Climate change impacts on hydropower in the Swiss and Italian Alps

Ludovic Gaudard [a,*], Franco Romerio [a], Francesco Dalla Valle [b], Roberta Gorret [c], Stefano Maran [d], Giovanni Ravazzani [e], Markus Stoffel [f], Michela Volonterio [d]

[a] *Institute for Environmental Sciences, University of Geneva, Switzerland*
[b] *ENEL Produzione SpA, Venezia, Italy*
[c] *CVA SpA, Châtillon, Italy*
[d] *Sustainable Development and Energy Sources Department, RSE SpA, Milano, Italy*
[e] *Department of Civil and Environmental Engineering, Politecnico of Milano, Milano, Italy*
[f] *Institute of Geological Sciences, University of Bern, Bern, Switzerland*

1. Introduction

The impact of climate change on the water cycle is likely to affect the whole electric system as far as hydropower plays a critical role in the supply in electricity. At the same time, however, the assessment of consequences of global warming on this source of energy has proven fairly difficult as it is at the crossroads between hydrology, engineering, economy and politics (see Gaudard and Romerio (2013) for an overview).

* Corresponding author.
E-mail addresses: ludovic.gaudard@unige.ch (L. Gaudard), franco.romerio@unige.ch (F. Romerio), francesco.dallavalle@enel.com (F. Dalla Valle), gorret.roberta@cvaspa.it (R. Gorret), stefano.maran@rse-web.it (S. Maran), giovanni.ravazzani@polimi.it (G. Ravazzani), markus.stoffel@dendrolab.ch (M. Stoffel), michela.volonterio@rse-web.it (M. Volonterio).

This article synthesizes the key findings of the EU-FP7 project ACQWA project (www.acqwa.ch; also see Beniston et al., 2011) in the field of hydropower. It reviews the state-of-the-art of the methodologies used in this field, as well as the results obtained for the Swiss and Italian Alps by integrating an unusually large set of data from 36 hydropower plants.

Hydropower represents about 10% of electricity generation in the European Union and roughly 13.5% in Italy (GSE, 2010–2011). In Switzerland, the share of hydropower is on average 56% (SFOE, Swiss Federal Office of Energy, 2007–2011).

Hydropower plants with reservoirs play a key role in the storage of electricity at a relatively low price (IEA, 2012a). Due to their flexibility, they contribute significantly to the stability of the international network; to the follow-up of the daily and seasonal load fluctuations; and to the integration of the intermittent energy sources, notably solar and wind energy (IEA, 2012b).

Hydropower represents an important source of revenue for public bodies, in particular in the mountain regions (Alpine Convention, 2009). For example in Switzerland, water royalties, that power companies have to pay to cantons and municipalities, amount to 440 million Euros per year (SFOE, Swiss Federal Office of Energy, 2007–2011). They are regulated by the federal law, which defines a cap of 100 Swiss Francs per kilowatt until 2014 and 110 Swiss Francs until 2019 (Federal Hydropower Act, 1916a).

2. Natural, technical and institutional characteristics of the case study regions and installations

Three neighboring catchments in the Alps were selected in Switzerland and Italy, i.e. Valais, Val d'Aosta and Toce, represented in Fig. 1. The regions under investigation are particularly vulnerable from a socio-economical point of view to climate change (Beniston, 2012). They will likely be affected by important changes in the water cycle and ice melting. On the one hand, overall discharge may vary and impact the hydropower potential (van Vliet et al., 2013). Induced water scarcity may be a source of competition and potential conflicts (Beniston, 2012). On the other hand, seasonality may be perturbed. According to Wirth et al. (2013), the frequency of heavy rainfall will decrease in the Alps during summer and increase during winter. The intensity will increase throughout the year. Flood events may be stronger than in the past and may affect hydropower plant management.

The characteristics of the three natural catchments are provided in Table 1. All case-study regions are typical glacial basins with steep hill slopes, mostly covered by forests, and a glacier coverage in the range of 1 to 14% of the watershed. The differences in glacier coverage between the catchments are significant, and are likely to impact the quantity of inflows and its seasonality in the future.

Climate characteristics of investigated catchments range from temperate oceanic climate (Cfb) to alpine climate (ET), according to Köppen-Geiger climate classification (Peel et al., 2007). Fig. 2 shows monthly precipitation (mm) and air temperature (°C) computed as the mean of the months in the period 2001–2010 after observations available for the ACQWA project were spatially interpolated and basin averaged was computed. Mean annual temperature is 2.5 °C, 3.6 °C, and 1.2 °C for, respectively, Val d'Aosta, Toce, and Upper Rhone catchments. Precipitation is quite uniformly distributed along all months of the years in Upper Rhone catchment, and exhibits a maximum in spring

and autumn in Val d'Aosta and Toce. Mean annual precipitation is temperature is 960 mm, 1470 mm, and 1360 mm for, respectively, Val d'Aosta, Toce, and Upper Rhone catchments.

Climate projections to 2050, as resulting from analysis undertaken during the ACQWA project, show an increase of temperature more significant during summer and at higher elevations. This causes a significant decrease of ice melt implicating the reduction of runoff for high elevation catchments fed by glacier sources. Changes in precipitation on Upper Rhone catchment are rather uncertain since they are variable across decades and typically the signal is below the noise induced by stochastic climate variability. The mean annual precipitation on Val d'Aosta is expected to remain unchanged or slightly increasing, according to the climatic model, while a significant increase ranging from 13% to 25% is expected on Toce catchment mostly concentrated during Winter. A reduction of monthly precipitation is expected during summer on Val d'Aosta and Toce catchment implicating the reduction of runoff. A shift in temperature and precipitation patterns and amount reflects an increase of snow accumulation during winter but a rapid melt during spring on Val d'Aosta and Toce.

Details regarding the hydropower installations are provided in Table 2. One-third of the Swiss hydropower generation is located in Valais, whereas the Val d'Aosta and Toce watersheds represent about 10%

Table 1
Key features of the three catchments.

