Climate change impacts on hydropower and the electricity market:

A case study for Switzerland

Master's Thesis

Faculty of Science

University of Bern

presented by

Advait Godbole

2014

Supervisor:

Prof. Dr. Gunter Stephan

Department of Economics and Oeschger Centre for Climate Change Research

Co-Supervisor:

Prof. Dr. Ralph Winkler

Department of Economics and Oeschger Centre for Climate Change Research

Abstract

With Alpine hydrology projected to undergo changes due to climate change, it is expected that there will be a direct impact on hydropower, which forms a key component of the electricity supply of several Western European countries. This will then have an effect on the electricity market in these countries, leading to a shift in their economic dynamics. The issue is examined in this thesis by using a least-cost optimization model of the electricity system and high resolution hydrology simulations of future water inflows to hydro reservoirs in Switzerland.

Contents

List of Figures

List of Tables

Acronyms

AT Austria

BFE Bundesamt Für Energie

CH Switzerland

CO_2 Carbon Dioxide

$^\circ$ C Degree Celsius

DE Germany

ED Economic Dispatch

EPSI European Power System Insight

ETHZ Eidgenössische Technische Hochschule, Zürich

FOC First Order Condition

FOCs First Order Conditions

FR France

GCMs General Circulation Models

HPS Pumped storage hydro plant

HRES Reservoir hydro plant

HROR Run-of-river hydro plant

IPCC Intergovernmental Panel on Climate Change

IT Italy

LDC Load-Duration Curve

LP Linear Program

LM Lagrange Multiplier

MC Marginal cost

MILP Mixed Integer Linear Programming

MWh Megawatt-hours

NSV Net System Value

RCMs Regional Climate Models

RS3.0 Routing System 3.0

SMP System marginal price

SRES Special Report on Emission Scenarios

SWV Swiss Wasserwirtschaftverband

UC Unit Committment

UC-ED Unit Committment-Economic Dispatch

VOM Variable Operating and Maintenance Cost

WV Water Value

Chapter 1

Introduction

There is unanimous consensus in the scientific community that there will be warming of global climate in future (IPCC [10]). Regional and local scale impacts might vary (IPCC [10]) and for Europe in general, and Alpine regions in particular, the ENSEMBLES[1] project makes projections of between 1.5 and 2 $^\circ$ C increase in mean annual temperature, small increases in autumn and winter precipitation and a small decrease in summer precipitation for the period 2021-2050 (van der Linden P. and Mitchell [22]). Given these changes, Alpine hydrology is also projected to undergo changes with regard to glaciation and precipitation (see van der Linden P. and Mitchell [22], example in Chapter 6). This will have an impact on the planning and operation of hydropower plants as they depend on the timing and amount of water inflows[2] due to snow-melt and precipitation. Since Alpine countries - mainly France, Switzerland, Austria and Italy - have significant hydropower generation, it can be surmised that the electricity supply systems of these countries will see a direct

[1]ENSEMBLES is an integrated research project which ran from 2004 to 2009 and was coordinated by the Met Office Hadley Centre. It has produced probabilistic projections of climate for Europe to help inform researchers, decision makers, businesses and the public with climate information from the latest climate modelling and analysis tools. ENSEMBLES was funded by the European Commission under the 6th Framework Programme Priority: Global Change and Ecosystems. For more information please see `www.ensembles-eu.org`.

[2]Inflow(s) is a term that refers to water which flows into a reservoir, usually that of a hydropower plant.

impact of global change.

Of the countries mentioned above, Switzerland is unique in the sense that over 50% of its electricity requirement is fulfilled by hydropower alone (BFE [3]). Moreover, it is tightly integrated into the European electricity network and any impact on hydropower operation in Switzerland will have an impact on the wider integrated electricity market. While there have been some studies on Europe-wide impacts of hydropower changes on the electricity system (see Golombek et al. [8], Van Vliet et al. [23]), no studies that focus on the system level impacts of changes in hydrology of Switzerland were found during the literature review for this thesis. In 2011, the Swiss Federal Office of Energy, Bundesamt Für Energie (BFE), published a study on the impacts of changes in hydrology on hydropower in Switzerland (Swisselectric [19]) but it focused on the changes in runoff[3] and inflow regimes, their impacts on plant operation, and financial implications for individual power plants. Thus, an analysis which explored system-level impacts such as changes in system marginal prices, system costs etc. was not attempted, although the study did allude to plans of such an analysis.

The present work focuses on analysing the impact of climate change induced hydrological changes in Switzerland on the electricity supply in Switzerland and its neighbouring countries. While doing so, the principle of *ceteris paribus* is applied, i.e. the only difference between the present and future scenarios is changed hydrology. Other factors that impact the costs of the electricity system such as fuel prices, operating costs, technological changes, changes in electricity demand etc. are not considered. Thereafter, several conclusions are drawn about changes of the system characteristics such as (a) changes in the valuation of stored water (called Water Value (WV)), (b) change in system marginal prices, (c) change in generation from hydropower and (d) change in electricity flows from

[3]Runoff is a term used in hydrology to refer to the water, from precipitation or snow-melt, that drains or flows off over land

Switzerland to neighbouring countries. Of these, the change in water value is the primary result which will be explained using an analytical economic model. It forms the basis on which other results can be explained. Lastly, the change in overall money value of the electricity system including revenue generated from electricity generation and trade as a consequence of changes in hydrology for Switzerland and its neighbouring countries is presented and analysed. This money value can be considered a proxy for electricity system welfare. These results are presented for a future scenario representing a mid-century (i.e. 2050) inflow and climate regime, compared with a present day (2010s) regime.

