3 System Dynamics Simulation to Explore the Impact of Low European Electricity Prices on Swiss Generation Capacity Investments

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Abstract

European electricity markets are coping with low energy prices as a result of overinvestments in generation capacity, subsidies for renewables and the financial crisis of 2008. In this chapter we explore the implications of low electricity prices on the Swiss electricity market, which is facing the additional challenge of phasing out nuclear power plants and market liberalization. System Dynamics is utilized to model and simulate the long-term impacts on investments in new generation capacity, security of supply and future electricity prices. Simulation results indicate that the current low electricity prices are likely to persist for another decade. The most likely response to the low prices is an underinvestment in generation capacity, with the risk of scarcity pricing under low security of supply, as it coincides with the decommissioning of nuclear power plants. There is little evidence this will lead to boom-and-bust investment cycles. Finally, in the long-term we observe a shift towards renewable energy sources and natural gas fired power plants, resulting in more volatile electricity prices. These findings are similar to earlier studies of the liberalized German and Belgian electricity markets, which are also facing the challenges of a nuclear phase-out under depressed European prices.

Keywords

Electricity market · Electricity prices · Hydropower · Liberalization · System dynamics · Simulation · Switzerland · Investment cycles

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3.1 Introduction

Switzerland has committed to an ambitious energy transition with far reaching social, technical and economic consequences as nuclear energy will be phased-out, while maintaining low carbon emission levels. Nuclear energy accounted for around a third (19–22 TWh) of the country's annual electricity production in 2015 and 2016 (SFOE 2017) and is ideally completely replaced by 2034 by new renewable energy sources (RES), such as solar photovoltaic (PV), wind, (micro-)hydro, biomass and geothermal sources. However, new RES face considerable challenges: social acceptance (Wüstenhagen et al. 2007), small potential of certain RES such as micro-hydro (SFOE 2012), or low economic attractiveness (Prognos AG 2012). Hence, energy import and natural gas-fired power plants could play a central role in compensating the production deficit caused by phasing-out nuclear energy. However, Switzerland's priority to remain electrically relatively self-sufficient and the congestion already occurring in some cross-border transmission lines (Swissgrid 2015) is likely to limit future electricity imports. Furthermore, the development of natural gas-fired power plants is considered only as a last resort due to the strong commitment to limit emissions, which includes the obligation of electricity producers to offset all CO_2 emissions.

Belgium and Germany are facing a similar challenge of phasing-out nuclear energy under stringent CO_2 emission targets. In a system dynamics (SD) simulation study Kunsch and Friesewinkel (2014) find that aggressively phasing-out nuclear energy in Belgium can have adverse effects on the country's RES deployment, electricity price volatility, CO_2 emissions and energy dependency. Indeed, an early phase-out of nuclear energy can result in a large production deficit despite RES investments, requiring additional investments in fossil-based generation technologies. Such a scenario might also unfold for Switzerland, which in 2015 produced only 4.45% of its electricity from new renewables, namely 0.17% from wind, 0.45% from biomass, 1.76% from solar, 0.20% from biogas, and 1.87% from waste sources (SFOE 2016).

Switzerland is facing the additional challenge of fully liberalizing its electricity market, which can lead to "boom-and-bust" investment cycles as demonstrated by Ford (1999) and Kadoya et al. (2005) using SD simulation. In liberalized markets, investments are made based on price signals and incomplete information, rather than using a central planner approach. Periods of overinvestment send a lack of price signals to market players once the market is liberalized, resulting in a period of underinvestment (Finon et al. 2004). Conversely, long delays between permit applications and the construction of power plants lead to overinvestment, as too many projects are initiated based on price signals during capacity shortage. These time-lags are an important contributor to investment cycles (Kadoya et al. 2005). Unique to the case of Switzerland is the combination of two additional factors contributing to a lack or delay of price signals: (1) low European electricity spot prices, particularly in neighboring countries, and (2) a large hydro storage capacity which dampens the electricity price and delays investment signals (Hammons et al. 2002).

Ochoa (2007) explored the likely market responses to liberalization in the Swiss electricity market, highlighting the importance of security of supply under a liberalized market design. Since then, the Fukushima disaster and subsequent decision to phase-out nuclear energy in Switzerland have further implications for the security of supply. In this chapter, we use the definition for security of supply by Helm (2002, p. 176): “. . . the level of fairly stable prices that consumers might be willing and able to pay, and to see whether, given this demand, there are ‘secure’ supplies available”. Such a definition is useful for analyzing potential scarcity pricing and “boom-and-bust” cycles in response to market liberalization and the phase-out of nuclear energy. Ochoa and Van Ackere (2009) found, using a SD model of Switzerland, that a nuclear phase-out can result in a significant electricity import dependency. More recently, Osorio and van Ackere (2016) confirmed this import dependency using a SD model of the Swiss transition from nuclear to RES. The nuclear phase-out will lower the security of supply, leading to higher and more volatile prices as a result of the new electricity-generation mix.

In this chapter, we present the design of a novel SD model for the Swiss electricity market which contains detailed endogenous investment pipelines, as well as bounded rational actors. This allows us to explore the question of investment cycles in a liberalized hydro-dominated market which is going through a nuclear phase-out. Furthermore, we place our study in the broader European context of low electricity prices and ongoing energy transitions (Verhoog and Finger 2016). In this chapter we address the following research question: What is the impact of low European electricity prices on Swiss generation capacity investments under market liberalization and nuclear phase-out policies?

This chapter is structured as follows. First, we provide an analysis of the uses and limitations of SD simulation to study energy transitions. Second, we describe the conceptual SD model developed to study the Swiss energy transition. Third, we discuss the simulation results and the impact of transition policies specific to the Swiss energy transition. Finally, we conclude the chapter by reflecting on the research question and theoretical and practical insights gained from the modeling and simulation exercise.

3.2 Methodology

Analyzing the Swiss energy transition is not straightforward, since energy systems are complex socio-technical systems (Hughes 1987; Verhoog et al. 2016) consisting of many sub-systems such as production, consumption, grids, investments, and spot markets. The complexity arises from the many parts which simultaneously interact in the energy system, resulting in complex feedback loops. Energy systems are characterized by emergent behavior which can only be explained by a detailed understanding of those feedback loops. Furthermore, there are many factors with a high impact on the energy system that have a high uncertainty, such as natural gas prices, electricity spot markets, technological developments, and (domestic) energy policies. Due in part to the long timeframe of energy transitions, typically multiple decades, it is very difficult to study how such transitions will unfold under different conditions. Computer simulation can be a useful method for analyzing energy transition by means of virtual experiments (Chappin 2011). Simulation approaches and available scenario (simulation) studies for Switzerland (Densing et al. 2016) are compared hereafter.

First, optimization models have been used to study the Swiss energy transition under the objective of cost minimization and environmental constraints (e.g. Pöyry 2012; Kannan and Turton 2016; Pattupara and Kannan 2016). These models have a central planner approach and assume perfect information, perfect foresight and economically rational decisions for the entire system. Such an approach is unsuitable to study liberalized markets with imperfect information and bounded rational investors. Indeed, such an approach would not allow for investment cycles to be explored. Furthermore, Trutnevyte (2016) found that optimization models greatly deviate (9–23%) from real system behavior in an ex-post analysis of the UK electricity system. This finding is over a period of 25 years, shorter than those typically considered for the Swiss energy transition.

Second, equilibrium models work under the assumption that the rational behavior of individuals in markets with perfect competition will find an equilibrium price (e.g. Andersson et al. 2011; Vöhringer 2012). However, such assumptions cannot be defended in electricity markets which have shown investment cycles following liberalization (Kadoya et al. 2005), as these markets are out-of-equilibrium when transitioning to their liberalized state (Gary and Larsen 2000). Furthermore, equilibrium searching models are not dynamic (Mitra-Kahn 2008), making them unsuitable to simulate boom-and-bust cycles.

Third, bottom-up simulation models of the Swiss electricity market generally have a high level of generation technology detail (e.g. Prognos AG 2012; Barmettler et al. 2013; Teske and Heiligtag 2013). Most of these models are well-documented, providing rich information required for model conceptualization, assumptions and data sources. These models rely on exogenous generation capacity expansion scenarios, resulting in rather static models which are used to explore a range of "what-if" scenarios. However, the investigation of boom-and-bust cycles requires endogenous investment calculations which allow for dynamic feedback with other system elements.

Fourth, SD models have a number of fundamental advantages over the previously discussed approaches. Teufel et al. (2013) identify a number of differentiating factors of SD models in their literature review, some of which are crucial for simulating investment cycles: (1) *time lags* in feedback processes to model lead-times for permitting and construction in generation capacity investment pipelines, (2) *bounded rationality* to model liberalized electricity markets in which firms have *incomplete information* on generation capacity expansion, (3) *social behavior* can be modeled directly, rather than relying on optimization of some objective function (Jäger et al. 2009). Incomplete information also implies that SD models incorporating the above differentiating factors do not use the perfect foresight assumption like most optimization models used for the Swiss electricity sector. Instead, forecasts are made endogenous to the modeled system using imperfect information, leading to sub-optimal system behavior over many scenarios using simulation. Such an approach deals with the inherent uncertainty of exploring the Swiss energy transition, as there is currently no historic data available of a liberalized Swiss electricity market (Osorio and van Ackere 2016).

A further argument to select SD is that our research question is concerned with system level behavior and interactions between various sub-systems which, at a structural level, are not expected to change during the studied period. A key assumption for SD is that the behavior of a system is fundamentally determined by its own structure (Pruyt 2013). The system structure is represented in stocks, flows, auxiliary variables, constants, parameters and the links (causal relations) between these elements. Therefore, it is necessary to clearly identify the justification of each link. Links can either be *positive* or *negative,*[1] and links between several elements of the model can compose feedback loops. A feedback loop is a path of links starting in one element of the system that, if followed, leads back to the starting element after passing through at least another system element. Two kinds of feedback loops can exist: *reinforcing loops* and *balancing loops*.[2] The modeled elements and links are translated into differential equations so as to allow for virtual experimentation to gain insights into the system's responses to policy designs and other scenario variables (Pruyt 2013).