	Upper Rhone[1]	Mattmark[2]	Val d'Aosta[3]	Toce[4]	Alpine
Watershed (km²)	5338	778	3260	691	190,568
Glacier coverage (%)	14.3[a]	29[b]	4.1[c]	1[d]	NA
Min altitude (m a.s.l.)	377	1738	312	300	0
Max altitude (m a.s.l.)	4634	4545	4810	4043	4810

Sources:
[a] Meile et al. (2011).
[b] Finger et al. (2012).
[c] Fondazione Montagna Sicura (2005).
[d] Based on results obtained in the framework of ACQWA project (2012).
[1] At Porte du Scex.
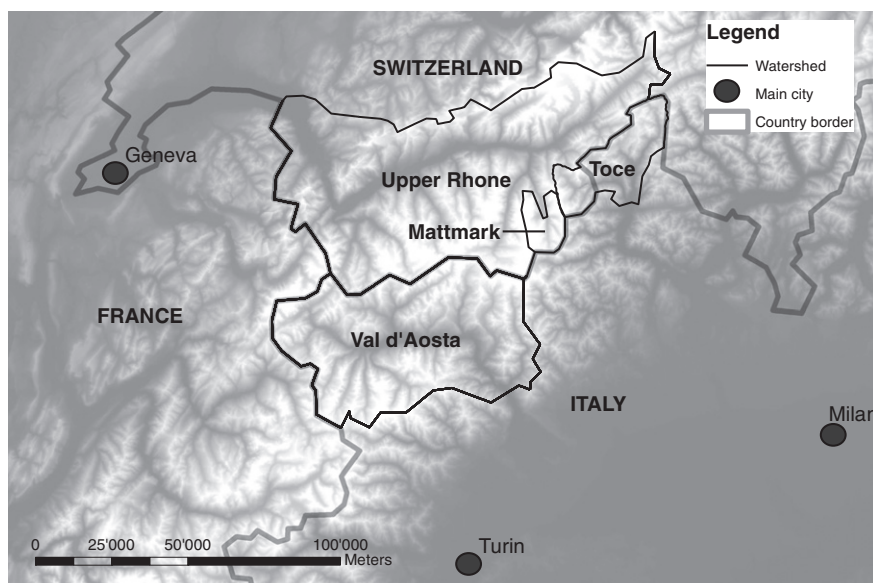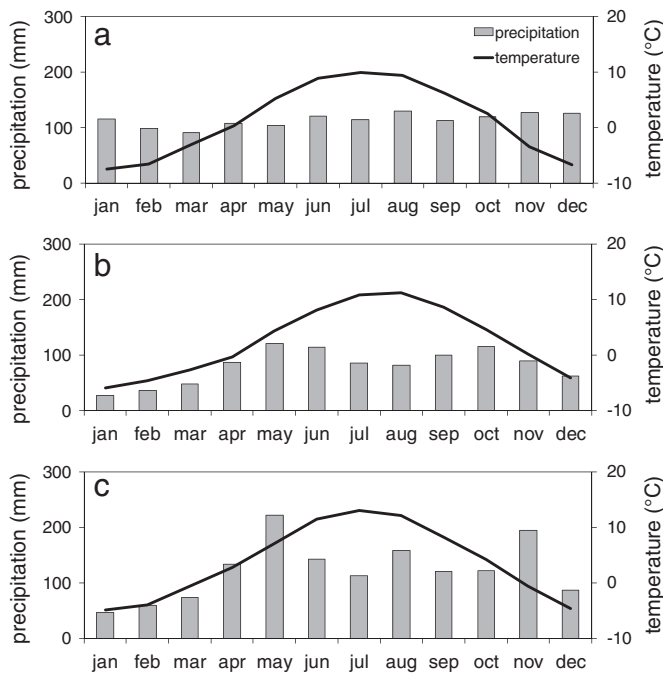[2] Saas Fee catchment at Zermeiggern.
[3] At Tavagnasco.
[4] At Crevola d'Ossola.

Fig. 1. Map of the catchments considered in this study.

Fig. 2. Monthly mean precipitation (mm) and temperature (°C) in the Upper Rhone catchment (a), Val d'Aosta (b), and Toce catchment (c).
(Sources: based on data provided by ARPA Piemonte (2013), ARPA Valle d'Aosta (2013), and MeteoSuisse (2013); years of reference 2001–2010).

of the Italian hydropower production. The basins highlighted in the study can be therefore considered as representative of Switzerland and Italy, and to some extent even of the Alps. The hydroelectric portfolio selected in this study also includes the main types of installations, namely run-of-river, storage and pumping-storage plants. The different installations will not only provide specific, but different, services, but are also likely to be affected in a different way by climate and market changes.

The overall assessment in the three case-study regions is complemented by small-scale case studies. In Valais, analysis focused on the Mattmark Dam (Saas Valley), where reservoirs are filled by natural flows and through pumping (so-called open-loop pumping-storage installation). In this case research is focused on the resilience of a pumping system to climate change. In Val d'Aosta, we performed a modeling approach of a complex network which consists of 17 inter-connected hydropower plants, with an in-depth assessment for the two largest

Table 2
Key features of hydropower installations by catchment.

	Upper Rhone	Mattmark	Val d'Aosta	Toce	Alpine
Number of hydropower plants	95[a]	3[b]	30[d]	18[e]	554[f]
Run-of-river plants	69[a]	1[b]	25[d]	6[e]	NA
Storage plants	26[a]	2[b]	5[d]	12[e]	NA
Total power output (MW)	4657[a]	260[b]	825[d]	470[e]	45,883[f]
Mean Energy annual (GWh)	9596[a]	649[c]	2500[d]	1400[e]	>46,000[g]
Storage capacity (10^6 m³)	1195[a]	100[b]	206[d]	139[e]	ca. 8900[h]

Sources:
[a] OFEN (2012).
[b] KWM (2001).
[c] KWM (2013).
[d] Plants owned by CVA (ca. 95% of capacity of Val d'Aosta), personal correspondence.
[e] ENEL, personal correspondence.
[f] Power output >10 MW; (Alpine Convention, 2009).
[g] CIPRA (2002).
[h] All purposes; Rhine, Rhone and Danube basins; (Alpine Convention, 2009).

installations, namely Valpelline – being the biggest storage power plant of the catchment – and the run-of-river power plant Hone II. The latter is considered to be very vulnerable to climate changes as hydropower generation completely depends on the temporal distribution of water supply. In the Toce case study, an assessment was performed for all plants to analyze changes in future production and the management of a series of interdependent storage and run-of-river hydropower plants.

To build and operate a hydropower plant, one needs a water concession which defines the concessionary's rights and obligations. Concessions have a maximum duration of 20 years in Italy and 80 years in Switzerland. In the Italian case, the State can acquire the hydropower plant once the concession expired (Regional Decree, 1933; Legislative Decree, 1998). In the Swiss case, upon expiration, the conceding community (cantons or communes) has the right to reclaim the 'wet parts' of the installation (reservoir, pressure pipes, hydraulic engines and buildings which shelter them) at no cost, as well as to take back the energy generation and transportation equipment in return for an 'equitable payment'. In principle, new concessions can be granted to the incumbent company, to another company, or to a company totally or partially controlled by the canton and/or the communes (Federal Hydropower Act, 1916b).

3. Market liberalization and hydropower

The opening of the European Union electricity market to competition in the 1990s has resulted in the creation of wholesale markets (e.g., spot markets), the end of monopoly in the retail markets, as well as the unbundling between generation, transmission, distribution and supply of electricity (EC, 1996). The new system also guarantees access to networks, although this sector remains a natural monopoly. This opening has also had significant impacts on the Swiss hydropower landscape, despite that fact that the Swiss market has not yet been opened completely to competition (Federal Assembly, 2007).

