in the Green Wave scenario.

4.2.3 Resilience

In the Resilience supply scenario, the nuclear power capacity is kept constant over time compared to 2017. Moreover, additional capacity for controllable thermal supply sources is constructed, with mainly CCGT.

4.2.3.1 Electricity Production and Consumption

The Resilience scenario leads to a large production of electricity, facilitated by the nuclear baseload, the large solar peaks and the important thermal controllable capacity. As a result, the yearly electricity production is higher than the consumption in 2030 and 2050 irrespective of the demand scenario (see Table 37). In the Resilience scenario, Switzerland would be a net exporter of electricity over the year.

	2030			*2050*		
Demand Scenario	*Low*	*Middle*	*High*	*Low*	*Middle*	*High*
Production [TWh]	79.7	81.3	82.4	85.7	90.4	95.3
Consumption [TWh]	61.9	69.8	76.4	59.8	75.0	92.6
Surplus [TWh]	0.4	2.1	4.3	0.0	0.5	5.1
Deficit [TWh]	18.1	13.5	10.2	25.7	15.9	7.9

Table 37: Resilience scenario, simulated aggregated production, consumption, surplus and deficit in 2030 and 2050 for the low, middle and high demand scenarios

Looking in more detail at the production and consumption in January and July 2030 in Figure 82, we see that there are production surpluses in January, which allows the storage to shift the surpluses in deficit hours. The thermal production in January is important as the production from non-controllable and hydro sources do not meet demand. In July, there is no need for controllable thermal production as the nuclear and hydro productions are sufficient to meet the demand.

The results are similar in Figure 83 for 2050. The thermal controllable production is important in July as it stands before storage and imports in the merit order. The production surpluses are mainly charged and discharged in the remaining deficit hours which removes the need for imports in January 2050.

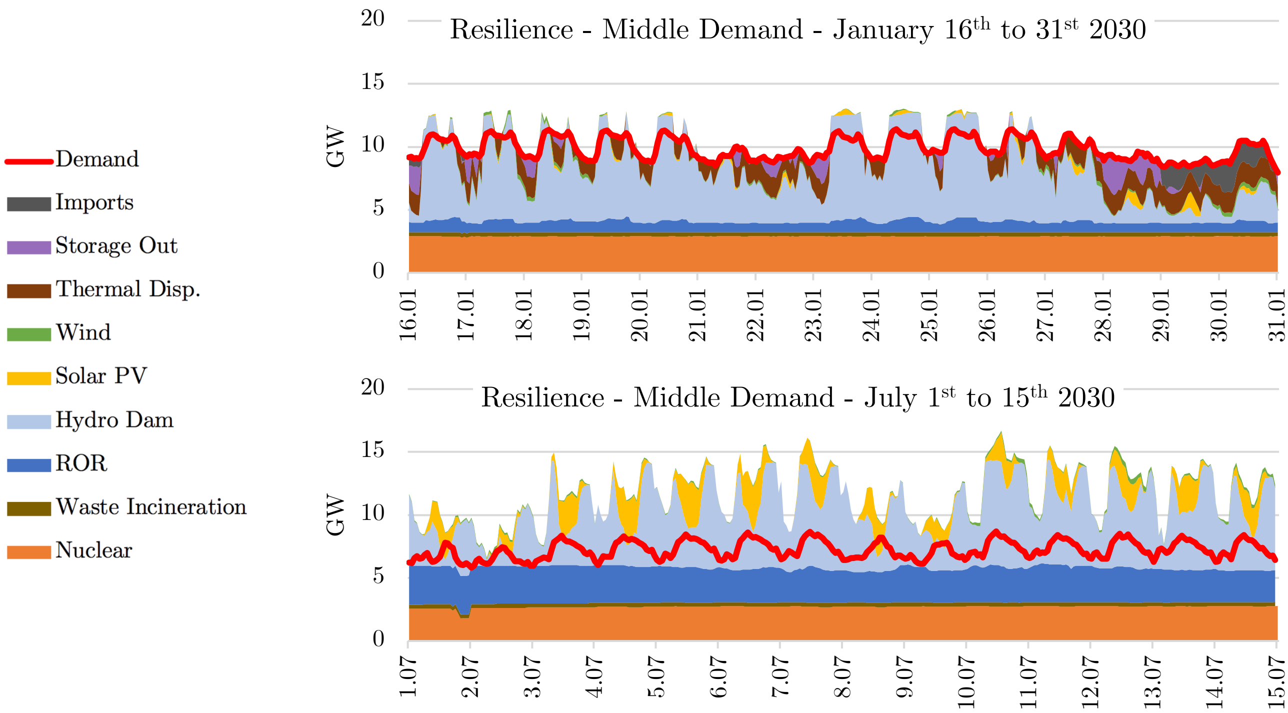


Figure 82: Resilience scenario, simulated electrical production and consumption for January 16th to 31st and July 1st to 15th 2030 in the middle demand scenario

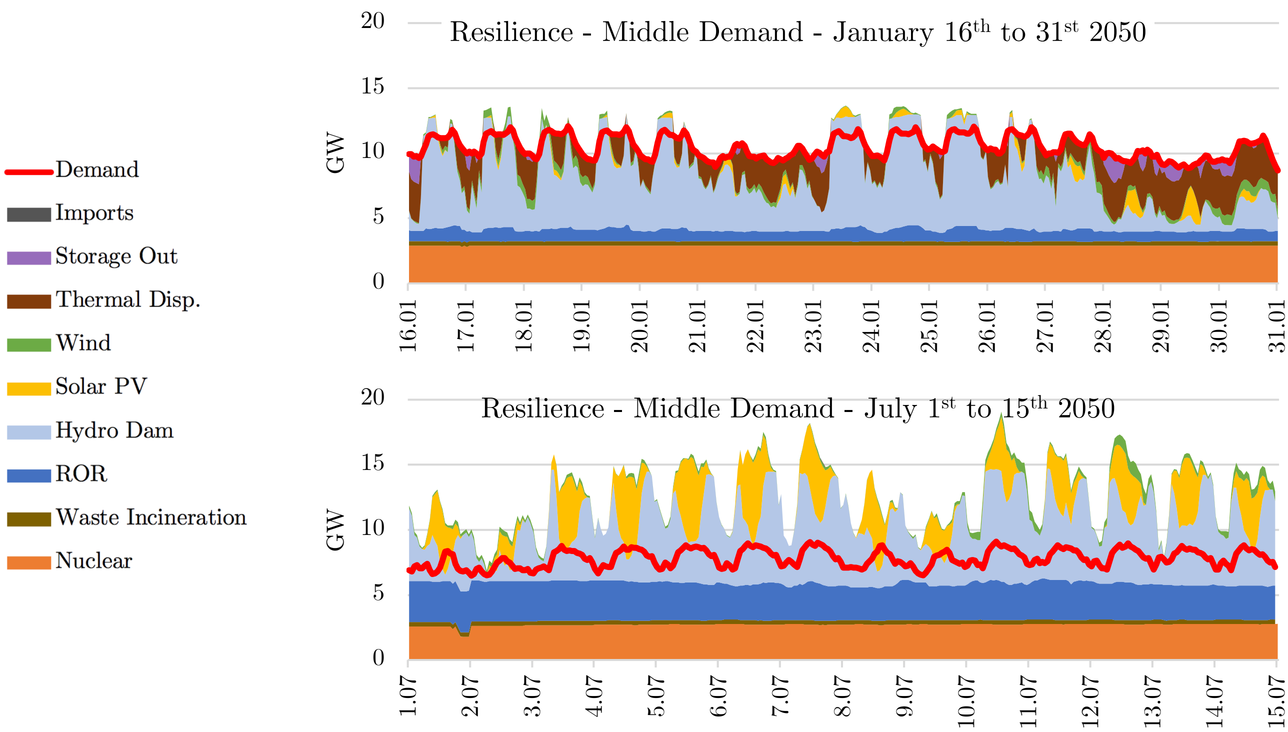


Figure 83: Resilience scenario, simulated electrical production and consumption for January 16th to 31st and July 1st to 15th 2050 in the middle demand scenario

Over the whole year, nuclear accounts for 27% and 24% of the electricity production in 2030 and 2050. In sum, 67% of the electricity produced is renewable in 2030 and 2050. The thermal fossil sources account for respectively 6 and 8% of production in 2030 and 2050 (see Table 38).

	2030		*2050*	
	Production [TWh]	*Share [%]*	*Production [TWh]*	*Share [%]*
Total	81.3	100	90.4	100
Nuclear	22.1	27	22.1	24
Run-of-River	16.3	20	16.8	19
Hydro Dam	28.6	35	28.7	32
Wind	1.3	2	3.2	3
Solar PV	5.0	6	9.0	10
Thermal Ren.	3.0	4	3.0	3
Thermal Fossil	5.0	6	7.7	8
Renewable	54.3	67	60.7	67

Table 38: Resilience scenario, simulated yearly production per technology in 2030 and 2050 in the middle demand scenario

Table 39 shows the absolute and relative contribution of electricity supply sources in consumption. The shares of renewable electricity consumed are lower than for production. This is explained by the fact that the exported electricity is cleaner than the electricity consumed. The largest contributor is the thermal controllable production, which is non-zero uniquely when production from the non-dispatchable sources and hydro dam are lower than the consumption. Hence, 100% of the CCGT production will be consumed in Switzerland compared to only 74% for solar and 86% for nuclear.

	2030		*2050*	
	Consumption [TWh]	*Share [%]*	*Consumption [TWh]*	*Share [%]*
Total	69.8	100	75.0	100
Nuclear	19.6	28	19.0	25
Run-of-River	13.5	19	13.6	18
Hydro Dam	22.6	32	22.3	30
Wind	1.7	2	3.1	4
Solar PV	4.2	6	6.7	9
Thermal Ren.	3.0	4	2.8	4
Thermal Fossil	5.3	8	7.5	10
Renewable	44.9	64	48.4	65

Table 39: Resilience scenario, simulated origin of electricity consumed in 2030 and 2050 in the middle demand scenario

We should finally note that the consumption is lower than the production and a large share of the produced electricity is hence exported.

4.2.3.2 Imports and Exports

As we saw in Table 37, Switzerland is a net exporter of electricity in the Resilience scenario. This is quantified in Figure 84 where the yearly amount of electricity exported exceeds the amount of electricity imported.

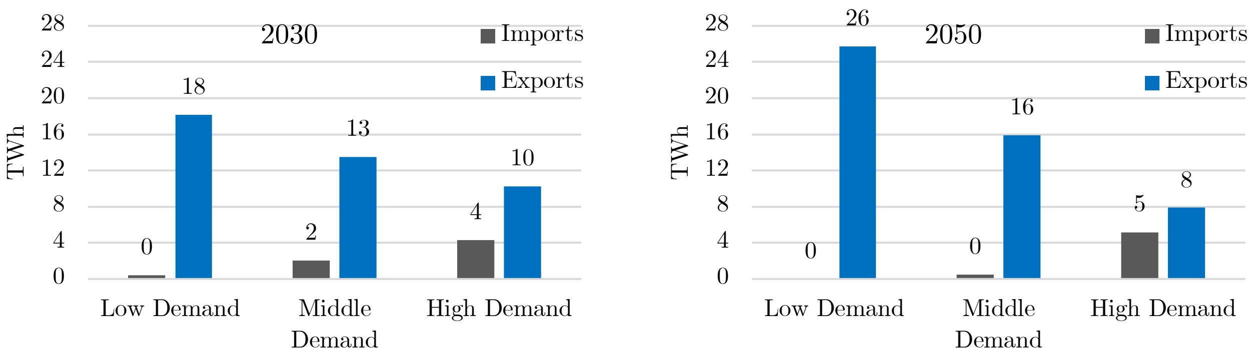


Figure 84: Resilience scenario, simulated yearly aggregated imports and exports in 2030 and 2050 for low, middle and high demand

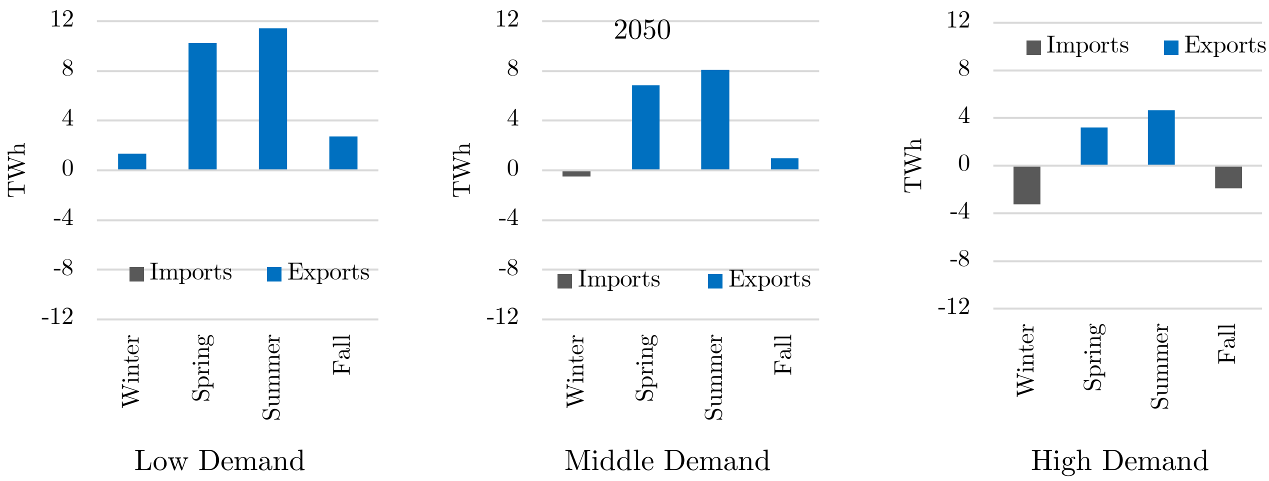


Figure 85: Resilience scenario, simulated seasonal imports and exports in 2050 for low, middle and high demand

As for the other supply-side scenarios, the majority of the exports are concentrated in the spring and summer seasons with imports needed only in winter and fall (see Figure 85).

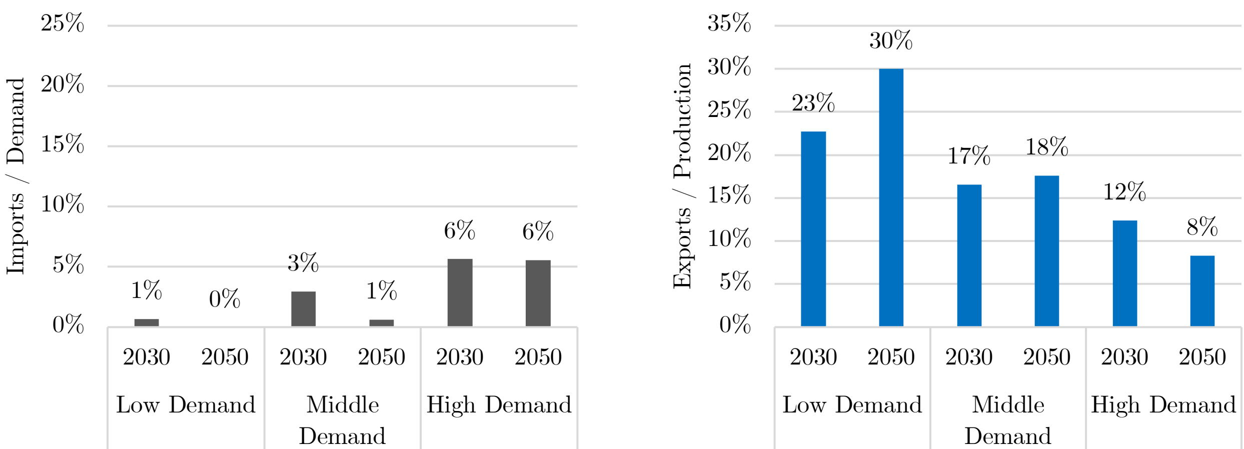


Figure 86: Resilience scenario, share of demand covered by imports and share of imports exported in 2030 and 2050 for the low, middle and high demand scenarios

In sum, the share of demand covered by imports in the Resilience scenario does not exceed 6%, and stays below 3% in the middle and low demand conditions. On the other hand, the share of production which is exported reaches 23% and 30% in 2030 and 2050 for the low demand scenario and still 12% and 8% in 2030 and 2050 for the high demand scenario. The monthly breakdowns of imports and exports are given in appendix L.

4.2.3.3 Greenhouse Gas Emissions

The total greenhouse gas emissions associated with the production and consumption of electricity in the Resilience scenario are shown in Table 40. The emissions of production are higher than the emissions of consumption in the low and middle scenarios. This is because the Resilience scenario leads to overproduction in those two demand conditions. In the high demand scenario, the GHG emissions are higher for consumption which is explainable by the fact that the electricity exported consists in nuclear, hydro, solar and wind production but no CCGT. All of the Swiss CCGT production is consumed in Switzerland. The exported electricity hence reduces only little the GHG emissions as it consists in low carbon sources, and the imported electricity has higher average emissions, leading to higher emissions for consumption than for production.

Annual GHG emissions [kt CO_2-eq]	*2030*			*2050*		
Demand Scenario	*Low*	*Middle*	*High*	*Low*	*Middle*	*High*
Of electricity production	2376	2809	3122	2373	3797	5257
Of electricity consumption	2112	2801	3414	1928	3548	5336

Table 40: Resilience Scenario, simulated total annual GHG emissions of electricity production and consumption in 2030 and 2050 for the low, middle and high demand scenarios

Figure 87 shows average GHG emissions of production and consumption. The average emissions from consumption are always higher than those of production. This has two reasons, first the higher carbon intensity of imports than of exports and second the fact that the electricity exported has in average lower emissions than the average of production. This should again be traced back to the whole CCGT production being consumed in Switzerland.

