SCCER CREST

In cooperation with the CTI

Energy funding programme
Swiss Competence Centers for Energy Research

Schweizerische Eidgenossenschaft
Confédération suisse
Confederazione Svizzera
Confederaziun svizra

Swiss Confederation

Commission for Technology and Innovation CTI

WP3 - 2017/07

Hydropower Operation in a Changing Market Environment – A Swiss Case Study

Moritz Schillinger
Hannes Weigt
Michael Barry
René Schumann

November 2017

Work Package 3: Energy Policy, Markets and Regulation
SCCER CREST

This research is part of the activities of SCCER CREST (Swiss Competence Center for Energy Research), which is financially supported by the Swiss Commission for Technology and Innovation (CTI) under Grant No. KTI. 1155000154.

Hydropower Operation in a Changing Market Environment – A Swiss Case Study

Moritz Schillinger[1], Hannes Weigt[1], Michael Barry[2], René Schumann[2]

[1] University of Basel, [2] HES-SO Valais

Corresponding author:

Moritz Schillinger
Forschungsstelle Nachhaltige Energie- und Wasserversorgung
Wirtschaftswissenschaftliche Fakultät der Universität Basel
Peter Merian-Weg 6, Postfach, CH-4002 Basel
Mail: moritz.schillinger@unibas.ch

Abstract

Hydropower (HP) is expected to play an important role in the European energy transition by providing back-up and storage capacity as well as flexibility for intermittent renewable energies. However, due to low electricity market prices the profitability of HP decreased in recent years. In this paper, we analyze historic revenue potentials and future market prospects for HP taking into account different development paths. Using a short-term HP operation model to capture market opportunities as well as technical and natural constraints of HP plants, we model three representative Swiss HP plants. The results indicate that in the last years, balancing markets could have provided significant additional revenues for HP plants. However, accounting for uncertainties and market characteristics, the potential of balancing markets is reduced but cross-market optimization is still beneficial. Looking into the future, market price prospects for the coming decade are low to modest. Global fuel markets and the European Union Emissions Trading System (ETS) will be the main drivers for decisions for Swiss HP. The revenue potential from balancing markets will be reduced significantly in the future if all Swiss HP operators aim for balancing. While optimized operation across markets helps Swiss HP to increase its revenues, it is limited in scale.

Keywords: hydropower; cross-market optimization; balancing; Switzerland

Acknowledgments: This research is part of the cluster project 'The Future of Swiss Hydropower: An Integrated Economic Assessment of Chances, Threats and Solutions' (HP Future) that is undertaken within the frame of the National Research Programme "Energy Turnaround" (NRP 70) of the Swiss National Science Foundation (SNSF). Further information on the National Research Programme can be found at www.nrp70.ch. This research is carried out within the framework of SCCER CREST (Swiss Competence Center for Energy Research, www.sccer-crest.ch), which is financially supported by the Swiss Commission for Technology and Innovation (CTI) under Grant No. KTI.2014.0114.

An earlier version of the paper was presented at the IEWT 2017 and the EEM 2017 conferences. We would like to thank for valuable comments. In addition, we would like to thank the Energy Economics Group of the University of Basel and the HP Future project team for valuable inputs, comments and suggestions.

1. Introduction

In many European countries, hydropower (HP) represents an important pillar of the energy system. With ongoing changes in the European energy system, HP is becoming even more important. In the energy transition, HP is expected to increase its generation while at the same time ensuring system security by providing back-up and storage capacity and flexibility. However, an increasing share of fluctuating renewable energies such as wind and solar also influences market dynamics (Gaudard and Romerio, 2014). Thus, an increase in renewable energies implies chances as well as threats for HP. On the one hand, flexible technologies such as HP will be needed to balance generation and demand and to provide reserves. This could provide additional income for HP plants. On the other hand, new renewable energies influence the merit-order and consequently lead to lower electricity prices. Since the share of new renewable energies is expected to increase further, HP operation needs to account for the resulting changes and dynamics in the market environment (Barry et al., 2015).

In addition, in the last years, low carbon and fuel prices have led to a general decrease of electricity wholesale prices in Central Europe. Thus, also HP profitability decreased over the past years. As hydropower covers about 60% of electricity generation in Switzerland, the reduced profitability has led to a debate on the role of Swiss HP (Betz et al., 2016) cumulating in proposals for financial support for HP.

The objective of this paper is to assess the revenue potential for Swiss HP under different market conditions and to evaluate the value of flexibility in the given electricity market structure. In order to analyze the short-term HP operation options, we develop a model framework accounting for different market options (day-ahead and balancing) as well as technical and natural production constraints. The model is applied to analyze historic revenue potentials and future market prospects for hydropower, while taking into account different pathways towards the energy future. Our results highlight the decline in HP revenues between 2011 and 2015 driven by the general decline in electricity prices. In theory, participation on balancing markets could provide a significant revenue increase and thereby partially mitigate the overall decline in prices. However, accounting for uncertainties and specific balancing market characteristics, the potential is reduced. Nevertheless, cross-market optimization was still beneficial in the last years. Regarding the future revenue prospects for HP, we produce a set of scenarios accounting for different developments of the EU generation mix and of carbon and fuel prices. The results indicate rather modest revenue prospects for the coming years. Furthermore, the potential of additional balancing revenues is rather low, if all Swiss HP plants offer their flexibility on the balancing market.

The remainder of this paper is structured as follows: in the second section, we provide a literature review regarding the current and future role of HP in the market. In addition, the modelling of HP operation is addressed. In section 3 and 4, the HP operation model and the data used in this paper are explained. In section 5 the historic revenue situation is assessed and an ex-post evaluation of different trading strategies is carried out. Section 6 provides estimates for future revenue prospects. Section 7 concludes.

2. Market prospects of hydropower and operational optimization

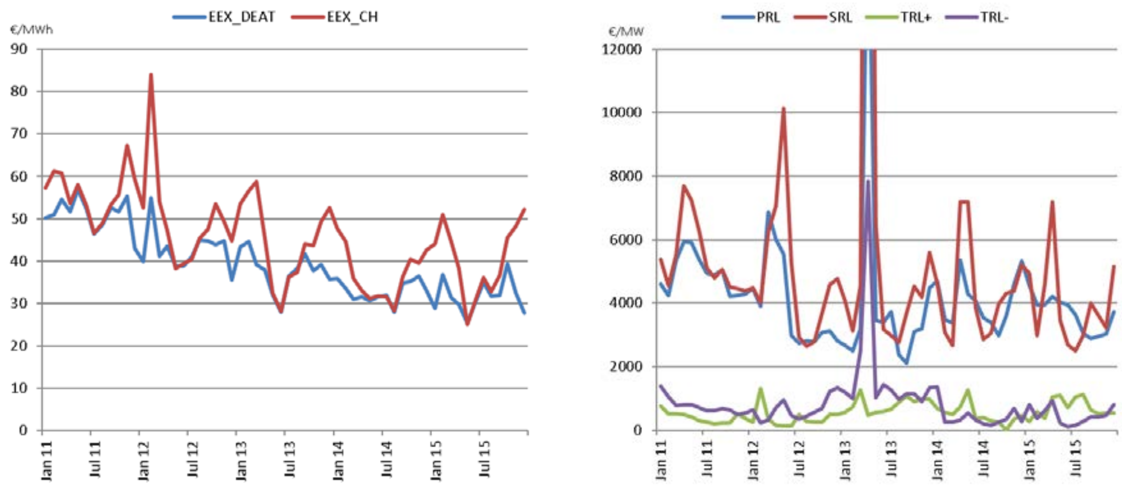
Research on HP covers a large variety of topics. For this paper we focus on the current role of HP in liberalized electricity markets and the role of flexibility therein as well as the future prospects and expectations for HP. Methodologically we rely on a techno-economic modeling approach of hydro operation and link it to similar existing approaches.

2.1. Current role of hydropower

HP plays an important role in the current European electricity system. In 2014, HP was supplying around 19% of the total generation in the region of the European Network of Transmission System Operators for Electricity (ENTSO-E). This makes HP the technology with the second highest generation share in the ENTSO-E region. However, even though HP is significantly contributing to the electricity supply of the ENTSO-E region, HP capacities in Europe are concentrated in a small number of countries mainly due to geological and meteorological reasons. In the ENTSO-E region, eight countries hold 76% of the total ENTSO-E hydropower capacity. Of these countries, Norway has the highest share of HP capacities followed by France, Italy, Spain, Switzerland, Sweden, Austria and Germany (ENTSO-E, 2014). Some of these countries obtain more than 50% of their electricity from HP, making HP the dominant electricity generation source (IEA, 2012). While HP contributes 96% to the total electricity generation in Norway, it contributes around 68% to the total electricity generation in Austria and 60% in Switzerland (ENTSO-E, 2014; SFOE, 2016).

Taking into account the different HP technologies, run-of-river (RoR) plants provide base load generation while reservoir or dam HP (Dam) plants provide peak load generation (VSE, 2014). In Switzerland, 40% of the electricity from HP comes from RoR plants while dam HP plants provide 60% (SFOE, 2016). Whereas RoR plants are running continuously and have to recover their costs given the average market price, dam HP plants are focusing on high price peak load hours and thus have to recover their costs in fewer hours during the year (Gaudard and Romerio, 2014; VSE, 2016). In general, HP has high capital costs but low operating costs while the level of costs depends on the specific site and additional factors such as national regulation (Gaudard and Romerio, 2014). Since electricity prices decreased in the past years (Figure 1, left panel), i.e. due to an increasing share of renewable energies and low fuel and carbon prices, the profitability of HP as well as of other generation technologies has decreased. However, the profitability situation of HP cannot be generalized since costs of HP are highly heterogeneous (Betz et al., 2016; Filippini and Geissmann, 2014).

Aside from electricity generation, HP is contributing to system stability, short-term security, and the integration of variable renewable energies such as wind and solar by providing ancillary services. In addition to the compensation of active power losses and the provision of voltage stability or black-start capacity, HP in Switzerland is especially important for the provision of frequency control via balancing markets (Gaudard and Romerio, 2014; VSE, 2016). In Switzerland, balancing markets are split according to their call-up time into a primary reserve market (PRL, within seconds), a secondary reserve market (SRL, within few minutes) as well as into tertiary positive and negative markets (TRL+, TRL-, within 15 minutes). Whether a HP plant can be active on those markets depends on the technical characteristics of the plant, as a prequalification is required for participation in each of the balancing markets (Swissgrid, 2015). In Switzerland, HP is supplying all PRL, SRL and TRL+ demand. TRL- is only partly supplied by HP while nuclear power plants supply most of the TRL- demand (VSE, 2016). The price development in recent years shows a less clear-cut trend than the spot market. While balancing prices show a similar winter-summer pattern as the energy prices, they exhibit larger deviations and price spikes (Figure 1, right panel).



(**a**) (**b**)

Figure 1. Price development 2011 - 2015. (**a**) Development of electricity prices in German/ Austrian and Swiss day-ahead market in € per MWh; (**b**) Development of prices in Swiss primary reserve market (PRL), secondary reserve market (SRL), tertiary positive (TRL+) and negative (TRL-) reserve market in € per MW. Data from EPEX SPOT (2017) and Swissgrid (2017c).

Several studies show that the participation of HP plants in the balancing markets in addition to the spot market can increase their profits (Abgottspon and Andersson, 2012; Chazarra et al., 2016; Deb, 2000; Fodstad et al., 2015; Kazempour et al., 2009; Rasmussen et al., 2016). However, the extent of those additional profits is difficult to generalize. While e.g. Fodstad et al. (2015) finds only a small added value from balancing, Chazarra et al. (2016) or Deb (2000) find a significant profit increase. The magnitude of the additional profits from balancing is influenced e.g. by the flexibility of a HP plant (Fodstad et al., 2015) or the bidding strategy (Abgottspon and Andersson, 2012). In general, the possibility of HP plants to be active on multiple markets should be considered when analyzing the profit potential of HP (Chazarra et al., 2016; Deb, 2000).

Beside generation and ancillary services, pump-storage plants (PSP) are contributing to system stability by providing the ability to store electricity. In general, PSP plants are operated by pumping water in low price hours and generating electricity in peak price hours. Up to date HP is the only mature electricity storage technology (Gaudard and Romerio, 2014).

2.2. Future role of hydropower

With the ongoing changes in the European energy system, HP is becoming even more important. On the one hand, HP is expected to increase its electricity generation to support the phase out of conventional generation. According to IEA (2012) the undeveloped technical potential of HP in Europe is 47% hinting towards a significant potential for further increases. However, it is important to distinguish between different types of potentials like the gross potential, the technical potential, the economic potential or the exploitable potential (Gaudard and Romerio, 2014; SFOE, 2012). In addition, in countries like Switzerland which already have a high share of HP, the potential for additional HP generation is limited since the best HP sites are already exploited and the national Waters Protection Act needs to be considered when estimating the additional HP potential. Estimates range between 4% to 8% increase of HP production. However, the 8% increase could only be achieved if the current economic and social conditions would change in the future. In addition, potential climate change impacts may influence the future HP generation potential (SFOE, 2012).

On the other hand, HP is expected to increasingly contribute to system security and stability in the future by providing e.g. balancing reserves, storage capacity or flexibility in order to contribute to the integration of the increasing share of variable renewable energies (Gaudard and Romerio, 2014). If and how much the balancing reserve requirements will change in the future is difficult to estimate. Hirth and Ziegenhagen (2015) for example show that the demand for balancing reserves decreased over the past years while the share of variable renewable energies increased significantly in the German electricity system. Since the development of future balancing demand is uncertain also the future revenue potential for HP is uncertain. In addition, potential changes in the balancing market rules could enable new market actors (i.e. renewable energies such as wind and solar) to participate in the balancing markets leading to an increasing number of potential suppliers and in turn increasing competition (Hirth and Ziegenhagen, 2015; Swissgrid, 2017b).

With a rising share of variable renewable energies, the need for storage and flexibility may increase in the future. Since HP could contribute to covering this need, an increasing share of variable renewable energies might provide additional profit opportunities for HP. However, the future need for storage and flexibility depends e.g. on the share of renewable energies (RES) in the market and the type of storage which is required (Saarinen et al., 2015; Weitemeyer et al., 2015). In addition, the role of HP regarding electricity storage also depends on the development of other storage technologies and their costs (Gaudard and Romerio, 2014).

Frauendorfer et al. (2017) also highlights the importance of price dynamics at day-ahead and intraday electricity markets for (pumped) hydro. The increase of price volatility (2008: 50%, 2015: 250%) due to the increase of stochastic renewable injection provides additional revenue potential for storage units if they optimize their trading of hourly day-ahead and quarter-hourly intraday products. They expect that the future increase of renewables and the emergence of further storage capacities will alter the seasonality and volatility of electricity markets and thereby also alter the revenue potential of pumped hydro. A related estimate by Schlecht and Weigt (2016) aims to assess the long term potential of the Swiss electricity market to provide sufficient price spreads for pumped hydro. They show that given the expected European capacity extension plans for renewables and conventional generation, the price pattern will be altered significantly. In the long run the emergence of large scale solar generation will lead to significant price dumps during daytime and price spikes in morning and evening hours. However, the existing and projected conventional capacities will lead to a rather flat price curve during the transition phase that can likely prevail for up to two decades until renewables have a much higher market share. During those years the average market conditions are likely to pose severe challenges for the profitability of storage operation.

Finally, the flexibility of HP can also contribute to the value of variable renewable energies such as wind and thus contribute to the implementation of the energy transition. As shown by Hirth (2016) the drop in the revenue (or market value) of wind generators with an increasing wind deployment is lower in a system with HP. Thus, HP can make variable renewable energies such as wind more valuable. At the same time, HP is becoming more valuable in the presence of variable renewable energies.

2.3. Modelling hydropower operation

A variety of literature exists regarding the modelling of HP operation. In general, the models differ in the way uncertainty in prices and inflows is addressed, the way in which technical details are modeled, and which markets are considered.

While deterministic models neglect the uncertainties in prices or inflows, stochastic models can explicitly address these uncertainties. Ladurantaye et al. (2009) compare a short-term (24h) deterministic HP operation model which neglects the uncertainty in the electricity price and a stochastic model considering the uncertainty in the electricity prices by a scenario tree. While the stochastic model outperforms the deterministic one in terms of solution quality, the application of the stochastic model to longer time horizons would significantly increase the solution time due to the increasing size of the scenario tree.

In practice, HP operation is influenced by a variety of technical plant characteristics. The power generated by a HP plant is a function of water discharge and head. In practice this function is nonlinear and non-concave. In addition, the operating performance of a HP pant depends on the efficiency as well as minimum and maximum discharge limits of the turbines. HP operation models differ in how accurately these technical characteristics are considered and how they are modeled. While nonlinear relationships such as head effects are neglected in linear HP models, mixed integer programming can be used to approximate the nonlinear relationships or nonlinear programming can be applied to directly include those aspects (Pérez-Díaz et al., 2010). For example, Conejo et al. (2002) or Borghetti et al. (2008) use mixed-integer linear programming to account for the nonlinear relationship between power, discharge and head while e.g. Pérez-Díaz et al. (2010) use nonlinear programming to model this three-dimensional relationship.

In addition to the way in which uncertainty and technical details are modeled, HP operation models differ in the markets which are considered. While many HP operation models analyze the operation of a HP plant on the spot market (e.g. Pérez-Díaz et al., 2010) some models take into account multiple markets such as spot and balancing markets (e.g. Kazempour et al., 2009; Ladurantaye et al., 2009). Since HP can participate in multiple markets all of these markets should be considered if the profits of HP are analyzed in order to not underestimate HP's profit potential (Deb, 2000).

2.4. Linkage and contribution

The objective of our paper is to assess the revenue potential for Swiss HP under different market conditions. Consequently, the analysis is linked to the ongoing debate about the role of HP in liberalized electricity markets. We will provide an ex-post evaluation of the value of flexibility offered by balancing markets. This provides the starting point for future revenue estimates and links to the debate highlighted in section 2.2. In particular, our model evaluation can be seen as an extension of Schlecht and Weigt (2016) by increasing the hydro detail and extending the market development space. Therefore, our results also add to the ongoing debate on Swiss HP and provide quantifications for potential market revenue developments.

From a methodological perspective, we rely on existing approaches and combine linear and non-linear elements to include sufficient technical details while accounting for market optimization on spot and balancing markets on a yearly time horizon. The details of the modeling approach are presented in the following section.

3. Hydropower operation model

In order to analyze the historic revenue potentials and future market prospects for HP, we develop a short-term HP operation model following the modeling approaches presented above. In the model, we take a single plant perspective. Since HP is a flexible technology, it can participate in different markets for energy and ancillary services (Kazempour et al., 2009). In our case, the HP plant is participating in the spot and balancing markets, capturing the different opportunities arising on those markets. Aside from economic aspects, the technical and environmental constraints of the plant are considered in the model. Taking into account technical aspects of a HP plant, nonlinearities have to be addressed (Pérez-Díaz et al., 2010). Thus, our model combines linear and nonlinear programming. While HP plants have to deal e.g. with stochastic water inflows and stochastic electricity prices in reality (see e.g. Ladurantaye et al., 2009) our model is deterministic. Thus, uncertainties e.g. in water inflows and prices are neglected. The underlying timeframe of the model is one year in order to capture the yearly seasonality of a storage reservoir and the smallest time resolution is 15 minutes for intraday market bids.

In the following, we provide the general model formulation accounting for the objective formulation, market restrictions, and technical constraints, provide a description of the underlying solve process addressing the non-linearity aspects, and discuss limitations stemming from the chosen model formulation.

3.1. Revenue optimization

The objective of the HP plant is to maximize its total revenue Rev which consists of the revenues Rev_m on the respective markets m the plant is active on (Eq. 1). Beside the day-ahead (DA) and intraday market (ID) the Swiss balancing markets, which are split into a primary reserve market (PRL), a secondary reserve market (SRL) as well as in tertiary positive and negative markets on weekly and daily basis (TRL_w^+, TRL_d^+, TRL_w^-, TRL_d^-), are considered in the model.[1] We follow Kazempour et al. (2009) and Ilak et al. (2014) in the modeling of the balancing markets aspects.

$$\begin{gathered} \max\ Rev = Rev_{DA} + Rev_{ID} + Rev_{PRL} \\ + Rev_{SRL} + Rev_{TRL_w^+} + Rev_{TRL_w^-} + Rev_{TRL_d^+} + Rev_{TRL_d^-} \end{gathered} \tag{1}$$

In the two energy markets (day-ahead and intraday) the HP plant is remunerated for delivery of energy for each trading period t ($G_{t,DA/ID}^+$). On the day-ahead market trading is scheduled hourly while the Intraday market is scheduled quarter-hourly, with respective market price $p_{t,DA/ID}$:

$$Rev_{DA/ID} = \sum_t p_{t,DA/ID}\, G_{t,DA/ID}^+ \tag{2}$$

In the reserve markets, the suppliers bid capacity for the underlying time period into the market. In case of deviations in real time, the TSO can call up those procured capacities to balance system deviations. If the capacity is called up, suppliers have to generate the required energy or reduce their generation in the case of a negative call-up. Depending on the balancing market design, the provision can be symmetric (i.e. being able to increase and decrease output) or asymmetric (i.e. a separate market for positive and negative call-up). In the former case, a plant has to ensure that it has sufficient spare capacities to cover a positive call-up while simultaneously operating at a level that ensures that it is able to reduce output in case of a negative call-up. In the latter case the plant only has to ensure one of the conditions.