The analysis is presented as a case study and the tools of choice are commercial simulation software, namely Routing System 3.0 (RS3.0) for hydrological simulation and the European Power System Insight (EPSI) modelling platform for electricity market modelling. Chapter 2 of this thesis presents some selected literature. Chapter 3 describes the theoretical background for this work and the modelling tools and methodology used. In the same chapter, the expected behaviour of the system is discussed using well known results from literature. In Chapter 4, results are presented and analysed, followed by a detailed description of the limitations and caveats of the analysis. Chapter 5 contains a summary of the results and delves into some policy relevant aspects of the results. Chapter 6 concludes.

Chapter 2

Review of select literature

The analysis of the economic operation of hydropower plants, in the context of the entire electricity system, has received significant attention in scientific literature. Early works like Koopmans [11] and Little [14] lay out the foundations of the economics of hydropower management. In the European context, extensive work on this topic was performed in Norway and Sweden, an example being the 1961 paper Stage and Larsson [18], which also lists even earlier references. Beginning with his PhD thesis in 1979, Read [15], Read has performed extensive work on the topic, up to 2004, which was the latest publication of his found during this review (see Read [16], Tipping et al. [20]). Read's work was performed in the context of the New Zealand electricity system. While the optimal management problem of hydro-thermal systems has thus received a lot of attention through the years, the issue of the influence of climate change on operation of power systems where hydro has a large share has not been explored a lot. During the course of this review, only a few studies which delved into this topic were found. The remainder of this literature review briefly describes those studies and some of their key results.

Lehner et al. [12] use the WaterGAP model to simulate the change in hydropower potential in Europe due to climate change and water usage over the next century. They find that for Switzerland, there could be a small increase in hydropower potential in mid-century. However, theirs was a gridded model driven by climate change data from General Circulation Models (GCMs) with a spatial resolution of approximately 35 km x 55 km and a monthly temporal resolution. Given the complex topography of Switzerland and the large share of hydropower in its electricity supply, this resolution is coarse, as is duly noted by the authors. Golombek et al. [8] model the effect of climate change on electricity markets in

Western Europe. They use an economic equilibrium model of the Western European energy industry which models both producers and consumers and determines prices and quantities of all energy goods (fuels and electricity). They look at the impact of climate change on both demand and supply, the latter being changes in generation potential occurring in hydropower plants due to changes in inflows and for thermal plants due to changes in thermal efficiency. They use the Intergovernmental Panel on Climate Change (IPCC) Special Report on Emission Scenarios (SRES) A1B emissions scenario[4] and results from Regional Climate Models (RCMs) to simulate changes in inflows in future. While they do not give the results for Switzerland, they report increases of about 8% in hydro production, a decrease in price of about 2% and a doubling of exports in the Nordic countries in the year 2085. The last Europe-wide system-level study reviewed is by Van Vliet et al. [23]. They use projections of daily river flows and water temperature to simulate the impact of future climate change on the generation potential of hydro and thermal plants in 16 European countries by means of an electricity system cost optimization model. Climate change projections for the SRES A2 and B1 (high and low emission) scenarios are used. For the period 2031-2060 they report an approximately 10% increase in electricity prices and approximately 10% decrease in hydropower potential for Switzerland. The same numbers for Norway are about a 40% price decrease and about 15% increase in hydropower potential.

Conceptually, the analysis in this thesis borrows from and builds upon the methodologies used in the literature cited in the previous paragraph. In addition, there are some Switzerland specific studies which examine the local-scale impact of climate change on hydrology and on the operation of individual plants. The methods from these studies are also adapted for this analysis. The following paragraph describes some of these Switzerland specific studies.

[4]For details on SRES emissions scenarios, the reader is referred to IPCC [9]

Uhlmann et al. [21] model the impact of climate change on water discharge in the Grande Dixence hydropower complex in the Swiss Alps. They use the RS3.0 software, the same one used for this thesis, and report an increase of about 19% in discharge in the mid- 2050s period under the A2 SRES emissions scenario. They also report seasonal shifts in discharge due to earlier snow melt. They note that this will have an impact on reservoir management. Gaudard et al. [7] propose that an interdisciplinary analysis that integrates hydrological and economic models is needed to devise optimal reservoir management strategies. They investigate the impact of climate change on the Mauvoisin hydropower complex, assuming that the plant manager faces exogenous prices. They derive an optimal generation schedule over the period 2011-2100. They find that inflows increase in the initial years of the modelling horizon, decreasing by about 18% towards the end of the century as compared to the present. This leads to a corresponding increase in electricity generation of about 4% in the 2050s and a decrease of about 16% at the end of the century. Lastly, the Swiss Federal Office of Energy (BFE), in collaboration with Swisselectric, carried out a comprehensive study on the impacts of climate change on the change in runoff, glaciation and hydropower plant operation. The findings were published in a synthesis report (Swisselectric [19]), of which Weingartner et al. [24] have an excellent summary. The report found a shift in runoff regimes from summer to spring and a flattening out in other seasons. The study analysed the impacts of change in runoff regimes on individual plant operation for a few selected plants. It concluded that the effects on the entire system cannot be generalized. For catchments areas dominated by glaciers, the study reports large increases in runoff and inflows coming into reservoirs by the period 2035 with a subsequent decrease in the longer term towards the end of the century. Run-of-river plants will see increased (decreased) production during corresponding periods.