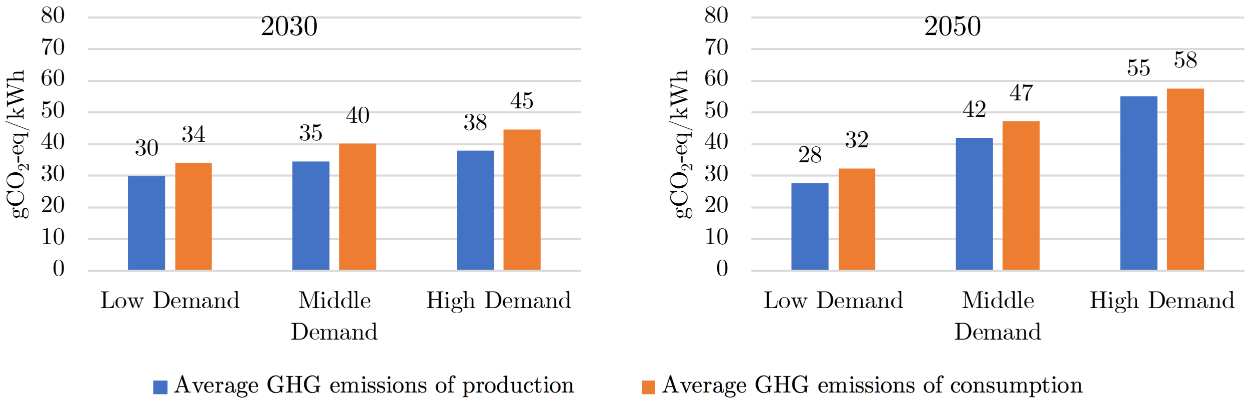


Figure 87: Resilience scenario, simulated average greenhouse gas emissions of electricity production and consumption in 2030 and 2050 for the low, middle and high demand scenarios

4.2.3.4 Summary

The Resilience scenario leads to a level of electricity production which systematically exceeds consumption. Switzerland is a net exporter of electricity over the year. Imports are necessary to meet demand solely in winter and fall in the high demand scenario in 2050. The total GHG emissions of production and consumption are driven by the high emissions from CCGT production.

4.2.4 Scenarios Comparison

After individually presenting the results of the supply scenarios we compare here their main results in this section.

4.2.4.1 Electricity Production

We start by outlining the differences in electricity production in 2050 in Figure 88. We should first notice that the run-of-river and hydro dam productions are identical across supply and demand scenarios. The nuclear, wind and solar generations, being non-controllable, do not depend on demand. The only technologies varying its production with demand are the thermal fossil and renewable. In the model described in chapter 3, the dispatchable thermal sources follow a deficit minimizing strategy: the higher the demand, the higher the deficit and hence the higher the thermal dispatchable production.

The different electricity mixes of each scenario are outlined in Figure 88 with a high solar production for Green Wave, a high nuclear production in Back to the Atom and a thermal fossil generation growing with demand for Resilience. The aggregated production also gives information about the importance of controllable supply sources for each supply-side scenario. The difference in production between the high and low demand scenarios is 3.5 TWh for Green Wave 2.6 TWh for Back to the Atom and 9.6 TWh for Resilience. These differences mirror the installed thermal dispatchable capacities of the three supply side scenarios.

The utilization rate of the storage capacity also varies significantly between supply-side scenarios. As we can see in Figure 89 for the year 2050, the storage system plays the biggest role for the Green Wave scenario. This reflects the effects of an electricity mix dominated by solar electricity. Large peaks of production take place in the middle of the day, leading to surpluses which are partly charged and then shifted into the deficit hours of the evening and morning, when the sun does not shine. The low contribution from storage in the Resilience scenario is a direct consequence from having the thermal controllable supply preceding storage in the merit order of the model.

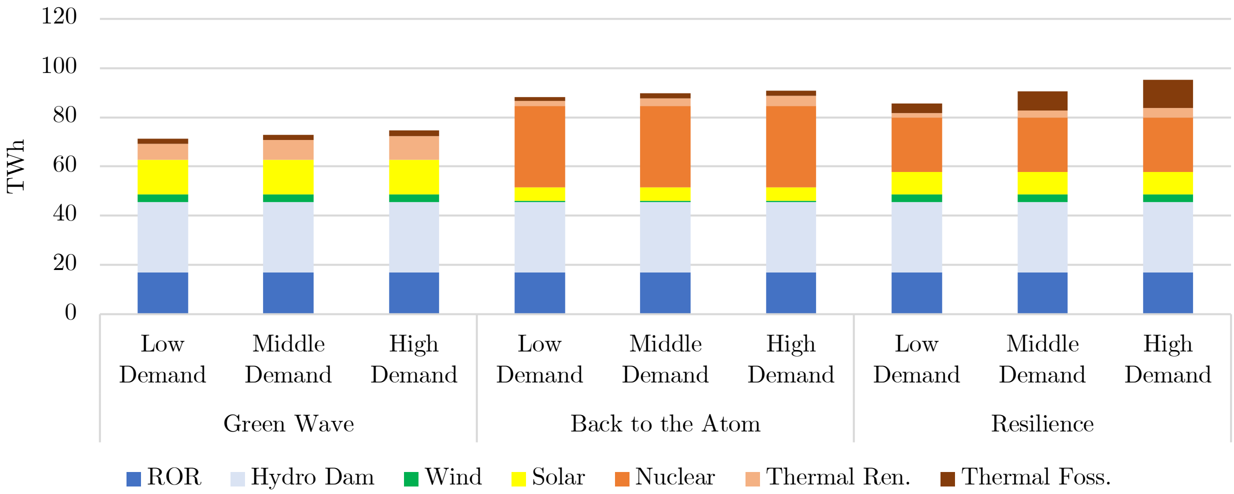


Figure 88: Simulated annual technology specific production for the Green Wave, Back to the Atom and Resilience scenario in 2050 in the low, middle and high demand scenario

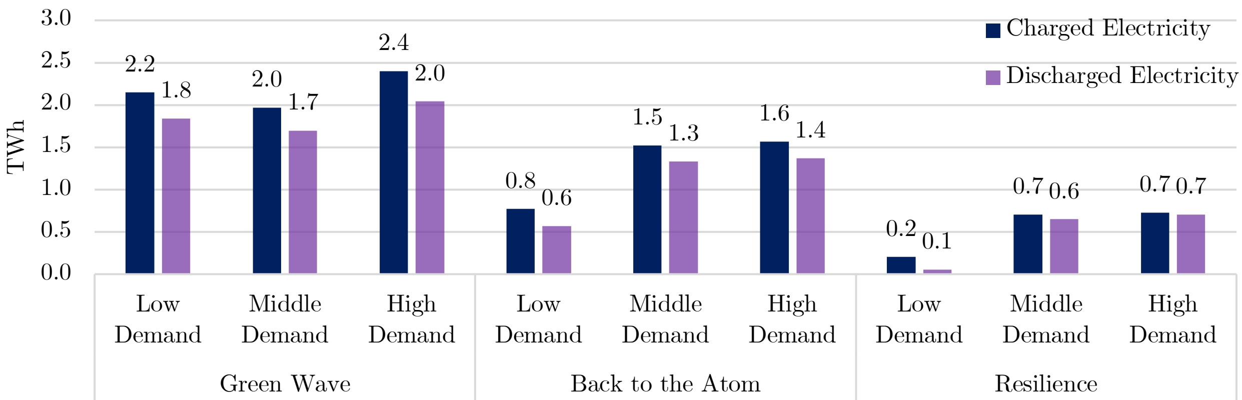


Figure 89: Simulated charged and discharged electricity for the Green Wave, Back to the Atom and Resilience scenario in 2050 in the low, middle and high demand scenario

4.2.4.2 Imports and Exports

The supply scenarios exhibit different profiles in terms of reliance on Europe for electricity imports (see Figure 90). The Green Wave scenario imports between 9% (low demand) and 17% (high demand) of its consumed electricity in 2030 and between 7% (low demand) and 23% (high demand) in 2050. The Back to the atom and Resilience scenarios are less dependent on electricity imports. Between 2% (low demand) and 8% (high demand) of the electricity consumed in 2030 comes from imports in the Back to the Atom scenario. In 2050, these shares vary between 0% (low demand) and 11% (high demand). Finally, the resilience scenario covers most of its electricity production with local production as it leads as only 6% of the electricity consumed is imported in 2030 and 2050 in the high demand scenario.

Furthermore, the aggregated annual imports in the Back to the Atom and Resilience scenarios vary less with changes of demand as in the Green Wave scenario. For example, in

2050, the difference in imports between the high and middle demand scenario for Green Wave is 10.1 TWh while it is 6.2 TWh for Back to the Atom and 4.7 TWh for Resilience.

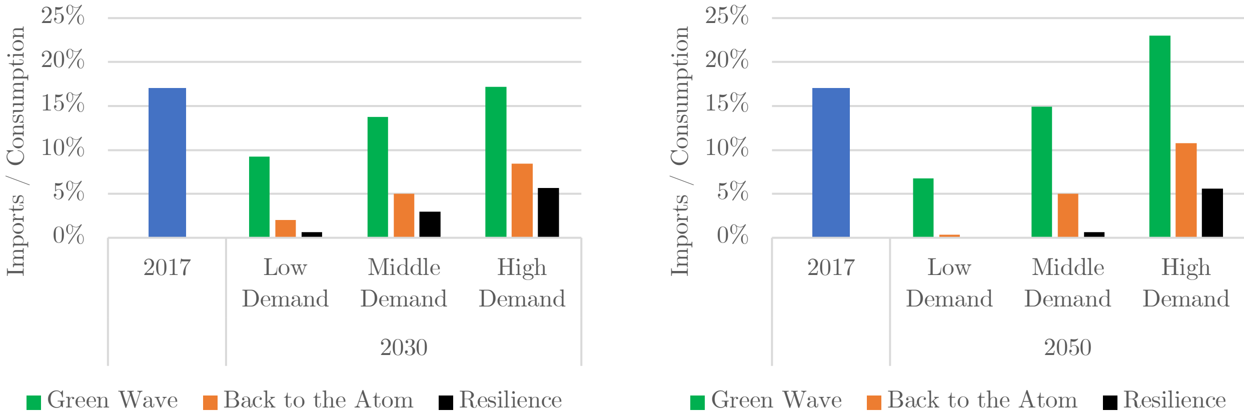


Figure 90: Share of demand covered by Imports for the Green Wave, Back to the Atom and Resilience scenarios in 2030 and 2050 for low, middle and high demand

The Back to the Atom and Resilience scenarios produce more electricity than Green Wave. It results in a lower need for electricity imports, in addition the two nuclear scenarios also export more of their electricity production (see Figure 91).

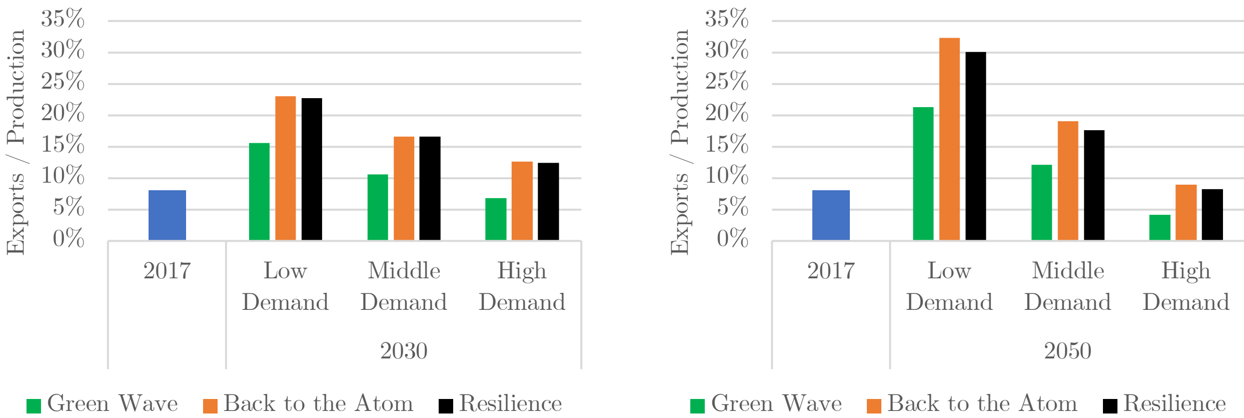


Figure 91: Share of production exported for the Green Wave, Back to the Atom and Resilience scenarios in 2030 and 2050 for low, middle and high demand

The majority of imports are concentrated in the winter and fall months and the exports in spring and summer. We see in Figure 92 the average imported power in the middle demand scenario. In the Green Wave scenario, the average imported power peaks during the night, due to the absence of solar PV production. The two nuclear scenarios have flatter curves of average imports as they exhibit a lower day-night difference in production.

On the export side, Figure 93 shows the average exported power in each hour of the day over the years 2030 and 2050. The exported power is the highest for Back to the Atom and Resilience. In 2050, it peaks around 12:00 due to the solar PV production peaks.

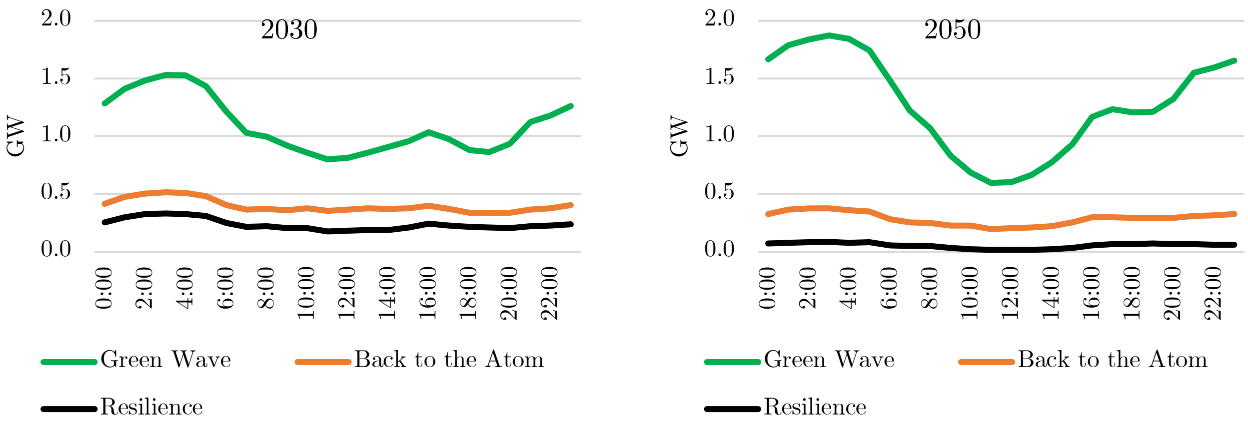


Figure 92: Average imported power in each hour of the day for the Green Wave, Back to the Atom and Resilience scenarios in 2030 and 2050 in the middle demand scenario

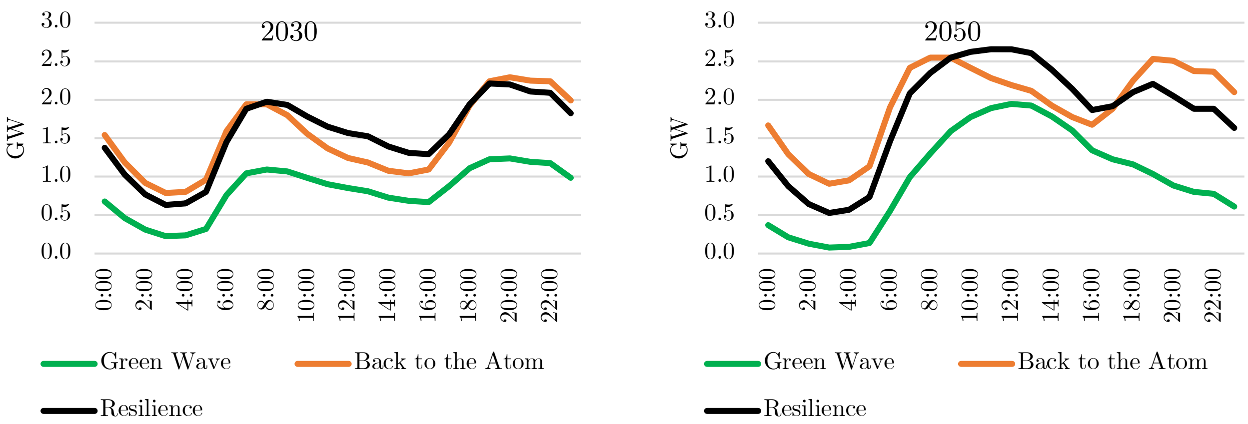


Figure 93: Average exported power in each hour of the day for the Green Wave, Back to the Atom and Resilience scenarios in 2030 and 2050 in the middle demand scenario

4.2.4.3 Greenhouse Gas Emissions

The GHG emissions of electricity production in 2030 and 2050 are the lowest for the Green Wave scenario as Figure 94 and Figure 95 show. This is due to the high share of low carbon technologies in the electricity mix and the lower production compared to the nuclear scenarios. The Resilience scenario has the largest GHG emissions of electricity production because of the contribution of the load following CCGTs. The annual GHG emissions of electricity production are higher in 2030 and 2050 than in 2017, for all supply and demand scenarios. This is a direct consequence of the higher annual electricity production in 2030 and 2050 compared to 2017.