In the symmetric PRL market, the weekly capacity bid into the market $Cap_{t,i,PRL}$ is remunerated by the weekly capacity price $p_{t,PRL}^{cap}$. The actual increase or reduction in generation is not remunerated.

$$Rev_{PRL} = \sum_t p_{t,PRL}^{cap}\, Cap_{t,PRL} \tag{3}$$

In the symmetric SRL market, the called up energy is remunerated in addition to the capacity $Cap_{t,SRL}$. If the call-up is positive, the HP plant has to increase its generation, while the requested energy $G_{t,SRL}^+$ is remunerated by the energy price $p_{t,SRL}^{energy+}$. If the call-up is negative, the plant has to reduce its generation. For the reduced amount of energy $G_{t,SRL}^-$, the plant has to pay the energy

[1] For details on the Swiss balancing/reserve markets see e.g. Swissgrid (2015) or Abrell (2016).

price $p_{t,SRL}^{energy-}$. The energy price in the SRL market represents the spot price +/- 20% based on a rule of thumb of the Swiss TSO (Swissgrid, 2015).

$$Rev_{SRL} = \sum_t p_{t,SRL}^{cap} \, Cap_{t,SRL} + \sum_t p_{t,SRL}^{energy+} \, G_{t,SRL}^{+} - \sum_t p_{t,SRL}^{energy-} \, G_{t,SRL}^{-} \tag{4}$$

The Swiss TRL markets are asymmetric markets. Thus, a positive and a negative market exist. The TRL markets can be traded on a weekly basis or on a daily basis while in the daily market 4-hour blocks are traded. The capacity procurement $Cap_{t,TRL_{w/d}^{+}}$ in both markets is remunerated by the capacity price $p_{t,TRL_{w/d}^{+}}^{cap}$. In addition, the positive energy which is called up $G_{t,TRL_{w/d}^{+}}^{+}$ is remunerated by the energy price $p_{t,TRL_{w/d}^{+}}^{energy+}$.

$$Rev_{TRL_{w/d}^{+}} = \sum_t p_{t,TRL_{w/d}^{+}}^{cap} \, Cap_{t,TRL_{w/d}^{+}} + \sum_t p_{t,TRL_{w/d}^{+}}^{energy+} \, G_{t,TRL_{w/d}^{+}}^{+} \tag{5}$$

As in the positive TRL market, the capacity in the negative market $Cap_{t,TRL_{w/d}^{-}}$ is remunerated by the capacity price $p_{t,TRL_{w/d}^{-}}^{cap}$. In the case of a negative call-up, the HP plant has to reduce its output $G_{t,TRL_{w/d}^{-}}^{-}$ and pay the price $p_{t,TRL_{w/d}^{-}}^{energy-}$ to the TSO.

$$Rev_{TRL_{w/d}^{-}} = \sum_t p_{t,TRL_{w/d}^{-}}^{cap} \, Cap_{t,TRL_{w/d}^{-}} - \sum_t p_{t,TRL_{w/d}^{-}}^{energy-} \, G_{t,TRL_{w/d}^{-}}^{-} \tag{6}$$

The plants revenue objective is subject to several constraints covering market aspects and bidding restrictions as well as technical characteristics of the plant and hydrological structure.

3.2. Market aspects

When deciding about the optimal bidding strategy on the different markets, the maximum production capacity cap^{max} needs to be accounted for:

$$G_{t,DA/ID}^{+} + Cap_{t,PRL} + Cap_{t,SRL} + Cap_{t,TRL^{+}} \leq cap^{max} \quad \forall t \tag{7}$$

Consequently, providing balancing capacity reduces the potential trade on the energy markets. However, if the plant wants to be active in the symmetric reserve markets (PRL or SRL) or the negative reserve market TRL-, the plant operator needs to ensure that sufficient capacity is running and can be curtailed in case of a call-up. Consequently, the plant needs to be active on the day-ahead or intraday market to be able to reduce its generation if negative energy is required. Thus, the capacity on the day-ahead and intraday markets needs to be sufficient to fulfill the negative capacity requirements on the reserve markets plus any general minimum capacity constraint cap^{min}:

$$G_{t,DA/ID}^{+} \geq cap^{min} + Cap_{t,PRL} + Cap_{t,SRL} + Cap_{t,TRL^{-}} \quad \forall t \tag{8}$$

While in our case study, the technical minimum capacity of the plant is assumed to be zero (i.e. no residual water flow restrictions), the capacity bid into the balancing markets is constrained by the minimum bid size defined by the TSO (Swissgrid, 2015).

In addition, only what is produced at a specific point in time can be reduced. Thus, the reduction in the energy generation needs to be smaller than or equal to the positive energy generation:

$$\sum_{m} G_{t,m}^{-} \leq \sum_{m} G_{t,m}^{+} \qquad \forall t \tag{9}$$

Finally, only a fraction of the capacity bid into the reserve market is called up. The probability $prob_{t,m}^{+/-}$ of getting called up in a balancing market determines the amount of energy which has to be generated in the case of a positive call-up or reduced in the case of a negative call-up:

$$G_{t,m}^{+/-} = prob_{t,m}^{+/-} Cap_{t,m} \qquad \forall t, m = Bal \tag{10}$$

3.3. Plant characteristics

Given the large heterogeneity of hydro power plants, the market constraints described above need to be supplemented by a representation of the plants topology. Within this paper we focus on a generic setup with a single upper reservoir, one turbine and a lower reservoir (Figure 2). Consequently, we can neglect complex mapping structures between different turbines i and reservoirs r. However, an extension of the generic framework to account for relations between turbines and multiple upper and lower reservoirs can easily be achieved by a mapping $map_{r,i}$ assigning a reservoir to a turbine. In line with this approach, pumping facilities can be incorporated by linking the water balances of the respective reservoirs accounting for transitions between them.

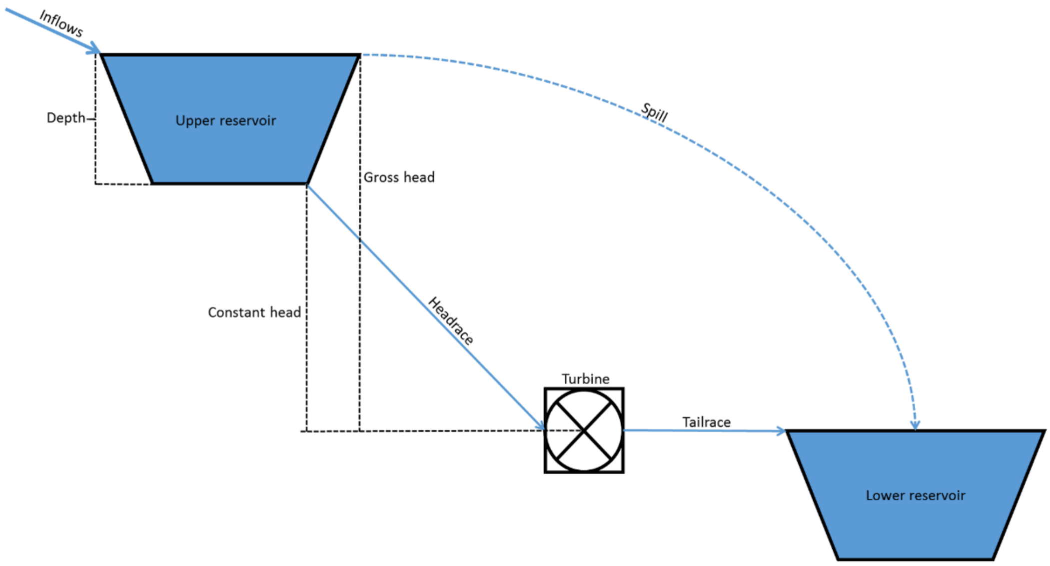


Figure 2. Topology generic HP plants.

The linkage between energy and hydrology is derived by a conversion function defining how much energy $G_{t,m}^{+}$ is generated by a specific amount of discharged water $R_{t,m}^{+}$. The amount of energy which can be generated by water flowing through the turbine is defined by the water to energy conversion factor α_t. Accordingly, the amount of energy which is reduced is defined by the reduction in the water which is discharged through the turbine $R_{t,m}^{-}$:

$$G_{t,m}^{+/-} = \alpha_t R_{t,m}^{+/-} \quad \forall t, m \tag{11}$$

The energy conversion factor defines the amount of energy in MWh obtained per m^3 of water and depends on the density of water ρ, the gravity g, the efficiency of a turbine η, the net head H_t^{net}, and the unit conversion factor θ accounting for time structures and scaling to MWh levels. While in reality the efficiency of the turbine depends on the discharge and the head (Pérez-Díaz et al., 2010) we assume a constant efficiency in our model in order to solve the model within reasonable time.

$$\alpha_t = \frac{\rho g \eta H_t^{net}}{\theta} \quad \forall t \tag{12}$$

The net head is given by the gross head H_t^{gross} less the head loss H_t^{loss} (Okot, 2013):

$$H_t^{net} = H_t^{gross} - H_t^{loss} \quad \forall t \tag{13}$$

The gross head is the height difference between the water level and the turbine. It is a function of the depth D_t of reservoir and a constant head $h^{constant}$ which does not vary (Figure 2). The constant head is measured as the height difference between the water level in the upper reservoir and turbine axis. This generally holds for impulse turbines (Pelton) but not necessarily for reaction turbines (Francis or Kaplan). In the latter case, the gross head is the height difference between the water level in the upper and lower reservoirs which cannot be assumed to be constant in all cases (see e.g. Aggidis and Židonis, 2014 or Catalão et al., 2009).

$$H_t^{gross} = h^{constant} + D_t \quad \forall t \tag{14}$$

The depth of the reservoir depends on the generation decisions. The linkage is derived via the relationship of depth D_t and storage volume S_t of the upper reservoir. We assume a linear relationship. The slope ($slope^{depth}$) and the intercept ($constant^{depth}$) are case-specific.

$$D_t = slope^{depth} S_t + constant^{depth} \ \forall t \tag{15}$$

Due to friction in the pipelines, the gross head is reduced by the head loss following a quadratic pattern. The head loss depends on the net amount of water which is discharged through the turbine R_t^{net} and the estimated slope of the function $slope^{hloss}$.

$$H_t^{loss} = slope^{hloss} {R_t^{net}}^2 \quad \forall t \tag{16}$$

The storage volume S_t of the upper reservoir in period t is defined by the storage volume of the previous period, natural water inflows i_t into the reservoir, the net amount of water discharged through the turbine and the amount of water which is spilled $Spill_t$.

$$S_t = S_{t-1} + i_t - R_t^{net} - Spill_t \quad \forall t \tag{17}$$

The volume in the lower reservoir is not needed for the chosen topology setting, but would follow a similar basic structure. The net discharge is defined as the difference between the amount of water discharged through the turbine and the amount of water by which the discharge is reduced (i.e. due to providing negative balancing). Thus, physically, only the net discharge is flowing through the turbine.

$$R_t^{net} = \sum_m R_{t,m}^{+} - \sum_m R_{t,m}^{-} \quad \forall t \tag{19}$$

The maximum discharge can be considered as a function of the head which in turn is depending on the reservoir level (Catalão et al., 2009). For simplification we assume a direct linear relationship between the maximum amount of water which can be discharged through the turbine at a specific point in time R_t^{max} and the storage volume of the reservoir.

$$R_t^{max} = slope^{release}\, S_t + constant^{release} \quad \forall i,t \tag{18}$$

The water discharged through the turbine is constrained by the maximum discharge.

$$\sum_m R_{t,m}^{+} \leq R_t^{max} \quad \forall t \tag{20}$$

As in the case of energy, only the amount of water that is discharged at a specific point in time can be reduced. Thus, the reduction in discharge needs to be smaller than or equal to the positive discharge.

$$\sum_m R_{t,m}^{-} \leq \sum_m R_{t,m}^{+} \quad \forall t \tag{21}$$

The amount of water which can be spilled out of the reservoir is constrained by the maximum spill $spill^{max}$. The maximum amount which can be spilled may be defined by regulations such as flood control or hydro peaking. In our case, the spill is unconstrained.

$$Spill_t \leq spill^{max} \quad \forall t \tag{22}$$

The storage volume of a reservoir is constrained by the maximum (s^{max}) and the minimum (s^{min}) storage capacity. The minimum storage capacity may again be defined by regulatory requirements.

$$s^{min} \leq S_t \leq s^{max} \quad \forall t \tag{23}$$

In addition, the storage volumes at the beginning and the end of the optimization period are defined by their start (s^{start}) and end values (s^{end}). The start and end values are defined by the hydrological conditions and the time structure of the model (i.e. starting with a full storage after the summer period, or with an empty storage after the winter period).

$$S_{t=t^{start}} = s^{start} \tag{24}$$
$$S_{t=t^{end}} = s^{end} \tag{25}$$

3.4. Solve process and model limitations

Given the structure of the model formulation as a nonlinear program (NLP), deriving a solution on hourly or sub-hourly time scale (to capture short-term dynamics) for a full year (to capture seasonal impacts) exceeds most computational capacities. Consequently, we proceed in a two stage process to derive a solution. First, a yearly linear program (LP) version without considering the non-linear elements is defined (i.e. assuming a constant depth (Eq. 15), head-loss (Eq. 16), and maximum discharge (Eq. 18)) and solved. The yearly LP accounts for the yearly seasonality of the reservoir. Afterwards, the NLP model is solved on a weekly basis taking into account all non-linear elements. In the weekly NLP, the weekly start and end values of the reservoir are given by the yearly LP.

Since the balancing market bids are constrained by minimum bid sizes, a full inclusion of those limitations would require a mixed-integer formulation. Due to the difficulties in deriving solutions for large scale mixed-integer non-linear problems, we utilize an approximation and let the NLP model run twice. In the first run, the minimum bid sizes on the balancing markets are neglected. In the second NLP run, the sizes of the balancing market bids from the first run are taken into account and adjusted based on the minimum bid sizes; i.e. if the bid amount on the respective balancing market is smaller than the minimum bid size, the bid is fixed to zero, if the bid is greater than the minimum bid size the bid remains free for the second run but is restricted downwards (i.e. $Cap_{t,PRL/SRL/TRL} \geq bid_{RL/SRL/TRL}^{min}$).

The models are all coded in GAMS 24.7.4 and solved using the Cplex 12.6 and Conopt 3 solvers. Given the two stage structure and approximation of the balancing market restrictions, the resulting solution will not represent the global optimum but should be a sufficiently close approximation.

In addition to the solve process itself, the formulation described above is subject to simplifications and assumptions impacting the obtainable results. One major drawback of the formulation is its deterministic nature. The impact of uncertainty in the water inflows and the prices is neglected. Given the objective to capture seasonal impacts, a full scale stochastic formulation is not feasible (see e.g. Ladurantaye et al., 2009). Consequently, the resulting operational decision will represent the theoretic best benchmark given perfect information. Real operational decisions under uncertainty are likely to lead to less optimal behavior and lower revenues. This has to be kept in mind when evaluating the resulting revenue numbers. We will address part of the uncertainty aspects related to balancing markets in subsequent sensitivity analyses.

In addition to uncertainty, the consideration of more detailed technical characteristics of hydropower, e.g. regarding the turbine efficiency, could decrease the estimated revenues as well. We use a generic setup with stylized representations of i.e. head losses and reservoir depth that can both under- and overestimate the real world counterfactuals. Generally speaking, hydro plants usually have a high heterogeneity. Focusing on a generic setup therefore only provides an average benchmark when comparing the results to an individual real world plant. However, the model formulation is kept flexible to allow for the inclusion of more detailed plant specific data if it is available.

At the same time, the consideration of three generic HP plants does not take into account specific constraints on residual water flows or other regulations since these factors are case specific. A real HP plant may have to operate according to specific regulations. Another limitation of our analysis is the fact that we take the perspective of a single HP plant and assume a perfect competitive market setting; i.e. the bidding strategy of the plant has no feedback on the market price. While this is likely true for the energy market, it may not necessarily hold for balancing markets. In addition, companies which have a portfolio of generation units need to have a strategy how to bid their portfolio into the balancing market instead of a single plant. Bidding a portfolio may increase the flexibility of the company in bidding capacity and delivering energy. Due to our single plant perspective, those benefits are ignored.

4. Market scenarios and data

The objective of our analysis is to assess the potential for Swiss HP to increase their revenue by utilizing the flexibility of hydro plants. We will investigate this potential under different market conditions, namely in a historic setting and for a set of potential future scenarios. Given the large diversity of plants in Switzerland, we derive three generic HP plant types which should be representative for Switzerland and provide a reasonable benchmark.

Following, we will present the underlying technical and hydrological data used for the three generic types, the energy and balancing market data used for the historical evaluation, and the future market scenarios.

4.1. HP data

Based on Swiss HP data from Balmer (2012) providing technical characteristics for all larger hydro plants in Switzerland categories were defined based on two criteria: the ratio of inflows of the catchment area to the capacity of the storage lake and the ratio of the storage to turbine capacity. Using those two structural indicators, Swiss plants were clustered in three categories (a small, a medium and a big HP category) and the average plant characteristics for each group were derived to define the needed input data for the above described model formulation. The resulting generic plant types should be representative for Switzerland.

For the big category, the storage is only filled twice during a year and the reservoir allows to store enough water to generate 1000 full load hours. HP plants belonging to this category are typically seasonal storage plants which only generate at full load in a small number of hours per year when the prices are sufficiently high. In contrast, plants belonging to the small category are only equipped with a short-term storage which is why they are operated similar to run-of-river (RoR) plants. Thus, the reservoir inflow is equivalent to 1300 times the reservoir size during a year while the reservoir is emptied after 3 full load hours. Due to the low storage capacity, the small plants generate at full load in a high number of hours during the year and are more subject to average price levels as they are close to a base-load generation profile. The medium category encompasses HP plants which lie in between these two extremes.

Table 1. Characteristics of generic HP plants. Data from Balmer (2012).

	Big	Medium	Small
Ratio inflow to storage capacity	2	40	1300
Ratio storage to discharge capacity (h)	1000	72	3
Turbine Capacity (MW)	100	50	22
Maximum Head (m)	530	530	350
Constant Head (m)	440	500	340
Depth (m)	90	30	10
Full load hours (h)	1800	2900	3700

Since we use generic HP plants instead of a case study, the water inflows are average values of the real Swiss HP plants belonging to one of the three categories. The water inflows are defined on hourly levels and are assumed to be constant over a month (Figure 3). Thus, short-term variations are not covered. The water inflow across the categories follows the usual Swiss hydrological cycle: inflows are highest in May to August when runoff is high due to snow melt and lowest in December to February.

Regarding the inflow quantity, the big category has the highest total inflows, representing the usual larger catchment area of large scale seasonal plants. Those plants usually have their highest storage level at the end of summer and use the stored water to generate during peak hours in fall and winter months. In contrast, the small plant type usually has such a high inflow level during spring and summer months that it has to operate as a base-load plant. During winter months, the inflow levels are usually small enough for those plants to store over a few hours and operate more on a peak-load basis. The medium category again lies in between those extremes.

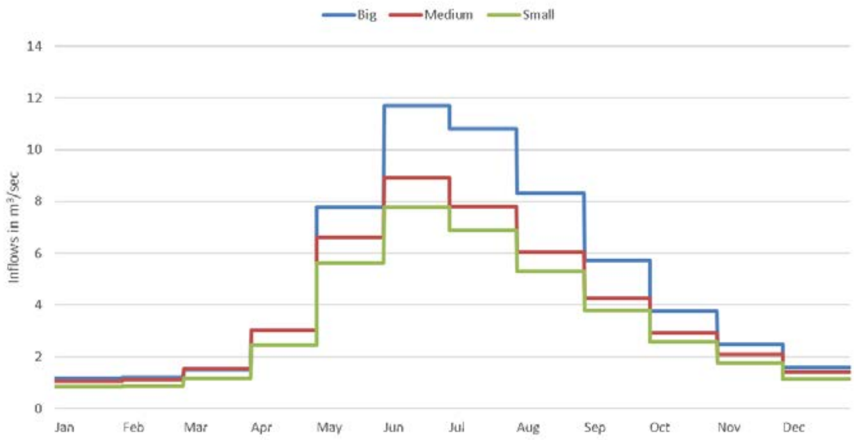


Figure 3. Water inflows in reservoirs in m3/sec by category. Data from Balmer (2012).