3.3 Modeling the Swiss Energy Transition

The conceptual model presented in this section is an extension of the model elaborated in van Baal (2016). Additional information on the underlying equations, data and other Swiss models can be found in Verhoog (2018). Specific attention is paid to the structure, feedback loops, assumptions and publicly available data underlying the sub-systems. The model simulates the period from 2015 to 2050 with hourly time-steps, which is a unique feature compared to other simulation models available for Switzerland. The model clears the electricity market and dispatches all production units for each hour of the year, rather than using a reduced set of representative time-slices as done in Osorio and van Ackere (2016) or monthly time-steps as in Ochoa and Van Ackere (2009). Another key-feature of the model is that it allows for dynamic endogenous generation capacity investment decisions using bounded rational investor behavior. Finally, in contrast to earlier models (e.g. Kadoya et al. 2005; Osorio and van Ackere 2016) the model includes hourly transmission constraints, which are required to determine the impact of low

[1] A *positive* link from A to B means that an increase in A leads to an increase in B. A *negative* link from A to B means that an increase in A leads to a decrease in B.

[2] *Reinforcing loops* are positive feedback loops which further increase a positive or negative change in the system. Reinforcing loops can be utilized in policy design to destabilize the system. *Balancing loops* have a damping effect on positive or negative changes in the system and typically stabilize the system.

European electricity prices and interconnector congestion on developments in the Swiss market.

3.3.1 Swiss Electricity Spot Market

In liberalized electricity markets the price signals for capacity investments are sent by the spot market. The present model implements a clearing mechanism for the Swiss spot market, based on the physical hourly match of electricity supply and demand. This is a common approach for simulation models exploring the dynamics of liberalized electricity markets (e.g. Kadoya et al. 2005; Vogstad 2005; Osorio and van Ackere 2016). Vogstad (2005) additionally implemented a futures market. However, typical investment horizons in electricity markets go well beyond the horizon of a futures market, making them no more useful than expected spot price foresighting. Furthermore, capacity mechanisms as implemented by Kadoya et al. (2005) are not included in the model, as there are currently no capacity market designs for Switzerland.

Inputs for the spot market are most dispatchable generation, marginal costs per generation technology and the residual demand (Fig. 3.1). All power plants are aggregated per technology, resulting in the installed capacity. The actual dispatchable generation depends upon scheduled maintenance, such as the maintenance of nuclear power plants during summer, and the availability of water in the hydropower reservoirs. The marginal cost, the price at which the dispatchable generation technologies are offered on the spot market, is taken from Pöyry (2012), and increases on a yearly basis for fossil-fuel fired power plants. New renewables such as PV and

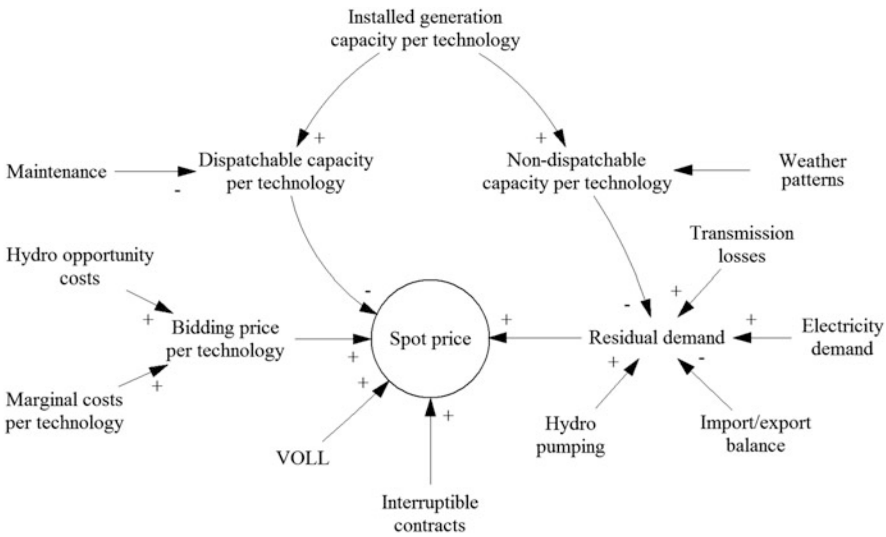

Fig. 3.1 Swiss electricity spot market

wind, typically offered at zero-cost, are depressing prices on European spot markets with high shares of renewables. Switzerland has access to long-term and low-cost import contracts with France. These contracts participate in the market clearing process at 35 CHF/MWh with around 2000 MW, are gradually reduced until 2040 (Osorio and van Ackere 2016), and are not expected to be renewed as they conflict with European market coupling rules (VSE 2012). Hydropower is an exception to the rule of marginal cost bidding, as it is offered at opportunity cost. Since hydropower plays a central role in the Swiss energy system it will be discussed in more detail in Sect. 3.3.3.

The system operator dispatches generation capacity in the most cost-efficient way to meet the (residual) demand in the system using the merit order. The least-cost dispatch is determined by intersecting the supply curve, which is made up of the price-sorted capacity bids, with the demand curve. The intersection point of both curves is the market clearing price, corresponding to the price of the marginal producer. The market clearing price will be paid for every MWh generated by dispatched generators. Complicating this process is the import and export of electricity from neighbouring countries, which happens ex-ante (i.e. before the market is cleared), changing the residual demand. In the present model, hourly spot markets are implemented for France, Germany-Austria and Italy using EPEX[3] and GME[4] data from 2010 to 2014. The hourly time series are used to create spot price profiles, which are then combined with yearly price scenario calculations based on the ENTSO-E 10 Year Network Development Plan (10YNDP) and underlying market modeling data (ENTSO-E 2014). A novel feature of the model is that hourly transmission capacity constraints are taken into consideration for all cross-border trades using net transfer capacity (NTC) values for 2013 and 2014, available from ENTSO-E.[5] Future transmission capacity expansions are based on the 10YNDP. It is important to model the NTC and potential congestion for each border since Switzerland heavily relies on electricity imports during the winter period, especially from Germany. Switzerland also has access to interruptible contracts to lower the residual demand at an estimated 900 CHF/MWh (De Vries and Heijnen 2008). Finally, when interruptible contracts are exhausted and a physical shortage of electricity supply occurs, then the clearing price will be set at the Value of Lost Load (VOLL) (Olsina et al. 2006; Hasani and Hosseini 2011), estimated at 3000 CHF/MWh (Osorio and van Ackere 2016).

Hourly electricity demand data from Swissgrid[6] is used to create standardized profiles from 2010 to 2014, which is combined with three electricity demand scenarios from Pöyry (2012), resulting in a total of 15 profile-demand scenario combinations. These scenarios are exogenous and do not take electricity price

[3]https://www.eex.com/en/market-data/power/spot-market/

[4]https://www.mercatoelettrico.org/en/mercati/MercatoElettrico/MPE.aspx

[5]https://transparency.entsoe.eu/content/static_content/Static%20content/legacy%20data/year%20selection.html

[6]https://www.swissgrid.ch/swissgrid/en/home/experts/topics/energy_data_ch.html

elasticity into consideration, as evidence of such elasticities is limited for Switzerland (Filippini 2011). The profiles are static in the sense that they are not adjusted to potential future demand profile changes as a result of electric vehicle charging, demand response, or other technological and behavioral developments. The spot market is cleared using the hourly residual demand, rather than the hourly electricity demand. First, transmission losses of roughly 7% (SFOE 2015) have to be compensated. Second, electricity demand for hydro pumping, as well as electricity exports, are added to the hourly demand. Third, electricity production from intermittent renewables such as solar, wind and run-of-river are subtracted from the demand, as they cannot be dispatched like conventional thermal or hydro storage plants. The resulting residual demand represents a shift in the merit order curve, which can push more expensive generation options such as gas fired power plants out of the market. A lower residual demand will lead to lower electricity prices and lower profits for electricity producers (Haas et al. 2013).