The opening of markets to competition is a big challenge due to technico-economical characteristics of electricity, in particular the fact that:

1. one must ensure the constant equilibrium between demand and supply,
2. direct electricity storage is not possible, and
3. the electricity price-elasticity tends to be very low (Kanamura and Ohashi, 2007; Stoft, 2002).

In addition, investments are jeopardized by the so-called 'missing money problem' (Joskow, 2006), meaning that capital costs are covered only if spot prices are high enough. If this is not the case, the rent, which is given by the difference between the market prices and the marginal costs, is too low to justify new investments in generation of electricity. This problem, which is topical at present, is particularly pernicious if the new power plants have a low load factor, as in the case of facilities that should provide reserve capacity.

The new intermittent renewable energies are exacerbating this problem. Fig. 3 shows that their penetration shifts the supply curve to the right which in turn provokes the decrease of price and of rent. One should consider that the supply curve is given by the marginal cost (almost equal to the fuel cost) of the different power plants, which are activated incrementally (the so-called 'merit order principle'). As the renewable energies have very low marginal costs, they are the first to be dispatched.

The fall of prices can not only, however, be attributed to renewable energies alone, but is also reflective of the decrease in electricity consumption resulting from the economic crisis and CO_2 price fall. As wind and solar energy typically have zero marginal costs, the market no longer guarantees investments in new conventional capacity. By contrast, the development of new renewable energy is generally rendered possible by subsidies (in particular, feed-in tariffs). Additionally, the strong reduction of the gap between peak and off-peak prices affects
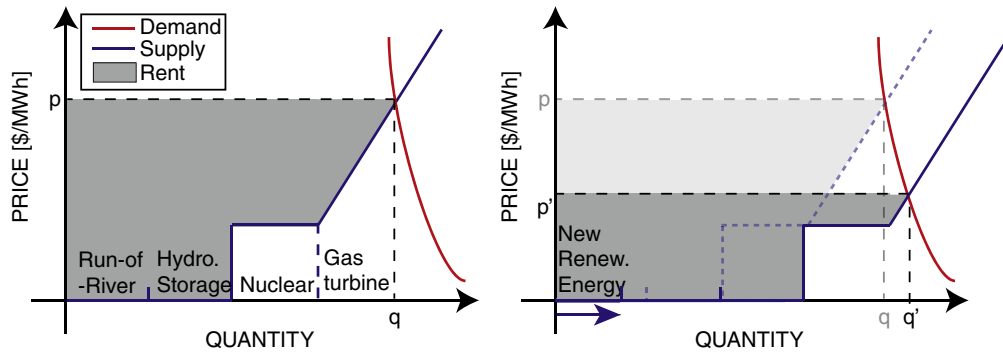
Fig. 3. Impact of new renewable energy introduction on spot price and consequently on rent.

the profitability of the pumping-storage plants and it resulted in a sharp pumping decline in Italy between 2008 (which exceeded 5.6 TWh) and 2011 (1.9 TWh). As shown in Fig. 4, the decrease of the peak-price is partially due to the introduction of photovoltaic (PV), which generates energy during daytime, when demand is high. This also explains the reason why the peak price is more affected than the off-peak price.

On the other hand, hydropower plants of the alpine region are well integrated in the international network and are relatively close to the big urban load centers. Development of renewable energy is often in peripheral regions, where bottlenecks still exist and where a new sizable investment in networks is required.

At the national level, Switzerland is preparing the phase out of nuclear energy, which represents about 40% of its electricity generation (SFOE, Swiss Federal Office of Energy, 2007–2011). Besides energy efficiency, such a goal requires a strong development of renewable energy to meet the CO_2 emissions target. However, the contribution of hydropower will be relatively small due to the fact that its economical potential is almost completely exploited, and new regulation requires an increase in residual waters downstream of installations. The most important contribution of hydropower in this new context lies in its flexibility. Italy, on the other hand, decided to abandon nuclear energy in the 1980s and its electric mix includes hydropower and fossil fuels (in particular combined cycle gas turbines). Renewable energy experienced a strong growth because of subsidies. Electricity prices are high in Italy as compared to the rest of Europe, but currently are decreasing due to overcapacity.

Consumption represents another significant difference between the two countries under investigation. In Switzerland, the consumption pattern follows a sinusoidal shape, with relatively low demand during summer and high demand in winter. In Italy, high consumption mainly occurs in winter, with a second smaller peak in summer, except for the first half of August when most industries are closed for the holidays.

4. Method

Our researches merge various models and scenarios. Fig. 5 provides an overview by showing how data and models interact. The models are described in the following sections.

4.1. Hydrological models

Future hydrological data was obtained with different models. For the Upper Rhone and the Val d'Aosta case studies, data was generated with the TOPKAPI model (Ciarapica and Todini, 2002) and taken from Fatichi et al. (2013). TOPKAPI is a rainfall–runoff model that handles the topography and a representation of below ground in three layers. For the Toce case study, data was obtained with the FEST-WB distributed water balance model (Boscarello et al., in press; Ceppi et al., 2013; Pianosi and Ravazzani, 2010) developed on top of MOSAICO (Ravazzani, 2013), which is a library specifically developed for a raster based hydrological model. Discharge time series were simulated for 36 river sections with basin areas ranging from 1 to 372 km². Both models produce output for the main processes of the hydrological cycle, namely evapotranspiration, infiltration, surface runoff, flow routing, sub-surface flow, snow melt, and accumulation, with data being provided at hourly time intervals.

The meteorological forcing of future scenarios was performed with two regional climate models (RCMs), the REMO (Jacob, 2001) and the RegCM3 (Pal et al., 2007) models. In the Val d'Aosta case, only results from the REMO model were considered for the analysis of the hydropower plants management. In TOPKAPI, the transposition uses a merging of dynamic and stochastic downscaling (Bordoy and Burlando, 2013). In Toce case study, the hydrological model FEST-WB was fed by point scale meteorological forcing computed from RCM simulations with a quantile based error correction approach (Themessl et al., 2011,
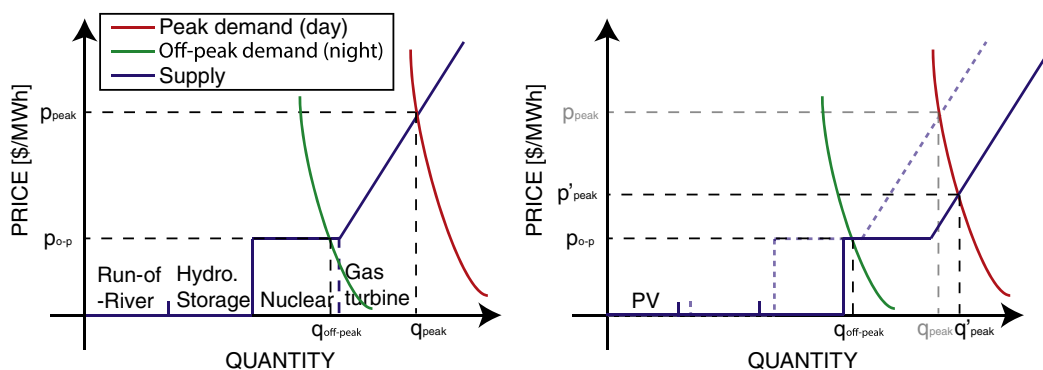