The GHG emissions of consumption however are consistently lower for the Back to the Atom scenario than for the other supply scenarios. This is driven by the general tendency to have more export than imports and the low GHG emissions of nuclear power. As for production, the Resilience scenario has the highest emissions. Compared to the 2017 emissions of consumption which we calculated to be 2489 kt CO_2-eq[12], the Green Wave scenario leads to lower emissions in the low demand conditions in 2030 and 2050 and in the middle demand conditions in 2050. The Back to the Atom scenario leads to lower values in all demand conditions.

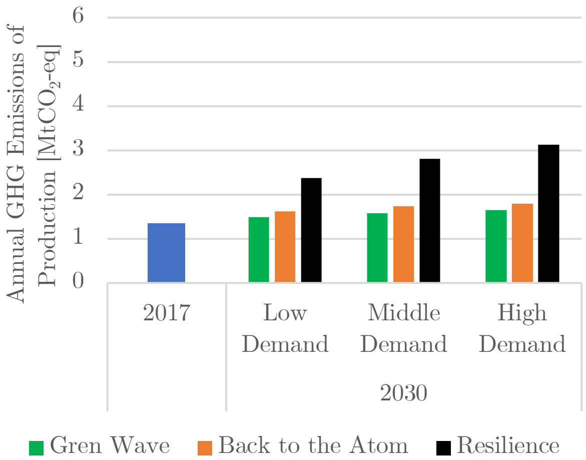


Figure 94: Simulated GHG emissions of electricity production in 2030 of the Green Wave, back to the Atom and Resilience supply scenarios for the low, middle and high demand scenarios

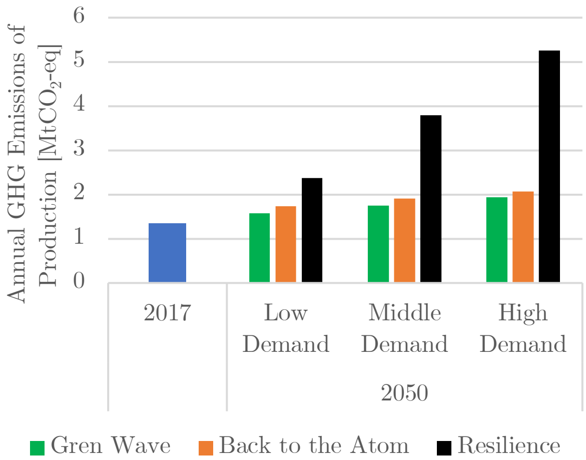


Figure 95: Simulated GHG emissions of electricity production in 2050 of the Green Wave, back to the Atom and Resilience supply scenarios for the low, middle and high demand scenarios

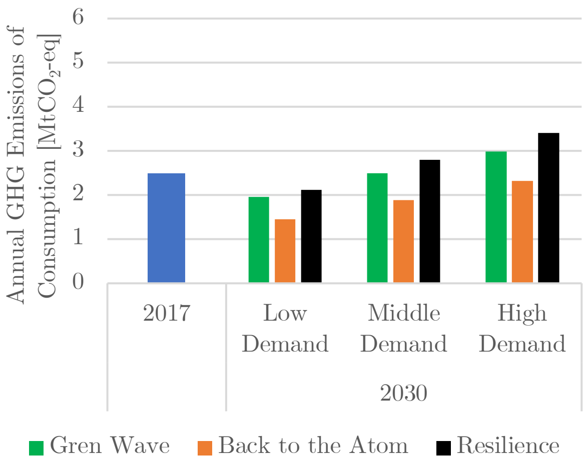


Figure 96: Simulated GHG emissions of electricity consumption in 2030 of the Green Wave, back to the Atom and Resilience supply scenarios for the low, middle and high demand scenarios

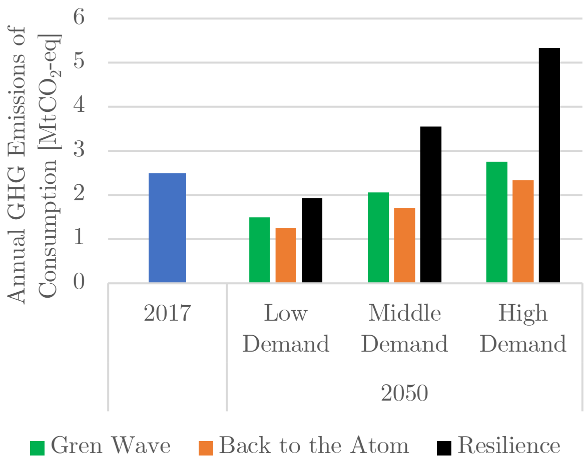


Figure 97: Simulated GHG emissions of electricity consumption in 2050 of the Green Wave, back to the Atom and Resilience supply scenarios for the low, middle and high demand scenarios

[12] This number is obtained by using the method described in appendix N with technology specific production aggregates from the SFOE for 2017 (SFOE, 2017, b), the import time series from (Swissgrid, 2017) and the estimated European mix in 2015 from (European Commission, 2018).

4.3 Conclusion

On the 21st of May 2017 the Swiss people voted to phase out nuclear power and to develop instead intermittent renewable energy sources. This decision is now embedded in the Swiss energy law. The objective of this work was to quantify the impacts of these actions upon the Swiss electricity system with particular reference to changes in electricity import / export dependency and GHG emissions reductions. We did this using computer simulations of the Swiss grid and three supply scenarios called Green Wave, Back to the Atom and Resilience.

Developing intermittent renewable electricity sources and phasing out of nuclear would significantly transform Switzerland's future electricity system. The Green Wave supply scenario illustrates that replacing nuclear with solar PV exacerbates the already existing seasonal imbalance in electricity supply and demand characterized by large supply deficits in the winter and large surpluses in the summer. In the absence of seasonal storage strategies, imports have to fill the deficits, and surpluses have to be exported. Daily load shift storage helps solve the supply demand imbalance only a little and barely contributes at all to the annual imbalance. Our storage model shows that storage is either empty during the winter months when supply is tight or full during the summer months when there is a supply surplus. This simply mirrors short sunshine hours in winter and long sunshine hours in summer.

The GHG emissions of the Green Wave scenario are sensitive to the European electricity mix since about 15 % of Swiss electricity needs to be imported in the middle demand scenario in 2030 and 2050. All the supply scenarios result in Swiss GHG emissions of electricity production rising relative to 2017, as production increases. The modeled GHG intensities of electricity production for the three supply scenarios and middle demand are shown in Table 41. For the emissions of consumption, Back to the Atom has the lowest GHG intensity while Resilience has the highest. This is down to Resilience employing CCGTs to provide load-following security. Both Green Wave and Back to the Atom are associated with a decrease of GHG emissions of consumption in 2050 compared to 2017.

	GHG Emissions of Production [$MtCO_2$-eq]			GHG Emissions of Consumption [$MtCO_2$-eq]		
	2017	*2030*	*2050*	*2017*	*2030*	*2050*
Green Wave	1.3	1.6	1.8	2.5	2.5	2.1
Back to the Atom		1.7	1.9		1.9	1.7
Resilience		2.8	3.7		2.8	3.6

Table 41: Annual GHG Emissions of electricity production and consumption of the Green Wave, Back to the Atom and Resilience supply scenarios in 2030 and 2050 in the middle demand scenario. The assumed GHG intensity of imports is 108 gCO_2-eq/kWh in 2030 and 41 gCO_2-eq/kWh in 2050.

The GHG dependence of the Green Wave scenario on the evolution of the European electricity mix contrasts with the Back to the Atom and Resilience scenarios. Both of these scenarios preserve a nuclear baseload. As a consequence, production is less variable over the year and imports are lower as summarized in Table 42 for the middle demand scenario. In the Green Wave scenario, the share of demand covered by imports will rise compared to the 2010 to 2017 average while it decreases for the nuclear scenarios. The lower import dependency of Back to the Atom and Resilience means that the evolution of the European mix affects less the Swiss GHG emissions of consumption and that Switzerland hence has greater control over its emissions than in the Green Wave scenario.

Annual Imports	*2010-2017 average*		*2030*		*2050*	
	[TWh]	*[% of demand]*	*TWh*	*[% of demand]*	*TWh*	*[% of demand]*
Green Wave	6.5	10%	9.6	14%	11.2	15%
Back to the Atom			3.5	5%	3.8	5%
Resilience			2.1	3%	0.5	0%

Table 42: Annual imports of electricity production of the Green Wave, Back to the Atom and Resilience supply scenarios in 2030 and 2050 in the middle demand scenario compared to the 2010-2017 average. The imports in 2017 amounted to 11.0 TWh (17% of demand). The 2010 to 2017 imports and demand data originate from (Swissgrid, 2017).

Due to the increasing solar PV capacities in each scenario compared to 2017, more surplus power needs to be exported in the middle of the day, when the sun shines. In this project, we assumed that there is a market for these exports, but neighboring European countries which follow a similar route will also have excess solar PV production in the middle of the day. This poses the question of the existence of a market for exporting solar power in the future. Storage is often mooted as the solution to these large mismatches between supply and demand. The scale of storage required depends on the distribution of surpluses and deficits over the year and hence on the electricity mix. We estimate the minimal storage size necessary for shifting all summer surpluses in winter in 2017 to lie between 3.2 and 4.0 TWh for the 2017 electricity mix and between 5.8 and 7.3 TWh for the 2017 mix in which nuclear has been replaced by solar and wind. Compared to the estimated 240 GWh of pumped-hydro storage size available in 2017, these represent at best 13 and 24 times the available reservoir size in 2017. The cost of storage has not been addressed by this project.

The Green Wave Scenario, will reduce Swiss electricity security and independence. Resilience provides the greatest security of supply but at the expense of higher GHG emissions. Back to the Atom also provides secure electricity supply and low import dependence along with the lowest GHG intensity of electricity consumption. The import dependency of natural gas and uranium has not been considered. Furthermore, costs have not been calculated and this omission may be addressed in future work.

Finally, our results are subject to the limitations of the simulation models mentioned in chapter 3. The most central limitation lies within the hydro dam model as changes of market power and endogenous effects of production on the bid price of electricity are not considered. Further research could extend the model to allow for such changes.

Appendix

A. Power, Energy and Capacity Factors

An electricity production plant or technology is characterized by parameters including, the electrical power, the produced electrical energy and the capacity factor.

The electrical power describes how much electrical energy can be released by unit time, it generally takes the unit of Watt (W), kilowatt (kW, 1 kW = 1'000 W), megawatt (MW, 1 MW = 1'000'000 W), gigawatt (GW 1 GW = 1'000'000'000 W) or terawatt (TW, 1 TW = 1'000'000'000'000 W). A system with one kilowatt installed can produce an amount of electricity of one kilowatt-hour (1 kWh) per hour. For illustration purposes, a nuclear power plant typically has between 500 MW and 1500 MW of installed power. Today's solar panels typical peak power ranges between 150 W and 300 W per square meter (Bauer & Hirschberg, 2017). Note that in the case of solar panels, one speaks of watt-peak (Wp) and not Watts. This means that the solar module, in its optimal functioning conditions, with no cloud cover and a good orientation relative to the sun, can generate its peak-wattage. Under less favorable conditions, the solar module will generate less than the peak-wattage. This translates directly in its capacity factor.

Capacity factors describe the relationship between a plants' installed power and the amount of electricity it produces over a certain amount of time. Over one year, it is calculated according to the formula in Equation 8.

$$capacity\ factor = \frac{annual\ generated\ electrical\ energy\ (MWh)}{365\ days \times 24\frac{hours}{day} \times installed\ power\ (MW)}$$

Equation 8: Capacity factor over one year

A capacity factor of 100% means that the plant generates electricity all the time at its maximal power. A capacity factor of 0% means that no electricity is generated over the period of time studied. In the case of renewable energy like wind and solar, the weather conditions are going to greatly impact the yearly generated electrical energy and hence the capacity factor.

B. Simulated and Reconstructed Production

In this section, we compare the simulated and reconstructed production, with key data from the year 2017. We show the results for January, July and August. In all the graphs in this appendix, the plotted demand is the historic one from Swissgrid. Note that the simulated model has not been developed for matching exactly the 2017 data, we show the differences here in order to grasp the inner workings of the model.

The non-dispatchable supply sources (ROR, Solar PV and wind) are exactly equal between the reconstructed and the simulated data, as our method for the simulation of non-dispatchable supply sources relies on a scaling of the reconstructed data, based on the installed capacities. As the installed capacities are equal for 2017, the non-dispatchable supply sources are identical in the simulated and in the historical version, for 2017. The main difference lie in the nuclear, the hydro dam, the thermal production as well as in the storage and imports.

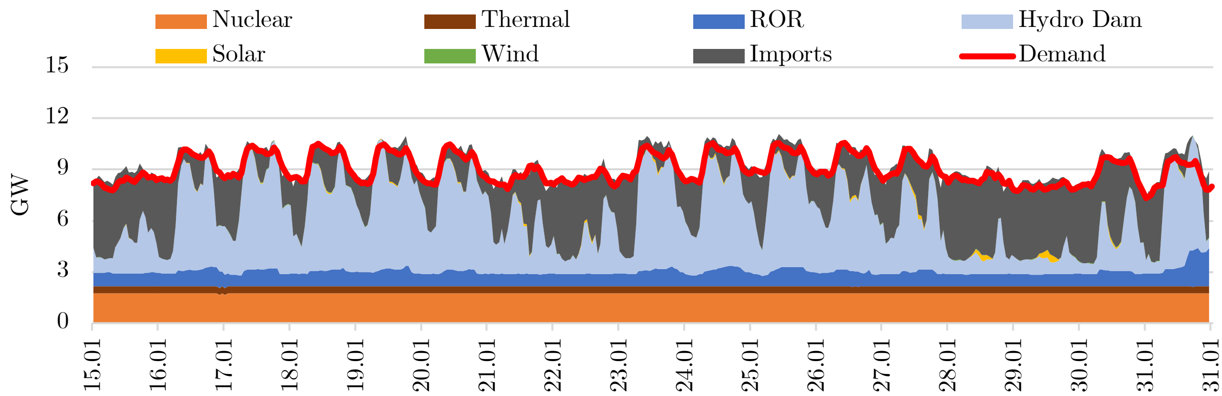


Figure 98: Reconstructed production and historic imports and demand, January 2017

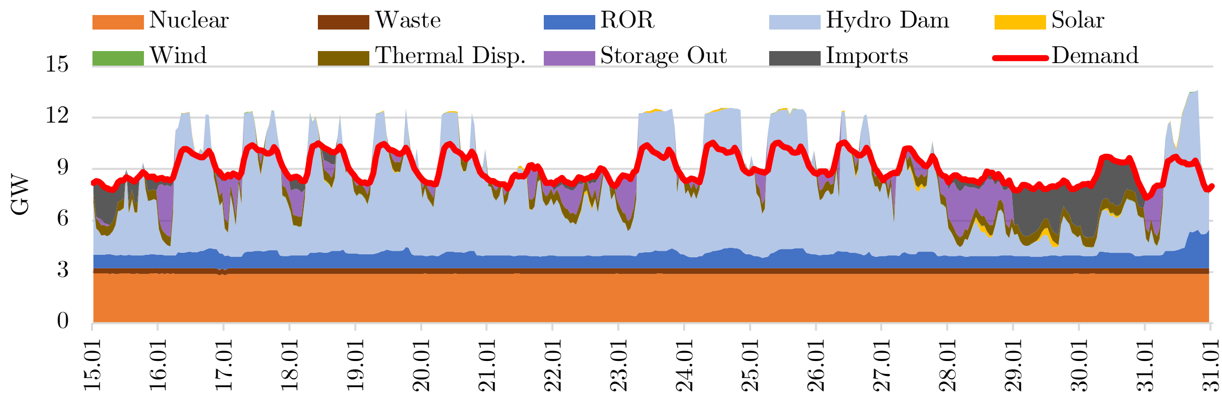


Figure 99: Simulated production and imports, historic demand, January 2017

Figure 98 and Figure 99 show the results for January 15th to 31st. We notice a higher baseload for nuclear, arising from the adjustment of the capacity factor in our model (see 3.2.1.1). The simulated hydro dam time series tends to overproduce in the off-peak hours and in the middle of the day compared to the reconstructed data. It does not exhibit the decrease in production as we already outlined in Figure 46. Thanks to the presence of surpluses in January, the storage model is able to charge the surplus and discharge in the deficit hours, which leads to a decrease in the imports. Note that during the second half of January, the storage model is in the low regime.

Figure 100 and Figure 101 show the comparison for August 15th to 31st. The nuclear, ROR, solar and wind time series of production are identical in both graphs. The main difference lies in the hydro dam model which tends to generally overproduce in the summer. The daily tendency of overproducing during the night and in the middle of the day is also visible in 2017, even after the correction of the bid price we introduce for the hydro dam model. We also show the comparison for the month of July in Figure 102 and Figure 103 where the hydro dam model does not fit the reconstructed data as well as for the month of August. The hydro dam production in the month of July should be considered as an outlier in an otherwise reliable model on average for 2017.