The available electricity generation per hour is determined by the installed capacity, maintenance and weather effects (Table 3.1). The installed capacity is driven by investment decisions, which are covered in more detail in Sect. 3.3.2. Currently, most of the electricity is supplied from reservoir, pumped storage and run-of-river hydropower plants. Run-of-river plants depend on relatively predictable water flows and cannot be dispatched since they cannot store their electricity. Reservoir hydro plants also depend on a relatively predictable natural inflow from meltwater and rain, but are modeled as dispatchable generation capacity as they can storage large amounts of hydropower. Pumped hydro plants are also dispatchable, and react more closely to market signals for pumping and production. Hydropower has a strong seasonal pattern in Switzerland, and is heavily relied upon during the higher winter electricity demand. The seasonality of hydropower water inflow is based on weekly SFOE[7] profiles from 2010 to 2014 and future inflow predictions (Pöyry 2012). Another major source of electricity production is nuclear energy, which is assumed to be phased-out according to the initial predictions, with the last plant shutting down in 2034. Furthermore, maintenance is often scheduled during the summer months, resulting in a lower dispatchable capacity. Hourly wind speed data is publicly available for non-commercial use from the NNDC Climate database.[8] Wind data from stations closest to 110 potential Swiss wind sites (Kunz et al. 2004) is weighted based on the site's size and then converted to power curves to approximate electricity production. Hourly wind data from 2010 to 2014 is used. The online European PVGIS tool (Šúri et al. 2007; Huld et al. 2012) was used to estimate yearly production figures for a 1 kW_{peak} solar photovoltaic installation in 200 Swiss cities, weighted according to population. Hourly solar irradiance data was obtained for all locations for the period of 1996 to 2000 from the EU S@tel-light

[7] http://www.bfe.admin.ch/themen/00526/00541/00542/00630/index.html?lang=en&dossier_id=00767

[8] https://www7.ncdc.noaa.gov/CDO/cdo

Table 3.1 Generation option assumptions as implemented in the model

Generation option	Capacity (MW)	Investments	Bidding price (CHF/MWh)	Dispatchable	Availability
Combined cycle gas turbines (CCGT)	75[a]	Endogenous	Exogenous[b]	Yes	100%
Combined heat and power (CHP)	0[b]	Endogenous	Exogenous[b]	Yes	100%
Solar PV	378[a]	Endogenous	0	No	Weather profile
Wind	60[a]	Endogenous	0	No	Weather profile
Interruptible contracts	–	n/a	900[c]	Yes	100%
Nuclear	3278[a]	n/a	7[b]	Yes	Seasonal
Run-of-river	–	Exogenous[b]	0	No	Seasonal profile
Reservoir hydro	9920[a]	Exogenous[b]	Opportunity cost	Yes	Dynamic
Pumped hydro	1800[a]	Exogenous[b]	Opportunity cost	Yes	Dynamic
FR import contracts	3466[d]	n/a	35[d]	Yes	100%
Geothermal	–	Exogenous[b]	20[b]	Yes	100%
Renewable CHP	56[a]	constant	42.2[b]	Yes	100%
Waste burning	342[a]	constant	7.3[b]	Yes	53%
Other thermal	542[a]	n/a	37.25[b]	Yes	100%

[a]SFOE (2014)
[b]Pöyry (2012)
[c]De Vries and Heijnen (2008)
[d]Osorio and van Ackere (2016)
For some technologies the bidding price will change over time as a result of fuel and CO_2 price developments

project database.[9] An average standardized irradiance profile was calculated and adjusted with the average yearly production for a 1 kW_{peak} installation. While the periods covered by the solar data do not overlap with the other input data of the model, this is not an issue because the currently installed capacity of PV in Switzerland is very low. We assume that the most attractive wind and solar sites are exploited first, resulting in the average utilization curve for Switzerland in Fig. 3.2.

[9]http://www.satel-light.com/indexs.htm

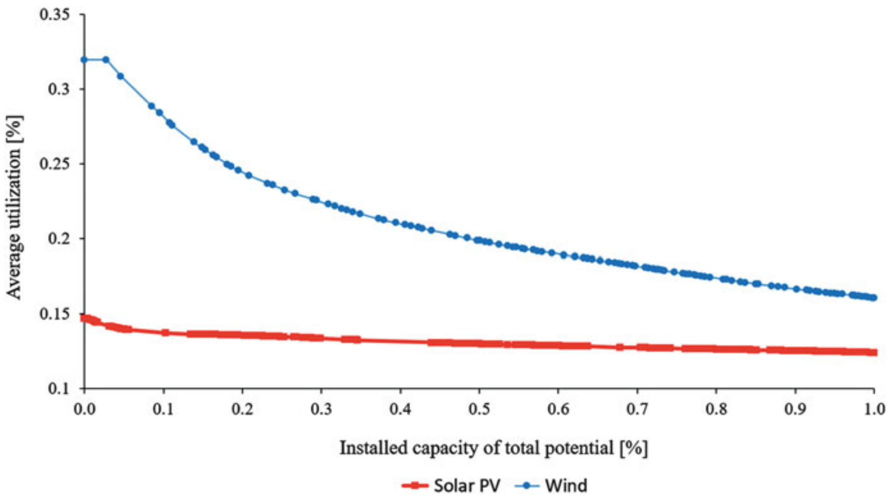

Fig. 3.2 Average yearly solar PV and wind utilization as a function of potential resource usage

3.3.2 Capacity Investments

In the current model implementation only CCGT, CHP, wind and solar investments are determined endogenously. The project pipeline in Fig. 3.3, based on the work by Vogstad (2005), is central to model bounded rational investment behavior, capacity expansion delays and resulting boom-and-bust cycles. Project permit applications are initiated when the project is expected to be profitable enough, given the investment risk associated with that technology. A proven way to model this investor behavior is by comparing the project's internal rate of return (IRR) with a corporate hurdle rate (Bunn and Larsen 1992; Olsina et al. 2006; Pereira and Saraiva 2010;

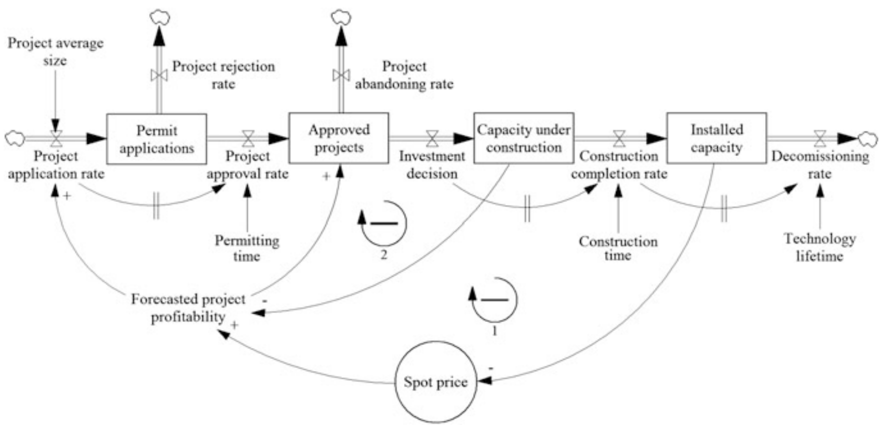

Fig. 3.3 Generic investment pipeline

Hasani and Hosseini 2011). The IRR is the discount rate r at which the Net Present Value (NPV) is equal to zero:

$$NPV = \sum_{n=0}^{N} \frac{C_n}{(1+r)^n} = 0$$

Where n denotes the time period in the project's economic lifetime N, and C_n is a cash flow at period n. The market forecast module is used to estimate the cost and revenue over the entire project's economic lifetime. The market forecast module has a similar structure to the spot market described in Sect. 3.3.1, but uses imperfect information for future generation capacity, electricity demand and spot prices. Planned capacity expansions are not known in the market if they are not yet under construction. Forecast heuristics are used to estimate the revenue over the asset's economic lifetime, taking into account the expected utilization (Fig. 3.2 for solar and wind) as well as the average price during typical production hours (e.g. daylight for solar). Capital cost, fixed cost and variable cost scenarios are taken from Pöyry (2012) to calculate the IRR. The economic lifetime of projects is assumed to be 20 years, with a hurdle rate of 9% for CCGT and CHP, 12% for solar and 11% for wind (Pöyry 2012). If the IRR is greater than this hurdle rate, then the project application is started. Subsidies for solar and wind projects play an important role in guaranteeing their profitability. However, subsidies are linked to government targets and are finite, which has resulted in large waiting lists for solar projects. Under certain conditions investments might become feasible without subsidies.

Returning to the investment pipeline; permit applications can either be approved or rejected. Low social acceptance plays an important role for wind project rejection in Switzerland, as citizens can vote against projects in their region. Another potential limitation is the number of suitable sites, which are assumed to allow for a maximum of 2282 MW installed wind capacity (Osorio and van Ackere 2016). The delay for CCGT project applications is considerable, assumed to be between 2 and 4 years in our model to explore the effect of long permit application delays. Consequently, the economics of the project might have changed by the time the permit is obtained, requiring new IRR calculations. Changes in the project's economics might result in delayed investments, or even complete project abandonment. Longer delays cause the system to respond less quickly to market signals, increasing the system's susceptibility to investment cycles (Kadoya et al. 2005). In the event that the approved project is still profitable, the investment decision is made. The capacity under construction is based on the average size of projects for that technology, meaning that capacity investments are not continuous, but rather occur in blocks of capacity representing typical power plants. Once under construction the capacity is communicated to the market, and will be taken into consideration for IRR calculations. The capacity construction introduces another delay of 1 year for solar projects and 2 years for CCGT, CHP, and wind projects. The installed capacity is available until the power plants are decommissioned after their lifetime of 25 years for CCGT and 20 years for CHP, solar and wind (Pöyry 2012).

There is an important feedback loop between the spot market and investment pipeline, indicated as (1) in Fig. 3.3. When electricity generation is short during peak demand spot prices will increase. Increased spot prices send investment signals to market players, who will respond by initiating project permit applications. After the application and construction delays the capacity becomes available, resolving the market shortage and reducing the spot price. As the spot price decreases, investment signals are no longer sent to market players. The delays play an important role, as investment signals might be broadcasted for too long (i.e. permit applications are already underway), and do not allow market players to resolve shortages quickly (Kadoya et al. 2005). There is another feedback loop (2), which gives an earlier signal to market players as soon as capacity is under construction. Expected profitability is lower as more capacity is under construction. Both feedback loops are negative, which means that they balance the system. However, given the bounded rational behavior of market players, relying on price signals and incomplete information, it is unlikely that investments are perfectly aligned with demand and supply changes.

3.3.3 Hydropower

The misalignment of investments and required generation capacity is exacerbated if market signals are interfered by the presence of large amounts of hydro production. Cross-border trading using large interconnector capacity (Sect. 3.3.4) permits Swiss dam and pumped storage operators to directly respond to seasonal and diurnal trading opportunities on foreign spot markets (Kannan and Turton 2011). Hydropower is a seasonal resource, and depends on weather and climate factors for the inflow of water. Thus, accurately modeling the capacity and utilization of hydropower is crucial for capturing seasonal patterns and effects on price signals.