4.2. Historic market data

In addition to the HP data, prices for the different markets are needed for the model analysis. For the historic market evaluation, we focus on the period between 2011 and 2015 as shown in Figure 1. On average, day-ahead market prices decreased between 2011 and 2014 and slightly increased between 2014 and 2015. Since no complete dataset on intraday market prices for Switzerland was available, we neglect the intraday market in our analysis. Consequently, this leads to a potential underestimation of the benefit of hydro flexibility as HP plants are well equipped to benefit from high intraday prices.

The capacity auctions of the Swiss balancing markets are designed as pay-as-bid. For the model analysis we transfer the market results into average uniform prices for each market using the weighted average price of all accepted bids. The required quantities by market are approximations by the Swiss TSO (Table 2). While the PRL and SRL market are symmetric and on weekly basis, TRL is split into a positive and a negative market which are both on weekly as well as on daily (4 hour blocks) basis. The PRL market is the smallest market in terms of requested quantity while the positive TRL market (weekly plus daily) is the biggest market. Bidding on the balancing markets is subject to prequalification for these markets. We assume that the three generic plant types are all qualified to bid on all balancing markets. In the PRL market, the minimum bid size is 1 MW while in the other balancing markets the minimum bid size is 5 MW (Table 2).

If the realized system demand and supply are in imbalance, the TSO has to call up some of the procured balancing capacity. In the SRL and TRL markets, the energy which has to be delivered is remunerated in addition to the capacity. The historic balancing energy prices are given by Swissgrid (2017a). Since the balancing energy price data is incomplete for some years, we assume that the missing prices have the same yearly profile as the available prices. In addition, we assume correlation between the day-ahead market prices and the balancing energy prices to scale the missing prices.

The required called up energy is only a small fraction of the balancing capacity (Abrell, 2016). On average, between 3-6% of the balancing capacity were called up per year between 2011 and 2015 (Swissgrid, 2017a). However, even if the call-up of balancing energy is low over a year, it can be high during some hours/weeks of the year. While in our model the call-up is perfectly known, in reality the call-up in the balancing markets is an element of uncertainty for the HP plants (Abrell, 2016). We will address the uncertainty of the balancing provision in subsequent sensitivity evaluations. Due to missing data for the balancing energy in the PRL market, we assume an equivalent call-up of balancing energy as in the SRL market.

Table 2. Required balancing quantities and minimum bid sizes in the Swiss primary reserve market (PRL), secondary reserve market (SRL), tertiary positive (TRL+) and negative (TRL-) reserve market. Data from Swissgrid (2015).

Balancing market	Required quantity	Minimum bid size
PRL	+/- 74 MW	+/- 1 MW
SRL	+/- 400 MW	+/- 5 MW
TRL+	+ 450 MW	+ 5 MW
TRL-	- 300 MW	- 5 MW

4.3. Future market data

In order to derive future Swiss market prices for the analysis of potential revenue prospects, we rely on a scenario outlet derived from coupled investment and dispatch models. First, using an aggregated European model, we obtain future power plant capacity investments (see appendix for details on the model) which are afterwards transferred into the hourly Swiss electricity market model Swissmod (Schlecht and Weigt, 2014). Future electricity and balancing market prices as well as the procured balancing capacity and the call-up of balancing energy are derived from Swissmod.

Since the PRL market is not considered in Swissmod, future PRL capacity prices are estimated based on SRL prices. Energy prices for call-up in the SRL markets are calculated using the rule of thumb of the Swiss TSO (Swissgrid, 2015) and the energy market prices of Swissmod. The future prices for call-up on the TRL markets are based on the historic prices and scaled using the energy market prices as reference level. Swissmod is calibrated to 2012 including the required balancing capacities and the balancing energy. We keep those structures constant. Consequently, the future balancing market quantities are equivalent to those for 2012.

A detailed presentation of the underlying market scenarios and resulting prices is provided in Section 6.

5. Market opportunities: historic estimation

In a first analysis, we evaluate the revenue possibilities for Swiss HP in the period from 2011 to 2015. The focus lies on identifying whether participation on the Swiss balancing markets would have provided sufficient revenue potential to counter the decreasing energy price trends. Given the deterministic nature of our model approach and the uncertainty involved when bidding on week and day ahead balancing markets, we perform a set of sensitivity simulations to judge the robustness of our findings.

5.1 Theoretic benefit of balancing market participation

As benchmark for the remaining evaluation, we first derive the revenue the three generic plants could obtain by solely participating on the hourly energy market. Figure 4 illustrates the shift in revenues from 2011 until 2015 in relative terms. In total, the revenue of the big plant is between 8.3 and 11.4 Mio € per year, between 5.4 and 8 Mio € per year for the medium plant, and between 2.8 and 4.3 Mio € per year for the small plant.

Since the day-ahead market price decreased on average between 2011 and 2014, e.g. due to an increasing share of renewable energies as well as low carbon and fuel prices, the spot market revenues decreased as well. We observe that the decline is more pronounced for smaller plants. This is in line with the storage potential of the different plant types. A seasonal storage plant aims to use its stored water in the highest priced hours and is less subject to a decline in average prices if peak prices remain high. This effect is visible in 2012. While the spot prices decreased on average between 2011 and 2012, high price hours were more frequent and more pronounced in 2012.[2] Between 2014 and 2015 all HP plants could slightly increase their revenues due to an increase in spot prices.

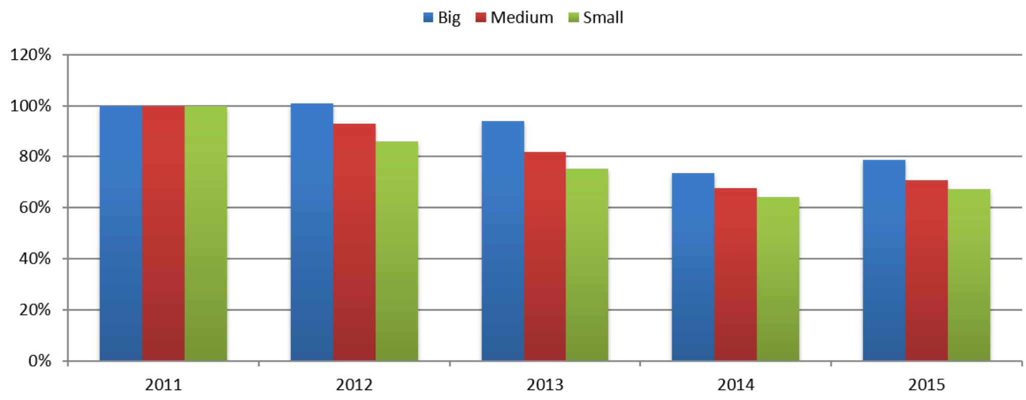


Figure 4. Historic day-ahead market revenues by HP category and year.

In a next step, we evaluate the potential benefit if the plants would optimize their operation across energy and balancing markets. Figure 5 contrasts the obtainable revenues on the respective markets with a spot-market only strategy for each year. In theory, the balancing markets could provide significant additional revenues: the big plant could increase its yearly revenues by 50-130%, the medium plants between 50-100% and the small plants between 40-90%. The highest increase is obtainable in 2013 since balancing prices were extremely high during a few weeks of the year. In general, the big plants benefit most from balancing, showing the importance of a larger reservoir when it comes to balancing. Having a look at the individual balancing markets, the secondary reserve market offers the highest potential.

Figure 5 also provides the total obtainable revenue when operating on all markets in comparison to the 2011 revenue with a spot-market only strategy (as provided in Figure 4). For all plant types the theoretic revenue potential due to balancing market participation would have been sufficient to ensure at least as high revenues as on the 2011 spot market. In other words, the price decrease on the spot market could have been compensated by switching to a combined energy-balancing trading strategy.

[2] In 2012 for example more than 100 hours had a spot price above 100€/MWh while in 2011 only around 10 hours had a spot price above 100€/MWh (see EPEX SPOT, 2017).

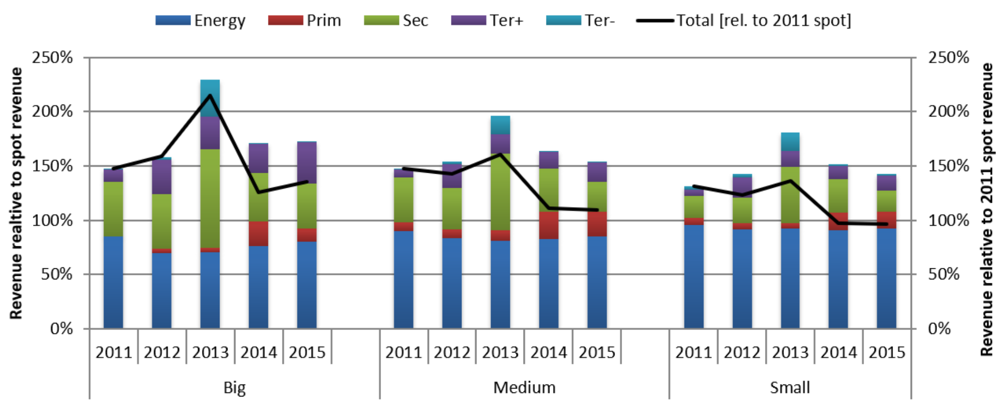


Figure 5. Historic day-ahead and balancing market revenues by HP category and year.

5.2 Limitations of balancing participation

The above sketched results show a significant potential of a combined trading strategy for Swiss HP. However, the results so far represent a theoretical maximum (upper bound) for the additional revenues. Since the underlying model is deterministic, the HP plant operator has perfect knowledge of the resulting prices on each market and the call-up structure on the balancing markets. In addition, the small size of the Swiss balancing markets and its influence on the revenue potential for a single HP plant is not considered. Thus, in order to estimate more realistic balancing market benefits for a single HP plant, specific uncertainties and market characteristics of the Swiss balancing markets have to be taken into account.

Following, we address three distinguished aspects that could lower the revenue potential. First, we address the uncertainty of the actual call-up. Second, we address the limited size of the Swiss balancing markets. Third, we identify if small scale companies with limited trading capacities could still benefit from balancing participation using rule of thumb strategies.

5.2.1 Impact of uncertainty of call-up

As a HP plant can be called up in the balancing market for its offered balancing capacity or a fraction thereof, some water has to be reserved in the reservoir in order to be able to deliver the requested energy in times of a call-up. However, for how many hours a plant is called up during a week or a day is uncertain. While the average call-up is rather low with 3-6% it can peak to the full offered capacity for specific hours. As future inflows can help to refill the reservoir, the relation is not straightforward. A risk adverse operator may keep a fixed water quantity once it provides balancing capacity equal to the maximum potential call-up energy. A risk seeking operator may reduce this storage amount accounting for the low probability of call-ups and the potential of future inflows to provide additional energy.

To capture these possibilities, we adjust the basic model formulation by including a reservoir constraint. If the plant participates on the balancing markets it has to block a certain amount of energy in its storage equal to its bid capacity times a predefined duration ranging from 0 hours (no additional precaution) to 168 hours (covering the full weekly provision for primary and secondary provision). The actual call-up remains as in the base case. Thus the reservoir requirement just blocks the water for the respective time frame.

The impact on revenues for 2015 relative to the case in which the HP plant operator has perfect knowledge about the call-up (0h) are shown in Figure 6. The results for the years 2011-2014 follow a similar pattern (see appendix Table A2). In general, we do not see any impact for the big plant type. Given that this plant represents large scale seasonal storage plants with a high ratio of lake to turbine capacity the reservoir requirement has little impact. As the water is available for trades on the energy market after the balancing requirement is relieved, the opportunity costs of keeping a specific amount of water in the reservoir are rather low for those plants as they usually have more than enough water in their storage anyway. The same holds for the medium plant. Only in the case in which the water has to be reserved for the whole week (168h), the balancing market revenues of the medium plants are slightly reduced.

For the small plants, uncertainty in the call-up of balancing energy has larger impacts on their potential balancing market revenues. Since the smaller plants have only short-term storage reservoirs, the attractiveness of the balancing markets is strongly reduced if the water has to be reserved for a longer time horizon. With increasing time for which the water has to be reserved, the smaller plants decrease their participation in the weekly symmetric balancing markets (PRL and SRL). At the same time, the small plants slightly increase their spot and negative reserve market participation for which no water has to be reserved. However, the uncertainty in the call-up of balancing energy reduces the potential balancing market revenues for smaller plants.

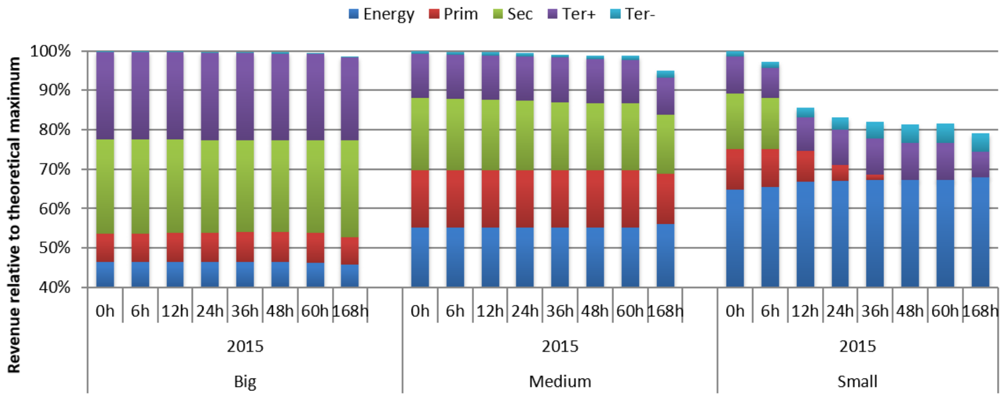


Figure 6. Revenues by HP category for the year 2015 taking into account water reserve requirements**.**

5.2.2 Limited market size

A second important limitation of the analysis is the missing feedback effect of the balancing bids on the resulting balancing price. As we assume perfect competition, the price is fixed and independent of the company's operation decision. Given that the Swiss secondary and tertiary balancing markets have a total demand of about 400MW each and the primary even less with around 75MW, a bid by a 100MW hydro plant on one of those markets is likely to have a significant impact on the resulting price levels.

To capture this effect, we impose additional bidding limitations for the balancing markets. As maximum bid size we consider the average accepted bid in each market based on data from Swissgrid (2017c), 10%, 5% and 2.5% of the total requested capacity in each market. By comparing this to the case with unrestricted bidding underlying the above model runs, we can estimate how a bidding strategy that is more likely to have no feedback on the obtainable balancing price limits the revenue possibilities. Figure 7 illustrates this comparison for the year 2015. Again, the results for the years 2011-2014 follow a similar pattern (see appendix Table A3).

Compared to the call-up analysis above, the findings are exactly opposite. For the small category, the size of the accepted bid has only minor impact on the revenue. As the small category has a lower generation capacity (22MW), its balancing market bids are lower anyway. However, for the big category, the balancing market revenues are significantly reduced if the sizes of the accepted bids are reduced. If the size of the accepted bid is equal to the average accepted bid in the markets (avg.) or 10% of the requested balancing capacity, the revenue is reduced by approx. 15% compared to the case in which the bid size is unconstrained. If the bid size is further reduced, the balancing revenue is further decreased while the spot market participation is increased leading to a total revenue reduction of about 30%. Compared to a pure spot-market strategy, this would lead to a surplus of about 20% whereas in the unrestricted case, the additional revenue is close to 50%. For the medium plant, the balancing market revenues are reduced by between 8 to 15%. Thus, taking into account that only in case of a relatively small market share, a single HP plant is likely to have a negligible impact on the resulting prices, the reserve market potential is decreased significantly for larger plants.

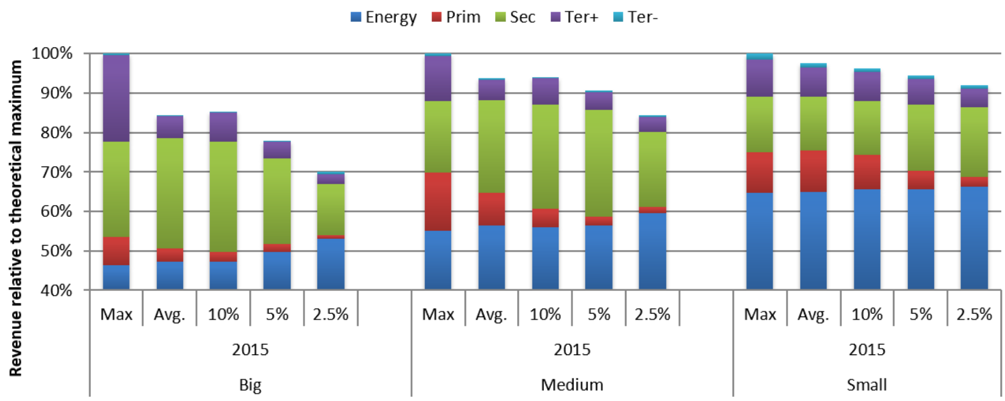


Figure 7. Revenues by HP category for the year 2015 taking into account bid sizes.

5.2.3 Limited trading capacities

Finally, our model approach assumes that the hydro company is optimizing across all markets and has the required capacities to derive price forecasts for the different markets. While this likely holds for large scale energy providers, it does not necessarily hold for smaller scale companies. Especially since the balancing markets are pay-as bid markets and thereby do not provide a single historic reference price but a range of accepted prices. This makes it harder to derive a solid forecast which bid level will still be accepted while aiming for maximum revenue.

To consider a HP company that does not have the possibility to perfectly optimize across markets e.g. due to missing forecasting tools or modelling tools, we develop a rule-of-thumb trading strategy. We assume that the company's primary focus is the spot energy market (or future trading linked to spot prices). Given that balancing markets are linked to energy markets via opportunity cost structures, we transfer the company's energy bids into an equivalent balancing market bid. The basic logic of the heuristic is illustrated in Figure 8. In essence we want to identify what bid a company would need to make on the balancing markets given its spot-energy strategy to be equally well off.

If a storage HP plant participates only in the spot market, it would optimally bid into the spot market in a few peak price hours of the week (Figure 8, left graph). Now, under the heuristic, we identify balancing market bids that have an equivalent expected energy content. For the positive TRL market we identify the capacity bid that – based on average call-up structures – amounts to a similar energy output (Figure 8, upper right graph).[3] The same logic is applied for the SRL and negative TRL market. Since in the symmetric SRL and the negative TRL market the plant needs to be able to reduce its generation, it must run at constant quantity in all hours during the week in the spot market - similar to a base load plant (Figure 8, lower right graph).[4] Those quantity values need to be

[3] For example, if the company sells 120MWh on the spot market over a day and assumes a 5% call-up probability for the positive TRL market, it could sell 100MW TRL balancing capacity for the next 24 hours.

[4] For example, if the company sells 120MWh on the spot market over a day and assumes that call-ups on the SRL market for positive and negative energy are symmetric it could sell a constant capacity of 5MW for the next 24 hours on the spot and provide 5MW of SRL capacity.

matched with respective opportunity cost information to derive the balancing market bids. For the TRL+ bids, the opportunity costs are equal to the revenue on the spot market in the spot-only strategy. For the SRL and TRL- markets the opportunity costs are defined as the difference between the spot-only revenue and the spot revenue obtained by following the balancing bid. Furthermore, to capture parts of the uncertainty, we add a security margin of 20% on top of the opportunity costs.

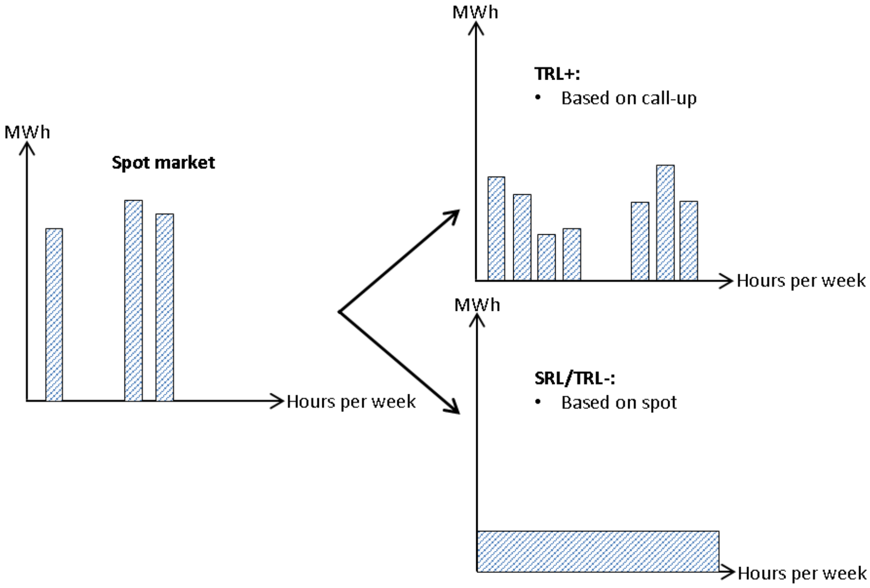


Figure 8. Basic logic of balancing market heuristic.