This thesis builds on this body of knowledge by making a contribution to the projections of the system level economic impacts of climate change on the electricity system of Switzerland by employing detailed hydrology and electricity system models.

Chapter 3

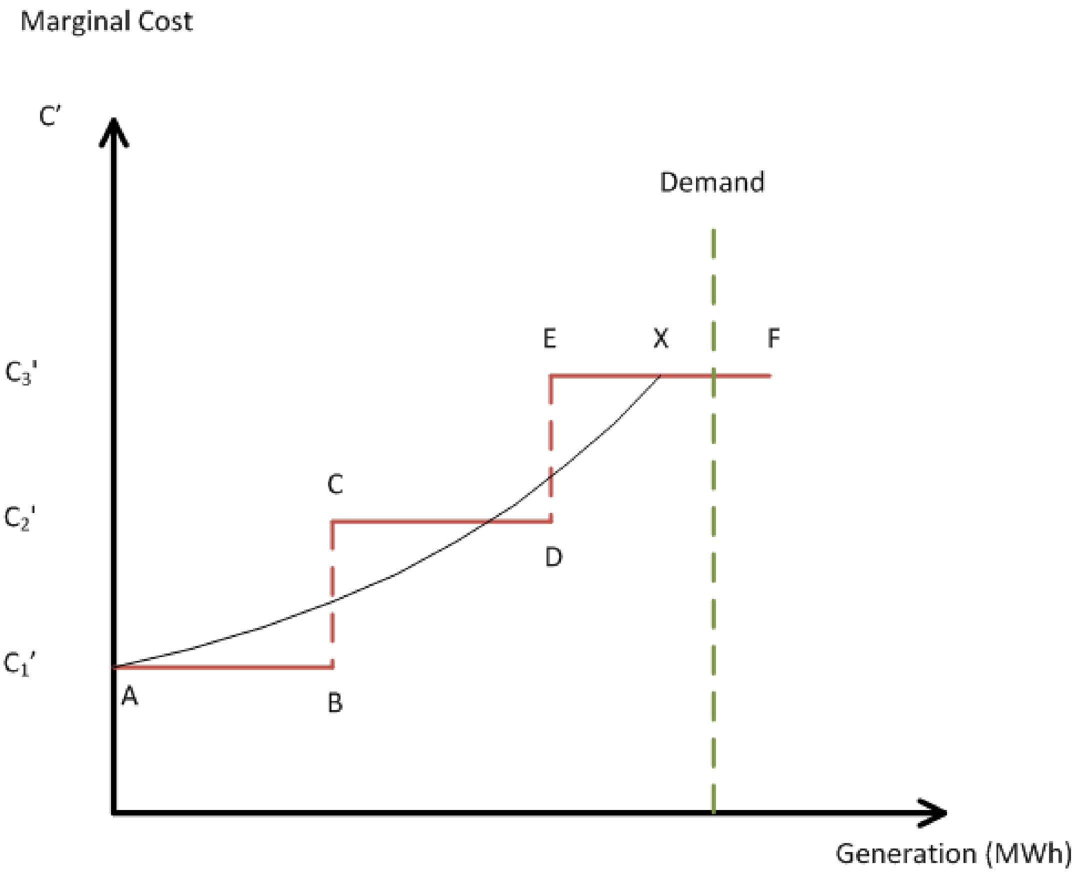
Models and Methods

3.1 Background: Notes on electricity demand and supply and electricity markets

Electricity is a good unlike those commonly encountered in economic theory. The demand for electricity has to be supplied at each instant in time such that mathematically, it can be seen as a continuous function in time. Moreover, in the short run, electricity demand is seen to be highly inelastic (Lijesen [13]). Electricity demand also exhibits characteristic patterns of temporal behaviour driven primarily by seasonal variations in temperature and by daily human activity. In the northern latitudes demand is typically high in winter and low in summer. During the week, demand is higher on weekdays and lower on the weekends. During a day, demand peaks during the morning and evening when people run appliances and commercial activity is high. Electricity suppliers therefore face the situation of supplying this varying demand at the least cost (to generate most profit). If one adopts the point of view of a social planner, this can be seen as an optimization problem of cost minimization such that demand is fulfilled and the technical constraints of the generating plants (hereafter referred to as just 'plants') are not violated. In engineering literature this is called the problem of Unit Committment-Economic Dispatch (UC-ED)[5]. Unit Committment (UC) means that for a given demand schedule, the cost optimal schedule of on-off states of

[5] The UC-ED problem is typically defined as a least-cost optimization problem. A simplified representation is given in Appendix B.