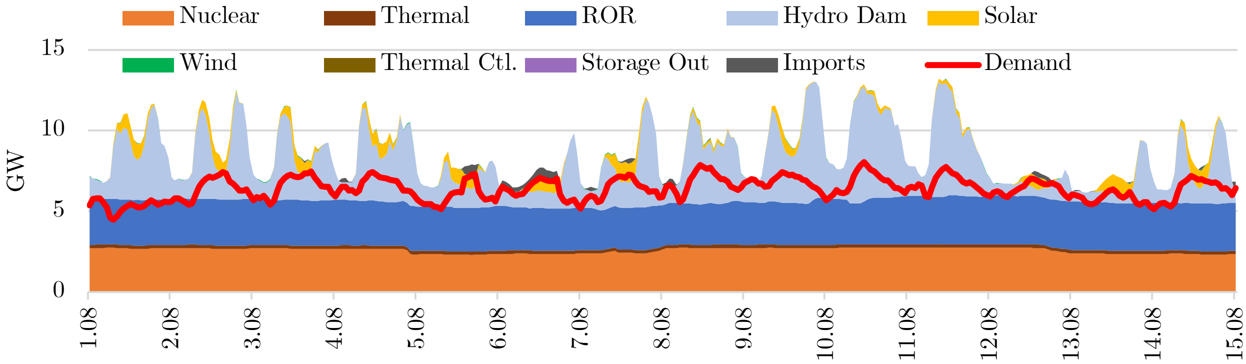


Figure 100: Reconstructed production and historic imports and demand, August 2017

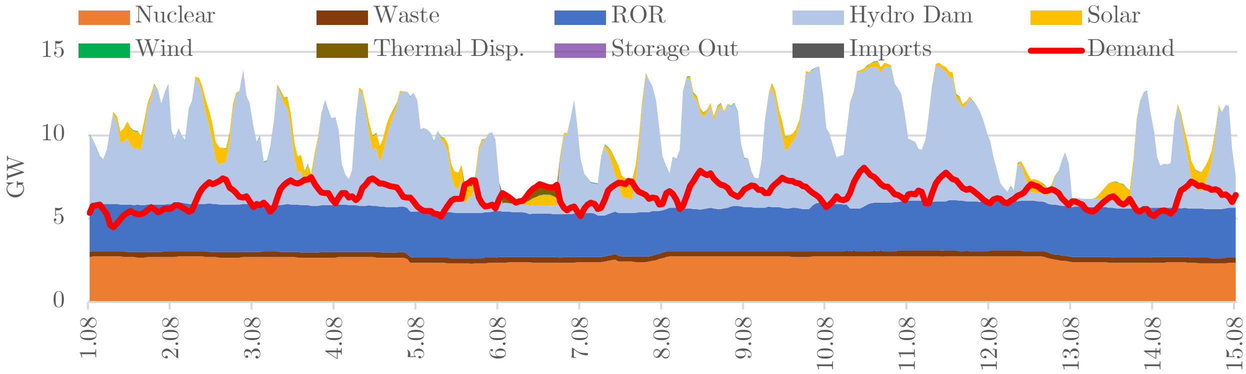


Figure 101: Simulated production and imports, historic demand, August 2017

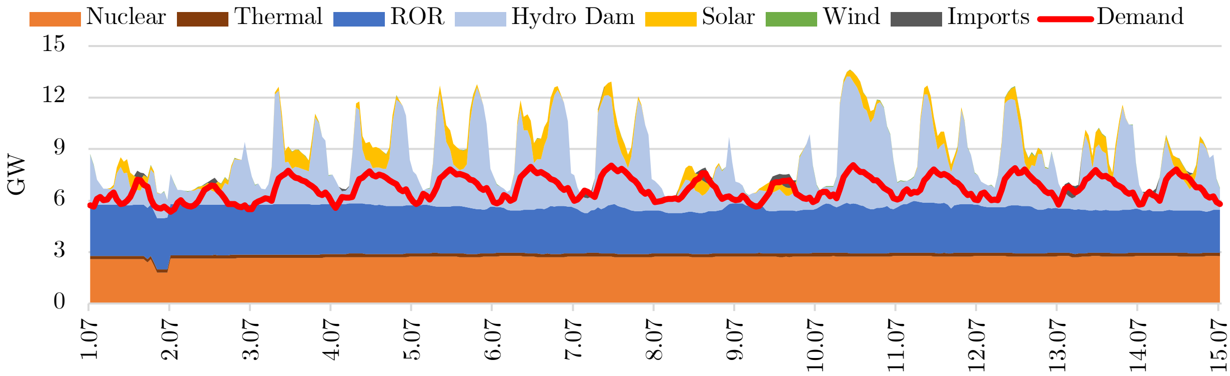


Figure 102: Reconstructed production and historic imports and demand, July 2017

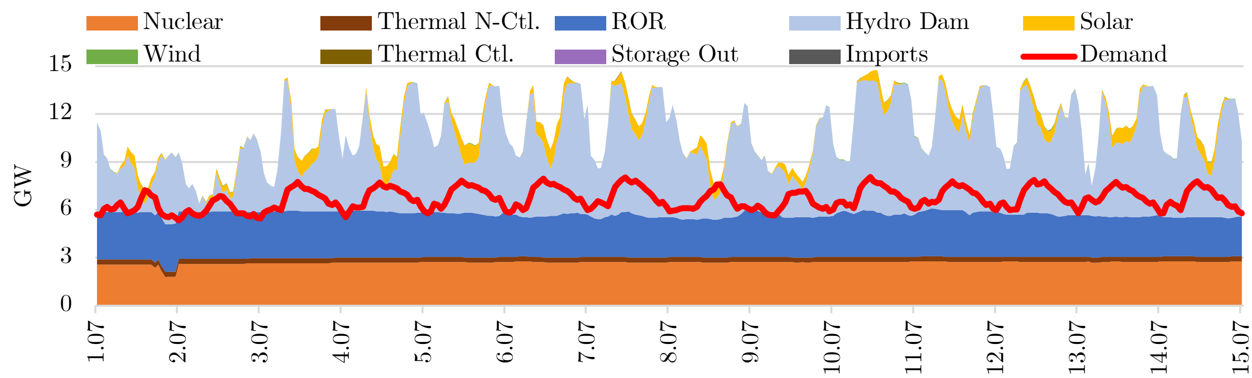


Figure 103: Simulated production and imports, historic demand, July 2017

C. Parameters of the hydro dam model

The hydro dam model relies on twelve parameter pairs (A, β) which mimic the market power structure leading to the hydro dam production curve. The parameter pairs (A, β) arising from the minimization of the Euclidean distance between the simulated and the reconstructed hydro dam production are shown in Table 43.

	A	$\boldsymbol{\beta}$
January	0.8	2.0
February	1.7	1.8
March	23.0	1.3
April	18.4	1.8
May	127.3	1.1
June	247.0	1.1
July	91.9	1.8
August	117.8	1.2
September	35.9	1.5
October	0.0007	3.9
November	0.0003	4.1
December	0.0002	4.1

Table 43: Optimized parameter pairs of the linear response function for the hydro dam production model

We continue by analyzing the effect of the variation of A and β on the simulated aggregated production in 2017 and on the MAPE between the 2017 simulated and reconstructed hydro dam production time series. Figure 104 and Figure 105 show the effect of varying β and A on the MAPE between the simulated and reconstructed 2017 hydro dam time series. We observe that the MAPE is very sensitive to variations of β, whereas varying A by 20% leads to a maximum of 3% change in the MAPE.

In Figure 106 and Figure 107, we study this effect on the yearly aggregated simulated hydro dam production. Unsurprisingly, increasing and decreasing A or β directly translates into an increased respectively decreased production. The magnitude of the variations are lower than for the MAPE, but we also observe that the parameters β have more effect on the production of electricity as the parameters A. This shouldn't come as a surprise as we remind that the quantity of electricity produced is equal to the parameter A multiplying the difference between the bid price and the marginal cost to the power β.

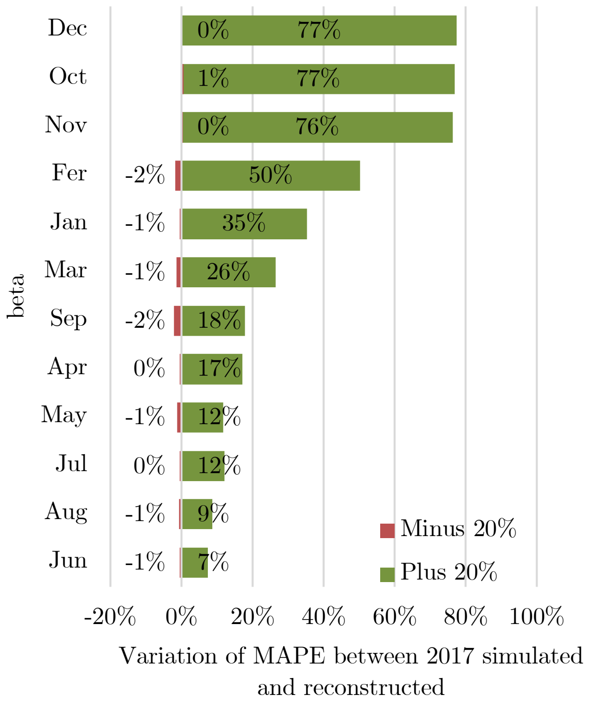


Figure 104: Tornado diagram presenting the sensitivity of the MAPE between the 2017 simulated and reconstructed hydro dam time series of on the 12 parameters β

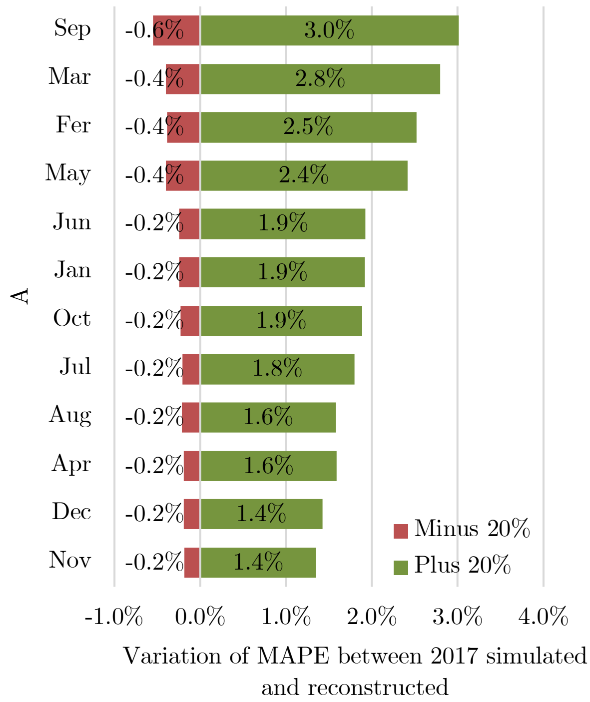


Figure 105: Tornado diagram presenting the sensitivity on the MAPE between the 2017 simulated and reconstructed hydro dam time series of the 12 parameters A

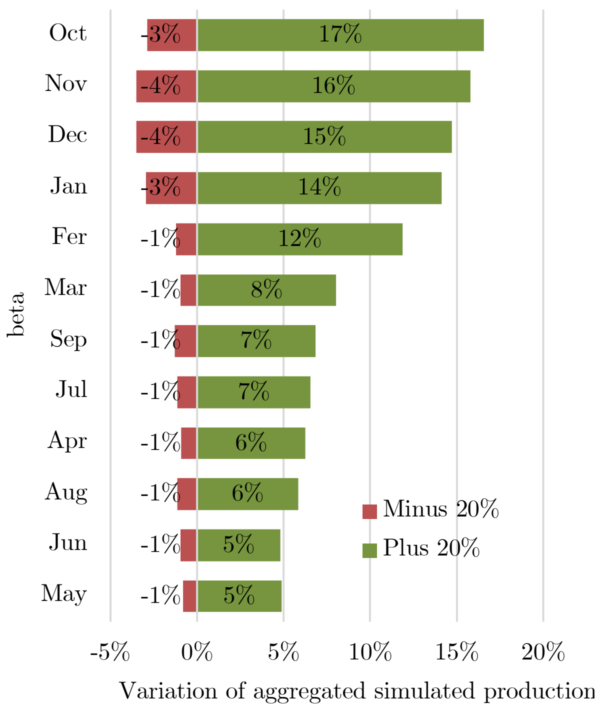


Figure 106: Tornado diagram presenting the sensitivity of the annual 2017 production on the 12 parameters β

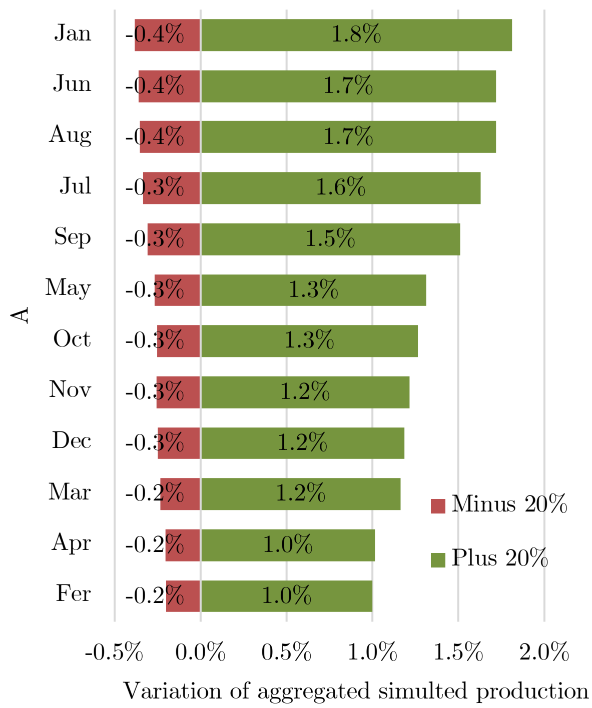


Figure 107 Tornado diagram presenting the sensitivity of the annual 2017 production on the 12 parameters A

D. Choice of Storage Strategy

Stationary Electrical Storage Systems (SES) are multi-purpose technologies (Battke & Schmidt, 2015). It means that they have "different sources of value creation and [are] used by different customers groups.". A sensible use of SES in the supply chain can be found on the generation side, in the transmission and distribution network or directly at the end consumer (private or industrial) (Battke & Schmidt, 2015). The strategies used to generate economic value are various, with for example arbitrage, power quality or reliability. At the grid level there are several possibilities for value creation like load following, load shifting or seasonal storage. The supply model we develop has as leading objective the minimization of imports without cost considerations. A load following strategy would not meet these conditions but seasonal storage could.

We saw in chapter 2 that, in Switzerland, the demand is higher in winter than summer, whereas the production is larger in summer than winter. With the ability to shift production from one month to another, SES can contribute reducing the deficit between demand and generation in winter. The strategy would be similar to load shifting, with the batteries and reservoirs filled during hours of surplus in summer and emptied in winter during deficit hours. One could reserve some of the storage capacity for seasonal load shift and the other for daily load shift.

However, given the size of the batteries one can reasonably assume for Switzerland, seasonal storage is out of reach as one would need storage capacities of the order of 3.2 to 4.0 TWh in order to be able to shift all surpluses in deficit hours, with the 2017 electricity mix, as calculated in section 2.3.2. When nuclear production is replaced by solar and wind, the necessary storage capacities reach 5.8 to 7.3 TWh. These storage sizes are at best 13 to 24 times bigger than the 240 GWh estimated pumped hydro storage size in 2017 by (Piot, 2014). We hence exclude any seasonal storage from our model.

E. Electricity Storage Model, Mathematical Formulation

In this section we complete section 3.2.4 with a more formal formulation of the storage model's constraints. At the start of each day, the model calculates the objective amount of electricity to charge and discharge based on the sizes of the deficit and surplus during the day.

Box 4 shows a pseudocode for the formulation of Constraints 1, 3 6 and 7 of Box 3 for the objective amounts to charge and discharge during the day. The time series of charging arise from a simple algorithm which reduces the surplus by the wished quantity by minimizing its maximum, under the constraint that the storage level stays below 100% and that the amount of electricity charged per hour is lower than the charging power. The algorithm for reducing the deficit is strictly identical, but insures that the storage level stays above 0%. The python code for the algorithms can be obtained by writing an email to the author (scott.reiser@protonmail.com).

if $(\sum_h surplus_h) \times \eta > \sum_h deficit_h$:

$$discharge_{day} = \sum_h deficit_h$$

$$\max chargeable_{day} = 85\% \times storage_{max} - storage_{h=0} - discharge_{day}/\eta$$

$$charge_{day} = \min\left(\sum_h surplus_h, \max chargeable_{day}\right)$$

else:

$$charge_{day} = \sum_h surplus_h$$

$$\max dischargeable_{day} = storage_{h=0} - 15\% \times storage_{max} + charge_{day}$$

$$discharge_{day} = \min\left(\sum_h deficit_h, \max dischargeable_{day}\right)$$

Box 4: Determining how much to charge and discharge during the day. h stands for hour within the modelled day, h=0 for the beginning of the day, $charge_{day}$ and $discharge_{day}$ are the amount of electricity we wish to charge and discharge over the day.

F. Choice of Supply-side Scenario Parameters

The scenario analysis relies on the variation of the solar PV, wind, nuclear and thermal power capacities. In this section, we present and justify our choice of supply scenario parameters for these technologies.

Solar PV

In 2017, the installed Solar PV power capacity was 1906 MWp, with a produced electricity of 1683 GWh (SFOE, 2017, c), this corresponds to a 10.1% capacity factor. We make our assumption for the future of solar PV based on aggregated production data. This is motivated by the fact that the majority of solar PV production estimates in the literature are given in TWh per year rather than in installed capacities. It hence facilitates the comparison with existing works.

We developed our projection of solar PV production in the future based on reports from Prognos (Prognos, 2012), the SFOE (SFOE, 2011) and the association of Swiss Electricity Companies ("Verband Schweizerischer Elektrizitätsunternehmen", VSE) (VSE, 2012). We develop three variants which shown in Table 44. Comparisons with the estimates from the SFOE, Prognos and the VSE are shown in Figure 108.