If a company would follow such a balancing bid strategy and gets accepted in the balancing market, it would ensure to at least get the same expected revenue as with a spot-only strategy plus the security margin and use the same amount of water over the week. Thus, the company can participate in the balancing markets based on its optimal spot market generation schedule and obtain additional revenues from balancing in weeks in which the balancing market prices are high enough. However, it would not profit from further price spikes on the balancing market as it would only obtain its bid price due to the pay-as-bid mechanism.

Figure 9 shows the impact of the trading heuristic for the different plants in 2015. While the big plant can increase its revenue by around 2% if it is active in the TRL+ market (heuristic TRL+) compared to the case in which the plant is only participating on the spot market (energy only), the heuristic does not benefit the small and medium HP plants in 2015. The results for 2011, 2012 and 2014 are rather similar (see appendix Table A4). Only in very few weeks would the company have been accepted with its bid in the balancing markets. Overall, the potential for additional benefits is rather limited.

The findings are different for 2013 (Figure 10). In 2013, the balancing market prices spiked in three weeks. The bidding strategy would have allowed the company to benefit from those revenue opportunities increasing its revenues between 4-13%. Thus, the heuristic enables HP plants to benefit from balancing in years in which the balancing prices are really high while in years in which the balancing prices are normal, the heuristic does not change the revenues. Therefore, the heuristic can be seen as lower bound for the balancing market revenue potential.

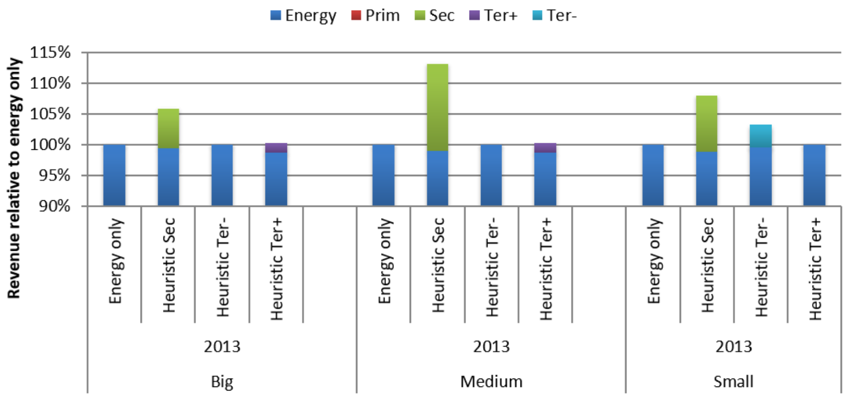


Figure 9. Revenues by HP category for the year 2015 for the heuristic trading strategy.

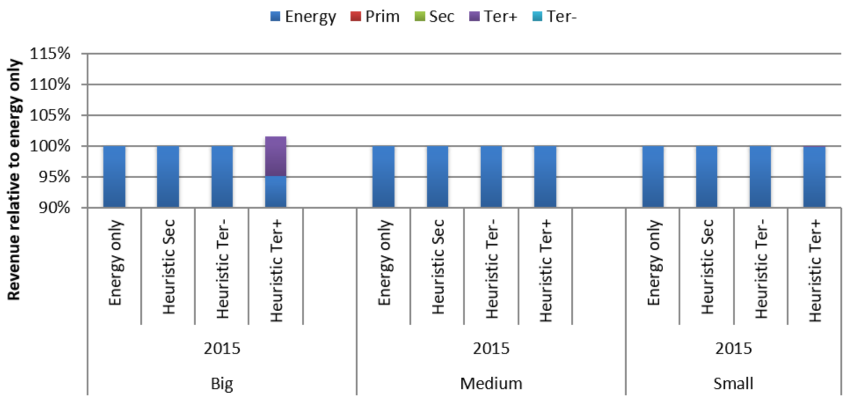


Figure 10. Revenues by HP category for the year 2013 for the heuristic trading strategy.

5.3 Conclusion on historic revenue opportunities

The historic model results show a significant decrease in the spot revenues due to decreasing spot prices over the last five years for Swiss hydro plants. In theory, balancing market participation could significantly increase the revenue of the HP plants and compensate the loss on the spot markets. Overall, the additional revenue from optimized joint operation allows a theoretic revenue increase from more than 50% compared to an energy-only trading strategy.

However, those results represent the theoretic upper bound. Since uncertainties and market characteristics are not explicitly considered in the basic model formulation, a set of sensitivity analyses highlights the potential limitations to those findings. On the one hand, uncertainty about the actual call-up structure on balancing markets and the subsequent need for additional stored water significantly reduces the potential for smaller plants. On the other hand, the small size of the Swiss balancing markets and the likely price feedback limits the potential for larger plants if they don’t want to suppress prices – and thereby revenue potential – with their bids.

In general, the pay-as-bid structure of the Swiss balancing markets makes it harder to derive a solid revenue estimation. Whereas the model estimates are based on the average accepted bids, a company would need to derive a robust bidding strategy for the balancing markets to not forego potential profit by bidding too low while at the same time not pushing itself out of the market by bidding to high. An analysis with a heuristic trading strategy capturing this challenge showed a significant reduction in revenue potential. In a normal year, the heuristic will bring no additional money from balancing. However, if balancing prices peak during a few weeks of a year, the revenues can be significantly increased even with only a few successful trades on the balancing market. The heuristic can be seen as a lower bound for the balancing market revenues.

Summarizing, the analysis shows revenue potential by an optimized trading strategy covering energy and balancing markets for Switzerland. However, lifting this potential is not straight forward. Furthermore, given the small size of the Swiss balancing market in relation to the total installed capacity of storage plants (around 9 GW) only a fraction of Swiss hydro plants will be able to benefit from those opportunities.

6. Market opportunities: future scenarios

In the second part of our analysis, we evaluate the revenue possibilities for Swiss HP for the coming decade. Following, we first provide an overview on the underlying price scenarios and market drivers and second, the resulting hydro revenues and operational strategies.

6.1 Future price scenarios

Based on an aggregated European investment model (see Appendix) and the hourly dispatch model Swissmod (Schlecht and Weigt, 2014), we derive a set of potential market scenarios up to 2030. In the investment model, the development of electricity demand and renewable energies was exogenously given by the EU Energy Trends by European Commission (2016) as well as national energy strategies while the development of conventional capacitates results from the investment model. Based on the resulting power plant mix (see appendix Table A1), the respective capacities were fed into Swissmod in order to simulate the cost minimal market dispatch for Switzerland while taking into account the Swiss neighboring countries (see appendix for details).

To capture a range of potential developments, different scenarios for three underlying parameters were included: carbon prices, fuel prices, renewable deployment. Using the 2015 values as starting point, we include two variations for each parameter. For the carbon price, a linear increase to 35€/t in 2030 (CO2+) and to 50€/t (CO2++) is assumed; for the fuel prices a linear increase of 50% until 2030 compared to the 2015 price level (Fuel+) and of +100% (Fuel++) is assumed; for renewable deployment we use the EU Energy Trends as basis and include a 10% upscaling (RES+) and a 10% downscaling (RES-). Furthermore, potential combinations of those scenarios are also considered. The scenario set is complemented by a scenario representing the EU Energy Trends and a Base Price 2015 scenario in which carbon and fuel prices remain on their current level.

The scenarios span a range of low and high price pathways until 2030 (Figure 11). On the lower price end are those scenarios that have a high renewable deployment (RES+) and low carbon and fuel price assumptions. Consequently, the high price scenarios have the opposite underlying parameter assumptions. The EU Energy Trends represent a high price pathway with an increase up to 80€/MWh in 2030; only matched by scenarios with high carbon and fuel price assumptions (CO2++Fuel++). However, all scenarios have a modest price level in 2020 meaning that the current low prices are expected to remain for some more years (see also appendix Table A5).

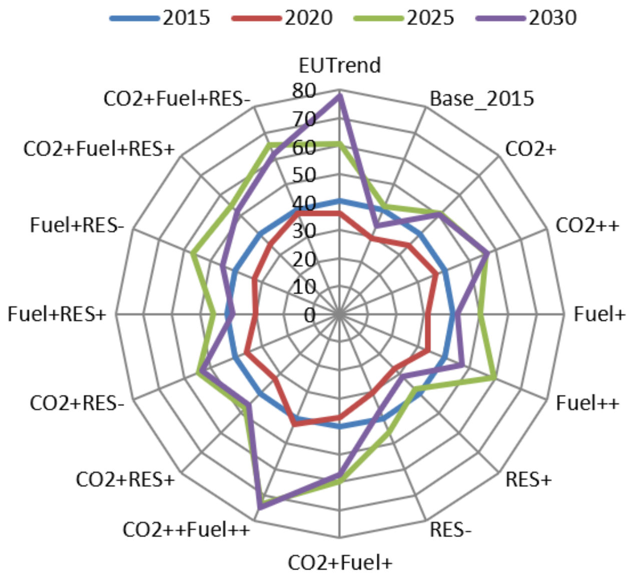


Figure 11. Future spot market prices [€/MWh] by scenario.

6.2 Future revenue potential

To get an overview on the potential future development, we derive aggregated revenues across all scenarios (Figure 12).[5] One striking feature of those results is the significant reduction in the revenue potential for balancing markets. Across all scenarios, the three plant types are only moderately active on the balancing market and the resulting balancing revenue only covers a small fraction of total revenue (i.e. 7 to 16%). The additional profit gained by a joint trading strategy compared to spot-only trading is in a similar range. This is an effect of the underlying price modeling within Swissmod. As Swissmod assumes perfect competition, perfect foresight and allows all Swiss hydro plants to participate in the balancing market, the energy and balancing market are perfectly coupled. In other words, the price level on the balancing market perfectly reflects the opportunity costs for foregone energy market profits. While being based on the underlying model assumptions this result nevertheless is of importance for the future revenue potential. If more hydro plants are participating in the balancing market, competitive pressure will reduce arbitrage possibilities reducing the potential for additional profit generation.[6]

Furthermore, the plants are mostly only active in the TRL markets, and in those mostly in the four-hour block markets (see Section 4.2). Especially the TRL- market provides an easy revenue opportunity if the plant is scheduled for full operation on the spot market anyway.

[5] We do not differentiate between the probabilities of the scenarios, assuming all are equally likely.

[6] Note that the for the future scenarios both prices and operational strategies are derived from deterministic perfect foresight simulations whereas the historic evaluation the underlying market prices are real world prices reflecting uncertainties while the operational model uses perfect foresight.

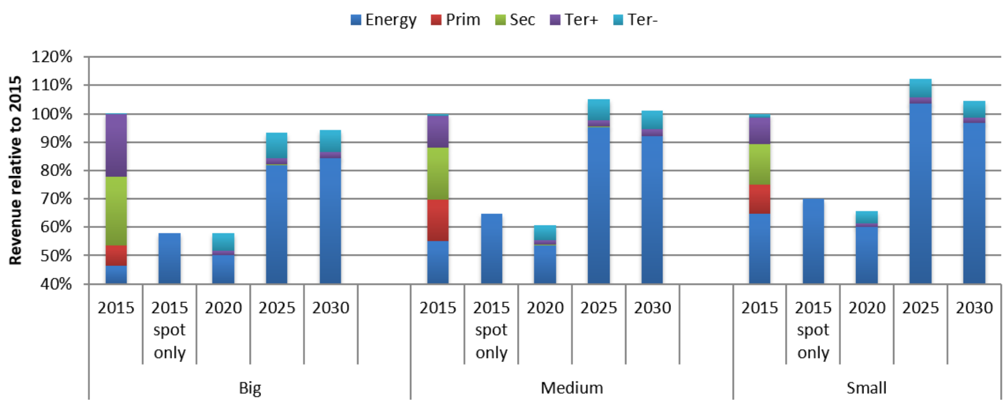


Figure 12. Average future revenue across scenarios by market, year and category.

Comparing the overall revenue development across scenarios we can observe an increase in 2025 and 2030 in obtained revenue of around 50% to 60% compared to a 2015 spot-only revenue for all three plant types. However, compared to an optimized 2015 trading level, the revenue levels remain within a -10%/+10% range. This is again a result of the modeled balancing prices being perfectly coupled. However, if in the future more hydro plants are starting to participate in the balancing market (or other new actors join the market) this could translate into reduced revenues for those companies that are already active today.

Given the large diversity of scenarios, Figure 13 shows the range of obtainable revenues across all modeled scenarios (see appendix Table A6 for revenues by scenario). In general, the developments look similar for the three plant types. However, there is a slightly more pronounced downward structure for the medium and small plant type compared to the big seasonal plant. Since smaller plants are less flexible to shift generation to peak hours, the variance in the future revenues is higher. For the small HP plants, the quartile-range of revenue in 2030 lies between +23% and +73% relative to the spot-only revenues in 2015, whereas the big plant has a range of +42% and +87%. Thus, the lower flexibility due to the lower storage capacity reduces future revenue prospects and also increases the overall uncertainty (i.e. the small plant has a total min/max-range of 135 percentage points whereas the big plant only has 120).

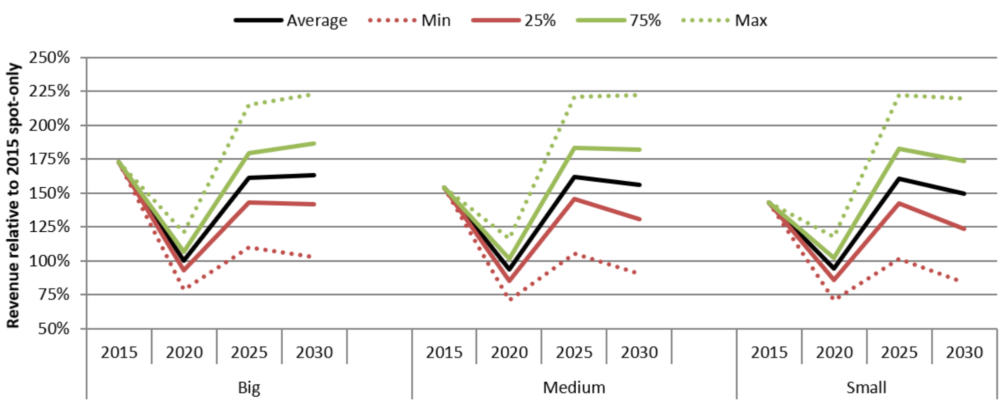


Figure 13. Future revenue across scenarios by year and category.

In sum, the future results show that the market price prospects for Swiss HP until 2030 are mixed. Within the next five years the existing European plant capacities are likely to keep prices on comparable levels as today. Afterwards the price development becomes less predictable and strongly depends on the development of carbon and fuel prices. Compared to historic revenues on the energy market, the future developments are likely to provide similar or higher returns. However, compared to an optimized plant operation on both energy and balancing markets, the future developments are not necessarily providing higher returns. This will strongly depend on the competitive pressure on the balancing markets and whether additional profits beyond an opportunity cost equivalent can be achieved.

7. Conclusion

Within this paper, we assess the revenue potential for Swiss HP under different market conditions. We develop a short-term operational model approach and apply the model to three generic plant types capturing the diversity of Swiss hydro plants. Examining both historic market results and potential future market scenarios, we aim to evaluate whether an optimized trading strategy across energy and balancing markets can increase profitability in a low price market environment.

The historic revenue analysis shows that the profitability of Swiss HP significantly decreased in the last years due to the decreasing spot market prices. Additional revenues from balancing could have relaxed the situation. However, uncertainties of the call-up of balancing energy, the small size of the Swiss balancing markets, and the need to have robust price forecasts to derive optimal bids for the pay-as-bid balancing markets can greatly limit this potential. The analysis of the future revenues shows that the prospects for Swiss HP naturally depend on the development of the EU generation mix, the global fuel markets and the European Union Emissions Trading System (ETS). As Switzerland has no influence on this development, Swiss HP has to adapt to whatever development will materialize. However, if many hydro plants aim to benefit from balancing revenues a rush on the balancing markets could easily depress the balancing market potential in the future. In general, optimized operation across markets helps Swiss HP to increase its revenues, but is limited in scale as the majority of income is still defined by the energy market.

Albeit the three plant types provide a generic benchmark there is a large heterogeneity among Swiss hydro plants. Given the decrease of energy market revenues, a debate within Switzerland started whether Swiss HP needs additional support (see Betz et al., 2016). Our analysis highlights that additional revenue from balancing markets is likely insufficient to compensate energy market losses for a large fraction of Swiss HP. Thus future energy market developments become crucial. As the current low price level is likely to prevail for a few more years the profitability of Swiss HP is likely to remain challenged (see e.g. Filippini and Geissmann, 2014 regarding the costs of Swiss HP).

An important option for utilizing the high flexibility of hydro plants are intraday markets with bidding structures below one hour. As neither our historic analysis nor our future market scenarios could provide intraday prices, we cannot provide a quantitative estimation of this potential. However, given the limited possibilities to benefit from the high level of flexibility on balancing markets, optimized intraday trading is likely a more promising alternative. As the total installed capacity of hydro plants greatly exceeds the requested balancing capacities for many markets, the intraday market also holds more promise for a general approach.

In summary, the Swiss example showcases the challenges associated with the ongoing European energy transition for hydropower. The prevailing overcapacities coupled with low coal and carbon prices keep price levels low. At the same time, the increasing share of renewables especially solar power reduces peak prices. Albeit hydropower flexibility seems like a perfect complement for intermittent renewable energies, the market combination of low and flat prices is likely to remain a long term challenge (see Schlecht and Weigt, 2016).

Appendix

Investment model

To take into account different paths towards the energy future an EU investment model to simulate investments into conventional generation capacities is applied. While the investment in conventional technologies is endogenous in the investment model, the development of the renewable energies and the demand are exogenously given by the European Commission (2016) as well as national energy strategies. 20 countries (Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Hungary, Ireland, Italy, Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, UK) are represented in the investment model.

The objective of the investment model is to minimize total cost C composed of the generation and investment costs (Eq. 1).

$$\min C = \sum_{y,m,d,h,p,n} w_{m,d,h} \left(c\_var_{n,y,p}^{fix} + c\_var_{n,y,p}^{var} Q_{y,m,d,h,p,n}\right) Q_{y,m,d,h,p,n} + \sum_{y,n,p} c\_invest_{n,y,p} Q_{y,n,p}^{new} \qquad \text{(Eq. 1)}$$

The variable generation costs have a fix component $c\_var_{n,y,p}^{fix}$ and a variable component $c\_var_{n,y,p}^{var}$ while $Q_{y,m,d,h,p,n}$ is the generated electricity in year y, month m, day d, reference hour block h from plant type p in country n. Since we model only three days of every month with reference hour blocks instead of a whole year on hourly basis $w_{m,d,h}$ is the share of a specific hour in a year. $Q_{y,n,p}^{new}$ is the new capacity of a specific technology in a specific country and year resulting from the investment. The investment costs $c\_invest_{n,y,p}$ vary by country, technology and year.

The objective is subject to several equations and inequalities. The most important ones are shown in Eq. 2 to Eq. 5. The electricity generation is constraint by the available capacity consisting of the exogenously given capacity $q_{y,n,p}^{\max\_ex}$ and the endogenously defined capacity $Q_{y,p,n}^{max}$ (Eq. 2). $ava_{n,y,m,d,h,p}^{weather}$ represents the availability of a specific technology and country in a specific point in time. Since the solar and wind availability depends on the weather conditions we consider a day with normal solar and wind conditions, a day with high wind and solar availability and a day with low wind and solar availability.

$$Q_{y,m,d,h,p,n} \leq ava_{n,y,m,d,h,p}^{weather} \left(Q_{y,p,n}^{max} + q_{y,n,p}^{\max\_ex}\right) \quad \forall\, y, m, h, p, n, d \qquad \text{(Eq. 2)}$$

The endogen capacity is defined by the endogen capacity from the previous year, the new capacity and the depreciation of the new capacity over its lifetime LT (Eq. 3).

$$Q_{y,p,n}^{max} = Q_{y-1,p,n}^{max} + Q_{y,n,p}^{new} - Q_{y-LT,n,p}^{new} \quad \forall\, y, p, n \qquad \text{(Eq. 3)}$$

The total capacity of a specific technology in a specific country is limited by the potential $pot_{n,p}$ of that technology in that country (Eq. 4).

$$Q_{y,p,n}^{max} + q_{y,n,p}^{\max\_ex} \leq pot_{n,p} \quad \forall\, y, p, n \qquad \text{(Eq. 4)}$$

The generation, the electricity flows from neighboring countries $NTC\_Flow_{y,m,d,h,nn,n}$ as well as the generation from pump-storage plants $Pump_{release_{y,m,d,h,n}}$ need to satisfy the demand $d_{y,m,h,n}$, the electricity flow to neighboring countries $NTC_{Flow_{y,m,d,h,n,nn}}$ and the electricity which is pumped at the pump-storage plants $Pump_{load_{y,m,d,h,n}}$ (Eq. 5).

$$\sum_{p} Q_{y,m,d,h,p,n} + \sum_{nn} NTC\_Flow_{y,m,d,h,nn,n} + Pump_{release_{y,m,d,h,n}} \geq d_{y,m,h,n} + \sum_{nn} NTC_{Flow_{y,m,d,h,n,nn}} + Pump_{load_{y,m,d,h,n}} \quad \forall y,m,d,h,n \tag{Eq. 5}$$

The model defined above is formulated as quadratic constrained program (QCP), coded in GAMS and solved in 5 year steps up to 2050. From the investment model, we take the generation capacity, the demand, the solar and wind generation as well as the costs by technology, year and country for the future scenarios under consideration up to 2030.