Fig. 4. Impact of PV introduction on gap between peak and off-peak prices. Because production of PV occurs during day when demand is high, the peak price falls.
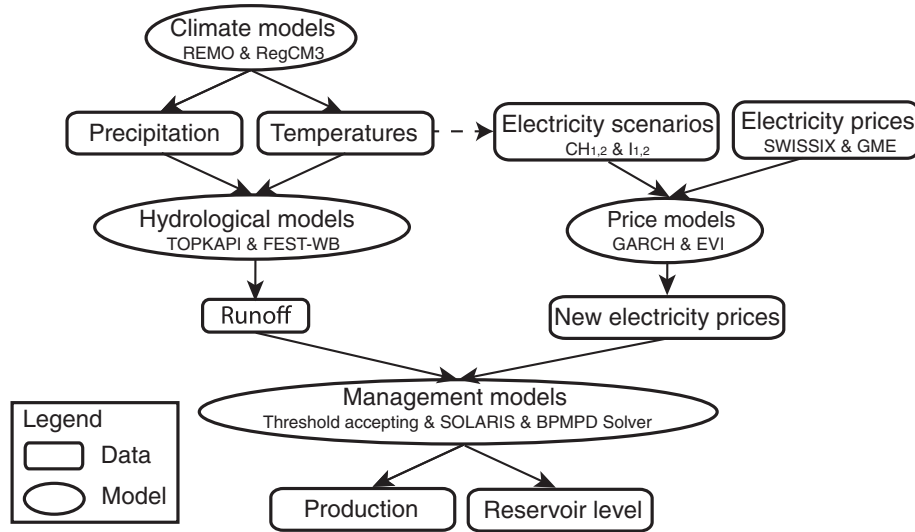
Fig. 5. Presentation of the model.

2012). The resulting daily scenarios were further refined to 3-hourly time series, using sub-daily data from the RCMs.

4.2. Electricity demand scenarios

Water inflows supply energy into the reservoir, but the production schedule is mainly determined by fluctuations in the electricity market, plus some technical constraints. As a consequence, price scenarios need to be defined for the future. As wholesale electricity prices are strongly linked to consumption, one should first investigate the impacts of climate change on demand of electricity, before the importance of the variation and its effect on electricity prices can be assessed. In this study, we therefore have considered the following steps:

(i) creation of retrospective series of Heating Degree Days (HDD) and Cooling Degree Days (CDD) based on meteorological data (see Eqs. (1) and (2));
(ii) construction of an econometric model for electricity consumption where Consumption = f(GDP, HDD, CDD, Dummies);
(iii) assessment the future evolution of HDD and CDD;
(iv) check of the implications for electricity consumption; and
(v) deduction of prices scenarios.

First of all, we analyzed the influence of meteorological variables on electricity consumption, which is partially shaped by demand for heating and cooling. HDD and CDD, which are variables that sum the temperatures that are below (the former) or above (the latter) a threshold temperature, are commonly used in the field of energy (Pardo et al., 2002). Mathematically, they are defined as follows:

$$HDD_t = \sum_{i_{\text{Stat}}=1}^{n_{\text{Stat}}} \omega_{i_{\text{Stat}}} max\left(\tau_H - \theta_{i_{\text{Stat}},t}, 0\right) \tag{1}$$

$$CDD_t = \sum_{i_{\text{Stat}}=1}^{n_{\text{Stat}}} \omega_{i_{\text{Stat}}} max\left(\theta_{i_{\text{Stat}},t} - \tau_C, 0\right) \tag{2}$$

where $\theta_{i_{\text{Stat}},t}$ is the average daily temperature [°C] at a time t and at the i_{Stat} weather station. For Swiss historical temperatures, we used data from 52 automatic weather stations administered by the MeteoSuisse (2013). For Italy, we used the point of the 0.25° regular grid of the ECA&D project (2013) (Haylock et al., 2008). Each station was then weighted by a factor $\omega_{i_{\text{Stat}}}$ related to the population census data (Swiss Statistics, 2013; Istat, 2013) for the area around measurement points.

As a result of temperature rises, the summer consumption should increase while the winter consumption should diminish. To test this hypothesis, we built an econometric model based on HDD and CDD. The link between temperature and electricity consumption is defined econometrically with a log–log model as defined by:

$$log(C_t) = \alpha_0 + \alpha_2 log(GDP_t) + \alpha_2 log(HDD_t + 1) + \alpha_3 log(CDD_t + 1)$$
$$+ \alpha_4 D_t^{Sat} + \alpha_5 D_t^{Sun} + \alpha_6 D_t^{Hol} + \epsilon_t \tag{3}$$

where C_t represents daily electricity consumption, GDP_t the quarterly real gross domestic product and $D_t^{Sat}, D_t^{Sun}, D_t^{Hol}$ are the dummy variables for Saturday, Sunday, and holidays, respectively. These latter quantities are binary variables with a 0 or 1 value. GDP_t data was provided by OECD (2013). Consumption data is not directly available and has been replaced by Swiss vertical load and North Italian demand provided by Swissgrid (2013) and GME (2013), respectively. As the Italian market is liquid, it is assumed that demand reflects the consumption pattern. Depending on data availability, the reference years used in the study are 2009–2011 and 2005–2011 for Switzerland and Italy, respectively.

Based on the future values of HDD and CDD, the consequences of climatic and market changes on consumption have been assessed with a delta method using RCM and historical data (Keller et al., 2005; Uhlmann et al., 2009). By merging meteorological data in Eq. (3), the effect of climate change on future electricity consumption was determined. We acknowledge that the use of this methodology does not consider changes envisioned by new energy policies, for instance concerning the consumer behavior, but that the approach nevertheless takes account of the direct impact of climatic changes on hydropower management.

4.3. Electricity prices models

4.3.1. Swiss prices and scenarios

In the Upper Rhone Valley, we use consumption data to build a GARCH model of spot prices (Engle, 1982) (see Eq. (4)). This is an econometric model well fitted to analyze and simulate time series that have high volatility like electricity spot prices. The model was parameterized using data for the period 2009–2011 provided by the EEX (2013) and Swissgrid (2013).

$$log(P_t) = f(log(C_t), D_i) + \delta_t \tag{4}$$

where P_t is the hourly spot price, C_t is the daily electricity consumption, D_t are various dummy variables that consider inter-day and intra-day

variations. δ_t represents the error term that follows a GARCH(1,1) model (Tsay, 2010).