Solar PV Production [TWh]	*2017*	*2030*	*2050*
Low	1.7	3	5.5
Middle		5	9
High		5.5	14

Table 44: Solar PV production assumption in 2030 and 2050

In the high variant, it is assumed that the policy instruments accelerating the adoption of solar panels are successful, and that the decreasing price per panel contributes to a strong growth of the Swiss solar sector. The low variant exhibit a different trend where the growth stabilizes to be linear. The low estimate for 2050 matches the lowest estimate from Prognos (Prognos, 2012). By keeping the Solar PV capacity factor constant at 10.1%, we can obtain the installed capacity corresponding to the generation from Table 44. We show the installed capacities in Table 45.

Figure 108 shows the comparison of our assumptions with the ones from the SFOE, VSE and Prognos. Our estimates for 2030 are all superior to the ones found in the literature for 2035, this is because the estimates from SFOE, VSE and Prognos were made respectively in 2011 for SFOE and 2012 for the VSE and Prognos. In 2050 however, we adapted our estimates to the numbers from the three aforementioned reports, taking the lowest estimation for our low variant, and the highest for the high variant.

Solar PV Capacity [GWp]	*2017*	*2030*	*2050*
Low		3.4	6.2
Middle	1.9	5.6	10.2
High		6.2	15.9

Table 45: Solar PV power capacity assumption in 2030 and 2050

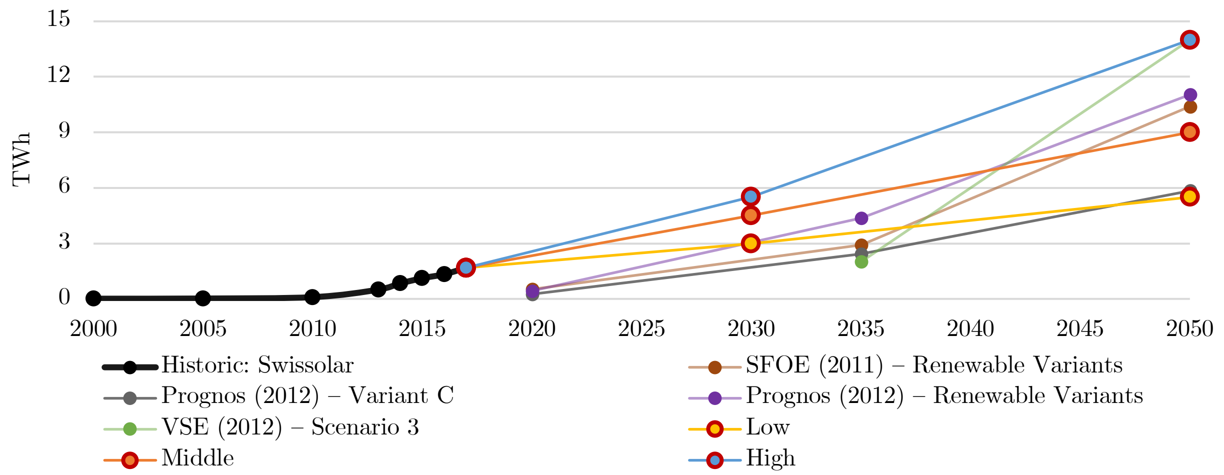


Figure 108: Predicted solar PV electricity production in 2030 and 2050

Wind

In 2017, the installed wind capacity was 75 MW with an annual production of 132 GWh (SFOE, 2017, c), this corresponds to a yearly capacity factor of 20.1%. Our three wind variants are based on the estimates of maximal onshore wind potential in Switzerland by Bauer, Hirschberg et al. (Bauer & Hirschberg, 2017). The capacities are given in Table 46.

Wind Capacity [MW]	*2017*	*2030*	*2050*
Low		150	250
Middle	75	500	1000
High		753	1789

Table 46: Wind power capacity assumptions for 2030 and 2050

Bauer and Hirschberg estimate the achievable wind potential in Switzerland in 2035 to lie between 0.7 and 1.7 TWh/a, and between 1.4 and 4.3 TWh/a in 2050. The average of both ranges multiplied by the constant wind capacity factor of 20.1% leads to the high power capacity estimates in Table 46. The realization of the estimates from the middle and high variants would require drastic improvement in public acceptance and a fading of the recurring oppositions that block the construction of new wind turbines and wind parks in Switzerland.

Nuclear

We also develop three variants for nuclear capacity. The first variant, called "Shutdown" follows the Energy Strategy 2050 with the progressive phasing out of nuclear. Each nuclear power plant should be taken off the grid after 50 years of operation, this means 2019 for Beznau 1 (365 MW) and Mühleberg (373 MW), 2022 for Beznau 2 (365 MW), 2029 for Gösgen (1010 MW) and 2034 for Leibstadt (1220 MW). The second variant corresponds to a simple replacement of the power plants once they reach their maximal lifetime. In this variant, the installed capacity stays constant over time. In the "New Generation" variant, it is assumed that instead of stopping its nuclear activities, Switzerland installs additional nuclear capacity. The power capacities corresponding to the three nuclear variants are given in Table 47.

Nuclear Capacity [MW]	*2017*	*2030*	*2050*
Shutdown		1220	0
Replacement	3333	3333	3333
New Generation		4000	5000

Table 47: Nuclear power capacity assumptions for 2030 and 2050

Thermal

Thermal electricity played a small role in the Swiss electricity system in 2017. With only 2.8 TWh of electricity generated with 990 MW installed, it contributed to only about 4% of the electricity generation in Switzerland. The Energy Strategy 2050 however counts on those electricity sources for renewable electricity, especially on biogas and biomass. In addition to these renewable sources we consider combined-cycle gas turbines (CCGT) as a cost competitive controllable source of electricity for Switzerland (Diaz, Van Vliet, & Patt, 2017).

Thermal electricity production is composed of two categories: renewable thermal and fossil thermal. Additionally, these can be either controllable or non-controllable supply sources. We develop three variants which differ in their shares of renewable and fossil installed capacities but also in the share which is controllable or not. The three variants are: Green, Constant and Gas Controllable.

The Green variant is mainly based on the development of thermal renewable sources. In the Constant variant the thermal renewable capacity slowly increases until 2050 and the thermal fossil capacity stays constant over time. Finally, the Gas Controllable variant has a similar slow increase of the thermal renewable capacity as the Constant variant, on the thermal fossil side however there is a large growth corresponding to an increase in the CCGT capacity. The capacities are shown in Table 48 and Table 49.

The high thermal renewable capacity in the Green variant for 2050 would consist primarily of biomass and biogas. Even working at full capacity for the 8760 hours of the year, this is well within the biomass theoretical potential of 209 PJ (58 TWh) as estimated by the Swiss Federal Institute for Forest, Snow and Landscape Research (Thees, Burg, Erni, Bowman, & Lemm, 2017).

In translating the thermal fossil and renewable in non-dispatchable and dispatchable we assume that biogas, biomass and CCGT are dispatchable supply sources and that waste incineration is non-dispatchable. The dispatchable and non-dispatchable power capacities are the inputs of the electricity model presented in the last chapter.

Thermal Renewable Capacity [MW]	*2017*	*2030*	*2050*
Green		1065	1565
Constant	625	715	815
Gas Controllable		705	815
Thermal Fossil Capacity [MW]	*2017*	*2030*	*2050*
Green		365	365
Constant	365	365	365
Gas Controllable		1335	2615

Table 48: Fossil and renewable thermal power capacities assumptions for 2030 and 2050

Dispatchable Capacity [MW]	*2017*	*2030*	*2050*
Green			
Constant	423	430	430
Gas Controllable			
Non-dispatchable Capacity [MW]	*2017*	*2030*	*2050*
Green		1000	1500
Constant	568	650	750
Gas Controllable		1400	3000

Table 49: Dispatchable and non-dispatchable thermal power capacities assumptions for 2030 and 2050

G. Supply Model Input Parameters

Supply Scenario	*Green Wave*		*Back to the Atom*		*Resilience*	
Year	*2030*	*2050*	*2030*	*2050*	*2030*	*2050*
Nuclear capacity [MW]	1220	0	4000	5000	3333	3333
Solar capacity [MWp]	6229	15855	3398	6229	5663	10193
Wind capacity [MW]	753	1798	150	250	500	1000
Run-of-river production [TWh]	16.4	16.9	16.4	16.9	16.4	16.9
Thermal						
Thermal dispatchable capacity [MW]	1000	1500	650	750	1400	3000
Thermal non-dispatchable capacity [MW]	430	430	430	430	430	430
Biogas capacity [MW]	150	300	85	100	140	300
Biomass CHP capacity [MW]	700	1050	415	500	140	300
CCGT capacity [MW]	150	150	150	150	1120	2400
Waste Incineration capacity [MW]	430	430	430	430	430	430
Hydro dam						
Storage size [TWh]	9	9.5	9	9.5	9	9.5
Marginal cost [€/MWh]	9.13	9.13	9.13	9.13	9.13	9.13
Min operational capacity [MW]	500	500	500	500	500	500
Turbine capacity [MW]	8300	8500	8300	8500	8300	8500

Supply Scenario	*Green Wave*		*Back to the Atom*		*Resilience*	
Year	*2030*	*2050*	*2030*	*2050*	*2030*	*2050*
Pumped Hydro Storage						
Storage size [GWh]	404	404	404	404	404	404
Charging capacity [MW]	4800	4800	4800	4800	4800	4800
Discharge capacity [MW]	5200	5200	5200	5200	5200	5200
Efficiency	80%	80%	80%	80%	80%	80%
Lithium Ion batteries						
Storage size [GWh]	5	10	5	10	5	10
Charging capacity [MW]	1000	2000	1000	2000	1000	2000
Discharge capacity [MW]	1000	2000	1000	2000	1000	2000
Efficiency	92%	94%	92%	94%	92%	94%

Table 50: Green Wave, Back to the Atom and Resilience supply scenarios, model input parameters

H. Choice of Demand-side Scenario Parameters

The three demand scenarios rely on the contribution of demand per capita changes and the extent of EV penetration. In this section we present and justify our choice of demand scenario parameters.

Demand per Capita

In the scenario analysis, we consider three cases for the evolution of demand per capita: Decrease, Stabilization and Increase. Our assumptions are based on other scenario analyses performed by Prognos (Prognos, 2012), the VSE (VSE, 2012) and a study from ETH Zürich (Andersson, Boulouchos, & Bretschger, 2011). The demand per capita assumptions are given in Table 51.

Demand per capita [MWh/a]	*2017*	*2030*	*2050*
Decrease	6.9	6.5	5.8
Stabilization		7.3	7.0
Increase		7.9	8.3

Table 51: Demand per Capita assumptions for 2030 and 2050

The demand per capita in 2017 was 6.9 MWh/a (SFOE, 2017, a). The Decrease variant would hence mean that the demand per capita (excluding EV charging) would need to be reduced by about 6% in 2030 and 16% by 2050, compared to the 2017 level. This corresponds to the scenario "Political Measures" (PM) of the Prognos study, ordered by the SFOE for the consultation on the Energy Strategy 2050. The stabilization scenario is in sync with the study from the VSE leading to a small increase by 2030 followed by a small decrease until 2050. Finally, the increase scenario means a significant growth in per capita consumption, namely plus 14% in 2030 and plus 20% in 2050, which corresponds to the consequences of an accelerating electrification of the Swiss economy.

EV Penetration

The simulation of the future BEV car fleets depends on a simulated share of BEVs in new registrations. We develop three variants for BEV penetration. The first one is based on a linear increase, following an extrapolation of the evolution between 2012 and 2017, where the BEV stock grew from 924 to 4929 (SFOS, 2015, b), that is an increase from 433%. This variant is called Linear Low. In the two other variants, the growth of BEV share in new registration follows a logistic function.

$$f(x) = \frac{L}{1 + e^{-k(x-x_0)}}$$

Equation 9: Logistic Function with parameters L, k, x, x_0

Adoption and diffusion of new technologies often follow an S-shaped increase (De Tarde, 1903; Zvi, 1957; Rogers, 2010)Such logistic growth rates have also been used in the analysis of EV market diffusion (Plötz, Gnann, & Wietschel, 2013; McCoy & Lyons, 2014). We choose to base the midle and high BEV penetration variants on a logistic diffusion, with different parameters. The shapes of the diffusion curves in the new registrations are shown in Figure 109 and the resulting BEV share in car fleet is visible in Figure 110. The key data used for the generating the diffusion curves as well as the exact resulting BEV stocks are presented in Table 52 and Table 53.

BEV penetration Variant	*New registration curve*
Linear Low	Linear increase (linear extrapolation of 2012-2017 evolution)
Logistic Middle	Logistic increase (L=0.5, k = 0.4, x0 = 2040)
Logistic High	Logistic increase (L=0.9, k = 0.3, x0 = 2029)

Table 52: BEV share in new registrations' curve for the three BEV penetration scenarios

BEV stock (share of total fleet)	*2030*	*2050*
Linear Low	133’635 (3%)	449’615 (8%)
Logistic Middle	269’464 (5%)	2’081’392 (38%)
Logistic High	765’716 (15%)	3’901’022 (70%)

Table 53: BEV stock and share of BEVs in the total car fleet arising from the car stock flow model and the new registration curves.

The Foundation for Technology Assessment Switzerland (TA Swiss) carried out in 2013 a project studying the opportunities and risks of electromobility in Switzerland, where they use a scenario analysis to study the future size of the EV fleet in Switzerland (De Haan & Zah, 2013). They do not assume anything about the shape of the adoption curve but simply give estimates for the share in new registrations. Compared to their estimates, our logistic high penetration scenario exhibits a steeper curve of adoption until 2030 and a stabilization starting in 2040. It should be considered as an extreme scenario. The logistic middle scenario follows a slow logistic growth until 2045 and starts stabilizing only then. Finally, the linear low scenario is the most pessimistic and describes a future in which electrical vehicles find only a low acceptance leading to a low adoption in the Swiss population.

Note that none of the logistic scenarios will reach a BEV share of 100% in new registrations. It is always assumed that other type of cars (be it ICE, hydrogen-power cars or else) will be part of the swiss fleet by 2050.

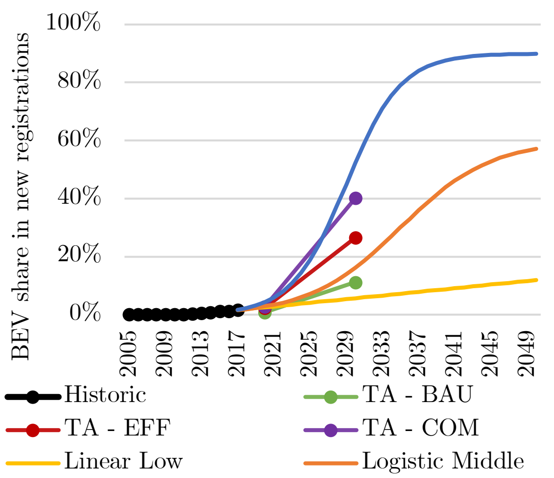


Figure 109: EV shares in new registrations, TA stands for Technology Assessment, BAU, EFF and COM are scenarios of (De Haan & Zah, 2013)

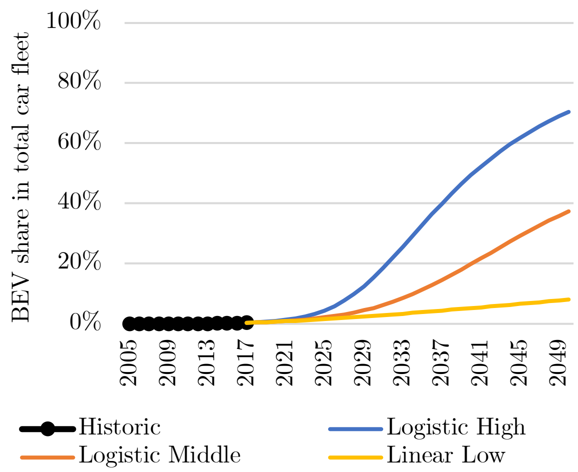


Figure 110: Simulated EV share in total car fleet according to the three penetration scenarios

Total Demand

We finish by comparing the resulting aggregate demand, that is the demand per capita and EV charging contributions, over the years 2030 and 2050 with the results from Prognos (Prognos, 2012), the VSE (VSE, 2012) and the ETH study from (Andersson, Boulouchos, & Bretschger, 2011). The comparison can be seen in Figure 111. Our low demand scenario is in phase with the low estimates coming from these three studies for 2050. The high demand scenario however is more extreme than the high scenario from (Andersson, Boulouchos, & Bretschger, 2011) predicting 92 TWh consumption in 2015 and it further confirms that this scenario should be considered as an extreme case. Finally, the middle demand scenario leads to an electrical consumption which is 6.1 TWh above the average of the scenarios estimates for 2030 and 8 TWh above the average 2050 values. This is something to keep in mind when analyzing the results.