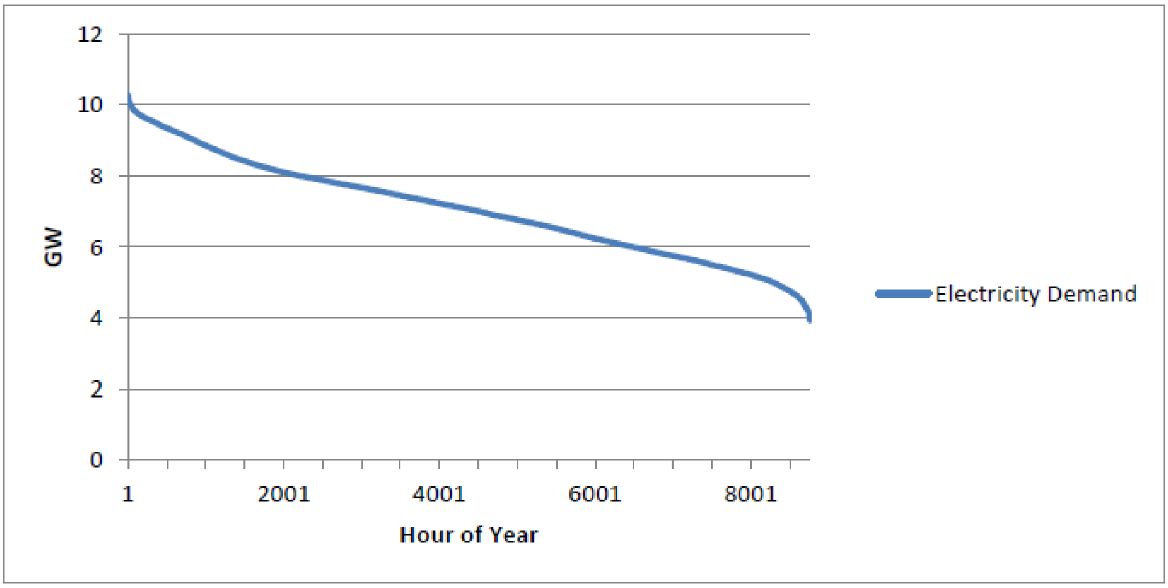
generating units is determined. Economic Dispatch (ED) is then a sub-problem in which the generation levels of those units that are on, are determined. The solution to the UC-ED problem can be visualized to be a set of plants stacked in such a way that the ones with the lowest Marginal cost (MC) are dispatched first, then the next higher ones and so on until the demand is fulfilled. This is called the merit-order. The last plant in the merit-order is the one with the highest MC and is generating at a level close to or below its full capacity. This is schematically shown in Fig 3.1.



Source: Own illustration, adapted from Forsund [5]

Figure 3.1: Merit-order of generating plants

Each horizontal red line is the generation level of a plant with a particular marginal cost. Together they form what is referred to as the supply-stack (used interchangeably with the term 'merit-order', although the former is a more general term). Another important concept is that of base load, intermediate load and peak load power plants. This can be illustrated with the help of a Load-Duration Curve (LDC), shown in Fig 3.2. The LDC is a plot of the (usually hourly) electricity demand values arranged in a descending order. Thus the highest load is active for only one (or a few) hour(s), called as the peak load, and the lowest load is active throughout the period in consideration, called as the base load. Plants which fulfil these loads are referred to by the same terminology. Base load plants are active throughout the year and are characterized by high fixed costs and low variable (marginal) costs whereas peak load plants are active only in periods of peak demand and have high variable costs but low fixed costs. Typical examples of the two categories are nuclear and gas plants respectively. It is important to note that these are not hard classifications and it is possible that in some systems, the cost structures may be such that technologies can move between them. These marginal cost based classifications do not apply to hydropower plants, as will be explained in Section 3.2.



Source: Own illustration, data obtained from the EPSI database

Figure 3.2: An example load-duration curve

Due to the nature of some of the technical constraints of the generating units, which are not elaborated here, the problem specification is such that Mixed Integer Linear Programming (MILP) techniques are needed to solve the optimization problem. Depending on the size of the system, therefore, advanced algorithms are needed to obtain a solution in a reasonable time. Since a discussion on computational techniques to solve optimization problems is beyond the scope of this work, this topic is not discussed further. The software tools used in the analysis take care of the necessary computations. For additional details on the UC-ED problem, the reader is referred to Wood and Wollenberg [25], a classic text on power systems, for an extensive academic treatment.

An electricity market can be idealized as a series of merit-order supply curves for each point in time. The equilibrium market clearing price of electricity is therefore the highest marginal cost i.e. the short-run variable cost of the plant at the margin (plant EF, in the case of Fig 3.1). Typically, these spot prices are calculated for every hour of the planning horizon. In actual electricity markets, suppliers submit their bids to the market operator who then aggregates them to calculate the market supply curve. A market demand curve is obtained in a similar fashion, and equilibrium prices are obtained[6]. This exercise is repeated every day for various time scales - one day ahead, one week ahead, one month ahead etc. to obtain forward price curves and prices are later re-calculated in real time at the actual instant of meeting demand (this is due to the stochastic nature of electricity demand i.e. actual realised demand is always different from projected demand). Thus, as mentioned previously, the case of Fig 3.1 is only an idealized approximation of a real-world electricity market.

[6] It should be noted that the electricity market in this context is a wholesale electricity market. Market participants in such a market are large suppliers and consumers and for a host of technical, regulatory and historical reasons, individuals do not trade on the market. While this does not in any way affect the results and interpretations of the analysis presented in the thesis, it is important to be kept in mind for prospective comparison.