Based on this equation, some hypotheses about consumption are accepted to test how prices may be affected. In addition to the baseline scenario, we take into consideration two additional scenarios. CH_1 considers the impact of warmer temperatures on the price. In other words, we change the value of HDD and CDD in Eq. (3) in accordance with climate scenarios. In CH_2, the elasticity with respect to HDD and CDD is influenced by behavioral changes induced by climate change. On the one hand, larger use of cooling systems may increase the reactiveness to CDD. On the other hand, HDD elasticity decreases due to higher thermal efficiency. We thus suppose $\alpha_1 = \alpha_2 = 0.009$. At present, in the Southern European countries, one observes almost the same consumption reactivity to HDD and CDD changes.

4.3.2. Italian prices and scenarios

For both Italian case studies, we first build an Energy Value Index (EVI) based on the Prezzo Unico Nazionale (PUN) provided by GME (2013) for the period 2006–2010. The price used is based on the mean of the five year period. Intra-week variability as well as off-peak prices during holidays were taken into consideration as well.

A sensitivity analysis is performed, which consists in a linear variation of the weekly moving average of the summer peak prices to take into consideration changes in the gap between low prices (in spring and autumn) and high prices (in summer). An important diffusion of the cooling systems may provoke an increase of the electricity price in summer, whereas the contrary may happen with a high PV penetration. The price scenarios therefore consider a variation of summer prices by $+10\%$ (I_1) and -10% (I_2).

4.4. Hydropower management

We suppose that the objective of the operator is to maximize the expected revenue under the installation constraints. The model inputs used here are therefore water intakes and electricity prices whereas the outputs are outflows and electricity generation. Physical constraints represent parameters. Mathematically the objective and constraints for a given pumping-storage installation may be formulated as follows

$$OF(z) = \text{Income} - \text{Cost} + R_T \tag{5}$$

$$= g\rho \sum_{t=1}^{t=T} \left(\eta_{\text{turb}} f_{\text{turb},t} - \eta_{\text{pump}}^{-1} f_{\text{pump},t} \right) h_t P_t \Delta_t \right) + R_T \tag{6}$$

where g is the acceleration due to gravity; ρ the water density; η_{turb} and η_{pump} efficiency of the turbine and pump, respectively; $f_{\text{turb},t}$ and $f_{\text{pump},t}$ are the water flow through the turbine and pump, respectively, at a time t; h_t is the hydraulic head; P_t the electricity spot price; Δ_t the unit of time and the time horizon for the optimizations T; R_T is the value of the volume of water that remains at the end of the period of optimization. The optimization problem consists in:

$$\max_z OF(z)$$
$$V_t = V_{t-1} + I_t \Delta_t - f_{\text{turb},t} \Delta_t + f_{\text{pump},t} \Delta_t$$
$$h_t = \Phi(V_t)$$
$$V_{\min} < V_t < V_{\max}$$

where V_t is the reservoir content at time t; and I_t is the water intake. The head of water is a function of V_t that depends on the installation characteristics. In the Italian case studies, it was assumed that head of water is constant. $V_{\min}$, $V_{\max}$ are the capacity limits of the reservoir.

Only the energy used for pumping is taken into consideration in the cost computation. As capital and operating costs are independent of management, they do not affect the production schedule. Only the starting cost may have an impact from this point of view, but one can skip this difficulty without affecting the final results.

All studies presented in this paper consider a deterministic optimization for the management of turbines and pumps downstream of each reservoir. For the Swiss case study, a binary local search algorithm, a so-called Threshold Accepting, has been used for this purpose (Gaudard et al., 2013; Dueck and Scheuer, 1990; Moscato and Fontanari, 1990). As a result of the small size of the compensating basin situated downstream of the Mattmark reservoir, the simulation had to be performed at time steps of 10 min. In the Val d'Aosta case study, SOLARIS (Maran et al., 2006) was used to analyze hydropower management. Here, the water system is represented by nodes, arcs, delay time and constraints and the model also takes account of the mass balance. In the case of the Toce, analysis was done with the BPMPD solver, Version 2.11 (Meszros, 1996). This software is able to solve 118,260 equations with a total of 280,320 variables through a linear programming approach. A time step of 2 h over a year was used in the Italian case studies to optimize dam management.

The simulation of power plant management was carried out as illustrated in Fig. 6 and according to the availability and nature of data, resulting in different approaches between Switzerland and Italy. In the Swiss case, the volume of the reservoir varies at the beginning and at the end of the year, as the annual optimization is adjusted every 6 months. On the contrary, in the Italian case, the initial and final volumes remain constant because annual optimizations are run simultaneously. Both methods are used to manage the value of remaining water R_T.

5. Results and discussion

5.1. Hydrology

Fig. 7 provides an overview of climate change impacts on runoff in the form of total inflows into the main reservoirs of the three catchments (Upper Rhone, Val d'Aosta, and Toce). As storage hydropower installations are always located upstream of run-of-river installations, Fig. 7 only takes account of unaffected water flows. However, such an approach will tend to give too much weight to changes in high-mountain climate (see Fatichi et al. (2013) for further details).

At present, runoff seasonality mainly depends on the region taken into consideration. As a result of ice and snow melting, maximum flows occur during spring and summer in all cases. In the Italian case, a second period of high variability in water flows occurs during fall when large amounts of precipitation can be recorded. The smoother pattern in the Swiss case-study region is essentially reflective of the larger size of the Upper Rhone watershed.

The most obvious difference in terms of pattern is visible between the Toce and the two other catchments as far as impacts of climate change are concerned. Whereas the latter exhibit a decrease in inflows, in particular during late summer and as a result of decreasing ice reservoirs, the Toce records increased flows as runoff will mainly stem from precipitation and not from solid phase water in this case. This difference is not only certainly due to the very low glacier coverage (1%) and comparably high precipitation totals ($1400 \, \text{mm} \, \text{y}^{-1}$) at Toce, but may also be influenced by the different downscaling techniques used during the definition of climate forcings.

The comparison between the periods 1991–2010 to 2031–2050 shows that Mattmark will lose about 21% and Val d'Aosta about 17% of their annual inflows. While the inter-annual variability remains almost stable in Mattmark, it will increase by a factor of 2.10 in Val d'Aosta. This may be quite challenging for hydropower operators because they should deal with less water but more uncertainties.