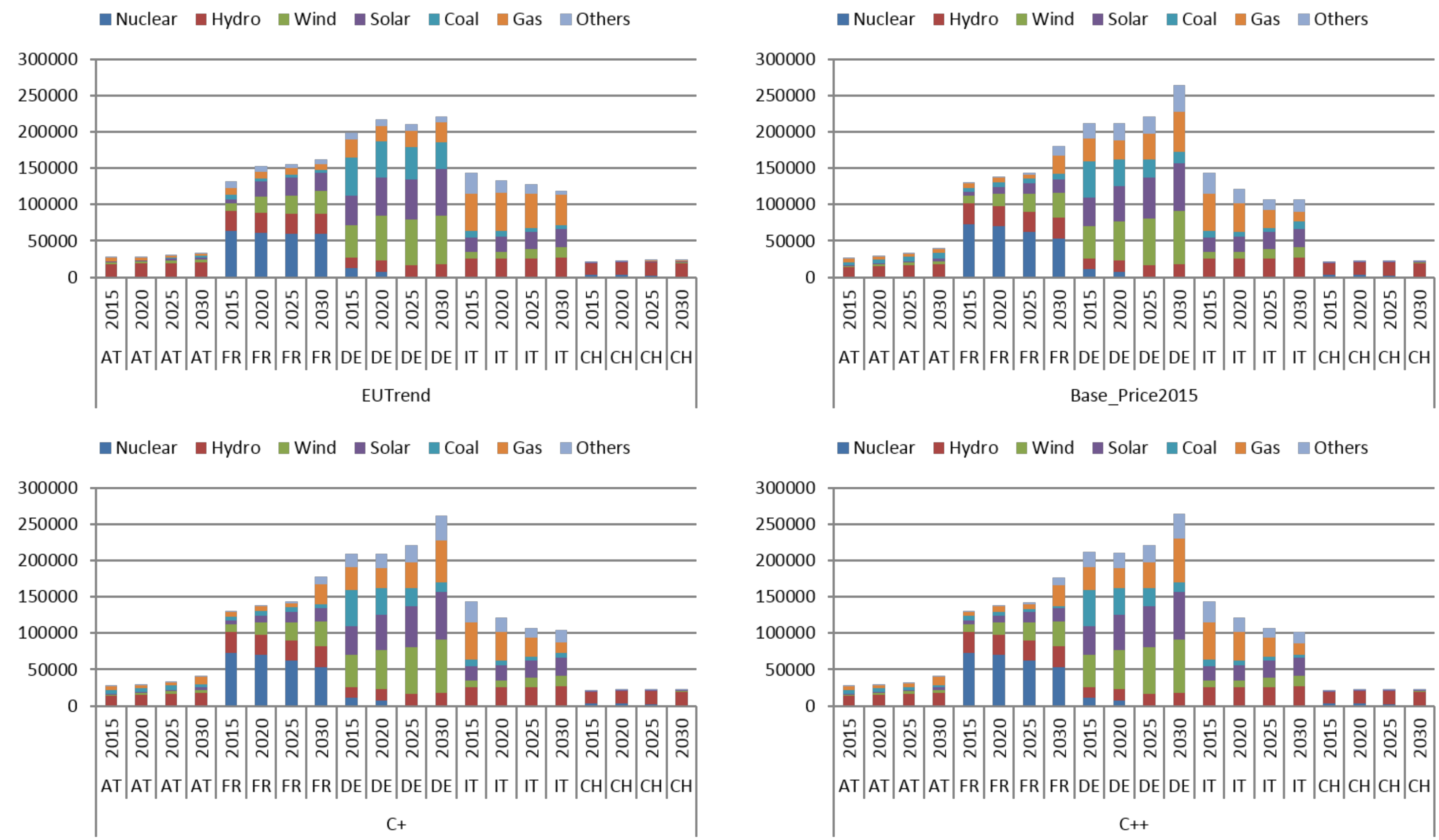
Swissmod

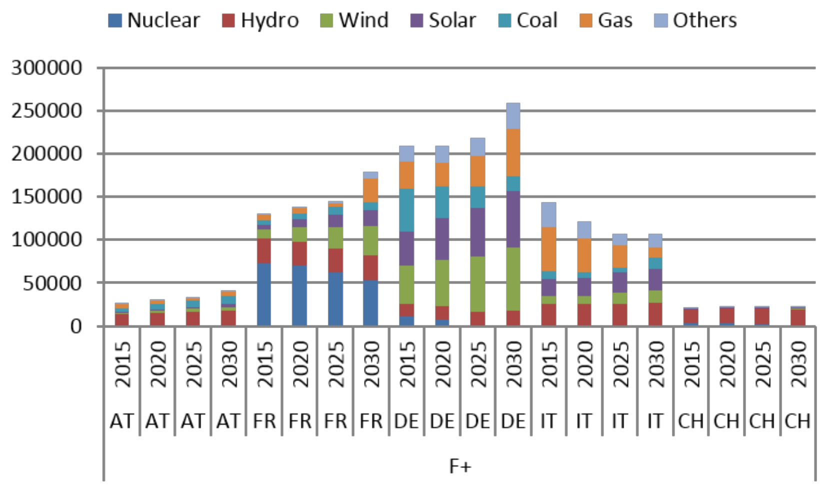
The results from the investment model are fed into the Swiss electricity market model Swissmod developed in Schlecht and Weigt (2014). Swissmod is a classical dispatch model based on a DC-Load-Flow Approach. It represents Switzerland in detailed spatial resolution while the surrounding countries Austria, Germany, France and Italy are aggregated. Since Switzerland is a HP dominated country, the water flows within Switzerland are defined endogenously in the model (Schlecht and Weigt, 2014). From Swissmod, we obtain the future day-ahead market prices and balancing prices for Switzerland for the individual scenarios which are fed into the hydropower operation model (for details on Swissmod see Schlecht and Weigt, 2014).

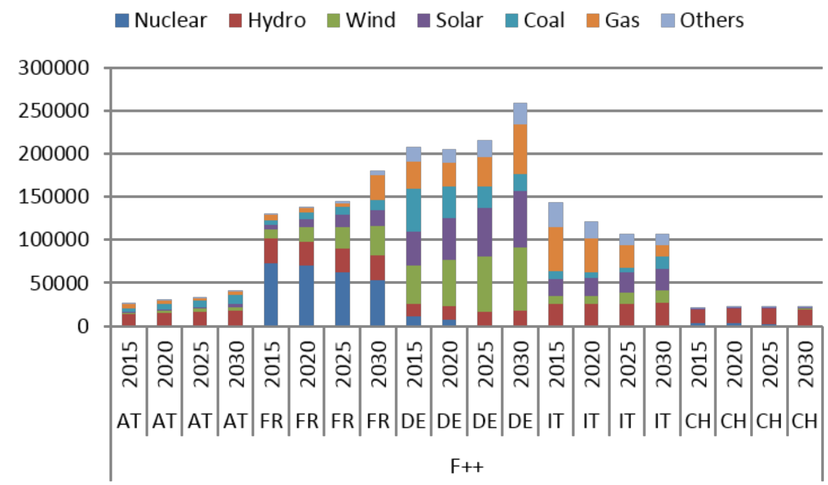
Scenario assumptions and capacity results

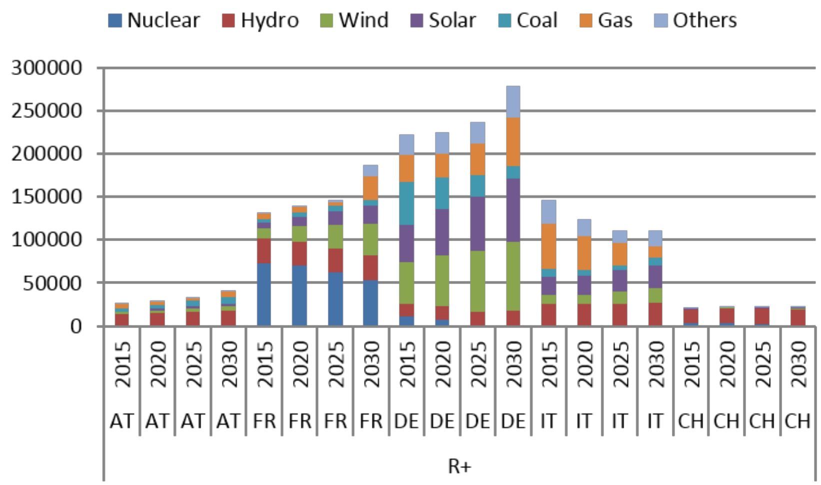
The development of the future electricity system of Switzerland and the Swiss neighboring countries Germany, Italy, Austria and France according to the EU Energy Trends by the European Commission (2016) and the national energy strategies show a decrease in the nuclear capacities in Switzerland and Germany across scenarios since these countries decided to phase out nuclear in the future. In addition, the nuclear capacities in France are slightly reduced. The HP capacities are slightly increased in Switzerland, Austria and Germany while the wind and solar capacities are increased in all countries. In Germany wind and solar capacities are increased most. Across scenarios the results of our investment model show a decrease in EU coal capacity while the Gas capacity is increasing. If the carbon price is increasing in the future, the coal capacities are greatly reduced due to their high carbon intensity. At the same time, gas capacities are greatly increased due to their lower carbon intensity and their lower investment costs compared to coal. Especially Germany and France increase their gas capacities while Italy reduces their gas capacities. Since gas prices are assumed to be higher in Italy, gas is less competitive in Italy compared to other Swiss neighboring countries. If the fuel prices increase, the reduction in the coal capacities and the increase in the gas capacities are less pronounced. If the RES capacity increases in the electricity system, gas capacities are slightly increased in order to have a flexible peak technology in the system which can counteract the variability of wind and solar (see figures in Table A1).

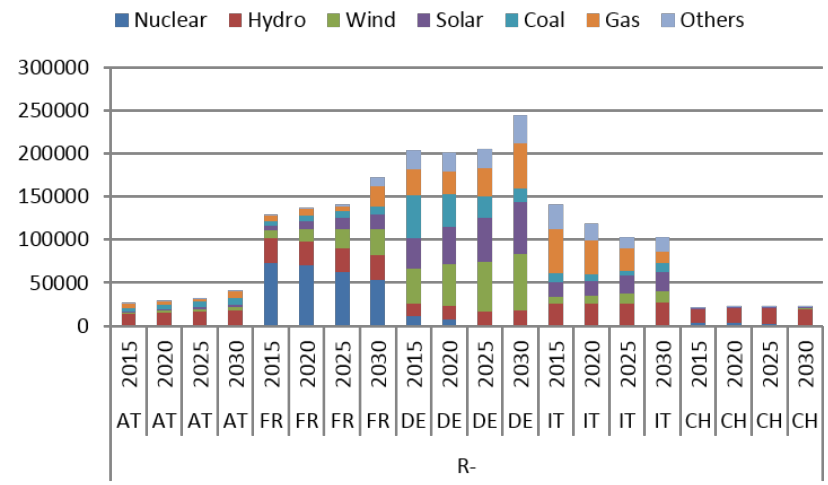
Table A1. Simulated future generation capacities by country, year and scenario [MW].

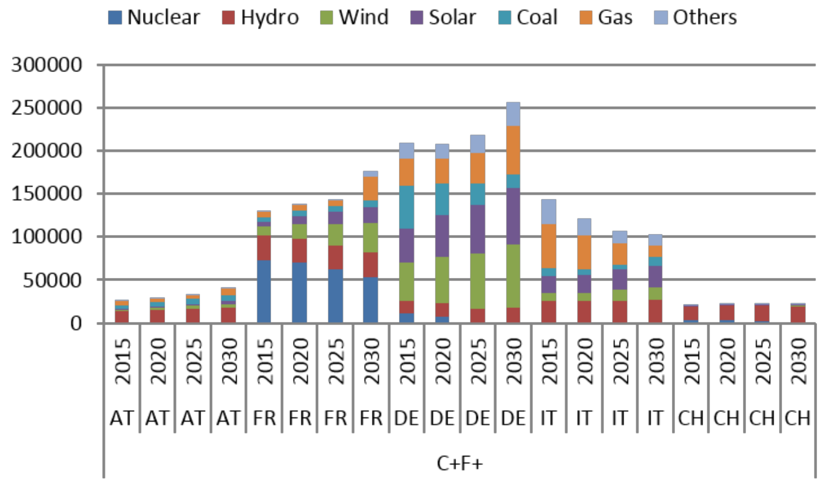


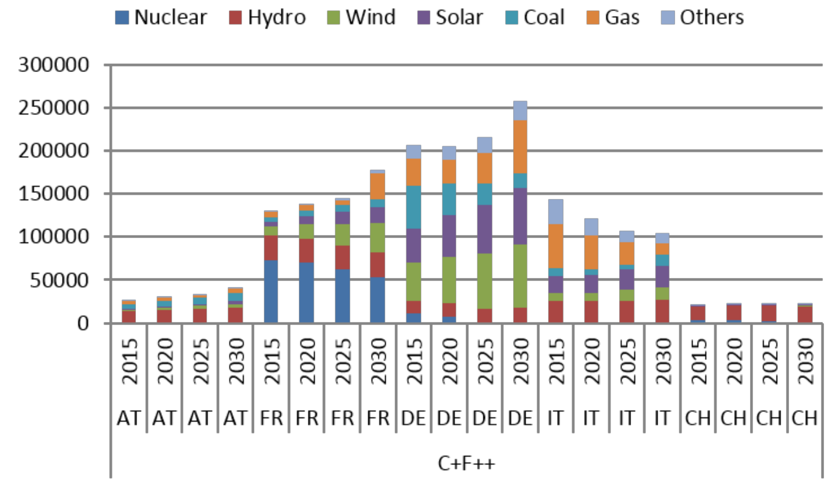

Nuclear
Hydro
Wind
Solar
Coal
Gas
Others
F+

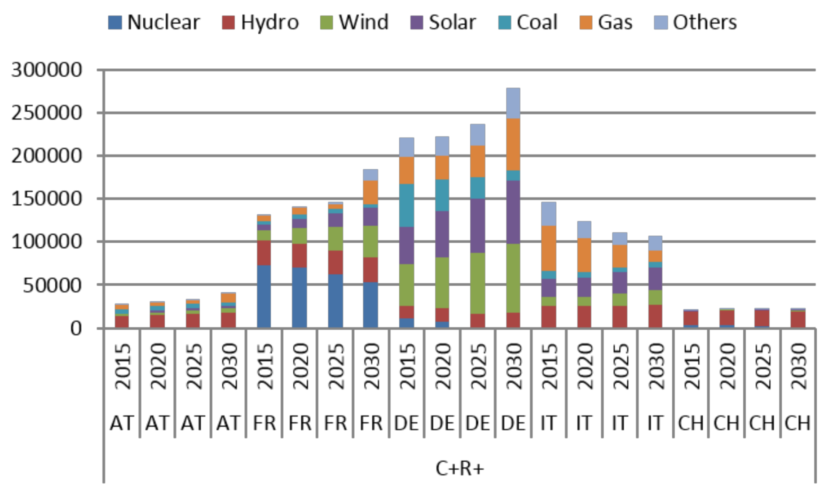

Nuclear
Hydro
Wind
Solar
Coal
Gas
Others
F++

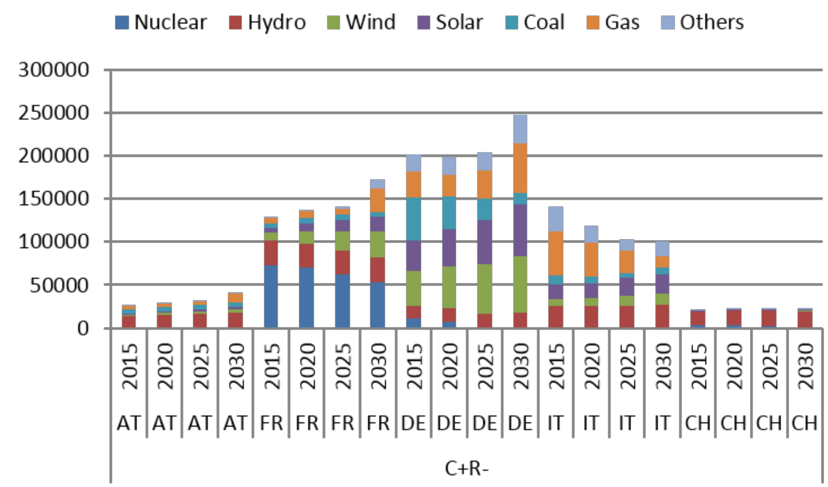

Nuclear
Hydro
Wind
Solar
Coal
Gas
Others
R+

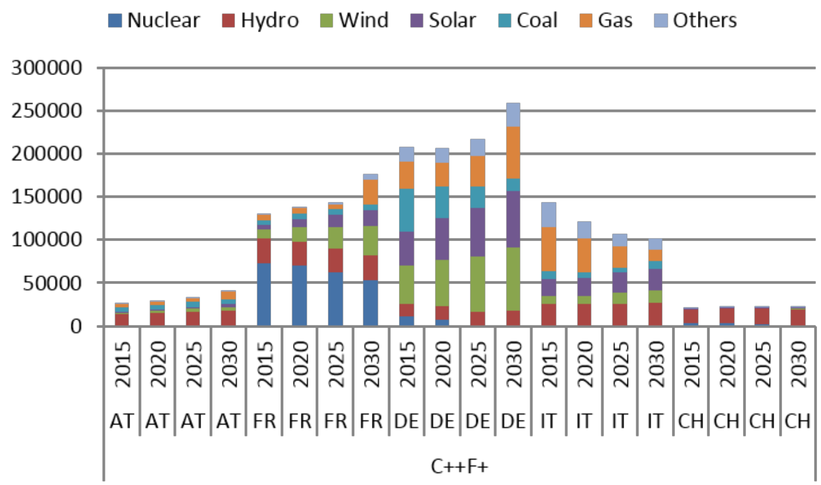

Nuclear
Hydro
Wind
Solar
Coal
Gas
Others
R-

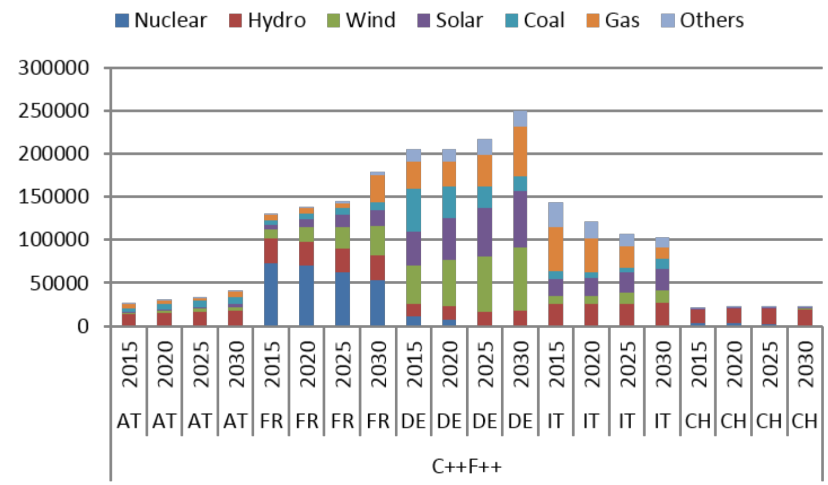

Nuclear
Hydro
Wind
Solar
Coal
Gas
Others
300000
250000
200000
150000
100000
50000
0
2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030
AT AT AT AT FR FR FR FR DE DE DE DE IT IT IT IT CH CH CH CH
C+F+