3.2 Analytical model of a hydro-thermal system

In an electricity system which has a mix of hydropower and conventional fossil-fuel fired power plants, the UC-ED problem mentioned in Section 3.1 takes a slightly different form. Hydropower plants can be broadly classified into three types - (a) Reservoir hydro plant (HRES), (b) Run-of-river hydro plant (HROR) and (b) Pumped storage hydro plant (HPS). They have different operational characteristics. Storage hydro plants, as the name suggests, store water in periods of high inflow so that it can be used at a later time. Run-of-river plants are constructed in the watercourses of rivers and therefore are constrained to run whenever there is enough flow. The latter are therefore not considered to be 'dispatchable' i.e. controllable sources of generation. Pumped storage plants, on the other hand, do not have reservoirs that receive natural inflows. They generate electricity by turbining water from the upper storage reservoir to the lower storage reservoir when the prices are high and pump the water from lower to the upper reservoir when prices are low. Since HPS plants do not receive natural inflows, they are assumed to not be affected by climate change[7], whereas HROR plants will only change their pattern of generation according to the pattern of inflows. For the purposes of modelling, therefore, only HRES plants which receive natural inflows and are dispatchable are considered.

The optimization problem for a mixed hydro-thermal system from a social planner's perspective takes the form given in the set of equations 3.1. For the time being one each of aggregate hydro and thermal producers is assumed. The theory has been borrowed from Forsund [5]. The analytical model described in this section will be used to make some

[7] In Switzerland, many pumped storage plants are of the open loop type i.e. they receive some natural inflows. However, for the purposes of this analysis, their contribution to total generation was deemed too low to significantly affect the overall picture of the results and therefore the climate change impact on HPS plants was neglected.

hypotheses about the expected results of the simulation.

$$
\begin{aligned}
\max \quad & \textstyle\sum_{t=1}^{T}[\int_{z=0}^{D_t} p_t(z)dz - c(G_t^{Th})] \\
\text{s.t.} \quad & \begin{aligned}
D_t &= G_t^{Th} + G_t^{H} \\
R_t &\leq R_{t-1} + w_t - G_t^{H} \\
R_t &\leq \bar{R} \\
G_t^{Th} &\leq \bar{G}^{Th} \\
D_t, G_t^{Th}, G_t^{H}, R_t &\geq 0, \quad t = 1, ..., T \\
T, w_t, R_0, \bar{R}, \bar{G}^{Th} & \text{ given}
\end{aligned}
\end{aligned}
\tag{3.1}
$$

Where

D_t, p_t : Electricity demand and price

$p_t(z)$: electricity demand function in price form

G_t^{Th}, G_t^{H} : Generation from thermal and hydro plants at time t

R_t, w_t : Reservoir content and inflows, in energy units, at time t

$\bar{R}$, $\bar{G}^{Th}$: Upper bound on reservoir content and generation

Here, the quantity being integrated is the demand function in price-form, net of the thermal generation cost with an aggregate cost curve similar to that represented by the curve AX in Fig 3.1. The objective function is therefore a measure of the stream of profits (or more generally, social welfare) for a mixed hydro-thermal system. For a hydro producer who uses water as a 'fuel', the marginal cost of producing energy is essentially zero since water coming into the reservoir is free. However, water used to generate energy today cannot be used for generation in future. Thus, a price-taking hydro producer faces the situation of maximizing profit by balancing opportunity costs of foregone income from generation in future. This opportunity cost determines the value of stored water. For a thermal producer, the marginal cost curve determines the aggregate cost of producing energy in each period. In this stylized model, this curve is not a function of time. Thus, while the optimization is a dynamic problem, only the part of determining the production levels of hydro producer is an inter-temporal problem.

The first constraint in equation set 3.1 is the demand constraint i.e. demand must be met at all times. The second constraint is the reservoir balance which states that the amount of water in the reservoir at time t is the net of the amount of water in the previous period plus the inflows arriving in the current period minus the generation from the plant in the current period. The third and fourth constraints are reservoir and generation bounds. For this model it is assumed that the reservoir can be emptied by energy generation, upper limit is not reached (no spill), and generation is always positive. The planning horizon T can be a week, several months or even a year. It is to be noted that the generation bounds for hydro generation are not considered as a constraint for the simplicity of presentation and interpretation i.e. it is assumed that the hydro plant always respects its generation limits.

Substituting the value of D_t and writing the Lagrangian gives

$$\begin{aligned} \mathrm{L} \;=\; & \textstyle\sum_{t=1}^{T}[\int_{z=0}^{G_t^{Th}+G_t^{H}} p_t(z)dz - c(G_t^{Th})] \\ & - \textstyle\sum_{t=1}^{T} \theta_t(G_t^{Th} - \bar{G}^{Th}) \\ & - \textstyle\sum_{t=1}^{T} \psi_t(R_t - R_{t-1} - w_t + G_t^{H}) \\ & - \textstyle\sum_{t=1}^{T} \gamma_t(R_t - \bar{R}) \end{aligned} \tag{3.2}$$