Dam and pumped hydro reservoirs are modeled as stocks of water with flow variables representing natural inflow, overflow, production and in the case of pumped reservoirs, pumped inflow (Fig. 3.4). Natural inflow is based on a standardized profile using SFOE data[10] from 2010 to 2014, and are split according to installed dam and pumped hydro capacities in the model as these respond differently to market dynamics. First, dam and pumped hydro installations place bids using a different value of water, which is the opportunity cost of using stored water at a given moment (van Ackere and Ochoa 2010; Densing 2013). The value of water is directly determined by the reservoir level, as a reservoir which is not using enough stored water has a risk of overflowing. This also means that seasonal inflow patterns must be taken into consideration for hydro reservoirs. The higher the

[10] http://www.bfe.admin.ch/themen/00526/00541/00542/00630/index.html?lang=en&dossier_id=00766

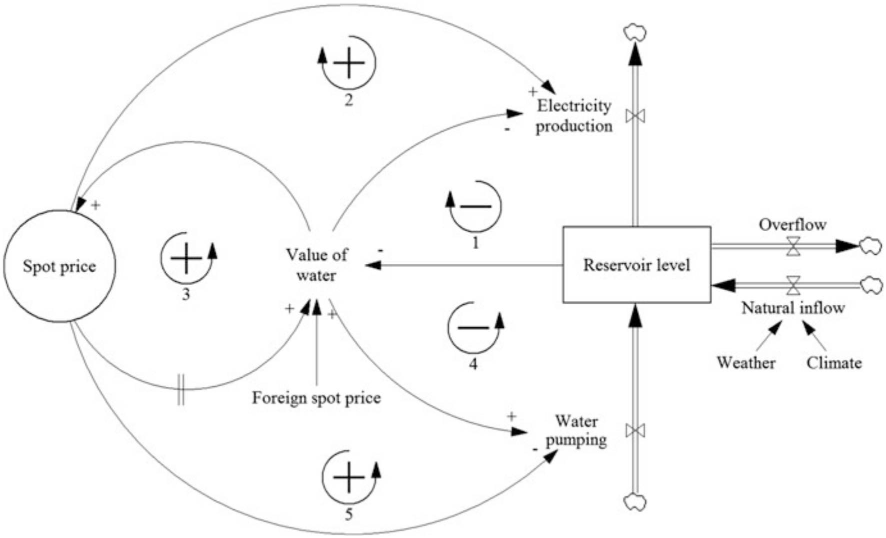

Fig. 3.4 Generic hydro reservoir. Dam and pumped hydro reservoirs are implemented separately in the model

relative filling grade of the reservoir, the lower the value of water (and bidding price), resulting in larger amounts of hydro capacity to be dispatched by the market. Feedback loops (1) and (2) ensure more hydroelectricity is produced when market prices are high, which is balanced by increasing the value of water when reservoir levels are low, resulting in less hydro capacity to be dispatched. However, there is also an implicit component to the value of water. While the value of water hovers around typical market prices its operators have a degree of flexibility to price above or below the expected marginal bid to increase or decrease the odds of being dispatched (Osorio and van Ackere 2016). As implemented, the value of water varies between 6 and 500 CHF/MWh, based on the reservoir level, domestic and foreign spot prices. Hydropower pumps are not dispatched by the market, but rather by the individual operators. Feedback loops (4) and (5) ensure that pumped reservoir levels are replenished when the value of water is high and spot prices are low, while not overflowing the reservoir. These feedback mechanisms also ensure that pumping is stopped as reservoir levels increase and the value of water drops. The most common "bang-bang" strategy found in competitive markets (Densing 2013) is implemented in the model. Under this strategy pumps only operate at full capacity when there is an economic incentive, and are fully stopped otherwise. If available, cheap foreign electricity can be used to pump hydro reservoirs as well. The endogenous operation of pumped hydro is a unique feature of our model, as pumping is assumed exogenous in other Swiss SD models (van Ackere and Ochoa 2010; Osorio and van Ackere 2016).

Finally, there is a positive feedback loop (3) which can destabilize the electricity prices in a hydro dominated market such as Switzerland. If the value of water is increased under scarcity conditions,[11] then spot prices will increase as long as hydro is the marginal producer. Consequently, the market power of hydro producers could be used strategically to increase electricity prices. However, such behavior would send investment signals and result in new capacity to be constructed, which would lower the spot price as illustrated in Fig. 3.3 feedback loop (1). In general, the availability of hydropower storage is expected to dampen electricity prices. Large storage capacities can be used to arbitrage between spot markets, within spot markets (e.g. diurnal and seasonal), and respond to supply shortages in the Swiss market. Using hydropower for these purposes, and for covering periods of shortage in particular, will delay price signals to the market until the available hydropower is inadequate to provide these services. In such an event price signals are likely to be much more pronounced.

3.3.4 International Trading

The misalignment of investments and required generation capacity is further exacerbated if market signals are interfered by structurally relying on imports from foreign markets such as France. There are a few key factors contributing to import reliance, especially during winter months (Fig. 3.5). Residual demand is higher during winter, which will increase the domestic spot price. Investment signals leading to increased investments, as part of balancing feedback loop (4), do not immediately broadcast as the market can rely on domestic hydro and imports. When foreign spot prices are lower than domestic spot prices, and sufficient NTC is available at interconnectors with that country, then electricity will be imported. The model is calibrated using historic transmission data from Swissgrid to import more electricity when the price difference is larger, as imports reduce the residual demand and domestic spot price. Switzerland is coupled to the French, Italian, and German-Austrian spot markets using ex-ante volume based bids. Commitments are made to volume exchanges before the respective spot markets are cleared, which recalling the assumption of imperfect foresight does not necessarily guarantee optimal outcomes in our model. No impact on foreign spot prices is modeled, as these markets are much larger than the Swiss market. This means that Swiss prices will converge with foreign spot prices, as shown in balancing feedback loop (1). Conversely, electricity is exported proportionally when foreign spot prices are higher than domestic spot prices, which increases the domestic demand and domestic spot prices as indicated in balancing feedback loop (2). Thus, imports and exports balance the reinforcing feedback loop (3), as discussed in Sect. 3.3.3. However, these balancing dynamics are limited by the availability of cheaper electricity and available NTC. As soon as transmission connections are congested (run out of NTC),

[11]This is not physical scarcity, but scarcity in the sense that other generation options and imports cannot satisfy demand if dam and pumped hydro are not dispatched. In such situations hydro operators could set monopolistic prices.

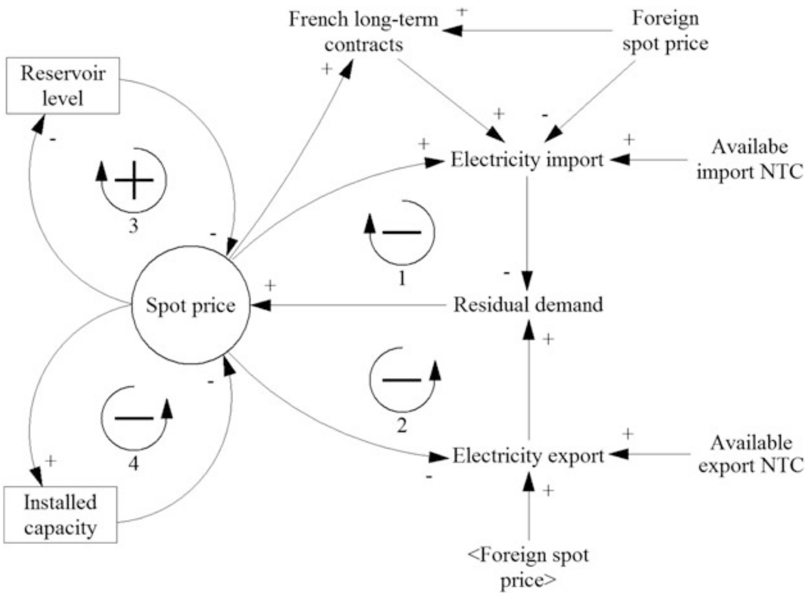

Fig. 3.5 Generic Swiss import and export dynamics. French, Italian and the coupled German-Austrian spot markets are implemented as separate exogenous spot markets in the model

then feedback loop (3) will be activated until the investment signal is strong enough. As a result, price signals in Switzerland are suppressed and delayed by the availability of large transmission capacities, low foreign spot prices and large hydro reservoirs. Due to delays in CCGT permitting and construction the market is slow to respond once price signals are broadcasted.

3.3.5 Model Verification and Validation

We tested our model along the principles laid down by Sterman (2000). He argues that all models are inherently false since they cannot pass the standard tests of falsification. Verification and validation tests of simulation models should thus aim to establish credibility and usefulness of a model. Our model passed all 12 of Sterman's standard model assessment tests. Here we will highlight two tests: boundary adequacy and behavioral reproduction.

The boundaries of the model are set at which technology is developed endogenously through investment dynamics (i.e. wind, solar, CCGT, CHP), versus those whose development is determined exogenously through scenarios. The scenario technologies are either phased-out (e.g. nuclear) or not expected to change significantly (e.g. waste burning). Hydropower is an exception, as investments are expected. However, hydro asset lifetimes far exceed the models time horizon of 35 years, and will thus not contribute to investment cycles. In addition, the model takes foreign spot market developments (e.g. Germany) as scenarios, making it impossible to identify the effect that the dynamics within Switzerland have on those markets. The focus of the model is Switzerland, which has a small market compared to its neighboring countries. The last boundaries are variables such as fuel prices, carbon prices, and technology cost developments. Since these are set on a global scale, Switzerland has virtually no impact on them.