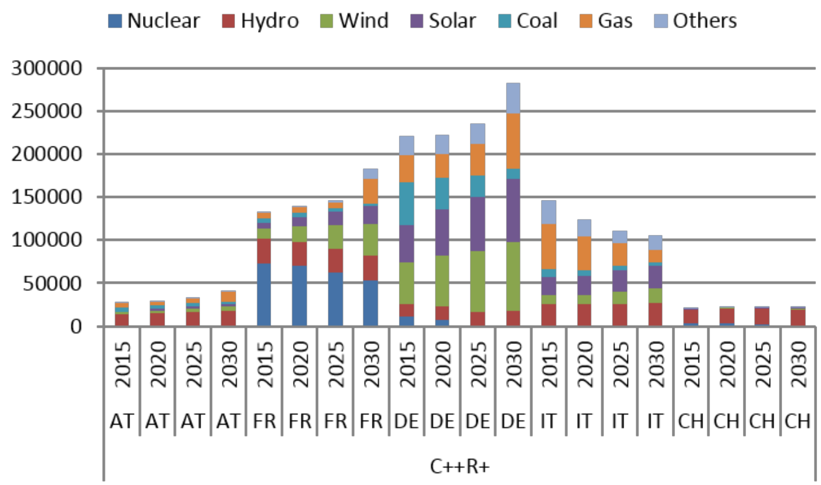

Nuclear
Hydro
Wind
Solar
Coal
Gas
Others
300000
250000
200000
150000
100000
50000
0
2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030
AT AT AT AT FR FR FR FR DE DE DE DE IT IT IT IT CH CH CH CH
C+F++

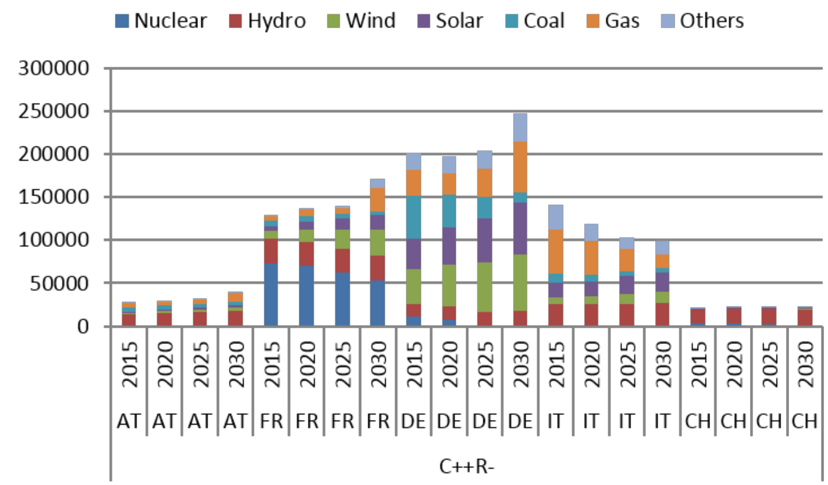

Nuclear
Hydro
Wind
Solar
Coal
Gas
Others
300000
250000
200000
150000
100000
50000
0
2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030
AT AT AT AT FR FR FR FR DE DE DE DE IT IT IT IT CH CH CH CH
C+R+

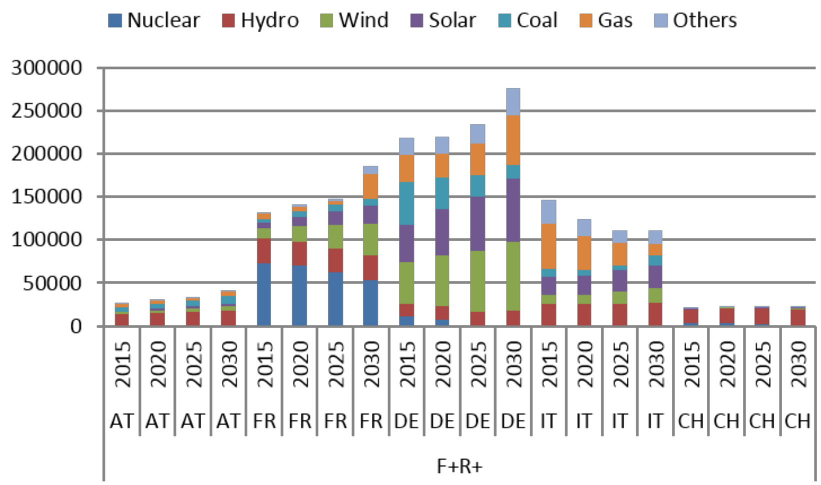

Nuclear
Hydro
Wind
Solar
Coal
Gas
Others
300000
250000
200000
150000
100000
50000
0
2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030
AT AT AT AT FR FR FR FR DE DE DE DE IT IT IT IT CH CH CH CH
C+R-

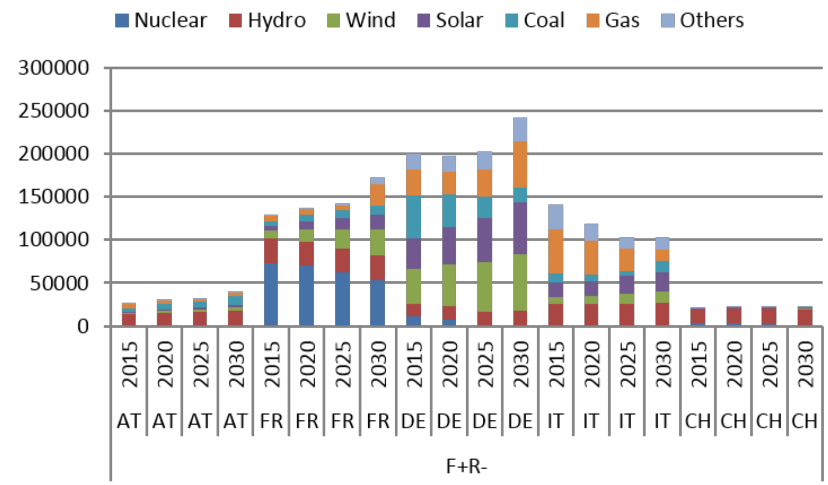

Nuclear
Hydro
Wind
Solar
Coal
Gas
Others
300000
250000
200000
150000
100000
50000
0
2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030
AT AT AT AT FR FR FR FR DE DE DE DE IT IT IT IT CH CH CH CH
C++F+

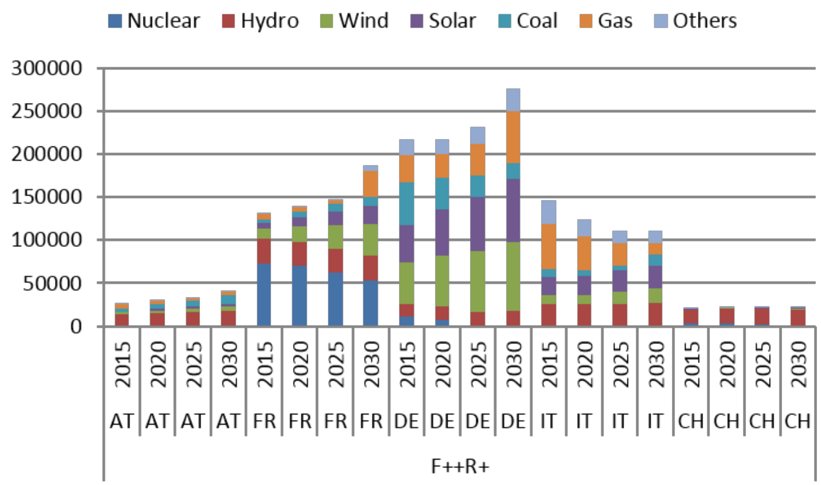

Nuclear
Hydro
Wind
Solar
Coal
Gas
Others
300000
250000
200000
150000
100000
50000
0
2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030
AT AT AT AT FR FR FR FR DE DE DE DE IT IT IT IT CH CH CH CH
C++F++

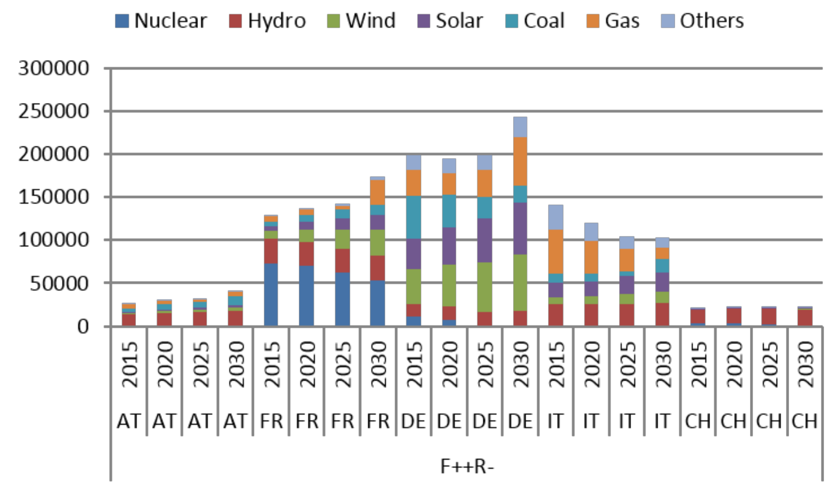

Nuclear
Hydro
Wind
Solar
Coal
Gas
Others
300000
250000
200000
150000
100000
50000
0
2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030
AT AT AT AT FR FR FR FR DE DE DE DE IT IT IT IT CH CH CH CH
C++R+

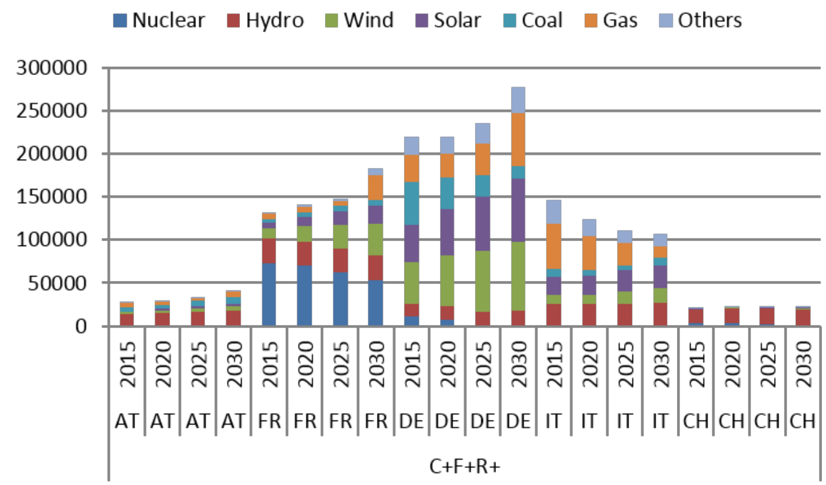

Nuclear
Hydro
Wind
Solar
Coal
Gas
Others
300000
250000
200000
150000
100000
50000
0
2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030
AT AT AT AT FR FR FR FR DE DE DE DE IT IT IT IT CH CH CH CH
C++R-

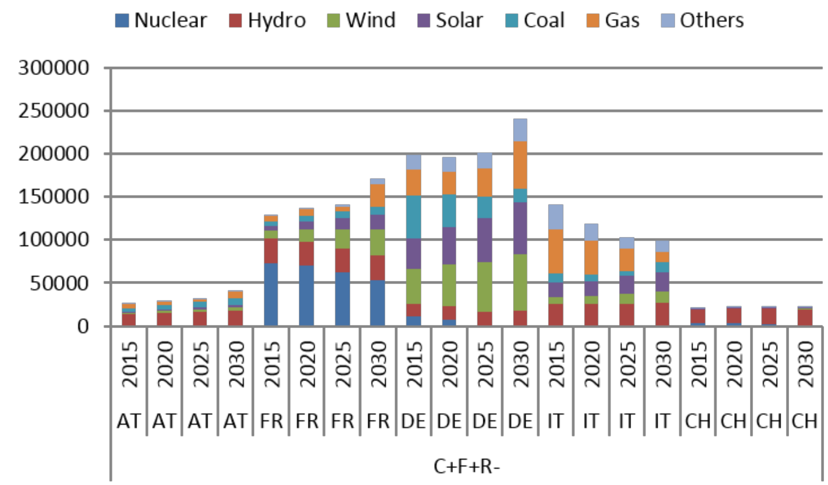

Nuclear Hydro Wind Solar Coal Gas Others
300000
250000
200000
150000
100000
50000
0
2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030
AT AT AT AT FR FR FR FR DE DE DE DE IT IT IT IT CH CH CH CH
F+R+

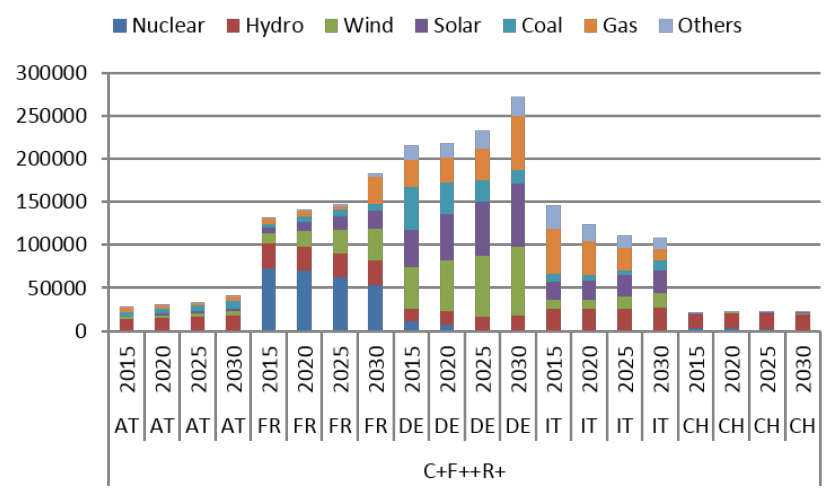

Nuclear Hydro Wind Solar Coal Gas Others
300000
250000
200000
150000
100000
50000
0
2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030
AT AT AT AT FR FR FR FR DE DE DE DE IT IT IT IT CH CH CH CH
F+R-

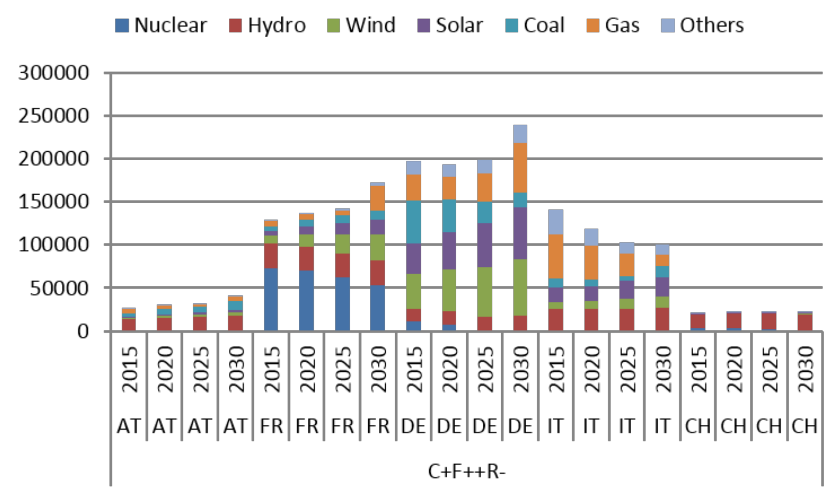

Nuclear Hydro Wind Solar Coal Gas Others
300000
250000
200000
150000
100000
50000
0
2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030
AT AT AT AT FR FR FR FR DE DE DE DE IT IT IT IT CH CH CH CH
F++R+

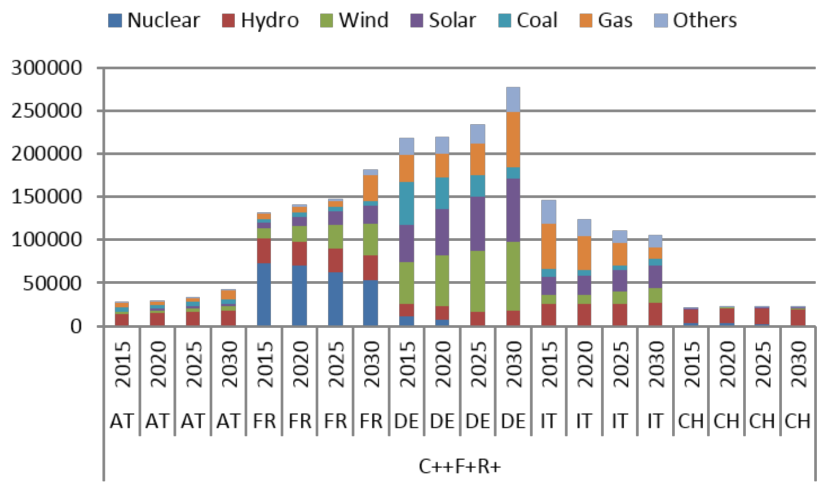

Nuclear Hydro Wind Solar Coal Gas Others
300000
250000
200000
150000
100000
50000
0
2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030
AT AT AT AT FR FR FR FR DE DE DE DE IT IT IT IT CH CH CH CH
F++R-

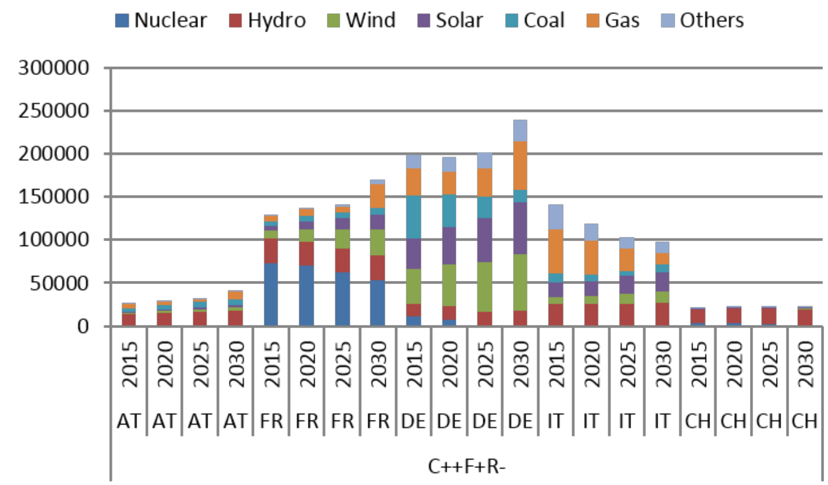

Nuclear Hydro Wind Solar Coal Gas Others
300000
250000
200000
150000
100000
50000
0
2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030
AT AT AT AT FR FR FR FR DE DE DE DE IT IT IT IT CH CH CH CH
C+F+R+

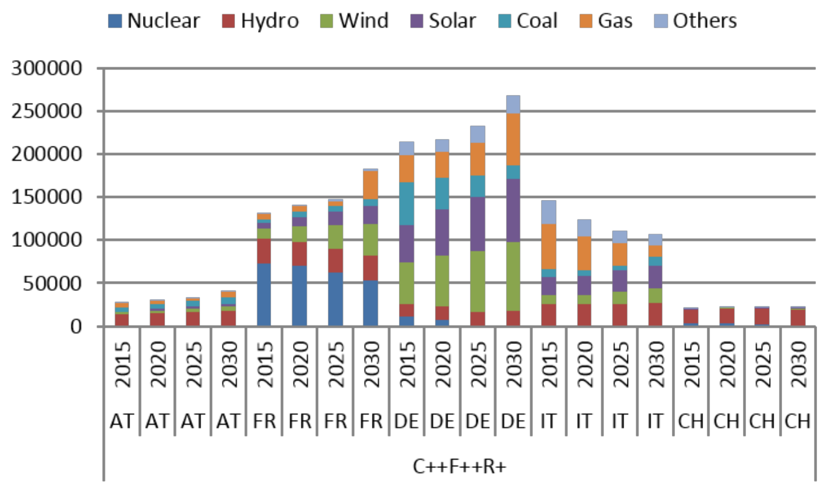

Nuclear Hydro Wind Solar Coal Gas Others
300000
250000
200000
150000
100000
50000
0
2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030
AT AT AT AT FR FR FR FR DE DE DE DE IT IT IT IT CH CH CH CH
C+F+R-

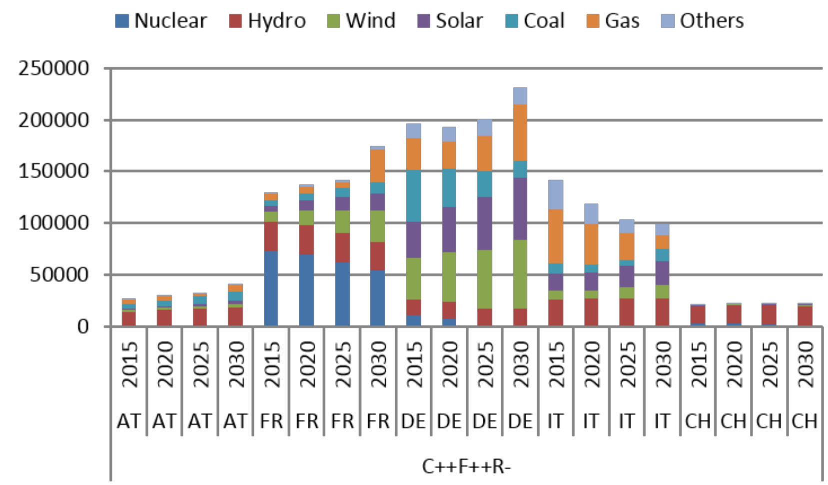

Nuclear Hydro Wind Solar Coal Gas Others
300000
250000
200000
150000
100000
50000
0
2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030
AT AT AT AT FR FR FR FR DE DE DE DE IT IT IT IT CH CH CH CH
C+F++R+


Nuclear Hydro Wind Solar Coal Gas Others
300000
250000
200000
150000
100000
50000
0
2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030
AT AT AT AT FR FR FR FR DE DE DE DE IT IT IT IT CH CH CH CH
C+F++R-


Nuclear Hydro Wind Solar Coal Gas Others
300000
250000
200000
150000
100000
50000
0
2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030
AT AT AT AT FR FR FR FR DE DE DE DE IT IT IT IT CH CH CH CH
C++F+R+


Nuclear Hydro Wind Solar Coal Gas Others
300000
250000
200000
150000
100000
50000
0
2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030
AT AT AT AT FR FR FR FR DE DE DE DE IT IT IT IT CH CH CH CH
C++F+R-


Nuclear Hydro Wind Solar Coal Gas Others
300000
250000
200000
150000
100000
50000
0
2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030
AT AT AT AT FR FR FR FR DE DE DE DE IT IT IT IT CH CH CH CH
C++F++R+


Nuclear Hydro Wind Solar Coal Gas Others
250000
200000
150000
100000
50000
0
2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030 2015 2020 2025 2030
AT AT AT AT FR FR FR FR DE DE DE DE IT IT IT IT CH CH CH CH
C++F++R-

Additional historic results

Table A2. Revenues by HP category for the years 2011 to 2014 taking into account water reserve requirements.