The necessary First Order Conditions (FOCs) are:

$$\begin{aligned}
\frac{\partial L}{\partial G_t^H} &= p_t(G_t^H + G_t^{Th}) - \psi_t && \leq 0 \quad (= 0 \text{ for } G_t^H > 0) \\
\frac{\partial L}{\partial G_t^{Th}} &= p_t(G_t^H + G_t^{Th}) - c'(G_t^{Th}) - \theta_t && \leq 0 \quad (= 0 \text{ for } G_t^{Th} > 0) \\
\frac{\partial L}{\partial R_t} &= -\psi_t + \psi_{t+1} - \gamma_t && \leq 0 \quad (= 0 \text{ for } R_t > 0) \qquad (3.3) \\
\psi_t &\geq 0 \quad (= 0 \text{ for } R_t < R_{t-1} + w_t - G_t^H) \\
\gamma_t &\geq 0 \quad (= 0 \text{ for } R_t < \bar{R}) \\
\theta_t &\geq 0 \quad (= 0 \text{ for } G_t^{Th} < \bar{G}^{Th}), \quad t = 1, ..., T
\end{aligned}$$

The Lagrange Multiplier (LM) on the reservoir balance, the shadow price ψ_t, is called the water value (WV) (specifically, it is a *marginal* price). It is the opportunity cost of using water across periods. This is the metric by means of which the hydro plant manager maximizes profit by choosing to release water for generation versus storing it for future use. A few important qualitative conclusions about the behaviour of this system can be drawn based on the set of equations 3.3. If hydro power plants are generating, the social price of electricity is equal to the water value. Conversely, if the social price is less than the WV, hydro plants will not generate and water will instead be saved for a later period. From the second FOC, it can be seen that thermal plants will only generate if the marginal cost of generation is equal to the WV. Conversely, thermal will not be used for periods when the marginal cost exceeds the WV. In other words, if the marginal cost curve starts at values higher than the WV, thermal plants will not be used. The third FOC gives Hotelling's rule for a hydro storage reservoir. In the case where the storage is large enough such that the upper bound is never reached ($\gamma_t = 0$), the WV is constant over time. Intuitively, this means that the hydro plant manager will choose to utilize water such that the opportunity costs are equalized. It should be noted that in the model used for the analysis, there are multiple generating units. Thus the optimization problem and the FOCs will be modified to reflect this fact. To illustrate this, a result from Forsund [5] is reproduced here to aid the reader's intuition.

$$\psi_{jt} + \rho_{jt} \quad = \quad c_i'(G_{it}^{Th}) + \theta_{it} \quad = \quad p_t \tag{3.4}$$

Here, j and i are the set of hydro and thermal plants respectively, and ρ_t is the shadow price on the upper generation bound of the hydro plant (which was previously excluded from the set of constraints in equation 3.2). This implies that the WV for hydro plants do not have to equal the marginal costs of thermal plants but the shadow prices on generation limits and water must adjust such that the respective sums add up to the social price for each period. Thus, while thermal marginal costs can be found from technical details of the plant(s), water values are implicitly determined as part solving the optimisation problem.

3.2.1 Response of HRES plants to a change in the inflows: some hypotheses

The simplified analytical model presented in Section 3.2 can be used to qualitatively describe the behaviour of an electricity system comprising of thermal and hydro plants. Thus, in the following paragraphs, the expected behaviour of the system will be laid out, subject to the condition that there is a change in the inflows and all other factors are kept constant.

Referring to that model, an increase in the inflows ω_t, all else being equal, implies that the reservoir constraint (constraint no. 2) in equation set 3.3 is relaxed and the shadow price of the reservoir constraint, ψ_t i.e. the water value (WV), decreases. It means that more generation is possible in that period (while respecting the generation bounds). The reverse is true when the inflows decrease. A decrease in ψ_t implies that the price of electricity in that period reduces, according to the first FOC in equation set 3.3. Of course, in an electricity system with multiple plants, equation 3.4 applies, as mentioned previously in Section 3.2.

From this model, one expects the water value and electricity price to decrease when there is an increase in inflows and to increase in case of decrease in inflows. In general, for an

Alpine hydrology regime as is observed in Switzerland, an intra-annual variation is observed in the inflows and it is correlated with the seasons. At the beginning of the year in the middle of winter, inflows are low. They increase in the summer as the snows melt and then decrease progressively as summer gives way to winter. There could be small increases in autumn inflows due to high precipitation events but they are never as high as summer peak inflows. Thus, the seasonal nature of the inflows will cause high prices in winter. A gradual decrease should then be observed in spring with a trough in June-July when the inflows peak. Later in autumn and winter, prices go back to high levels.

3.3 From theory to practice: Modelling tools used in the analysis

The analysis presented in this thesis employs a full-scale hydrology model to simulate future inflows for selected catchment areas of Switzerland, which are then suitably aggregated to generate a future inflow scenario for all reservoirs in the country. The climate change scenario used is the one from the Eidgenössische Technische Hochschule, Zürich (ETHZ) climate model, generated as part of the EU ENSEMBLES project, which uses the SRES A1B CO_2 emissions scenario. The inflow values so obtained are given as input to the electricity market optimization model which finds the optimum least-cost solution to the UC-ED problem mentioned in Section 3.1. Both models give their output at hourly time resolution and the modelling horizon for the study is one year. The models and the modelling methodology is described in brief in the following sub-sections.

3.3.1 Hydrology modelling

The RS3.0 hydrology simulation software developed and maintained by e-dric.ch allows for detailed simulations of all hydrological parameters of a catchment area (see García Hernández et al. [6]). Since a detailed investigation of modelling Switzerland's hydrology was not the primary purpose of this thesis, the expertise of engineers at e-dric.ch was leveraged in developing and specifying the hydrology models. Since the hydrology simulations were computationally intensive, a novel methodology was developed to generate country-wide aggregate inflows by running only a small number of models. The methodology used to select representative catchments and later aggregate the inflows is described in the following.