The behavioral reproduction test, contrasting model output versus historical observations, is an important and intuitive check of the credibility and usefulness of simulation models (Suryani et al. 2010). Switzerland only recently (partially) liberalized its electricity market, hence the period with which we can compare is short. We contrasted historical data from 2010 to 2015 with our model. Models are by definition a simplification of reality, which is why the objective is not to reproduce exact historical values, but rather to replicate dynamic system behavior under imperfect information. The results of the behavioral reproduction test for the most important parameter of the model, domestic spot price, is given in Fig. 3.6. Closely linked to this parameter is the import/export balance of Switzerland in Fig. 3.7. The most important property of both parameters is their seasonal pattern, which is captured well in the modeled values. However, peaks sometimes occur earlier in the observed data. Also, the amount of export is overestimated by the model during summer and fall. Regardless, the fit of the modeled and observed values is acceptable, given the fact that we modeled a market under the assumption of a fully liberalized market, using historic demand and supply profiles. The behavioral reproduction for the hydropower module, the most dynamic, unique and central part of the Swiss electricity system, is shown in Fig. 3.8. This module also exhibits important seasonal patterns, which are captured very well by the model.

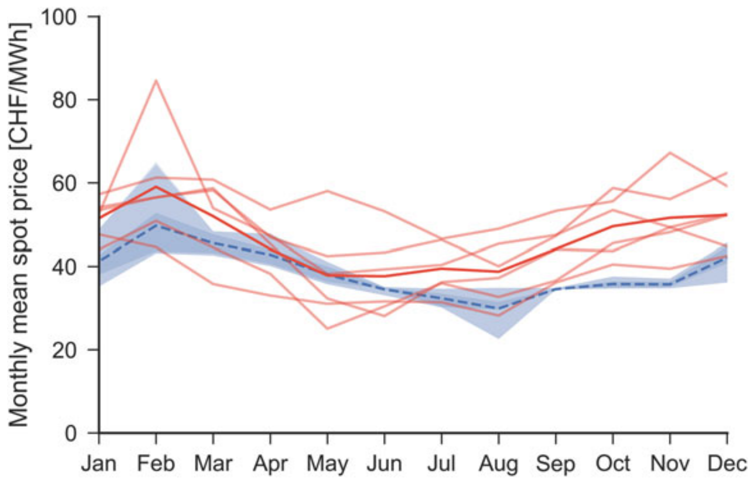

Fig. 3.6 Behavioral reproduction test for the average monthly Swiss spot price. The dashed line represents the average modeled spot price. The shaded areas respectively represent the 25–75, 5–95 and 0–100 percentile ranges. The solid lines (mean in bold) are the observed average monthly SWISSIX spot prices from 2010 to 2015, based on hourly values from the EEX platform

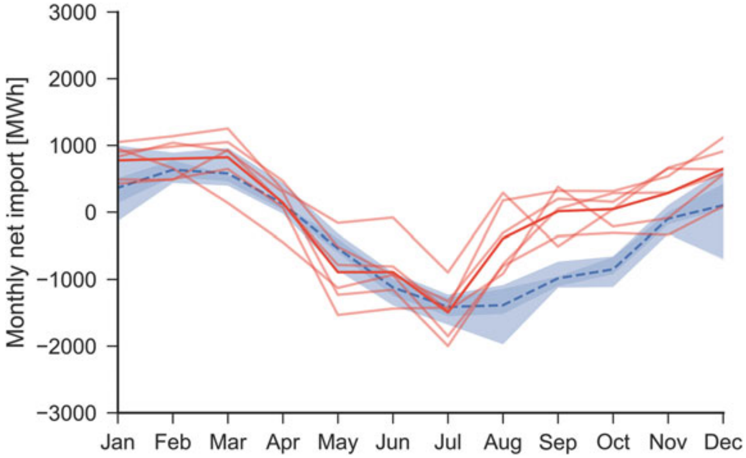

Fig. 3.7 Behavioral reproduction test for the average monthly Swiss import/export balance. The dashed line represents the average modeled monthly import/export. The shaded areas respectively represent the 25–75, 5–95 and 0–100 percentile ranges. The solid lines (mean in bold) are the observed monthly import and export values from 2010 to 2015, based on 15-min values from Swissgrid

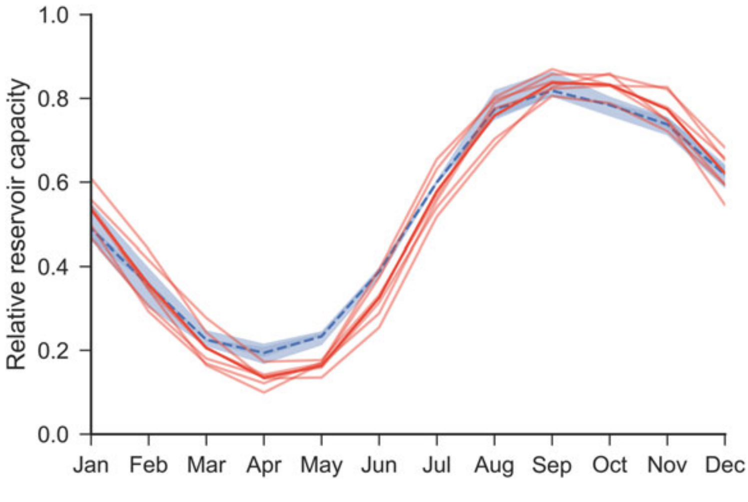

Fig. 3.8 Behavioral reproduction test for the relative reservoir capacity. The dashed line represents the modeled hydro reservoir levels. The shaded areas respectively represent the 25–75, 5–95 and 0–100 percentile ranges. The solid lines (mean in bold) are the observed reservoir filling grades from 2010 to 2015, based on weekly values from the Swiss Federal Office of Energy

3.4 Simulation Experiments

System Dynamics is a deterministic simulation approach, but long-term simulation of complex socio-technical systems is inherently uncertain. Scenarios simulation can be used to take policy and assumption uncertainty into consideration. However, the amount of simulation runs increases exponentially with the number of scenarios considered, dramatically increasing computational resource or time requirements to perform all runs. For this reason, we focus on the scenarios which are expected to be the most influential. In total 9000 simulation runs (virtual experiments) are performed over a simulation period of 35 years with hourly time-steps using Vensim® DSS for Windows Version 6.5E. Data analysis and visualization is done using Python 3.6.2, Pandas 0.20.3 and Seaborn 0.8.0. While the discussion and comparison of single runs, as is common for optimization and equilibrium models, can be illustrative, it does not do justice to the complexity and inherent uncertainty of the studied system. Therefore, we will only report the most prominent results as a subset of simulation runs for the scenarios detailed below. All graphs in this section report the modeled median value of the runs as a line, and the following percentile ranges as shaded areas: 25–75, 5–95 and 0–100.

3.4.1 Scenarios

First, an integral part of the Swiss Energy Strategy 2050 is the promotion of energy efficiency and sufficiency measures, as well as the electrification of fossil dominated sectors such as transport. Electricity demand developments have a high impact on electricity prices, especially when peak demands can be lowered. However, the package of measures and its effectiveness are uncertain. For this reason three demand scenarios are considered (Table 3.2), based on the report by Pöyry (2012): growing, stable and declining. Second, while major investments in Swiss generation capacity are endogenously determined, large uncertainty remains over foreign demand and supply developments. Due to the high level of interconnection these

Table 3.2 Scenario overview

Scenario variable	Values
Electricity demand	1 = Growing; 2 = Stable; 3 = Declining
Foreign spot prices	1 = Low; 2 = High
NTC expansion	1 = 10YNDP expansion; 2 = Constant 7500 MW
Policy options	1 = Business as usual; 2 = Delayed phase-out; 3 = Price floor; 4 = FIT cancelled early; 5 = Lower investment barriers
CCGT permitting time	2 years; 3 years; 4 years
Data profile year	2010; 2011; 2012; 2013; 2014
Solar profile year	1996; 1997; 1998; 1999; 2000
NTC profile year	2013; 2014

developments could significantly influence the Swiss market and prices. Homogeneity in foreign policy developments is assumed amongst the European member states bordering Switzerland. As a proxy for these developments two future spot price scenarios are determined based on the 10YNDP (ENTSO-E 2014): high or low prices. Third, NTC expansions are closely linked to foreign spot price developments. Lack of investments in transmission capacity might result in shortages during winter peak demand in Switzerland, while significant NTC expansions in combination with low foreign spot prices might result in electricity import dependency. Two scenarios are considered: a constant NTC value of 7500 MW (Osorio and van Ackere 2016), as well as the planned expansion figures in the 10YNDP. Fourth, several domestic policy options are considered. The business as usual option is used as a baseline, and assumes a continuation of policies as currently implemented or planned. In the delayed phase-out scenario the estimated lifetime of the nuclear power plants is increased from 50 to 60 years, extending the planned phase-out by 10 years. Potentially giving more time for investments in new renewables to compensate for the reduction in generation capacity. A price floor scenario is taken into consideration to guarantee revenues under high shares of domestic and foreign renewables. Looking at European developments in Spain and Germany it would not be unthinkable that the feed-in tariff (FIT) is cancelled earlier than currently planned. This would have significant implications for the capacity expansion of new renewables such as solar and wind. Investment barriers can delay investments despite the presence of investment signals. By lowering these barriers investors can respond more quickly to market developments. Fifth, the possibility of shortening the investment pipeline for CCGT projects is explored by varying the permitting time from 2 to 4 years. A shorter permitting time is expected to result in a quicker response by investors and less severe boom-and-bust cycles (Ford 1999, 2001; Kadoya et al. 2005). Finally, we perform simulation runs with various standardized profiles based on historic values for electricity demand, weather effects and market prices to see if the model results are robust. It should be noted that these scenarios and assumptions alone do not drive the system's behavior. Instead, the dynamics and feedback in the system's structure play an important role in determining the transition pathway. Thus, results presented in this section are likely to deviate from those given by existing scenario studies (e.g. optimization models), including the study by the VSE (2012).