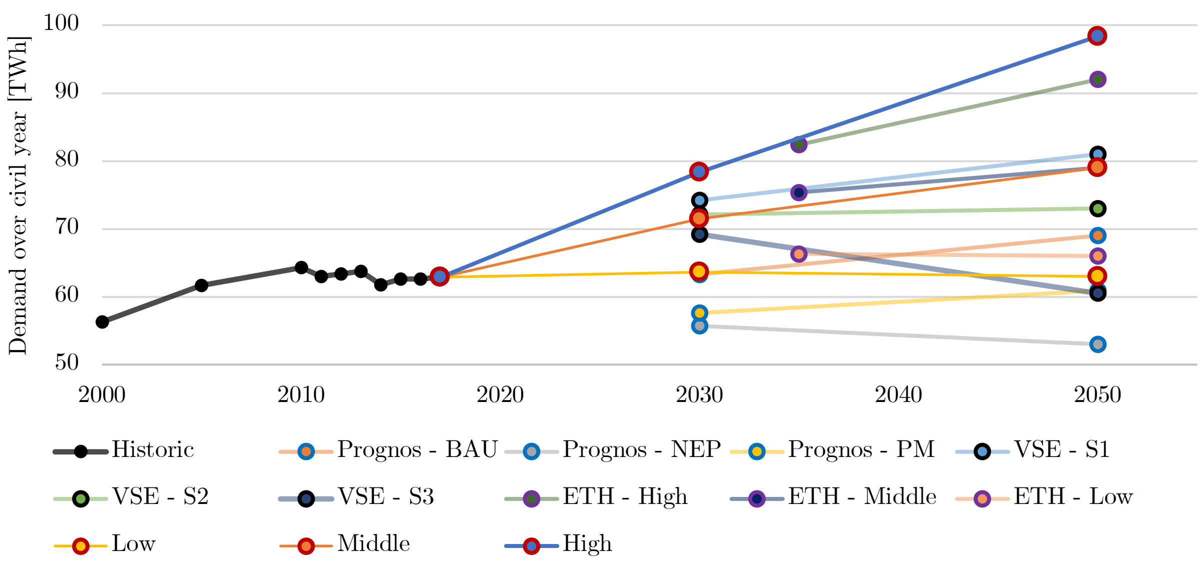


Figure 111: Comparison of aggregated demand in 2030 and 2050 with other scenario analyses. The three Prognos scenarios are Business as Usual (BAU), New Energy Policy (NEP) and Political Measures (PM).

I. Sensitivity Analysis of Aggregate Demand

The aggregate demand depends mainly on three parameters: the population size, the demand per capita assumption and the size of the EV fleet. In this section, we analyze the sensitivity of the annual aggregated demand to those three parameters by looking more closely at the middle demand scenario.

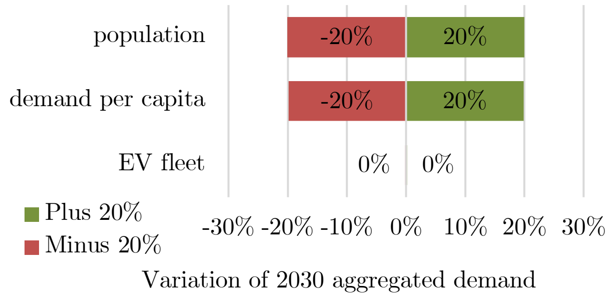


Figure 112: Tornado diagram presenting the sensitivity of the 2030 annual demand on the population size, demand per capita and EV fleet. The calculation are based on the middle demand scenario.

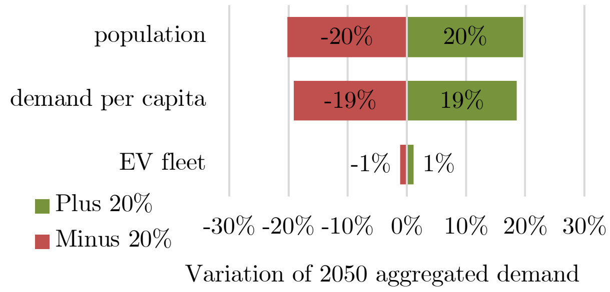


Figure 113: Tornado diagram presenting the sensitivity of the 2050 annual demand on the population size, demand per capita and EV fleet. The calculation are based on the middle demand scenario.

Figure 112 and Figure 113 show that population and demand per capita variations translate almost one-to-one into aggregate demand in the middle demand scenario in 2030 and 2050. The effect of the population size comes first as the EV fleet also depends on the population size too. In 2050 the size of the EV fleet is higher than 2030 and hence the effect of its variation is larger. Compared to the population size and the demand per capita however, its role is only minor. The population and demand per capita assumptions are therefore central determinants of aggregate demand.

We continue by looking at the effect of population, demand per capita and EV fleet on the maximal demand power. We first show in Figure 114 the EV charging load for a typical day for the three EV penetration scenarios. The electricity needs for of EV charging in 2030 are modest, as they oscillate between 0.01 GW (Linear Low variant) and 0.22 GW (Logistic High variant) maximal demand. In 2050 however, the difference is substantial with a peak of 0.6 GW (Logistic Middle variant) and 1.12 GW (Logistic High variant) at 20:00.

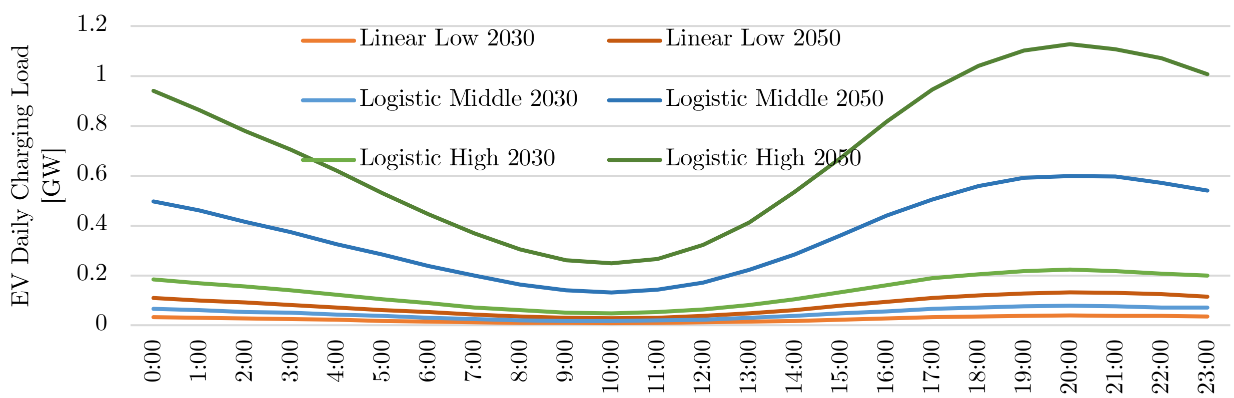


Figure 114: EV daily charging load arising from the car stock flow and charging model from section 3.1.2.

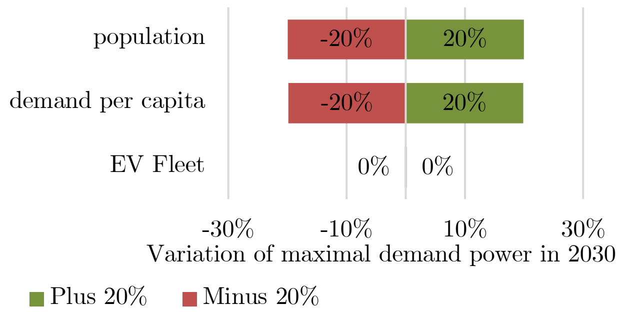


Figure 115: Tornado diagram presenting the sensitivity of the 2030 maximal demand on the population size, demand per capita and EV fleet. The calculation are based on the middle demand scenario.

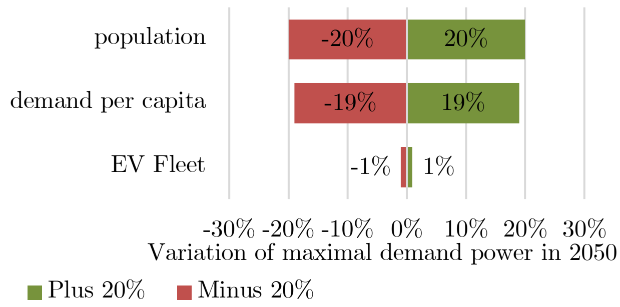


Figure 116: Tornado diagram presenting the sensitivity of the 2050 maximal demand on the population size, demand per capita and EV fleet. The calculation are based on the middle demand scenario.

Figure 115 and Figure 116 show in more details the sensitivity of the maximal demand power in 2030 and 2050 for the middle demand scenario on the three key parameters. We observe very similar results as for the aggregate demand. The biggest drivers for maximal demand are here also population and demand per capita. This analysis illustrates the moderate effects of EV charging on demand power and aggregate demand.

J. Green Wave Scenario Additional Results

In this section, we show the results of the simulation for the Green Wave scenario in 2030 and 2050 in the low and high demand conditions.

Electricity Production and Consumption

Low Demand

In the low demand conditions, the Green Wave scenario relies less on imports. Figure 117 and Figure 118 show that there is some surplus in the winter in the low demand scenario which allows the storage to perform some load shifting. In the summer the demand is met by the renewable electricity sources.

High Demand

In the high demand scenario, electricity production in winter is insufficient and leads to large imports needs (see Figure 119 and Figure 120). In the summer however, even if demand is high, the surpluses can be shifted thanks to the storage capacity and demand can be met without imports.

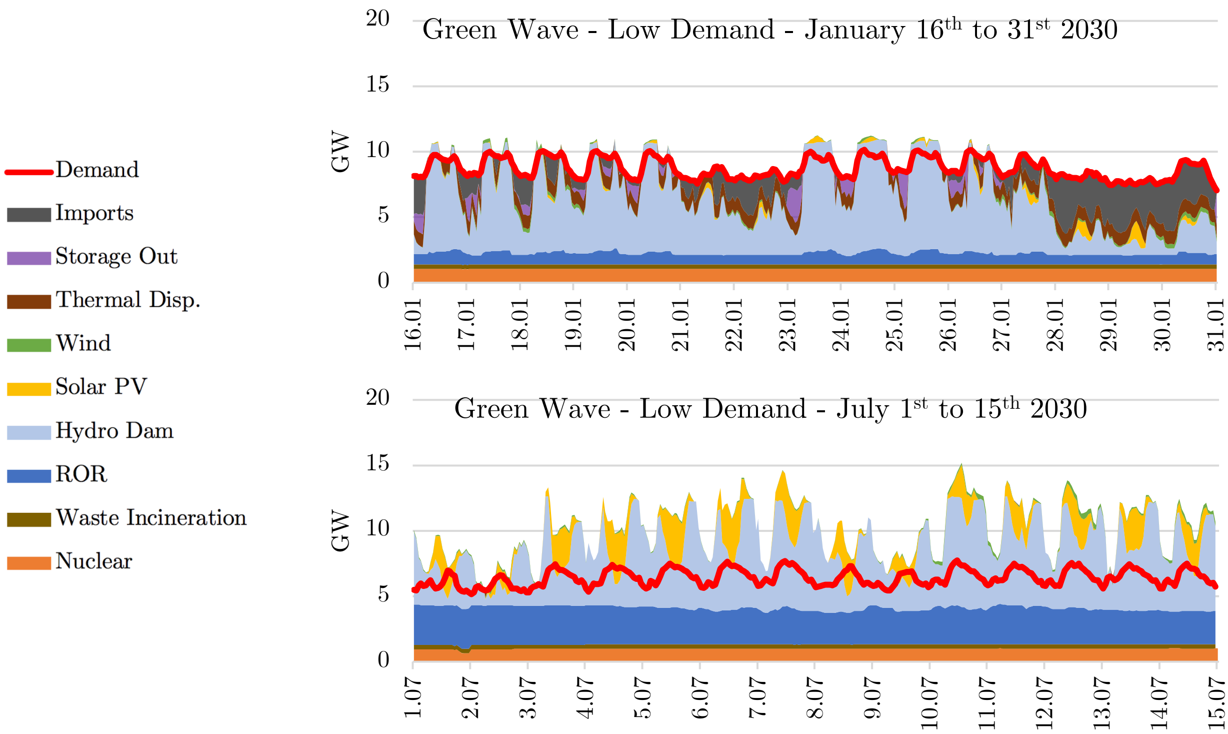


Figure 117: Green Wave scenario, simulated electrical production and consumption for January 16th to 31st and July 1st to 15th 2030 in the low demand scenario

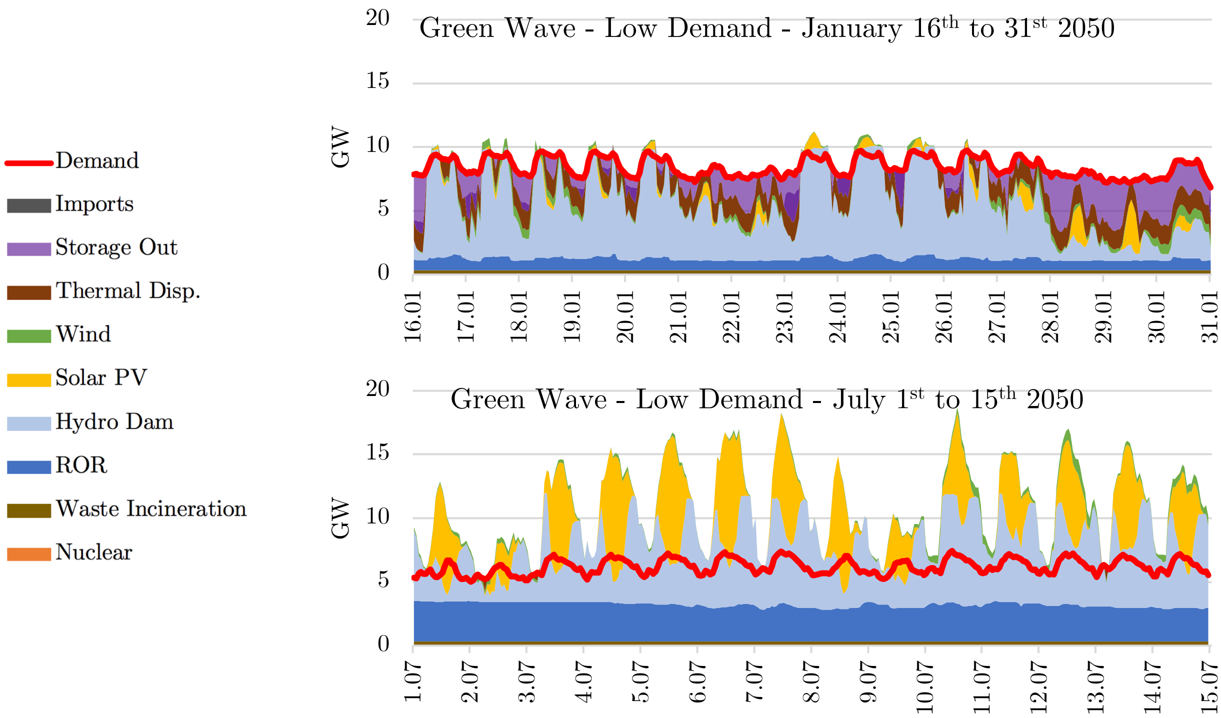


Figure 118: Green Wave scenario, simulated electrical production and consumption for January 16th to 31st and July 1st to 15th 2050 in the low demand scenario

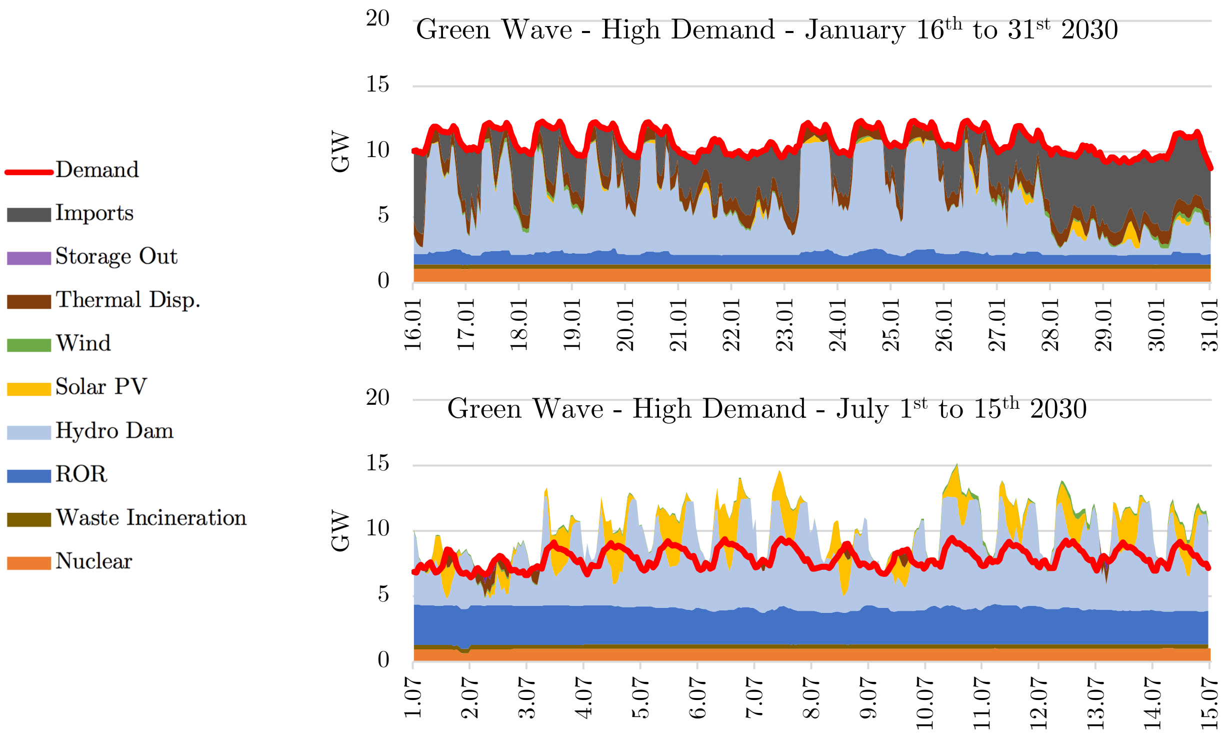


Figure 119: Green Wave scenario, simulated electrical production and consumption for January 16^{th} to 31^{st} and July 1^{st} to 15^{th} 2030 in the high demand scenario