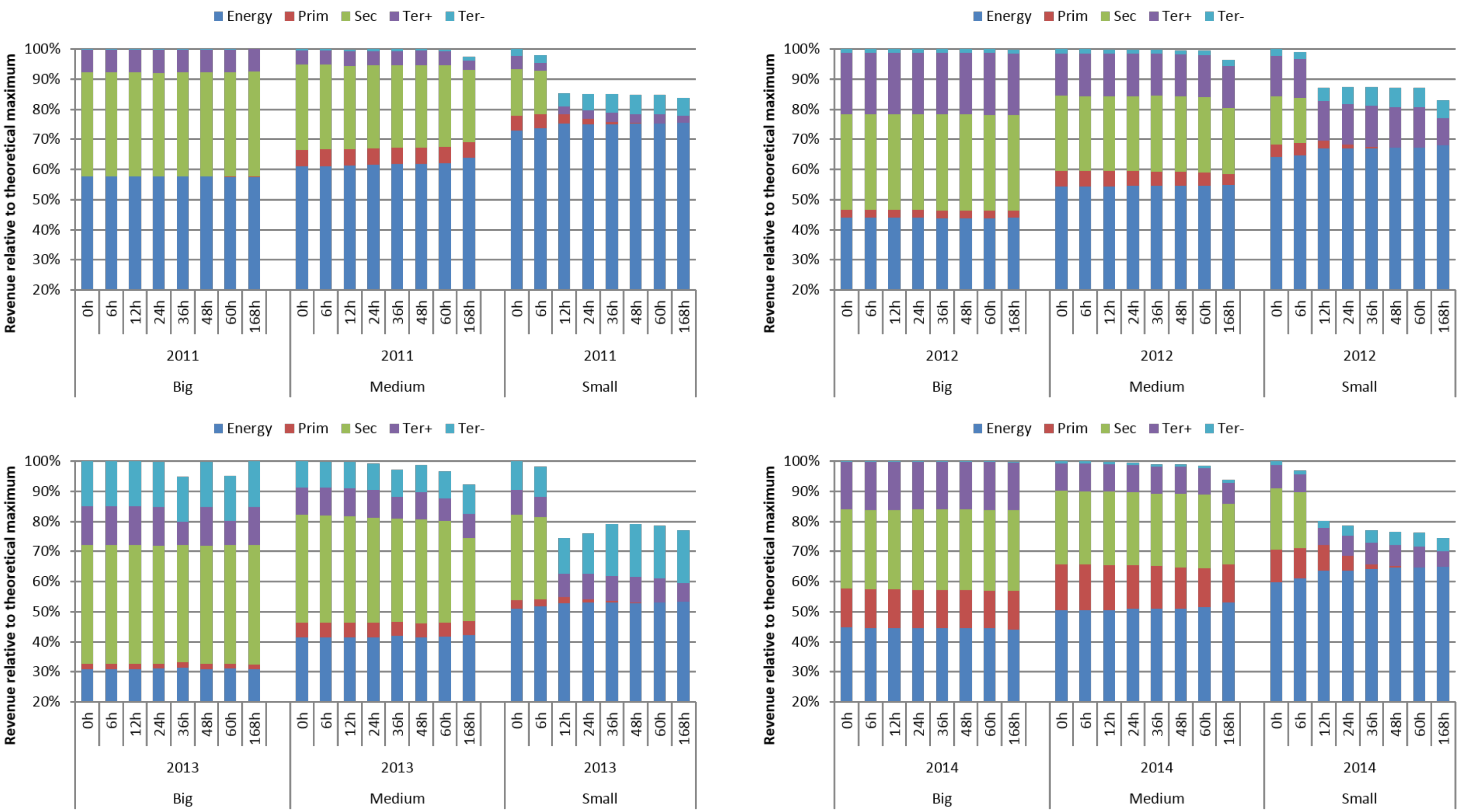


Table A3. Revenues by HP category for the years 2011 to 2014 taking into account bid sizes.

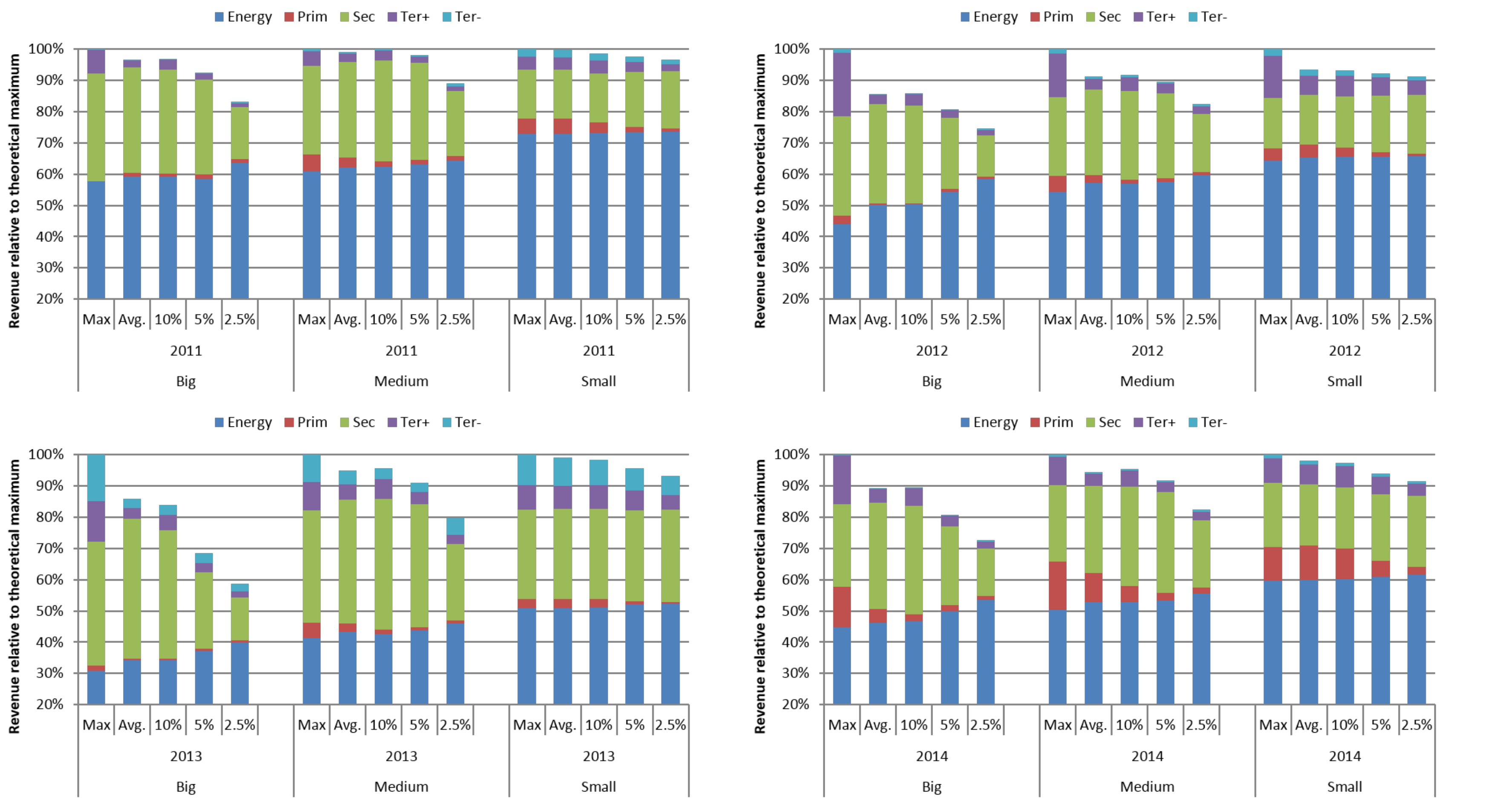
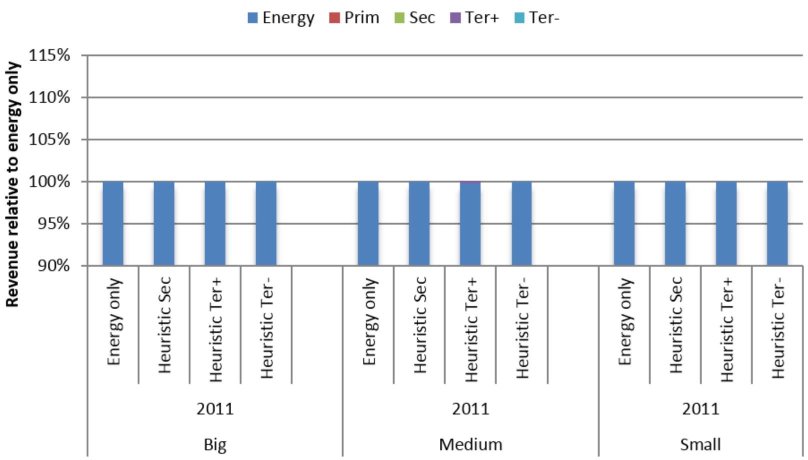
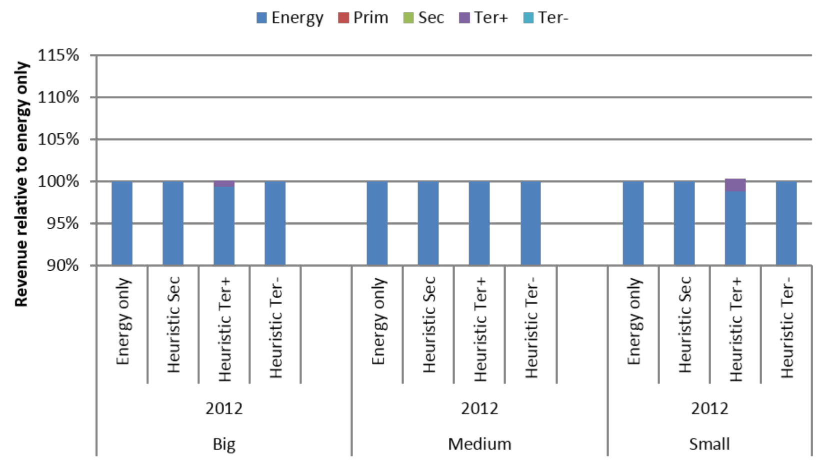
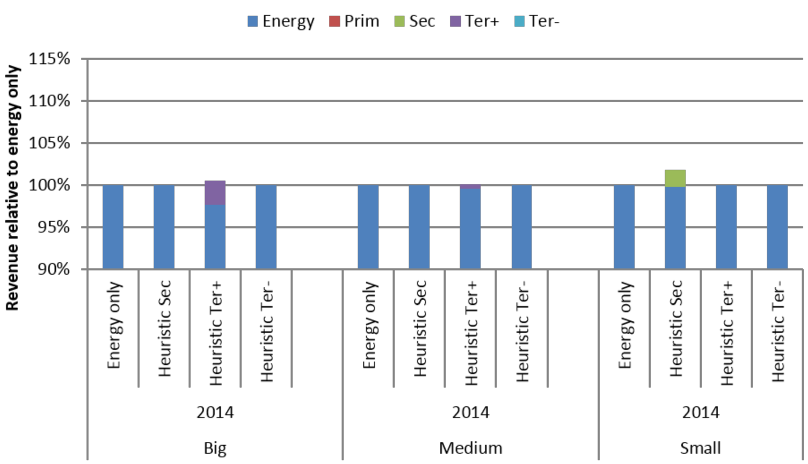


Table A4. Revenues by HP category for the year 2011, 2012 and 2014 for the heuristic trading strategy.

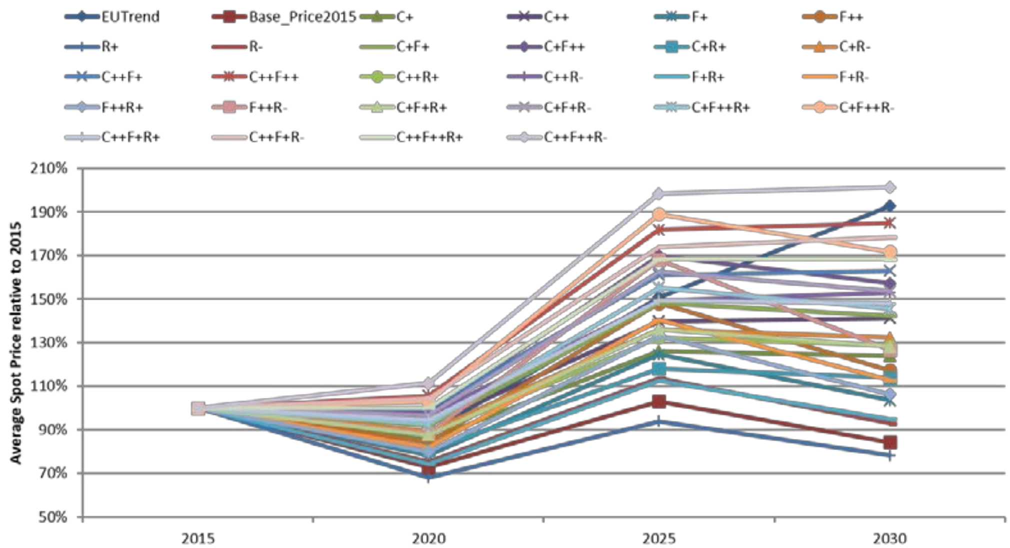


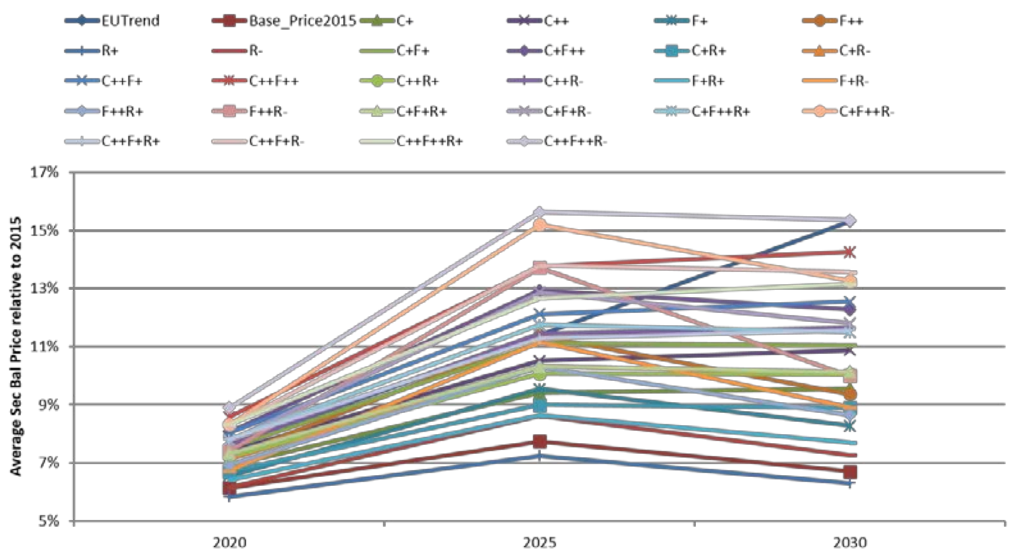


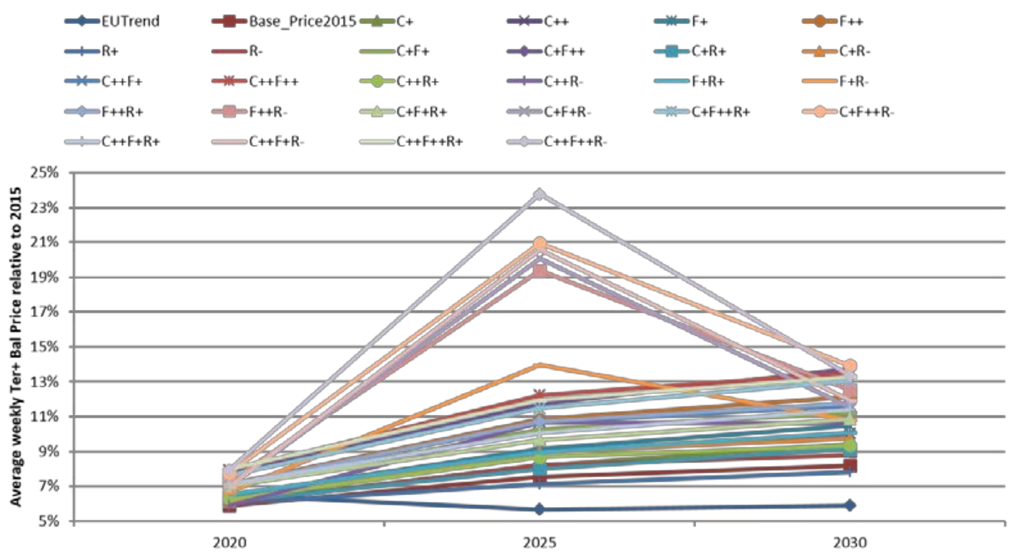


Additional future results

Table A5. Simulated future Swiss spot and balancing market prices by year and scenario.