In the case of the Upper Rhone, the hydrological results were discussed by Fatichi et al. (2013). On the contrary, it seems difficult to compare the Italian outcomes with other publications. At our best knowledge, the articles that tackle the issue of climate change in those specific regions focus on historical data (Diolaiuti et al., 2012; Calmanti et al., 2007). Due to local specificities, it is difficult to make comparisons with the Alps in general.
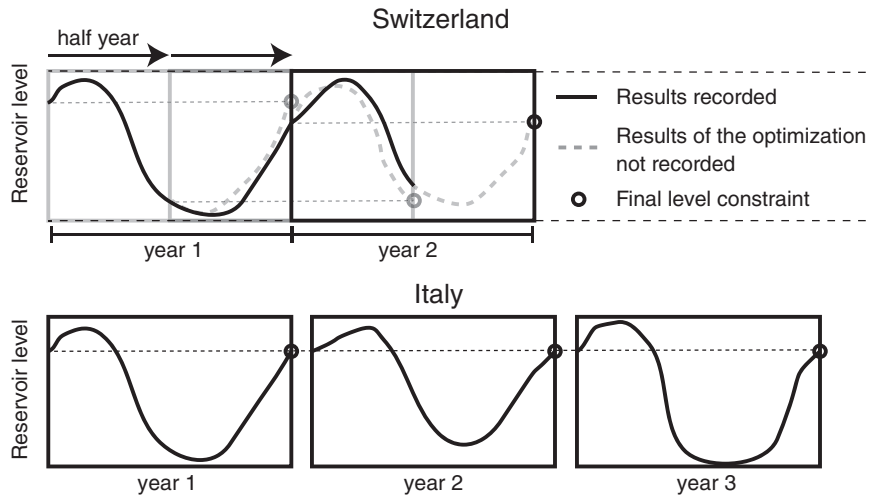
Fig. 6. Methods used to simulate the management of reservoirs in the Swiss and Italian case-study regions.

5.2. Electricity demand and price scenarios

As far as the analysis of electricity demand and price scenarios are concerned, we realize that the significance of the explanatory variables is quite different between Italy and Switzerland, as shown in Table 3. For instance, the GDP represents a relevant explanatory variable in Italy, but not in the Swiss case. The divergence between the countries can be explained primarily by the specificity of the economic situation, as well as by the number of years taken into consideration.

The most important differences between Switzerland and Italy are the estimators α_2 and α_3. The consumption response to a variation in HDD is much higher in Switzerland than in Italy, primarily as a result of the consumer's specific behavior and to a lesser extent to microclimate.

The impact of warmer temperatures on consumption can be detected through the evolution of HDD and CDD for the periods 1981–2010 (reference), 2011–2040, 2041–2070, and 2071–2100. The annual HDD decreases by 10% in each period to reach 70% of the reference value by the end of the 21st century. The HDD follows the same trend in both countries, but the CDD evolves somewhat differently between the regions. In Switzerland, the annual increase is 1.5, 2, and 3%, respectively, whereas it only reaches 1.2, 1.5, and 2%, respectively, in Italy. This

difference may be the result of the fairly low starting point of CDD in the Swiss case. We may nevertheless infer that electricity use for cooling will represent an important challenge for future energy policy, and that the 2003 heatwave alone had provoked an increase in summer consumption in this and subsequent years.

The impact of climate change on consumption is likely to be negligible. In Italy, we may expect an increase of consumption due to warmer climate by about 1% by the end of the 21st century. In Switzerland, according to scenario CH_1, the winter consumption (October 1 to March 31) will likely decrease by 1% every 30 years, whereas summer consumption (April 1 to September 30) will presumably remain stable. According to Scenario CH_2, winter consumption could decrease by 1%, whereas the summer consumption will increase by 2% by 2100. Fig. 8 also illustrates that the Swiss scenarios are somewhat more conservative than the Italian ones.

5.3. Hydropower management

Analysis of climate change impacts on hydropower were based on the distribution of annual electricity production as illustrated in Fig. 9. In the case of Mattmark (Upper Rhone catchment) and Val d'Aosta,
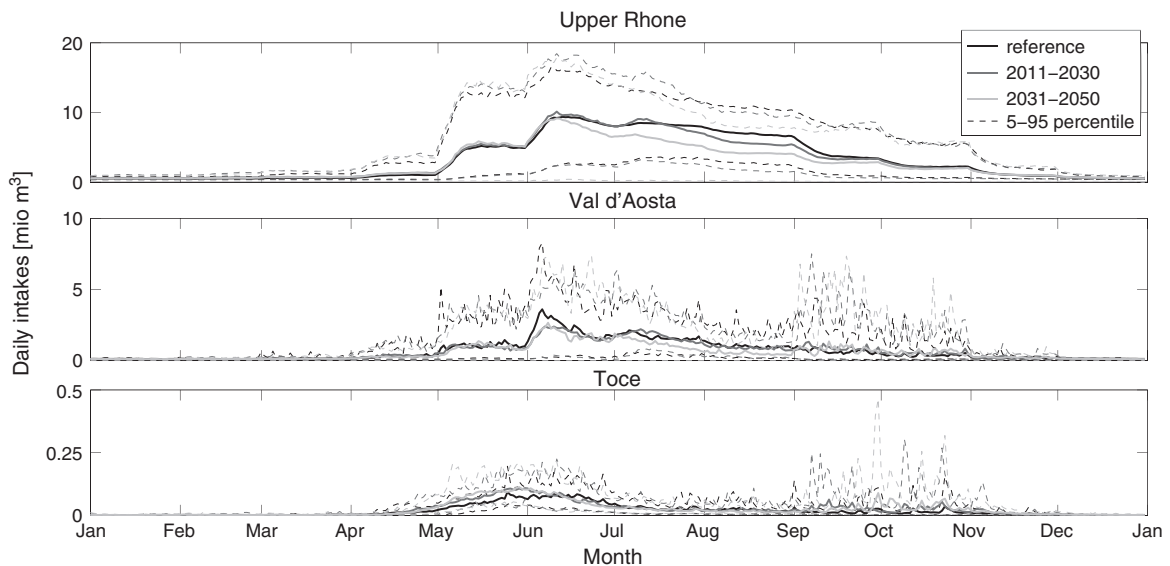

Fig. 7. Water inflows into the main reservoirs, present and future situation.

Table 3
Values and standard error of the parameters in the consumption Eq. (3).

	α_0	α_1	α_2	α_3	α_4	α_5	α_6	α_7
Switzerland	5.03	0	0.10	0.04	−0.14	−0.20	−0.22	NA
	(3e-3)		(2e-3)	(4e-3)	(4e-3)	(4e-3)	(1.1e-2)	(NA)
Italy	0	0.92	0.03	0.03	−0.21	−0.35	−0.30	0.50
		(1e-3)	(2e-3)	(2e-3)	(3e-3)	(3e-2)	(4e-3)	(1.7e-2)

production is projected to decrease by 18% and 10%, respectively, whereas an increase of about 15% seems likely for Toce. In the Swiss case, our results are similar to the ones obtained by Finger et al. (2012). They already used the TOPKAPI hydrological model, but considered seven regional climate models. According to model results, peak production does not seem to be affected by climate change, possibly as a result of the relatively large volume of existing reservoirs. In the future, however, reservoir management will become more challenging as a consequence of the uncertainties related to inter-annual water intakes. Indeed, change on inflows impacts the production. While Mattmark compensate all the variability with the head of water effect, annual production at Val d'Aosta and Toce will fluctuate wider. The inter-annual variability will grow by 21 and 24% respectively. Hopefully, reservoirs will mitigate part of these fluctuations. Further investigations on inter-annual variability should be carried out.