3.4.2 Simulation Results

Average Swiss spot prices in Fig. 3.9 indicate three important developments. Depressed electricity prices are most likely to be sustained at less than 50 CHF/MWh, at least until 2030. The underlying cause, oversupply at the Swiss and European level, is unlikely to change due to long asset lifetimes and a possible stabilization or reduction of electricity demand. On the long-term, electricity prices are most likely to increase moderately to a range of 60–120 CHF/MWh by 2050. The behavior of the system is a gradual increase in the electricity price after phasing-out

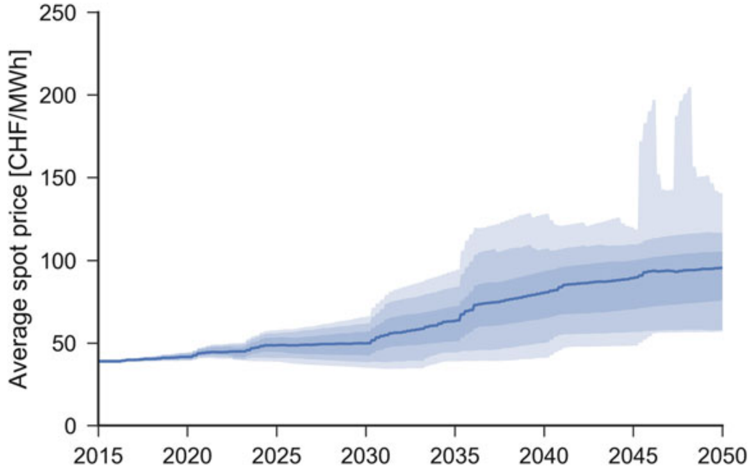

Fig. 3.9 Average spot price over 9000 runs. The solid line represents the modeled median average Swiss spot price

the final and largest nuclear power plants in Switzerland. As a result, the liberalized electricity market will not be broadcasting strong price signals for capacity investments in most scenarios. However, Fig. 3.9 is visually dominated by the occurrence of electricity shortages on the long-term, leading to high average spot prices. While these events have a low likelihood to occur, further investigation is warranted due to their disproportionate impact on consumers (De Vries 2007).

The modeled price spikes indicate a shortage of electricity supply, despite investments in RES. In fact, installed capacities should be more than enough to cover electricity demand, even during peak hours. However, not all installed capacity is available during winter peak hours, especially intermittent renewables such as PV. For this reason the de-rated capacities as presented by Osorio and van Ackere (2016) were used to plot the de-rated capacity against the peak demand in Fig. 3.10, which is a visual representation of the security margin. The security margin is the

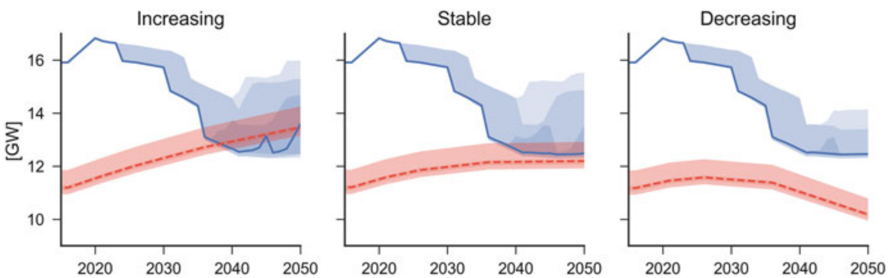

Fig. 3.10 De-rated capacity and peak demand. The solid line represents the modeled median de-rated capacity over 3000 runs per demand scenario. The dashed line represents the modeled median peak demand

relative amount of de-rated capacity versus the peak demand. Currently, peak demand is well below the de-rated capacity in Switzerland, which is reflected by the low and stable spot prices. When the de-rated capacity falls below the peak demand, then shortages, blackouts and scarcity prices can occur (Cepeda and Finon 2013). However, even periods leading up to scarcity can be marked by higher price volatility (Osorio and van Ackere 2016). This is exactly what can be observed from Figs. 3.9 and 3.10, as the de-rated capacity falls below the peak demand we observe scenarios in which scarcity pricing occurs. This mainly occurs in the scenarios where demand increases, highlighting the important role electricity demand reduction can play during the nuclear phase-out. However, scarcity pricing does not always occur in the increasing demand scenarios. Moreover, there seems to be a delayed and severe response by the spot market when the de-rated capacity falls below the peak demand. Why do we observe these delayed and lacking responses by the Swiss electricity market, which are well beyond delays inherent to the investment pipeline? To answer this question, a subset of 3000 simulation runs with increasing electricity demand is considered beyond this point.

There are indications in Figs. 3.9 and 3.10 that market signals are being distorted by hydropower and imports. About half of the scenarios are expected to experience shortages by 2040, under growing electricity demand assumptions (Fig. 3.10, left-hand graph), which are not met by scarcity pricing in most cases (Fig. 3.11, left-hand graphs). Hydropower plays an import role in maintaining stable and low electricity prices as long as there is adequate production capacity available. However, as soon

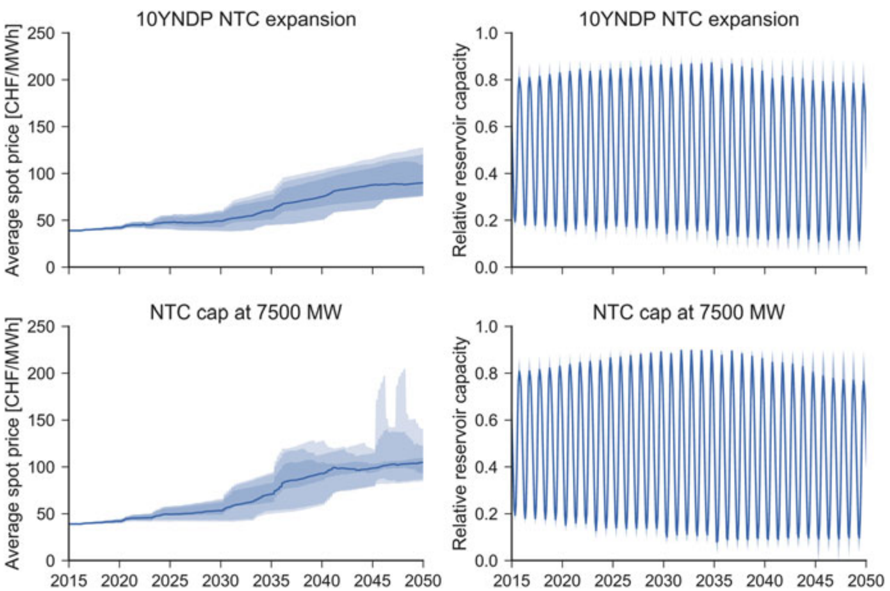

Fig. 3.11 Average yearly spot prices (left) and available hydropower reservoir capacities (right) over 3000 runs. All graphs display simulation experiments under increasing electricity demand assumptions

as the electricity market is faced with shortages, and especially when imports are constrained, then hydro reservoirs quickly prove inadequate. The maximum delay in price signals seems to be less than a year, as hydropower will signal scarcity prices when reservoir levels are too low. More importantly, the heavy reliance on hydropower resources only occurs in the scenarios in which the expansion of transmission capacity is constrained. This implies that Switzerland could meet increased electricity demand through imports, but only when transmission capacities are expanded according to the 10YNDP.

Switzerland can develop a long-term dependency on high levels of electricity imports when electricity demand increases, as shown in Fig. 3.12. In fact, when Switzerland becomes dependent on imports to cover its production deficit pricing signals are not broadcasted to investors. Consequently, the de-rated capacity will be below peak demand, which poses a real threat to security of supply. However, when NTC expansions are limited at 7500 MW Switzerland initially increases its imports, after which scarcity signals are sent to the market as the NTC is inadequate to cover peak demands. On the long-term imports are reduced slightly compared to scenarios in which NTC is expanded according to the 10YNDP. However, generation capacity is expanded too late, and too slowly, resulting in high electricity prices in some scenarios. Limited evidence of boom-and-bust cycles can be observed when the NTC is limited at 7500 MW, as oversupply (Fig. 3.12, bottom right graph) follows a

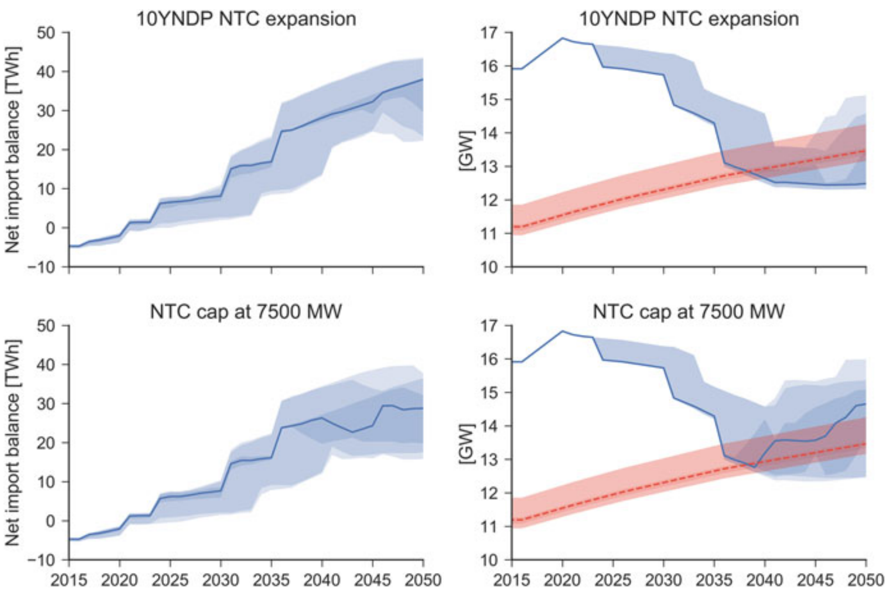

Fig. 3.12 Average yearly net import balance (left) and de-rated capacities and peak demand (right) over 3000 runs, represented by solid lines. The dashed line represents the modeled median peak demand. All graphs display simulation experiments under increasing electricity demand assumptions only