EUTrend
Base_Price2015
C+
C++
F+
F++
R+
R-
C+F+
C+F++
C+R+
C+R-
C++F+
C++F++
C++R+
C++R-
F+R+
F+R-
F++R+
F++R-
C+F+R+
C+F+R-
C+F++R+
C+F++R-
C++F+R+
C++F+R-
C++F++R+
C++F++R-
Average weekly Ter+ Bal Price relative to 2015
25%
23%
21%
19%
17%
15%
13%
11%
9%
7%
5%
2020
2025
2030

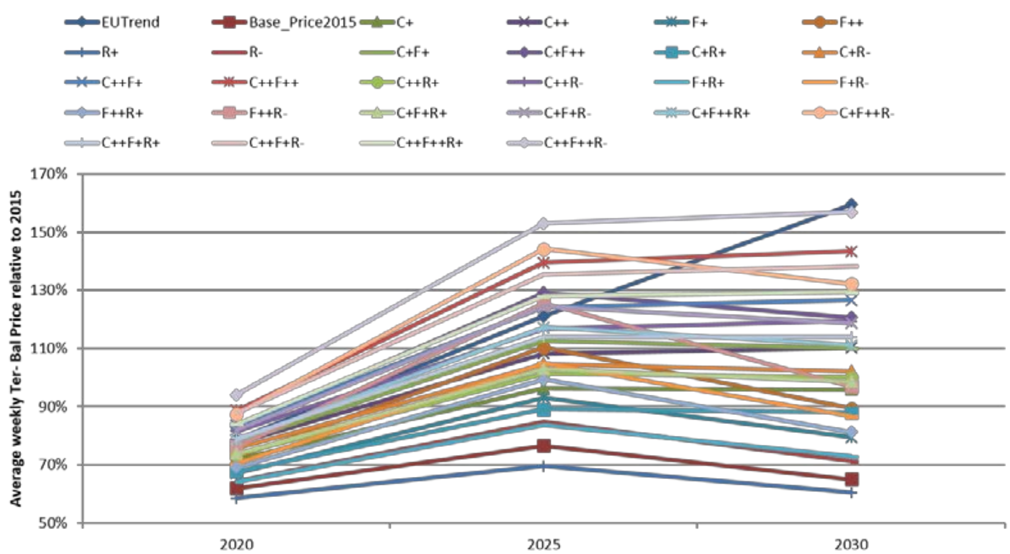
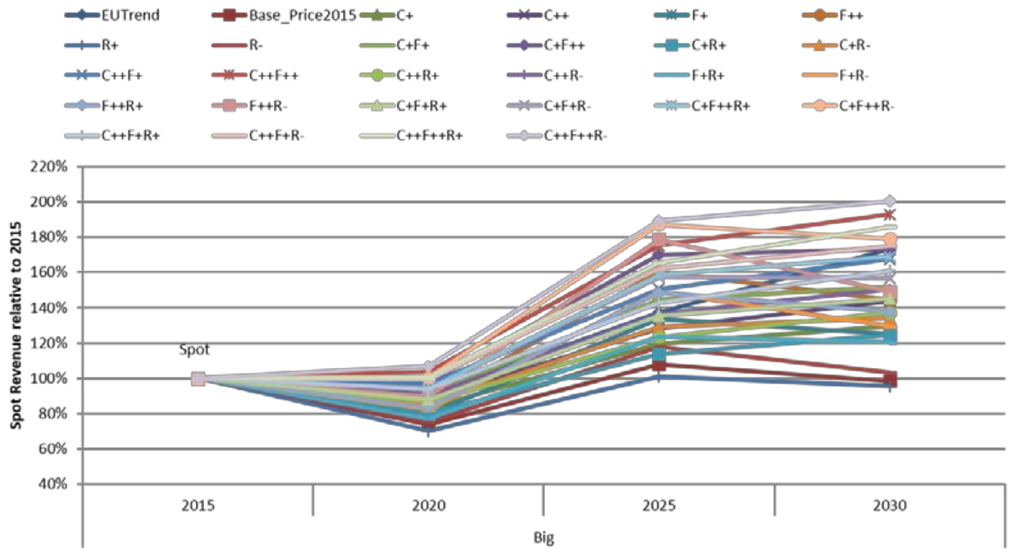
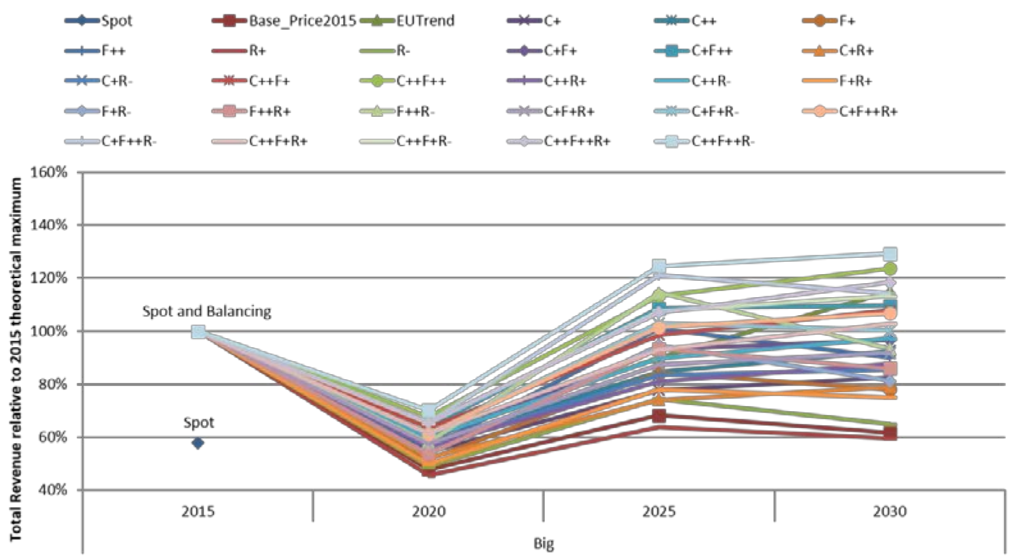
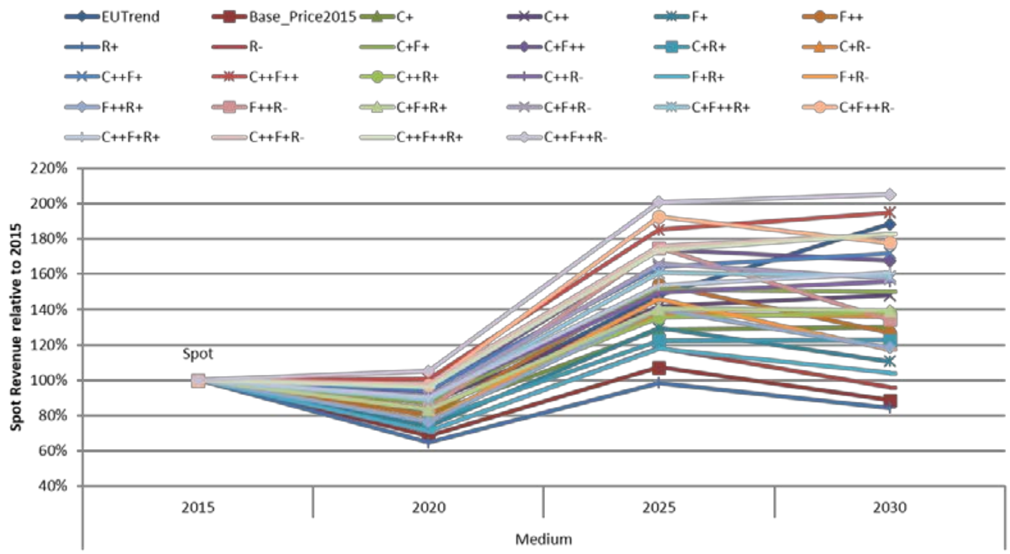
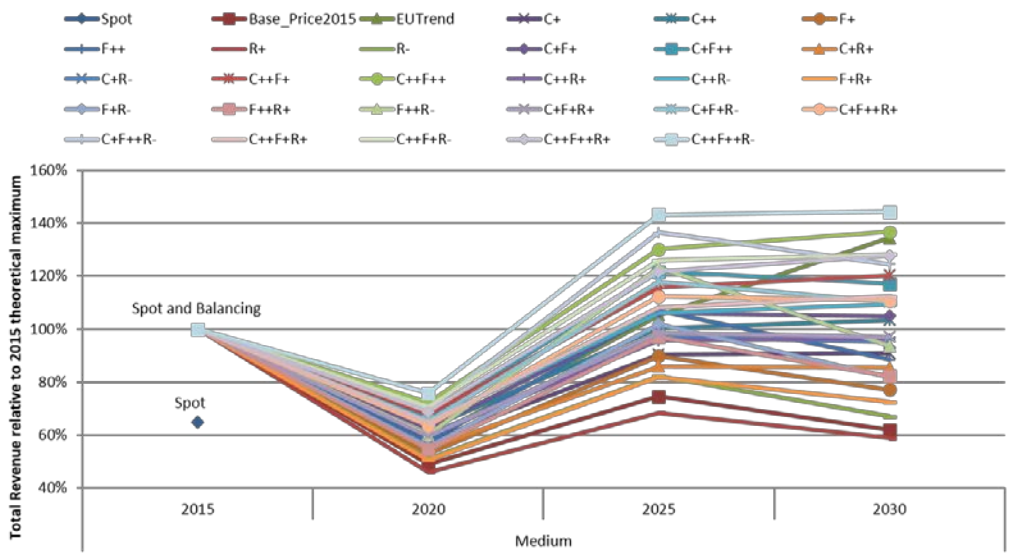

EUTrend
Base_Price2015
C+
C++
F+
F++
R+
R-
C+F+
C+F++
C+R+
C+R-
C++F+
C++F++
C++R+
C++R-
F+R+
F+R-
F++R+
F++R-
C+F+R+
C+F+R-
C+F++R+
C+F++R-
C++F+R+
C++F+R-
C++F++R+
C++F++R-
Average weekly Ter- Bal Price relative to 2015
170%
150%
130%
110%
90%
70%
50%
2020
2025
2030

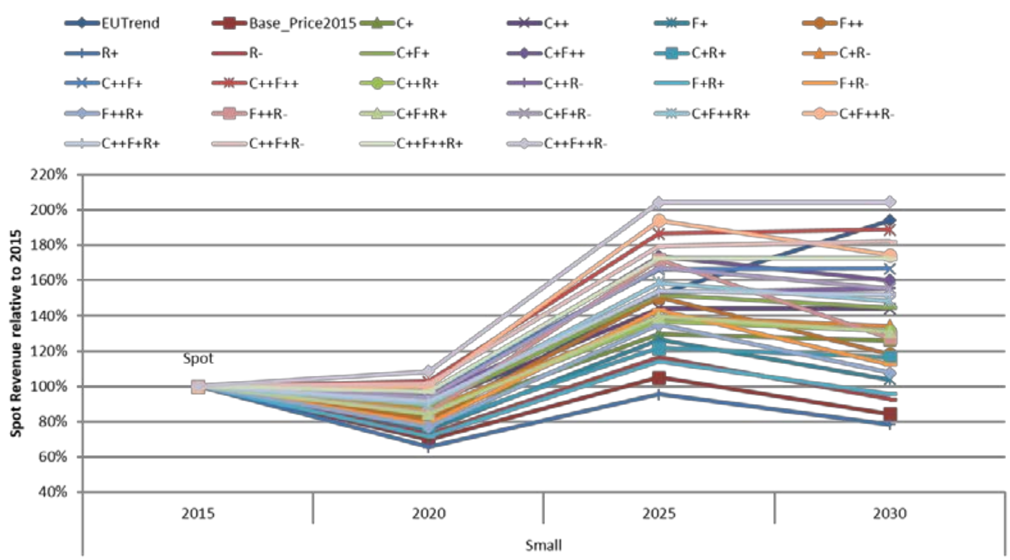
Table A6. Simulated future spot and total (spot & balancing) market revenues by year, scenario and HP category.

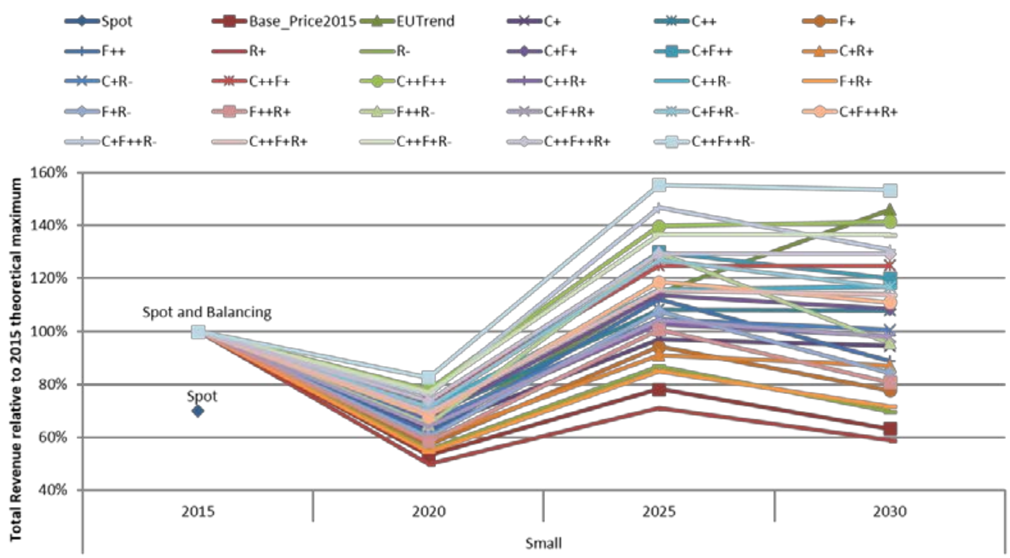





EUTrend
Base_Price2015
C+
C++
F+
F++
R+
R-
C+F+
C+F++
C+R+
C+R-
C++F+
C++F++
C++R+
C++R-
F+R+
F+R-
F++R+
F++R-
C+F+R+
C+F+R-
C+F++R+
C+F++R-
C++F+R+
C++F+R-
C++F++R+
C++F++R-
220%
200%
180%
160%
140%
120%
100%
80%
60%
40%
Spot Revenue relative to 2015
Spot
2015
2020
2025
2030
Medium


Spot
Base_Price2015
EUTrend
C+
C++
F+
F++
R+
R-
C+F+
C+F++
C+R+
C+R-
C++F+
C++F++
C++R+
C++R-
F+R+
F+R-
F++R+
F++R-
C+F+R+
C+F+R-
C+F++R+
C+F++R-
C++F+R+
C++F+R-
C++F++R+
C++F++R-
160%
140%
120%
100%
80%
60%
40%
Total Revenue relative to 2015 theoretical maximum
Spot and Balancing
Spot
2015
2020
2025
2030
Medium


EUTrend
Base_Price2015
C+
C++
F+
F++
R+
R-
C+F+
C+F++
C+R+
C+R-
C++F+
C++F++
C++R+
C++R-
F+R+
F+R-
F++R+
F++R-
C+F+R+
C+F+R-
C+F++R+
C+F++R-
C++F+R+
C++F+R-
C++F++R+
C++F++R-
220%
200%
180%
160%
140%
120%
100%
80%
60%
40%
Spot Revenue relative to 2015
Spot
2015
2020
2025
2030
Small


Spot
Base_Price2015
EUTrend
C+
C++
F+
F++
R+
R-
C+F+
C+F++
C+R+
C+R-
C++F+
C++F++
C++R+
C++R-
F+R+
F+R-
F++R+
F++R-
C+F+R+
C+F+R-
C+F++R+
C+F++R-
C++F+R+
C++F+R-
C++F++R+
C++F++R-
Total Revenue relative to 2015 theoretical maximum
160%
140%
120%
100%
80%
60%
40%
Spot and Balancing
Spot
2015
2020
2025
2030
Small

References

Abgottspon, H., Andersson, G., 2012. Approach of Integrating Ancillary Services into a medium-term Hydro Optimization. XII Symposium of specialists in electric operational and expansion planning.

Abrell, J., 2016. The Swiss Wholesale Electricity Market. SCCER CREST Working Paper.

Aggidis, G.A., Židonis, A., 2014. Hydro turbine prototype testing and generation of performance curves: Fully automated approach. Renewable Energy 71, 433–441. 10.1016/j.renene.2014.05.043.

Balmer, M., 2012. Nachhaltigkeitsbezogene Typologisierung der Schweizerischen Wasserkraftanlagen: Gis-Basierte Clusteranalyse und Anwendung in Einem Erfahrungskurvenmodell. Ph.D. Thesis, Zürich.

Barry, M., Baur, P., Gaudard, L., Giuliani, G., Hediger, W., Romerio, F., Schillinger, M., Schumann, R., Voegeli, G., Weigt, H., 2015. The Future of Swiss Hydropower: A Review on Drivers and Uncertainties. Discussion Paper 2015/01. FoNEW.

Betz, R., Cludius, J., Filippini, M., Frauendorfer, K., Geissmann, T., Hettich, P., Weigt, H., 2016. Wasserkraft: Wiederherstellung der Wettbewerbsfähigkeit. SCCER CREST White Paper (1).

Borghetti, A., D'Ambrosio, C., Lodi, A., Martello, S., 2008. An MILP Approach for Short-Term Hydro Scheduling and Unit Commitment With Head-Dependent Reservoir. IEEE Transactions on power systems 23 (3).

Catalão, J.P.S., Mariano, S.J.P.S., Mendes, V.M.F., Ferreira, L.A.F.M., 2009. Nonlinear optimization method for short-term hydro scheduling considering head-dependency. Euro. Trans. Electr. Power 142, n/a-n/a. 10.1002/etep.301.

Chazarra, M., García-González, J., Pérez-Díaz, J.I., Arteseros, M., 2016. Stochastic optimization model for the weekly scheduling of a hydropower system in day-ahead and secondary regulation reserve markets. Electric Power Systems Research 130, 67–77. 10.1016/j.epsr.2015.08.014.

Conejo, A.J., Arroyo, J.M., Contreras, J., Villamor, F.A., 2002. Self-Scheduling of a Hydro Producer in a Pool-Based Electricity Market. IEEE Transactions on power systems 17 (4).

Deb, R., 2000. Operating Hydroelectric Plants and Pumped Storage Units in a Competitive Environment. The Electricity Journal.

ENTSO-E, 2014. Yearly Statistics & Adequacy Retrospect 2014: European Electricity System Data.

EPEX SPOT, 2017. Market data day-ahead auction. http://www.epexspot.com/en/market-data/dayaheadauction. Accessed 9 February 2017.

European Commission, 2016. EU Reference Scenario 2016. Energy, transport and GHG emissions. Trends to 2050.

Filippini, M., Geissmann, T., 2014. Kostenstruktur und Kosteneffizienz der Schweizer Wasserkraft. Bundesamt für Energie.

Fodstad, M., Henden, A.L., Helseth, A., 2015. Hydropower Scheduling in Day-ahead and Balancing Markets. 12th International Conference on the European Energy Market (EEM).

Frauendorfer, K., Gratwohl, M., Haarbrücker, G., Schürle, M., 2017. Rentabilitätsfaktoren für Pumpspeicher-Kraftwerke. eco.naturkongress, 31 March 2017, Basel.

Gaudard, L., Romerio, F., 2014. The future of hydropower in Europe: Interconnecting climate, markets and policies. Environmental Science & Policy 37, 172–181. 10.1016/j.envsci.2013.09.008.

Hirth, L., 2016. The benefits of flexibility: The value of wind energy with hydropower. Applied Energy 181, 210–223. 10.1016/j.apenergy.2016.07.039.

Hirth, L., Ziegenhagen, I., 2015. Balancing power and variable renewables: Three links. Renewable and Sustainable Energy Reviews 50, 1035–1051. 10.1016/j.rser.2015.04.180.

IEA, 2012. Technology Roadmap: Hydropower.

Ilak, P., Krajcar, S., Rajšl, I., Delimar, M., 2014. Pricing Energy and Ancillary Services in a Day-Ahead Market for a Price-Taker Hydro Generating Company Using a Risk-Constrained Approach. Energies (7).

Kazempour, S.J., Moghaddam, M.P., Haghifam, M.R., Yousefi, G.R., 2009. Risk-constrained dynamic self-scheduling of a pumped-storage plant in the energy and ancillary service markets. Energy Conversion and Management 50 (5), 1368–1375. 10.1016/j.enconman.2009.01.006.

Ladurantaye, D. de, Gendreau, M., Potvin, J.-Y., 2009. Optimizing profits from hydroelectricity production. Computers & Operations Research 36 (2), 499–529. 10.1016/j.cor.2007.10.012.

Okot, D.K., 2013. Review of small hydropower technology. Renewable and Sustainable Energy Reviews 26, 515–520. 10.1016/j.rser.2013.05.006.

Pérez-Díaz, J.I., Wilhelmi, J.R., Sánchez-Fernández, J.Á., 2010. Short-term operation scheduling of a hydropower plant in the day-ahead electricity market. Electric Power Systems Research 80 (12), 1535–1542. 10.1016/j.epsr.2010.06.017.

Rasmussen, C., Hansena, J.B.Ø., Korpås, M., Fodstad, M., 2016. Profitability of a hydro power producer bidding in multiple power markets. Energy Procedia (87).

Saarinen, L., Dahlbäck, N., Lundin, U., 2015. Power system flexibility need induced by wind and solar power intermittency on time scales of 1–14 days. Renewable Energy 83, 339–344. 10.1016/j.renene.2015.04.048.

Schlecht, I., Weigt, H., 2014. Swissmod – A Model of the Swiss Electricity Market. WWZ Discussion Paper 2014/04.

Schlecht, I., Weigt, H., 2016. Long Drought Ahead? The Future Revenue Prospects of Swiss Hydropower. SCCER CREST Working Paper WP3-2016/03.

SFOE, 2012. Wasserkraftpotenzial der Schweiz: Abschätzung des Ausbaupotenzials der Wasserkraftnutzung im Rahmen der Energiestrategie 2050.

SFOE, 2016. Schweizerische Elektrizitätsstatistik 2015.

Swissgrid, 2015. Grundlagen Systemdienstleistungsprodukte: Produktbeschreibung – gültig ab Oktober 2015.

Swissgrid, 2017a. Energieübersicht Schweiz: Aggregierte Energiedaten aus dem Regelblock Schweiz. https://www.swissgrid.ch/swissgrid/de/home/experts/topics/energy_data_ch.html. Accessed 9 February 2017.

Swissgrid, 2017b. Systemdienstleistungen.

Swissgrid, 2017c. Systemdienstleistungen: Ausschreibungen. https://www.swissgrid.ch/swissgrid/de/home/experts/topics/ancillary_services/tenders.html. Accessed 9 February 2017.

VSE, 2014. Grosswasserkraft.

VSE, 2016. Beiträge der Erzeugungstechnologien zur Stromversorgung und Stabilität des elektrischen Systems.
Weitemeyer, S., Kleinhans, D., Vogt, T., Agert, C., 2015. Integration of Renewable Energy Sources in future power systems: The role of storage. Renewable Energy 75, 14–20. 10.1016/j.renene.2014.09.028.