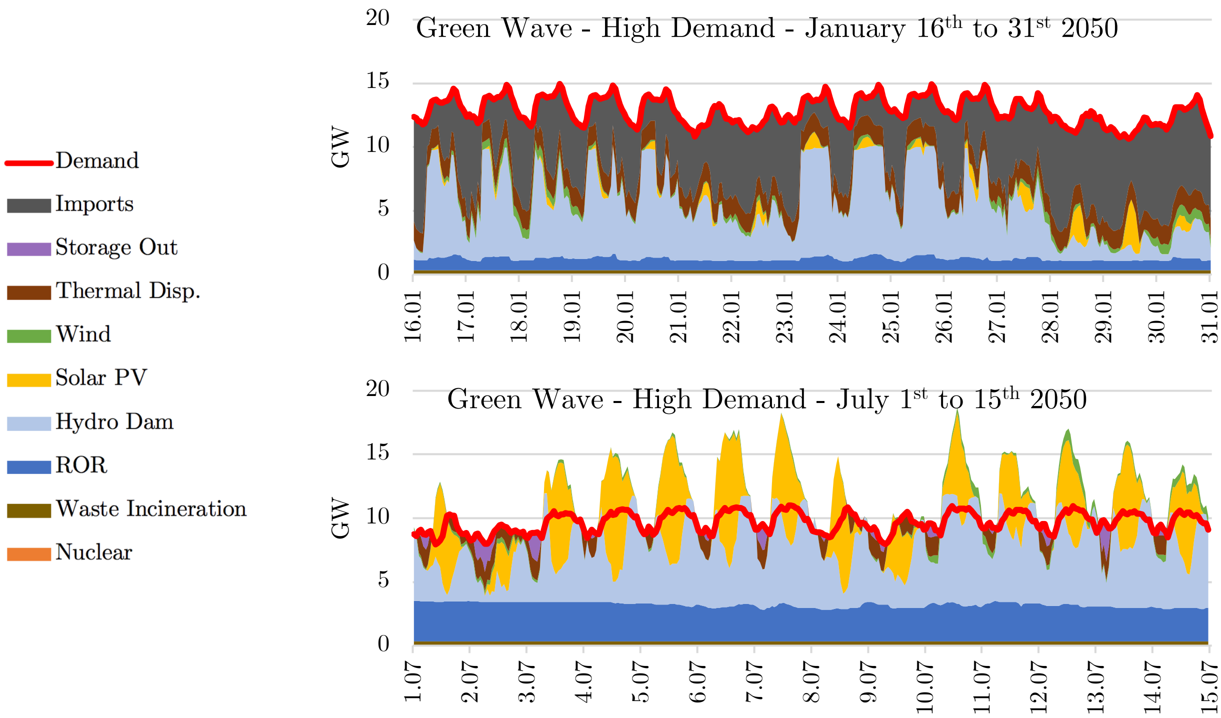


Figure 120: Green Wave scenario, simulated electrical production and consumption for January 16^{th} to 31^{st} and July 1^{st} to 15^{th} 2050 in the high demand scenario

Imports and Exports

	Share of demand covered by imports [%]					
Year	*2030*			*2050*		
Demand Scenario	*Low*	*Middle*	*High*	*Low*	*Middle*	*High*
January	18	26	31	18	32	44
February	34	41	46	25	39	50
March	12	21	27	4	21	34
April	0	0	3	0	0	10
May	0	0	0	0	0	4
June	0	0	0	0	0	0
July	0	0	0	0	0	0
August	0	0	0	0	0	0
September	0	0	0	0	0	3
October	5	13	20	0	16	32
November	12	21	27	9	25	37
December	21	30	35	17	32	43

Table 54: Green Wave scenario, monthly breakdown of the simulated share of demand covered by imports in 2030 and 2050 for the low, middle and high demand scenarios

	Share of production exported [%]					
Year	*2030*			*2050*		
Demand Scenario	*Low*	*Middle*	*High*	*Low*	*Middle*	*High*
January	0	0	0	0	0	0
February	0	0	0	0	0	0
March	0	0	0	0	0	0
April	9	0	0	18	2	0
May	20	10	0	30	14	1
June	36	28	21	45	31	13
July	35	28	21	43	29	13
August	34	26	19	41	27	10
September	19	10	3	28	12	0
October	0	0	0	1	0	0
November	0	0	0	0	0	0
December	0	0	0	0	0	0

Table 55: Green Wave scenario, monthly breakdown of the simulated share of production exported in 2030 and 2050 for the low, middle and high demand scenarios

K. Back to the Atom Scenario Additional results

In this section, we show the results of the simulation for the Back to the Atom supply scenario in 2030 and 2050 in the low and high demand conditions.

Electricity Production and Consumption

Low Demand

In the low demand conditions, the nuclear and hydro power sources are sufficient to meet demand in July. In the winter, the presence of surpluses enables the storage plants to perform load shift and fill the deficit when needed (see Figure 121 and Figure 122). In 2050, the large nuclear and run-of-river baseloads produce more than is consumed in the month of July.

High Demand

In the high demand scenario, Switzerland need to import electricity in the winter, especially in the weekends (see 21.01-22.01 and 28.01-29.01 in Figure 123 and Figure 124) when the electricity prices and hydro dam production are low. In July, the power generation from the nuclear and hydro sources exceeds demand.

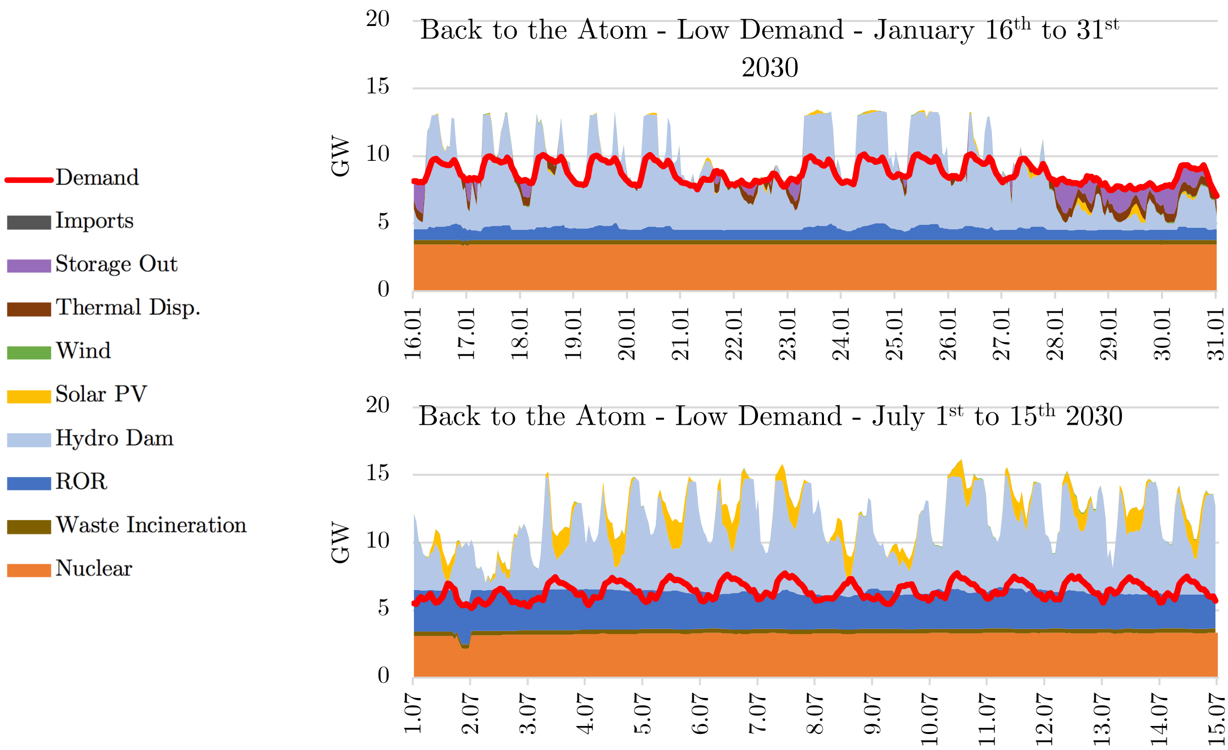


Figure 121: Back to the Atom scenario, simulated electrical production and consumption for January 16th to 31st and July 1st to 15th 2030 in the low demand scenario

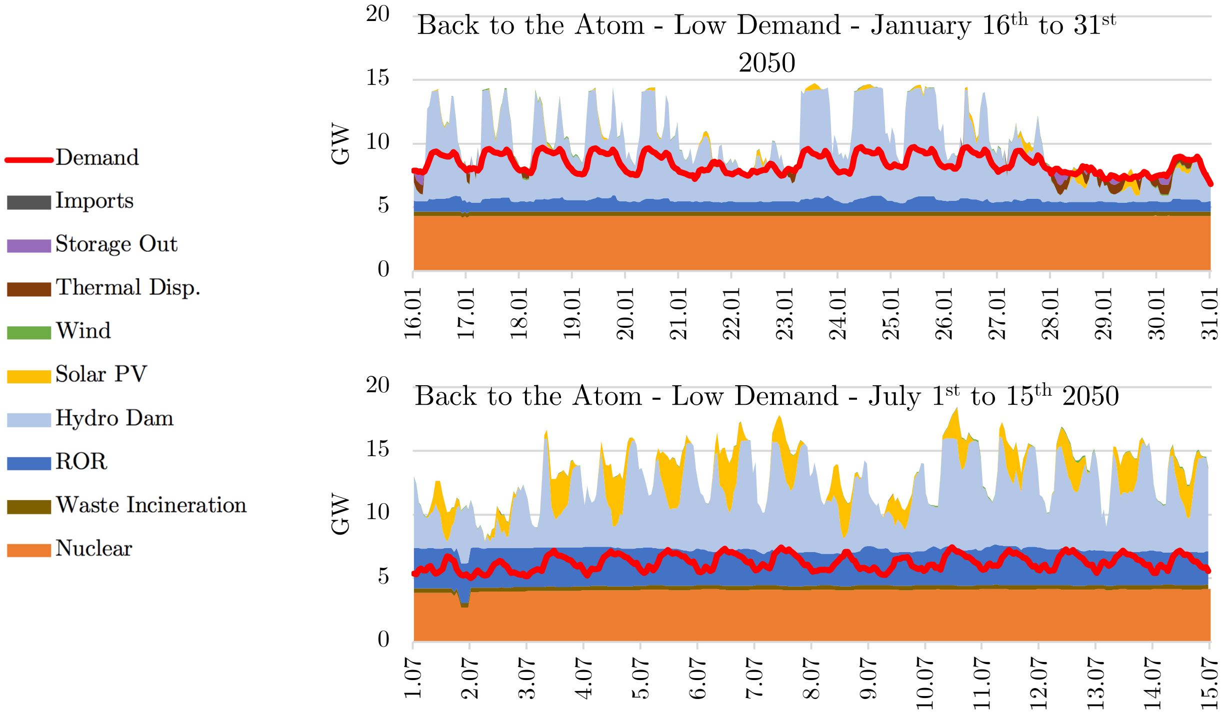


Figure 122: Back to the Atom scenario, simulated electrical production and consumption for January 16th to 31st and July 1st to 15th 2050 in the low demand scenario

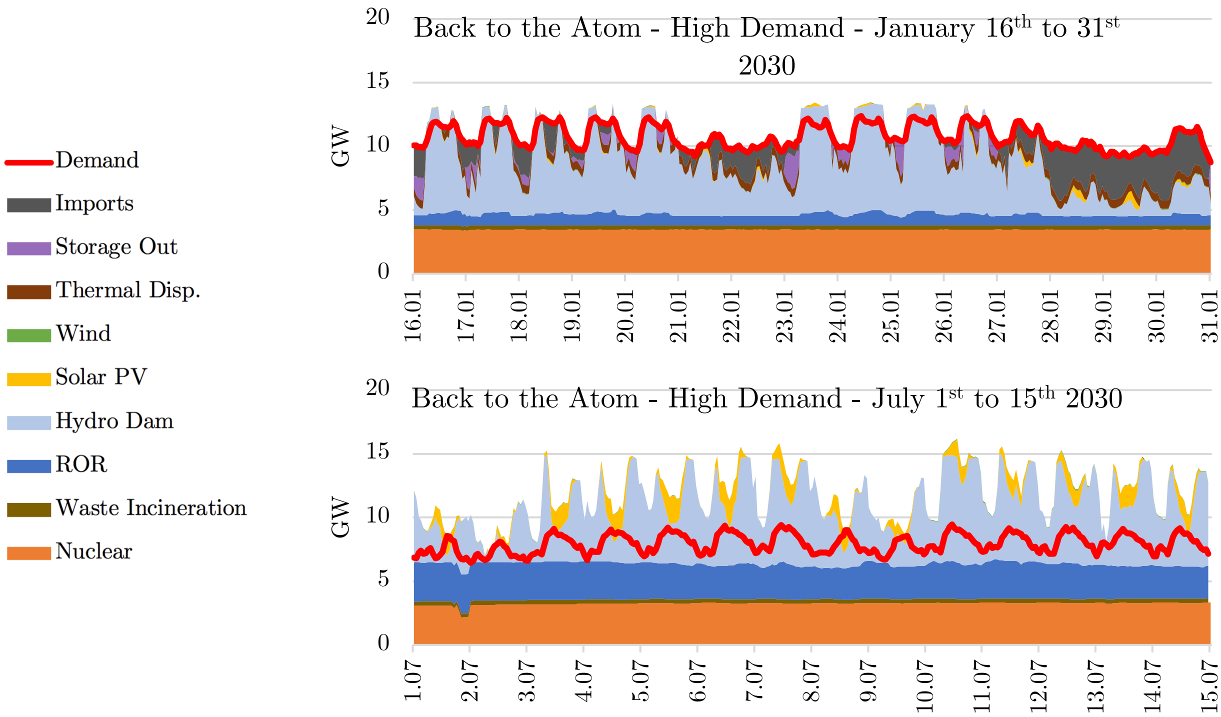


Figure 123: Back to the Atom scenario, simulated electrical production and consumption for January 16th to 31st and July 1st to 15th 2030 in the high demand scenario

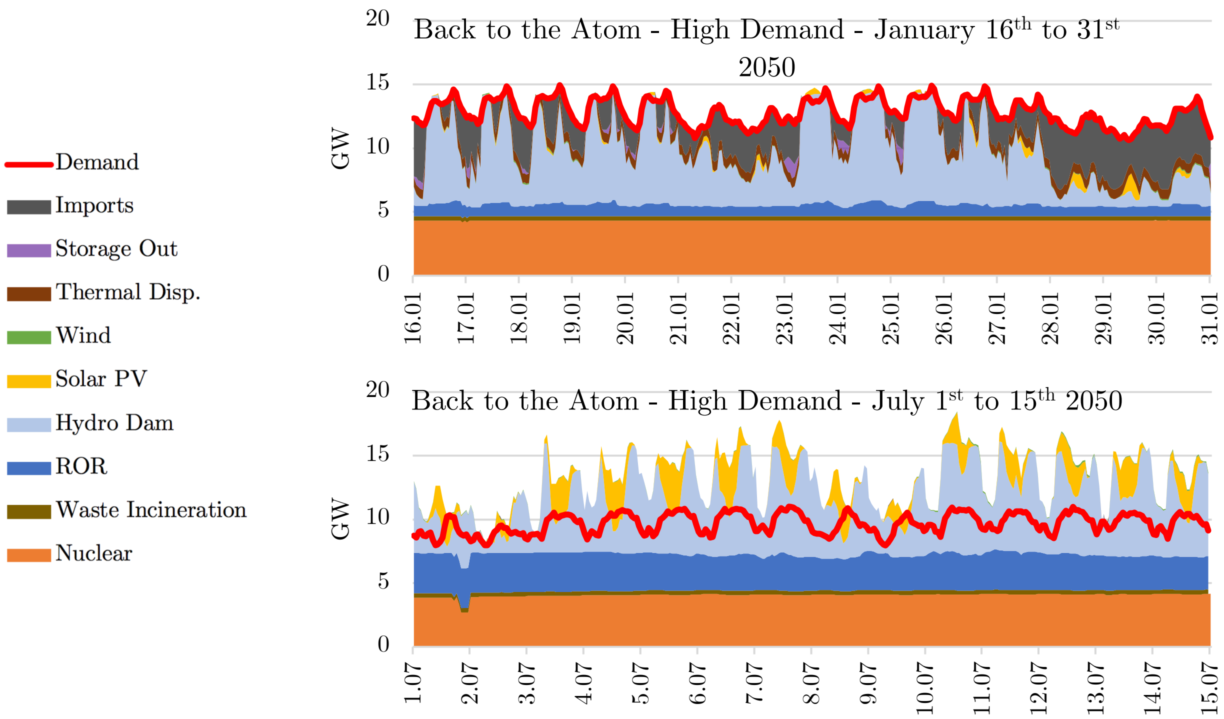


Figure 124: Back to the Atom scenario, simulated electrical production and consumption for January 16th to 31st and July 1st to 15th 2050 in the high demand scenario

Imports and Exports

Share of demand covered by imports [%]

Year	2030			2050		
Demand Scenario	*Low*	*Middle*	*High*	*Low*	*Middle*	*High*
January	1	7	14	0	3	19
February	18	29	36	4	24	38
March	0	3	10	0	0	13
April	0	0	0	0	0	0
May	0	0	0	0	0	0
June	0	0	0	0	0	0
July	0	0	0	0	0	0
August	0	0	0	0	0	0
September	0	0	0	0	0	0
October	0	0	2	0	0	7
November	0	0	9	0	0	13
December	4	15	23	0	10	28

Table 56: Back to the Atom scenario, monthly breakdown of the simulated share of demand covered by imports in 2030 and 2050 for the low, middle and high demand scenarios

Share of production exported [%]

Year	2030			2050		
Demand Scenario	*Low*	*Middle*	*High*	*Low*	*Middle*	*High*
January	1	0	0	11	0	0
February	0	0	0	0	0	0
March	0	0	0	16	0	0

April	29	17	10	40	24	5
May	34	25	18	44	30	13
June	41	34	28	49	36	21
July	45	38	32	53	40	26
August	42	35	29	50	37	22
September	28	20	12	37	21	4
October	12	2	0	25	8	0
November	10	1	0	22	4	0
December	1	0	0	6	0	0

Table 57: Back to the Atom scenario, monthly breakdown of the simulated share of production exported in 2030 and 2050 for the low, middle and high demand scenarios

L. Resilience Scenario Additional Results

In this section, we show the results of the simulation for the Resilience supply scenario in 2030 and 2050 in the low and high demand conditions.