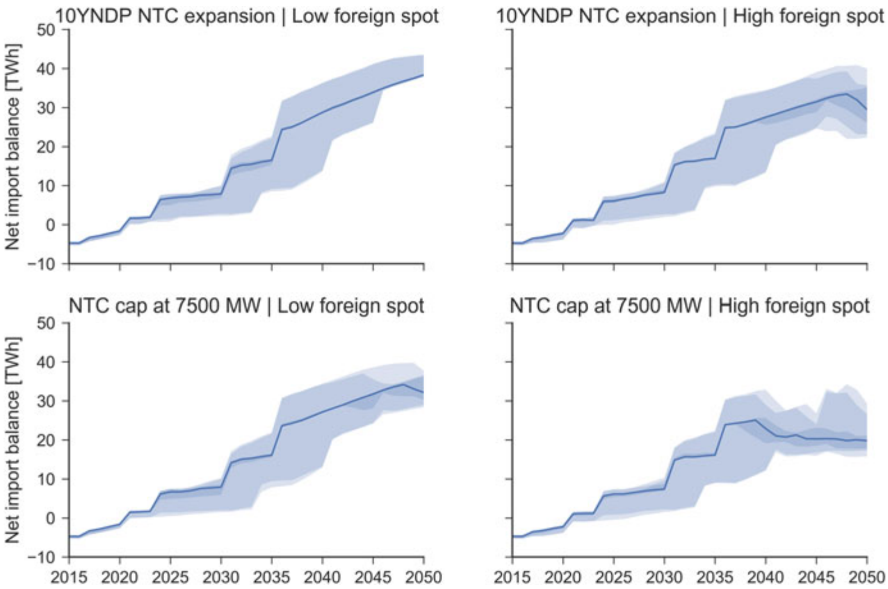

Fig. 3.13 Yearly net import balance over 3000 runs. All graphs display simulation experiments under increasing electricity demand assumptions only

period of undersupply after the last nuclear power plants are decommissioned and the French contracts have expired.

Foreign spot price developments have a large impact on electricity imports and exports (Fig. 3.13), significantly distorting market investment signals (Fig. 3.14). Lower foreign spot prices lead to a higher electricity import dependency, regardless of NTC expansions. However, due to low import prices the market is slower to respond to shortages as less hydropower is used to export to foreign markets. This highlights the interaction between foreign spot prices, electricity exports and hydropower as conceptualized in Fig. 3.4 by feedback loops (2) and (3). When NTCs are not expanded this can lead to more serious shortages and eventually higher domestic electricity prices (Fig. 3.15). As expected, price signals are suppressed and delayed in the scenarios in which large amounts of NTC are available. The 10YNDP expansion plans are sufficient for Switzerland to cover its import needs, assuming the electricity is physically obtainable from neighboring countries. This suppressing effect is amplified by the availability of cheap foreign electricity.

CCGT permitting time has a predictable impact on the installed de-rated capacity and domestic electricity prices. Once a shortage occurs, the market is less quick to respond with longer CCGT permitting times. Having established the influence of external factors on the operation of the Swiss market, we now turn to the influence of internal policies. Which endogenous policies help the market improve its performance and avoid scarcity pricing?

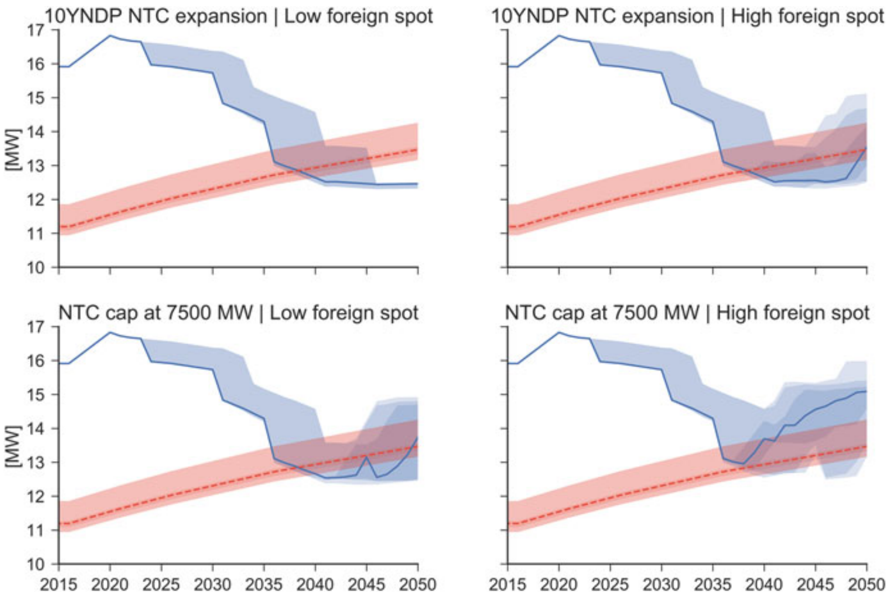

Fig. 3.14 De-rated capacity and peak demand. The solid line represents the modeled median de-rated capacity over 3000 runs. The dashed line represents the modeled median peak demand. All graphs display simulation experiments under increasing electricity demand assumptions only

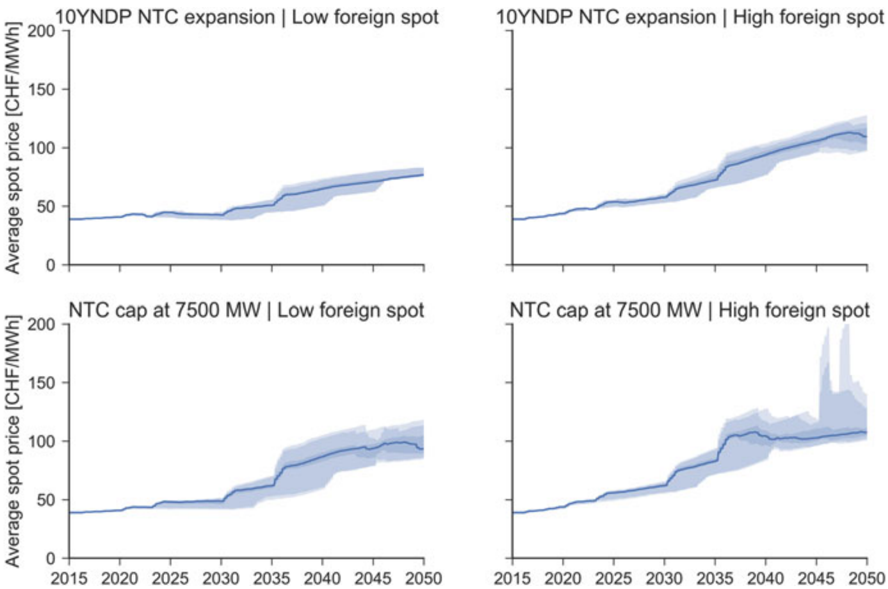

Fig. 3.15 Average Swiss electricity spot price over 3000 runs. All graphs display simulation experiments under increasing electricity demand assumptions only

As can be observed by comparing the first and second column of graphs in Fig. 3.16 NTC expansion has a significantly larger impact on electricity prices than any of the evaluated policies. However, Swiss domestic policies can make the difference when NTC expansions are limited at 7500 MW, compared to the business