The hydropower plants in the EPSI database were first divided into reservoir and run-of-river plants. Each plant in the list was then assigned a representative inflow regime out of six possible choices[8] - one of three possible reservoir regimes namely glacial, pluvio-nival and nival[9] or one of three possible river flow regimes from the Aare, Rhine and Rhone rivers. These six representative regimes received the modelling treatment. Of these, only the storage inflow group was modelled in RS3.0 and future river regimes were obtained by applying scaling factors from literature and expert judgement.

The three catchment areas of reservoirs Gebidem, Isola and Lac de Gruyere representing the 'inflow regime' group were modelled in RS3.0. The hydrology model itself was treated as a black-box; however the results were calibrated to present day discharge values. Then, future temperature and precipitation values obtained using the Delta-Change method[10] were input

[8]The choice of hydrological regimes was based on expert judgment. Selected results from the hydrology simulation are presented in Appendix A.

[9]These three terms are used to refer to hydrologcial regimes. *Glacial* means the main source of water is snow-melt from glaciers; *pluvio-nival* means the regime is predominantly rain-fed topped up by snow; *nival* means the hydrological catchment is snow-fed.

[10]This method essentially gives an arithmetic, bias corrected relationship between present and future climate variables, which can be used to construct future climate scenarios. As an illustrative example, the equation to construct a variable T, for a climate scenario 'SCE' based on a reference scenario 'REF', is given by $T^{SCE} = T^{REF} + \Delta T$. The Δ is estimated from data. The reconstructed variables (temperature

to the model as the climate change scenario and the values for future discharge/inflow were obtained. For inflows in rivers (relevant for run-of-river plants), present day hourly discharge was scaled according to values obtained from literature to get the future discharge. In the next step, actual hydro energy production for the year 2012 for each plant was obtained from the Swiss Wasserwirtschaftverband (SWV) and other public sources[11] and converted to an average hourly energy production value, assuming that the plant was generating for all 8760 hours of the year. The formula used for the same is given in equation 3.5, which states that the energy produced by each plant (in units of Megawatt-hours (MWh)) for each hour in a given year is equal to the annual energy production divided by 8760, the number of hours in a year.

$$MWh_{\text{annual average}} = (\textit{Annual energy production})/8760 \tag{3.5}$$

This average energy production for each plant was then scaled using the modelled normalized hourly discharge for the present and future inflow scenarios of the respective hydrology regime previously assigned to that plant. This gave the inflows[12] for each hydro plant, which were summed together to obtain an aggregate hourly inflow profile in energy units (MWh) for Switzerland. Two hourly profiles were thus obtained as a final result of the hydrology modelling; one for the average of the years 2008 - 2013 and another for the average of the years 2045 - 2050. These were considered as representative of present (i.e.

---

and precipitation) are calculated at each spatially distinct point wherever required by the RS3.0 model. More details about the Delta-Change method can be obtained in Bosshard et al. [4].

[11] Namely, websites of companies that own the hydropower plants and from the BFE.

[12] These inflows are a proxy for the actual inflows of water into the reservoir attached to the plant and are expressed directly in energy units.

2010s) and future (i.e. 2050s) inflow conditions, and throughout the remainder of this document and especially frequently in Chapter 4, whenever the terms 'present' and 'future' are invoked in referring to scenarios, they point to these two inflow scenarios.

3.3.2 Electricity market optimization model

For simulating the integrated electricity market of Switzerland (CH), Germany (DE), Austria (AT), Italy (IT) and France (FR) the ELAN model by Energy Fundamentals GmbH is used. This model is part of the EPSI power system modelling suite and contains an integrated database of electricity demand, generation plants, commodity prices and various other fundamental market data for all European countries. This, coupled with state-of-the-art computational algorithms allows for rapid simulation of power markets at the hourly level for any time horizon from a month up to several decades. Some economic features of this model are enumerated in the following.

3.3.2.1 Economic features of the ELAN model

The ELAN model solves a least-cost optimization problem[13]. Constraints included are (a) demand balance (generation plus the energy exchange must balance demand), (b) hydro reservoir balance (energy balance accounting for the inflows and extracted energy) and (c) upper and lower bounds on generation, reservoir volume and energy flows to and from countries. The optimisation problem is an inter-temporal problem due to the reservoir

[13]While details of the model cannot be given here due to a non-disclosure agreement with Energy Fundamentals, the optimization problem that the ELAN model solves is similar in essential mathematical features to the one described in Appendix B, wherein the objective function includes the cost of generation based on short-run marginal costs of individual plants of the particular electricity market, although it includes more detail and modifications to enhance computation.

balance constraint. Electricity prices in the ELAN model are derived implicitly as the shadow prices on the demand constraint[14] (i.e. they are the cost of meeting an additional unit of demand), and marginal costs of the plants are driven by fuel prices and variable operating and maintenance costs[15] (VOM) of the plants, which are user inputs. Once the fuel characteristics, fuel prices and VOM are specified, the objective function of the model is able to be fully specified[16].