The impact of climate changes on the management and production of hydropower plants is illustrated with three case studies from the Upper Rhone and Val d'Aosta catchments, as well as for the entire Toce catchment.

In the case of Mattmark (Upper Rhone), impacts of climate changes will likely affect the production throughout the year and for several reasons. First of all, and somewhat unrelated to climate, the production will likely increase in winter as a result of projected price dynamics. Second, and more importantly, future water intakes are likely to be insufficient to fill the reservoir, which is already too large under current conditions. As a consequence, the constraints inherent to the reservoir appear to be weak. In terms of pumping, the capacity of the downstream reservoir appears too small under current conditions and will not likely allow an increase of the rate of use. Two peaks are apparent for the use of the pumps: A first during summer, when water is abundant and prices

are low; and a second peak during winter, to take advantage of intra-day and intra-week price variability.

Production at Hone II (Val d'Aosta), where inflow is not affected by upstream reservoirs, is projected to decrease in spring and summer and increase during autumn, as illustrated in Fig. 10, which might indeed cause important losses of revenue as compared to the present situation. At Valpelline (Val d'Aosta), a power plant fed by the greatest reservoir in the valley, climatic changes will most likely impact summer production, in particular during dry years when inflows will no longer be sufficient to fill the reservoir. Whereas this change points to a likely loss of revenue overall, it is also likely that an increasing volume of water will be delivered and stored in spring for use in future summers.

In the case of the Toce catchment, simulations suggest an increase in electricity production in autumn, winter, and spring, whereas a decrease may likely appear in summer, in particular during the months of June and July. Based on model results, reservoir management should anticipate the maximum volume of stored water from August (reference period 2001–2010) to July (2011–2050) in the future in order to reduce possible losses. In addition, a reduction of the maximum average stored water is likely to occur, and should be compensated by a more rapid reservoir emptying in August and September so as to be ready to absorb higher inflows in autumn.

Differences in results are not only certainly reflective of the different geographic conditions between the sites, but also a result of different management, especially between Mattmark and Valpelline. First of all, and by realizing a parallel computation as explained in Fig. 4, we realize that the management is forced to maintain the same mean level as in the past at Valpelline. On the contrary, in the case of Mattmark, by contrast, we consider the impact of higher heads of water on power. We also notice some differences with previous results obtained by two studies on the same power plant carried out on Mattmark (Fatichi et al., 2013; Finger et al., 2012). This is due to the fact they supposed that the reservoir's management doesn't react to climate change. In fact, they considered a reservoir's target level based on historical data. No optimization was carried out and the simulations of the water stored in the reservoir were constraint by this target level.

We should point out that we are not able to determine to what extend these differences are due to the model's features instead of to the case studies' specificities. In fact, to a certain degree, our models are case study dependent. In other words, it is not possible to run them
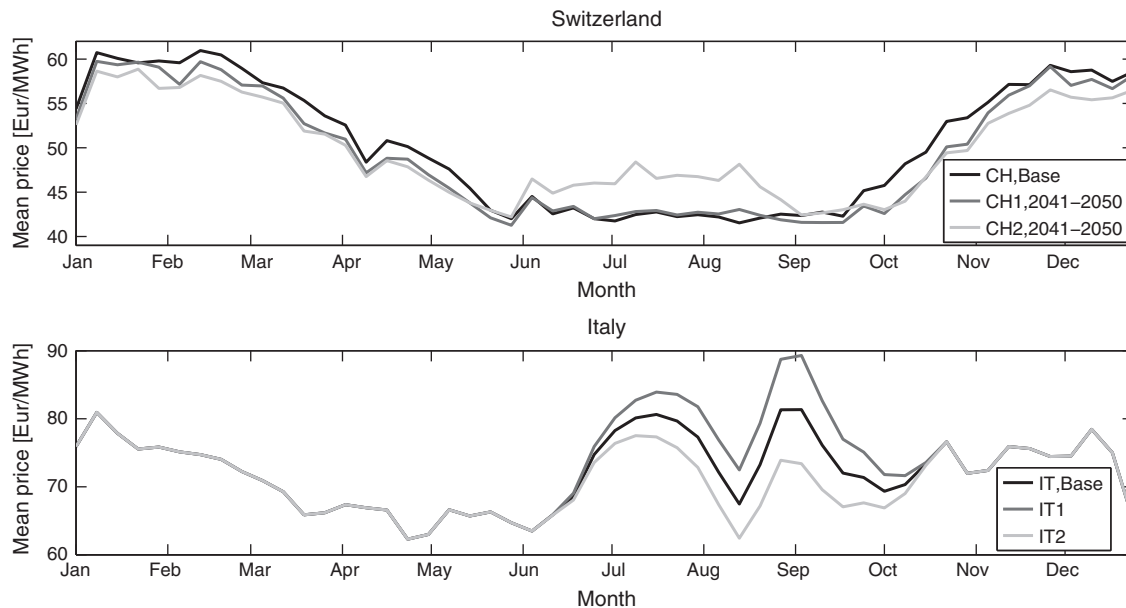
Fig. 8. Mean electricity prices for each scenario considered for Switzerland (up) and Italy (down).
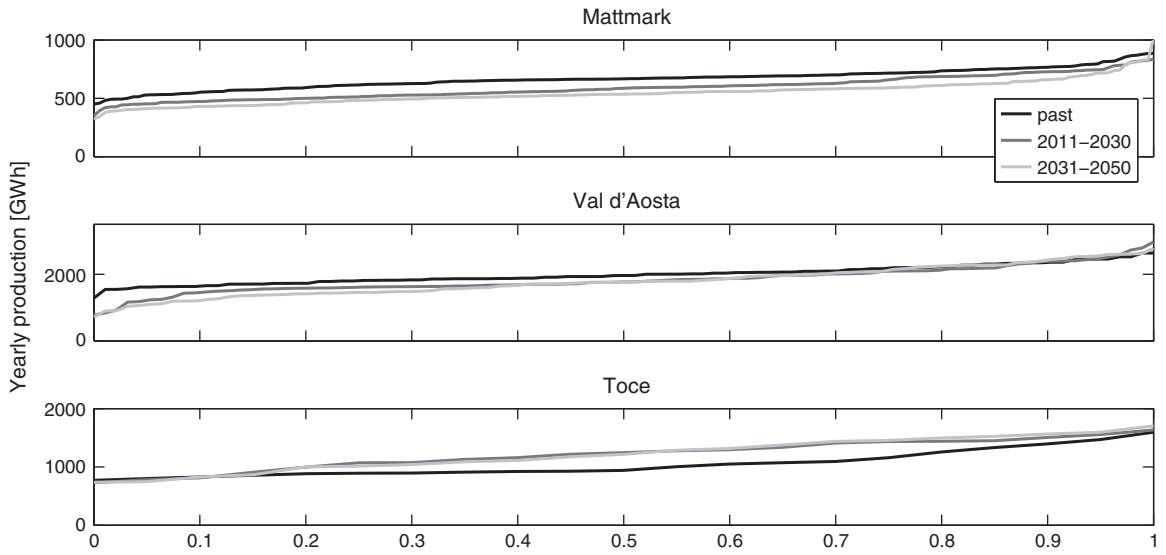
Fig. 9. Empirical distribution of annual production by catchment. Past periods are 1991–2010 for Switzerland and 2001–2010 for Italy.