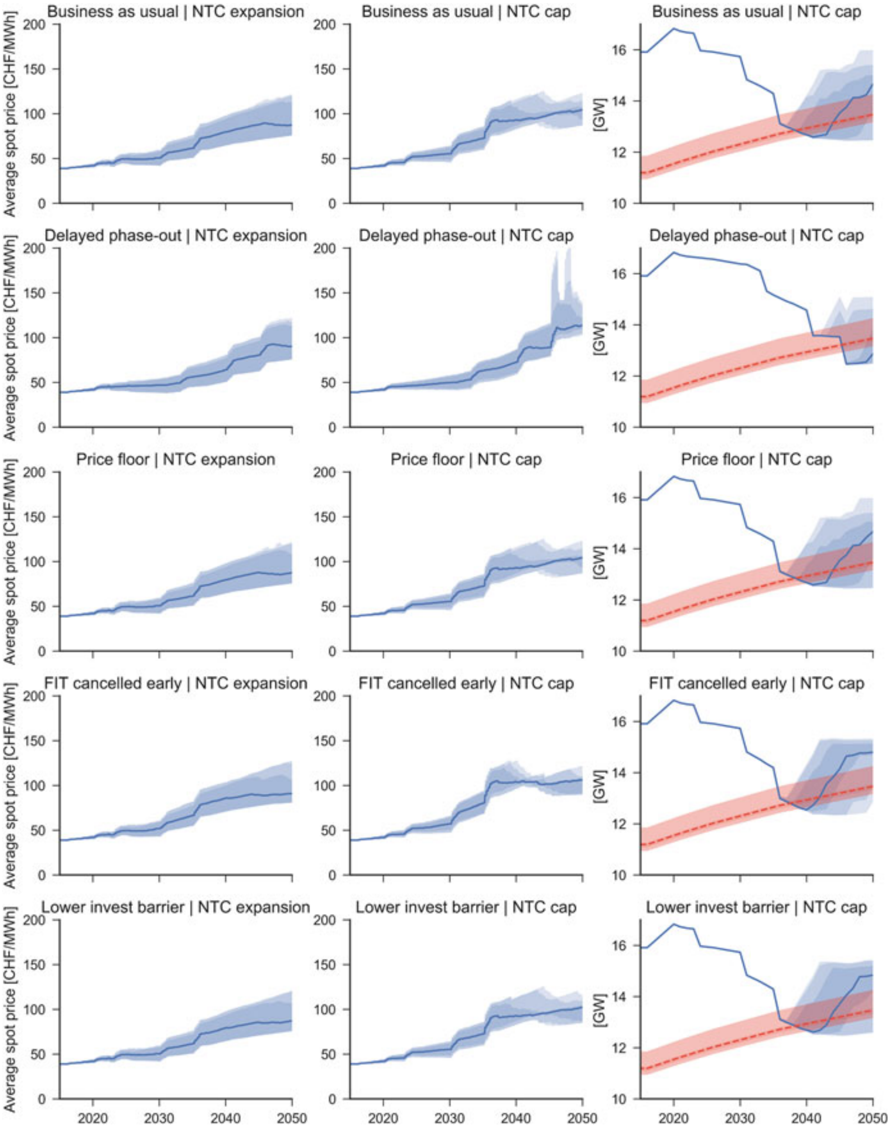

Fig. 3.16 Average Swiss electricity spot price (solid line) in columns one and two. The de-rated capacity (solid line) vs. peak demand (dashed line) in column three. All graphs display results over 3000 runs. All graphs display results under increasing electricity demand assumptions only

as usual scenario (top row of graphs in Fig. 3.16). In the following observations we only focus on the scenarios in which electricity demand is assumed to increase. First, a delayed nuclear phase-out (second row of graphs in Fig. 3.16) can lead to electricity shortage, as capacity investments are inadequate to meet peaks as demand continues to grow. The limited NTC available during the winter months is not sufficient to cover the electricity demand in Switzerland, leading to multiple years of scarcity pricing. Second, introducing a price floor (third row of graphs in Fig. 3.16) only has a minor impact in some cases, as it could help ensure the profitability of investments in generation capacity when spot prices are low. Third, an early cancellation of the FIT (fourth row of graphs in Fig. 3.16) increases the likelihood of an earlier shortage in supply when inadequate NTC is available. The acute shortage triggers a high level of investments, resulting in an oversupply in a majority of scenarios. It is unlikely that this will result in sustained boom-and-bust cycles, especially when the power plants replacing the phased-out nuclear power plants are much smaller in terms of installed capacity (e.g. solar, wind, CHP and CCGT). Finally, lower investment barriers (fifth row of graphs in Fig. 3.16) lead to earlier investments in installed capacity, lowering the chance of electricity shortages and price spikes.

To conclude, a clear trade-off exists between the risk of significant import dependency and that of electricity shortage. The optimal situation seems to lie somewhere between the large capacity expansions of the 10YNDP and the current levels of transmission capacity. Furthermore, artificial price signals such as a price floor can help secure a slightly higher level of investments, reducing the risk of undersupply. Renewable energy support schemes can have similar effects, but these simultaneously erode spot market prices through the merit order effect. There is little evidence of boom-and-bust investment cycles in most scenario combinations, especially in scenarios with low European electricity spot prices. On the other hand, higher foreign spot prices and limited availability of NTC can result in strong price signals and overinvestments. Importantly, the majority of scenarios lead to a lower security of supply, which is reflected by a de-rated capacity which is below the peak demand and an increase in the price volatility. Liberalized electricity markets commonly sustain lower levels of security of supply than regulated markets, which often have relatively high enforced targets. Thus, it is not unexpected to find decreasing security of supply levels after liberalization in Switzerland.

3.5 Conclusion and Discussion

Belgium, Germany and Switzerland have committed to phasing-out nuclear energy, while simultaneously maintaining low carbon emission levels. Additionally, Switzerland is facing the challenge of liberalizing its electricity market, which can lead to “boom-and-bust” investment cycles. Switzerland is in a period of electricity generation capacity overinvestment, resulting in a lack of investment signals for market players once the market is liberalized. Conversely, long delays between permit applications and the construction of power plants lead to overinvestments, as too many projects are initiated based on price signals during capacity shortage. Unique to the case of Switzerland is the combination of low European electricity spot prices, particularly in neighboring countries, and its large hydro storage capacity, which dampens domestic electricity prices and delays investment signals. In this chapter we have addressed the following research question: What is the impact of low European electricity prices on Swiss generation capacity investments under market liberalization and nuclear phase-out policies?

In order to answer this question, we have developed a novel SD model of the Swiss electricity market containing detailed endogenous investment pipelines, as well as bounded rational actors. This allowed us to explore the question of investment cycles in a liberalized hydro-dominated market which is going through a nuclear phase-out. Furthermore, we placed our study in the broader European context of low electricity prices and ongoing energy transitions. The practical contribution of this approach is that it allows us to explore future market developments under various policy options, taking into consideration the inherent system complexity and uncertainty over long time periods.

One of the key findings is that the period of overinvestment in Switzerland is most likely to be followed by a period of underinvestment. However, scarcity pricing does not always occur as the de-rated generation capacity falls below the peak demand. In fact, the price signal response by the spot market is often delayed, but can be quite severe.

The second key finding is that the electricity market is more often than not unable to address the capacity shortage under increasing electricity demand scenarios, leading to years of underinvestment in new generation capacity. Hydropower plays an important role in explaining the delayed market response, as it acts as a buffer for around 2 years. Once hydro reservoirs are depleted the shortage will be much more pronounced. Hydro reservoirs are depleted if there is insufficient NTC to import electricity during peak demand, and when companies export too much hydroelectricity. However, when transmission capacities are expanded it is very likely that Switzerland increases its import dependency, especially when European spot prices remain low. Consequently, investment signals will not broadcast and de-rated capacities will often remain below peak demand. Underinvestment will ultimately increase the price volatility in Switzerland. It was found that a clear trade-off exists between the risk of significant import dependency and that of electricity shortage. The optimal situation seems to lie somewhere between the large capacity expansions of the 10YNDP and the current levels of transmission capacity. Furthermore, artificial price signals such as a price floor can help secure a slightly higher level of investments, reducing the risk of undersupply. Renewable energy support schemes can have similar effects, but these simultaneously erode spot market prices through the merit order effect. Other policy options, such as a delayed nuclear phase-out and early cancellation of the FIT have a negative impact on the security of supply.

The theoretical contribution of this chapter is that we have found little evidence of boom-and-bust investment cycles in most scenario combinations, especially in scenarios with low European electricity spot prices. The phase-out of nuclear power and French contracts can quickly lead to low levels of security of supply, but there are a few unique characteristics of the Swiss electricity market which can protect it from scarcity pricing and boom-and-bust investment cycles. With these findings we pose a counter-example to earlier SD simulation work on boom-and-bust cycles (Ford 1999, 2001; Kadoya et al. 2005), and identify four key mechanisms contributing to the dynamics of investment cycles after market liberalization.

First, hydropower can act as a buffer for security of supply issues. However, reservoir storage capacities are limited compared to the annual electricity demand and reservoirs are drained quickly. While acting as a buffer the reservoirs also inhibit investment signals. Second, Switzerland has a relatively high NTC compared to its domestic electricity demand. Consequently, electricity can be important to cover peak demands. Third, the newly installed capacity is relatively small compared to the nuclear power plants which are being phased-out. As a result, future decommissioning of power plants will be more gradual, rather than large step-wise decommissioning of capacity. Fourth, the total installed capacity in Switzerland is relatively small compared to the size of nuclear power plants and even CCGT plants, resulting in a big change to electricity supply and prices after construction or decommissioning of a power plant.

There are several limitations to our analysis. First, the system boundaries are chosen in such a way that the neighboring countries are treated as exogenous, including investments in transmission capacity. Due to this limitation there is no feedback from the Swiss market to the foreign markets. While the Swiss market is relatively small compared to the German, Italian and French markets, it is likely that the endogenous investments in transmission capacity would more accurately capture impacts on electricity flows and spot prices between these countries. Second, SD does not allow for a very detailed dispatch model of individual power plants, including ramping constraints and individual marginal production costs. Other modeling and simulation paradigms, such as optimization approaches and agent-based modeling, are well-equipped to include such details in the model, leading to more realistic spot prices. Third, a time horizon until 2050 does not allow for multiple boom-and-bust cycles to be observed, as the full phase-out is not completed before 2034. However, longer time horizons are also inherently more uncertain.

We recommend multiple venues for future research. First, capacity remuneration mechanisms can be used to dampen investment cycles (Ford 1999) and are currently being implemented in countries around Switzerland (Betz et al. 2015). Modeling the implementation of a capacity mechanism for Switzerland, and its interaction with neighboring markets, will give more insights into policy options to address the challenges of transitioning to a liberalized market and avoiding security of supply issues. Second, implementing endogenous transmission capacity investments can address congestion issues in the model and potentially address the trade-off between import reliance and capacity shortage found in our scenarios. Third, neighboring markets should be modeled in more detail to consider the impact and feedback of foreign policies, foreign demand and supply at the hourly level. This would allow for the exploration of high RES penetration scenarios and the evaluation whether electricity is physically available during peak hours when relying on imports. As demonstrated by Jäger et al. (2009) and Kunsch and Friesewinkel (2014) the model and methodology used in this chapter can be applied to other countries phasing-out their nuclear energy supply, such as Belgium and Germany. Fourth, demand profiles are currently static and based on historic values. However, such profiles are likely to change due to the adoption of e-mobility, heat pumps and demand response.

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