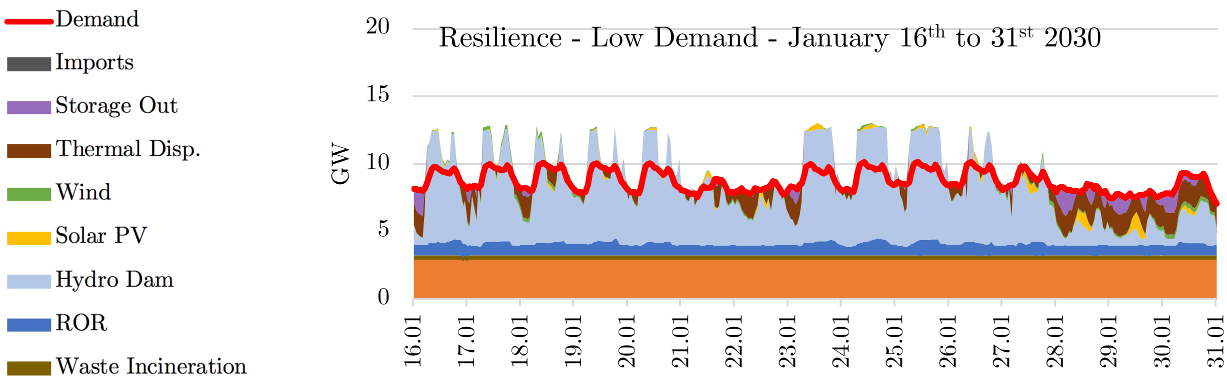
Electricity Production and Consumption

Low Demand

In the low demand scenario, the dispatchable thermal production and storage system fill the remaining deficits in the winter, eliminating the need for imports (see Figure 125 and Figure 126). In the summer, the nuclear and hydroelectric sources cover demand.

High Demand

In the high demand scenario, the CCGT controllable thermal source delivers a substantial contribution to electricity production in the winter (see Figure 127 and Figure 128). The thermal controllable sources are working almost constantly at full capacity in the month of January. In the summer, as for the other supply side scenarios, the demand is met primarily thanks to the high hydroelectric and renewable production and in this case, to the nuclear baseload.



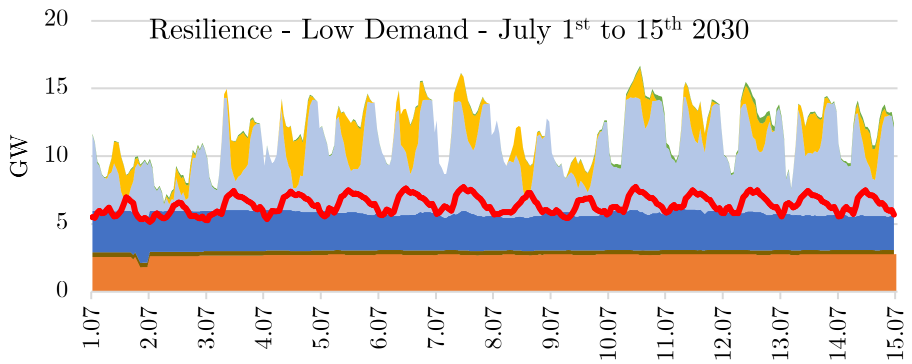


Figure 125: Resilience scenario, simulated electrical production and consumption for January 16th to 31st and July 1st to 15th 2030 in the low demand scenario

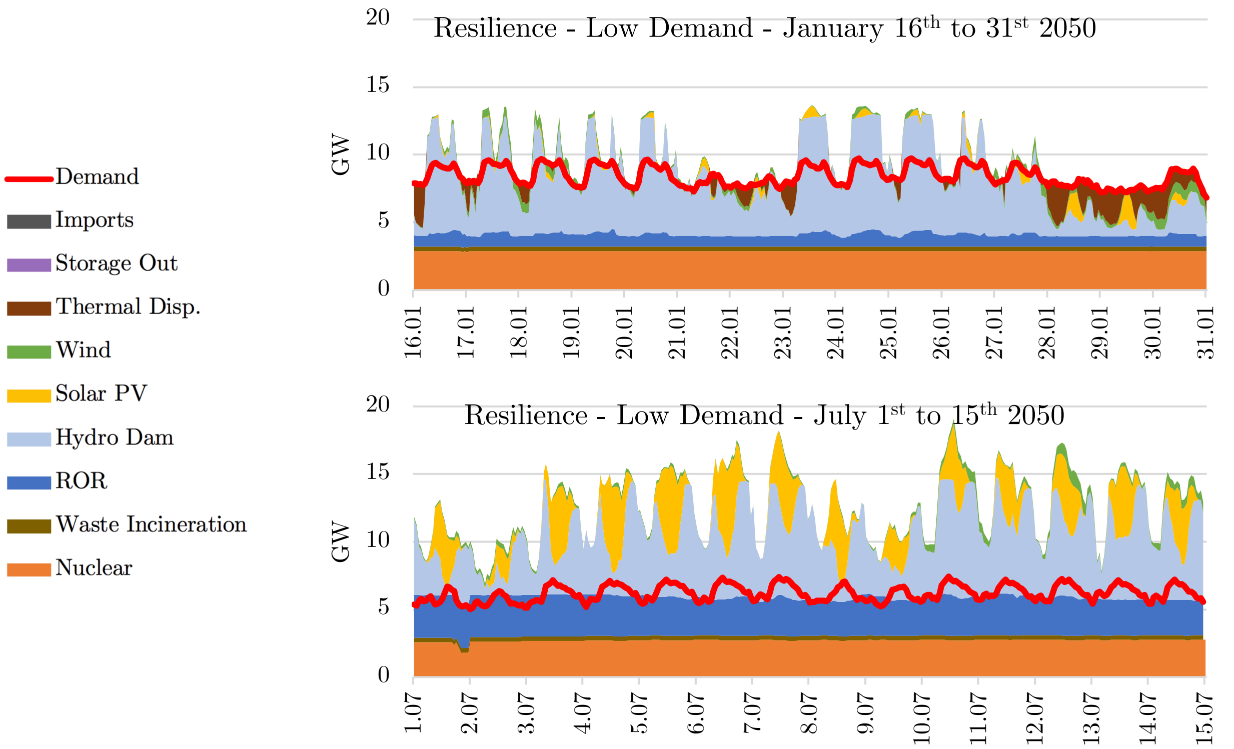
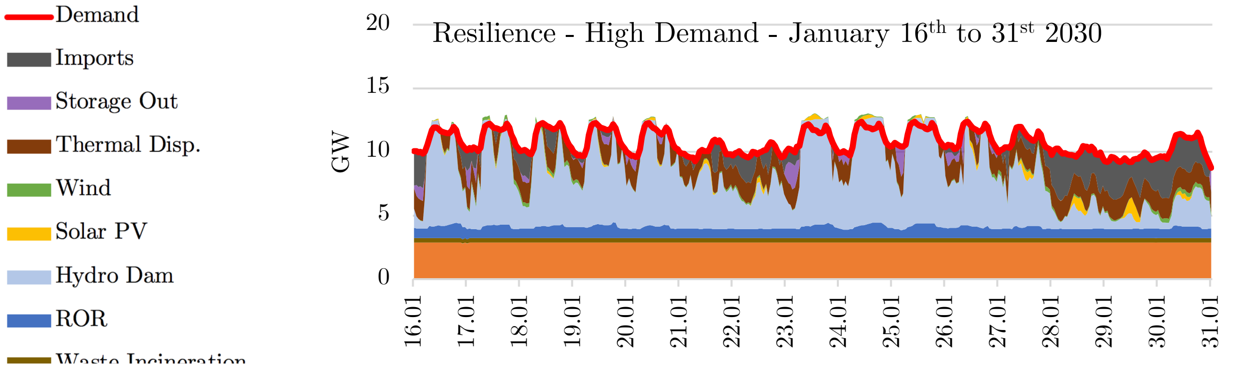


Figure 126: Resilience scenario, simulated electrical production and consumption for January 16th to 31st and July 1st to 15th 2050 in the low demand scenario



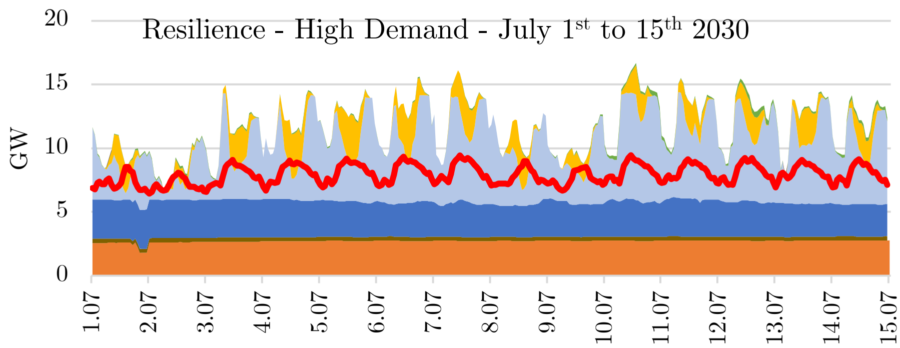


Figure 127: Resilience scenario, simulated electrical production and consumption for the end of January and start of July 2030 in the high demand scenario

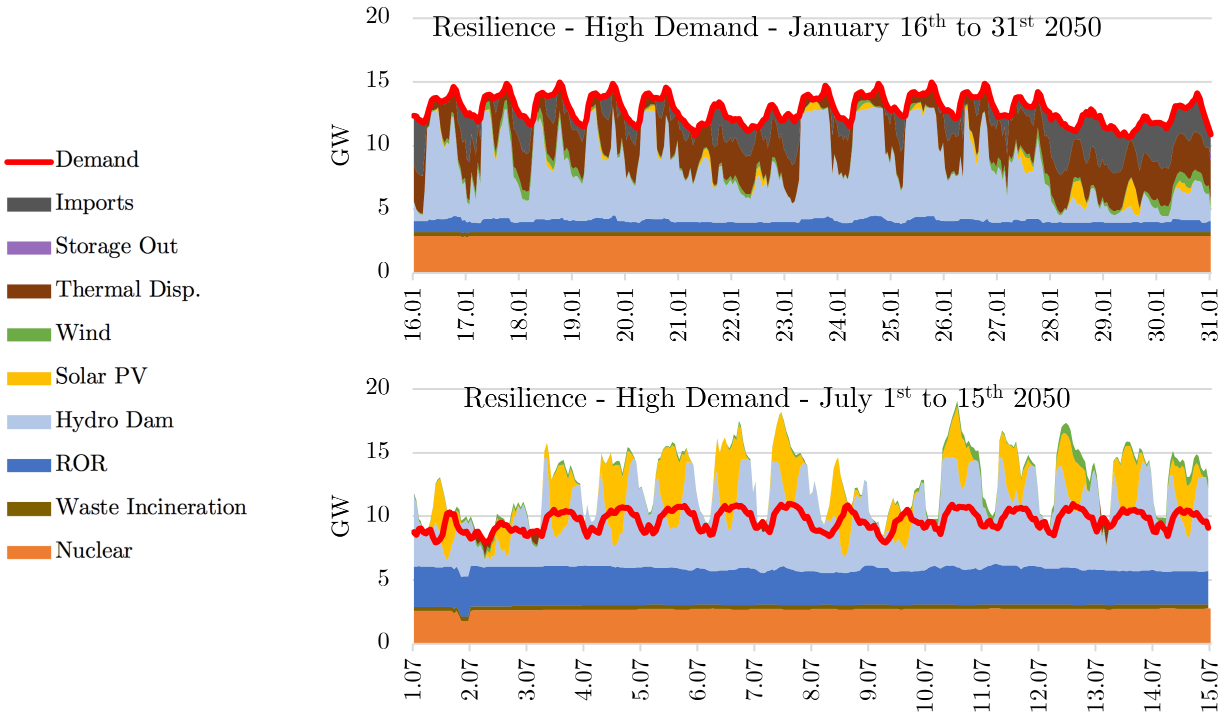


Figure 128: Resilience scenario, simulated electrical production and consumption for January 16th to 31st and July 1st to 15th 2050 in the high demand scenario

Imports and Exports

Share of demand covered by imports [%]

Year	*2030*			*2050*		
Demand Scenario	*Low*	*Middle*	*High*	*Low*	*Middle*	*High*
January	0	4	11	0	0	12
February	8	20	27	0	7	23
March	0	0	4	0	0	4
April	0	0	0	0	0	0
May	0	0	0	0	0	0
June	0	0	0	0	0	0
July	0	0	0	0	0	0

August	0	0	0	0	0	0
September	0	0	0	0	0	0
October	0	0	0	0	0	0
November	0	0	4	0	0	6
December	0	8	17	0	0	16

Table 58: Resilience scenario, monthly breakdown of the simulated share of demand covered by imports in 2030 and 205 for the low, middle and high demand scenarios

	Share of production exported [%]					
Year	*2030*			*2050*		
Demand Scenario	*Low*	*Middle*	*High*	*Low*	*Middle*	*High*
January	1	0	0	6	0	0
February	0	0	0	1	0	0
March	0	0	0	14	0	0
April	28	16	10	37	21	4
May	33	25	18	41	26	12
June	42	35	29	49	36	21
July	45	38	32	51	38	24
August	42	35	29	48	35	21
September	28	20	14	35	21	7
October	11	4	0	19	7	0
November	11	3	0	17	6	0
December	2	0	0	8	0	0

Table 59: Resilience scenario, monthly breakdown of the simulated share of production exported in 2030 and 2050 for the low, middle and high demand scenarios

M. Calculating the Contribution of each Technology in Electricity Consumption

The model presented in chapter 3 gives the following time series as output: nuclear, hydro dam, run-of-river, solar PV, wind, dispatchable thermal, non-dispatchable thermal, storage production and consumption, imports and exports. Calculating the relative contribution of each technology in electricity production is hence straightforward.

For consumption, there are two additional steps to be taken in order to determine what share of the consumed electricity was generated by which technology: first, deduct the electricity exported from the production time series, and second separate the imported electricity into its generating sources.

For deducting the exported electricity, we assume that share of each technology in the exports is identical as in the production. Let's consider for example a case where the production is larger than the consumption and 1 MW of electricity should be exported during an hour. If the production during this hour consists of 40% nuclear, 35% hydroelectric and 25% solar PV, we will assume that the exported power consists of 40% nuclear, 35% hydroelectric and 25% solar PV. Doing so, we can deduct the exported power from the production for each technology and obtain a time series of electricity produced and consumed in Switzerland for each electricity generating source.

In a second step we add the contribution from imports. In order to separate the imports in the technology used to generate the electricity in the first place, we rely on our assumption about the European electricity production presented in the section 4.1.1.4. This assumption gives us a share of electricity production by technology for the European and we simply multiply the amount of imported electricity by the share of production by technology in order to obtain time series of imports by technology.

We finish by adding, for each technology, the time series of imports to the time series of electricity produced and consumed in Switzerland in order to obtain the final time series of electricity consumed. This later time series allows us to calculate annual aggregates of electricity consumed, differentiated by the technology used to generate the electricity.

We do not have access to time series of production of electricity in Europe as we have for Switzerland. Our assumption means that regardless of the hour, the day or the month in which electricity is imported, the shares of technology in the production are assumed to be the same, i.e. if electricity is for example imported in the middle of a sunny day, our calculations will not reflect a potential high solar PV share in imports. This limitation may be addressed by future works.

N. Calculation of the GHG Emissions

The calculations of GHG emissions are based on Life-Cycle estimates from (Bauer & Hirschberg, 2017). The authors give technology-specific GHG emission intensity for 2035 and 2050 which we show in Table 60. We consider the 2035 estimates to be valid in 2030 already.

gCO_2-eq/kWh	*Nuclear*	*Run-of-River*	*Hydro Dam*	*Solar PV*	*Wind*	*Biogas*	*Biomass*	*CCGT*	*Waste*
2030	27.5	7.5	10	38	17.5	150	55	365	55
2050	27.5	7.5	10	26	17.5	150	55	354	55

Table 60: Life-Cycle GHG emissions of supply technologies from (Bauer & Hirschberg, 2017)

The aggregate and average GHG emissions of the Swiss electricity production are calculated by multiplying the annual production per technology by the corresponding emissions for the simulated year shown in Table 60. For the emissions of electricity consumption, we use the aggregates calculated following the method presented in appendix M.

The estimates in Table 60 are estimates for new plants built respectively in 2035 and 2050. Our model however does not consider the lifetime of each power plant. Consequently, by simply multiplying the time series for 2030 and 2050 by the GHG emissions we obtain emissions for the case where the plants were built on the year of interest. The GHG emissions estimates in this work are hence qualitative.

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