for each case study to test if some differences disappear. We recognize that this is a disadvantage. The advantage lies in the fact that the models fit well the case studies specificities.

Finally, we should examine the implications of different energy scenarios as given in Fig. 11 on hydropower. In the case of Mattmark, the impact of increasing temperatures is too low under scenario CH_1 to affect reservoir management. If we pass on to scenario CH_2, the situation might however change and the electricity generated in summer might become valuable enough to affect spring production, thereby resulting in reduced reservoir emptying during this season.

The Italian case studies present similar reactiveness to the electricity scenarios. We observe a modulation in the monthly production, in

particular during September and October, and increase of production in scenario I_1, but not under scenario I_2.

All scenarios are thus relatively conservative. One may even conclude that for power production electricity market prices' changes are no less important than climate change.

6. Conclusion

Assessing the impact of climatic changes on hydropower is rather complex, and even more so if analysis includes interactions between the technical, physical and economical components of the systems. As a consequence, various methods and approaches have been developed
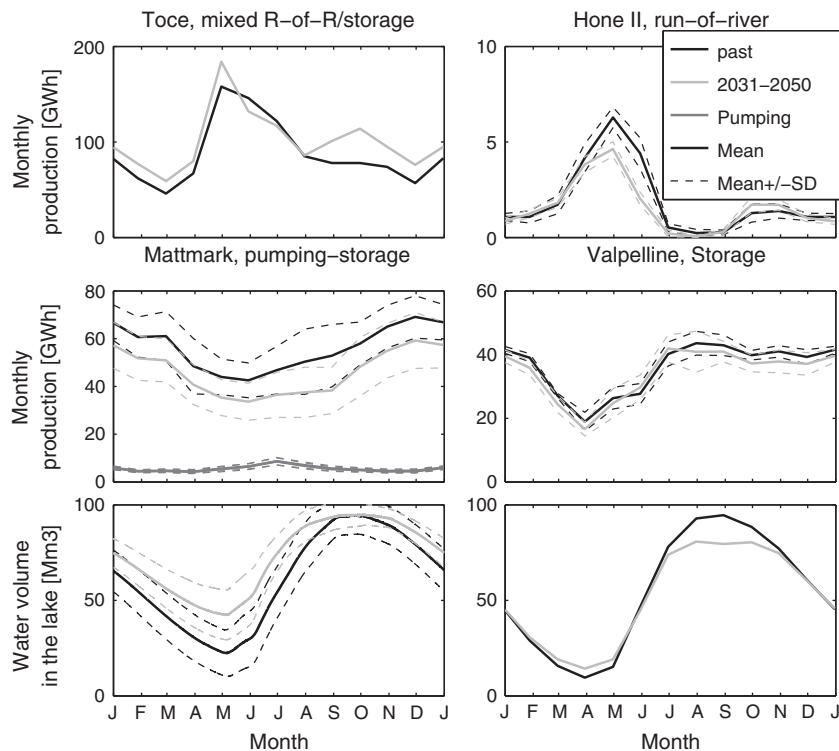

Fig. 10. Annual present and future production as well as the water volume stored. The standard deviation is represented when available (dotted line).
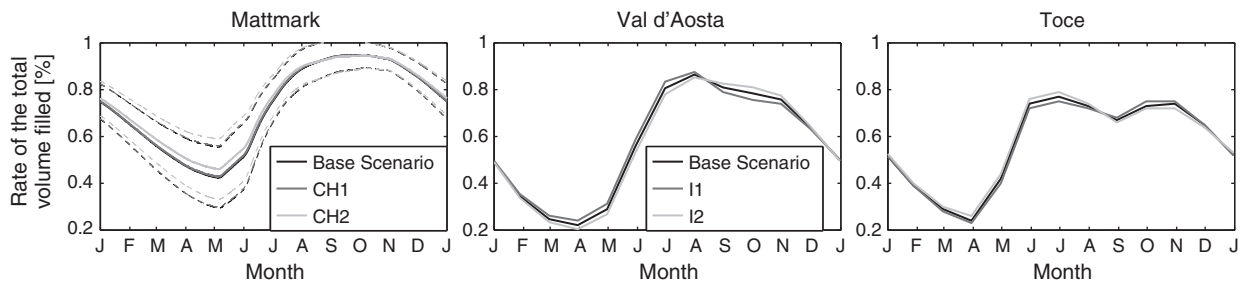
Fig. 11. Water volume management depending on the scenario.

not only to tackle this issue in general, but also in the framework of this paper.

The results of this paper illustrate a large variety of possible future evolutions in geographically quite closely located, yet quite differing sites in terms of snow and rainfall and management practices. Annual runoff is projected to increase in the Toce catchment, whereas models predict a decrease in the case of Val d'Aosta and Upper Rhone. This fact alone, and irrespective of differing management and evolutions on the electricity market, calls for greatest caution and localized assessments of climate impact studies.

Along the same line of thinking, one should keep in mind that hydropower plant management will encompass economic and hydrological components, which are not only both relevant for any future assessment, but also clearly inter-connected. Future runoff will affect electricity production, whereas market prices will be of key importance for the management of the reservoir and for revenue generation. This statement has been confirmed quite clearly in this paper through the inter-comparison of results gathered in the three regions where various scenarios and differing management strategies have been developed, and by taking into consideration conservative prices. In a context of high price volatility, more and more inter-disciplinary research will be critically needed in this field of research.

Future researches should assess the indirect impacts of climate change on hydropower. Indeed, water scarcity may bring about conflicts between different usages (tourism, artificial snow production, irrigation, floods management, etc.). Water reservoirs should be managed in a multipurpose way, taking into account other social benefits other than power generation.

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