As a point of note, the ELAN model is not a direct analogue of the one presented in Section 3.2. The analytical model described in Section 3.2 was presented only for the purpose of describing the behaviour of a single, aggregated hydropower plant from the point of view of social planner. Consequently, it was a profit maximisation problem whereas the ELAN model is a least-cost optimisation model. It also did not have any specification of how the marginal costs of the plants were calculated. The EPSI platform, on the other hand, is a modelling tool meant for short and long term scenario analyses. Thus, as described previously, the marginal costs of the plants are determined on the basis of input costs (fuel, variable operating and maintenance costs) over which the user is given full control. However, the essential features relevant for this thesis, namely the representation of the reservoir behaviour incorporated in the reservoir balance constraint is identical in the two models. Therefore although the analytical model serves only as a point of reference, sourced from a well established piece of literature, used to derive hypotheses about expected system behaviour, the qualitative behaviour of the ELAN model is similar to that described in

[14]The first constraint in equation set B.2 in Appendix B can be considered as a representative example.

[15]Since this is a *variable* cost, it is defined per unit of energy generation of a given plant

[16]All of this is performed within the EPSI platform. The model then constructs a Linear Program (LP) which is passed through to a solver and results are returned back to the EPSI platform.

Section 3.2.

3.3.3 The modelling methodology

As has been described in the previous sections, two models (and modelling environments) were used to separately simulate the hydrology and electricity system. These models were not coupled to each other[17]. Instead, the output from the hydrology model - the inflows - were processed and converted to aggregate inflow values in energy units (MWh). An electricity system model for Switzerland (CH), Austria (AT), France (FR), Germany (DE), Italy (IT) was created for the 'present' case i.e. for the year 2013. Hydro inflows calculated in Section 3.3.1 were given as an exogenous input to the model. The electricity system model also contains all data required to define the cost function of the electricity system (see Section 3.3.2.1), in addition to other technical parameters of the system[18]. Then, keeping all model assumptions constant except the inflows, a 'future' scenario was created, for which the inflows for 2050 were given as input. Both scenarios were run at a step size of five months with hourly resolution and their results compared. Since the only assumption changing between the two scenarios is the change in hydrology due to climate change, the model results reflect the impact of climate change on the electricity market. These results are presented in the next section.

[17]The models are not hard-coupled and there is no computational interaction between them.

[18]For example, generation plant availability, minimum stable generation level of plants, interconnection capacity etc.

Chapter 4

Results and discussion

Results from the analysis performed for this thesis can be divided into those pertaining to hydrology and water management, and those pertaining to the economics of the electricity system. Based on this division, this section is organized as follows. First, the aggregated inflows obtained from the hydrology simulation for Switzerland and the resulting reservoir filling levels for a representative reservoir are presented. Next, the relationship of water values and generation from HRES to inflows is examined. In the next set results dealing with the economics of the electricity system, the change in trade across the five countries is first presented. Following this, the change in export revenues and system cost for Switzerland is examined. Subsequently, the net change in the value of the electricity system between the present and the future scenario is compared for Switzerland and its neighbouring countries and it is linked back to the change in hydrology due to climate change.

While reading the results presented in this section, the following points should be noted:

- in all graphs, the future (2050s) scenario and the present (2010s) scenario are identified by the labels 'Future' and 'Present' respectively.
- when changes in quantities are presented, the change in the Future scenario with respect to the Present scenario is being referred to.
- since this thesis focuses on aggregate economic variables, monthly results are better suited for presentation since hourly level results are utilised for more operational-level analyses. Thus, in the remainder of the thesis, results are given in monthly values although both the hydrology and electricity model were run at an hourly resolution.

– although the entire spectrum of results are available for every country included in the model, since the focus of this study is primarily on Switzerland, the results for water management are presented only for Switzerland[19] whereas other countries are brought into the discussion when money values of the system are discussed.

4.1 Inflows, reservoir levels and water values

Figure 4.1 shows the inflows from the hydrology model and the reservoir levels obtained from the electricity system simulation. The electricity market model was run at an hourly resolution with a five month step size. The reservoir levels at the beginning and the end of each step were constrained to follow a given profile obtained from historically observed data (BFE [3]). Reservoir levels shown are those at the end of the month i.e. after energy has been extracted from them. There are two things of note, the seasonal pattern of the inflows and the difference between present and future inflows. In general, inflows are low in winter and higher in spring and summer. Comparing between scenarios, higher inflows are seen in the future scenario both in winter and summer, and are slightly reduced in autumn (Fig 4.2). The increases are due to climate warming whereas the decrease in precipitation is due to slightly reduced winter precipitation[20]. Considered annually, there is an increase of approximately 4.26% in inflows in the future scenario as compared to the

[19]Another point to be noted while interpreting the results is that all results pertaining to water management refer to an aggregated reservoir of all HRES plants which has more than 99% of the reservoir capacity. Thus, while it does not represent the entire reservoir volume of Switzerland, it has no bearing on the relative magnitude of the changes between the scenarios and on the economic results

[20]As mentioned in Section 3.3.1, since the purpose of this work is not to go into the details of the hydrology, these results and conclusions drawn from them were performed in conjunction with experts at e-dric.ch.

present. Comparing for the same periods within the year, during the period from January to March, 10 to 15% more inflows are obtained, whereas during summer about 6% more inflows are seen. Thereafter, inflows decrease in autumn and increase again in early winter.

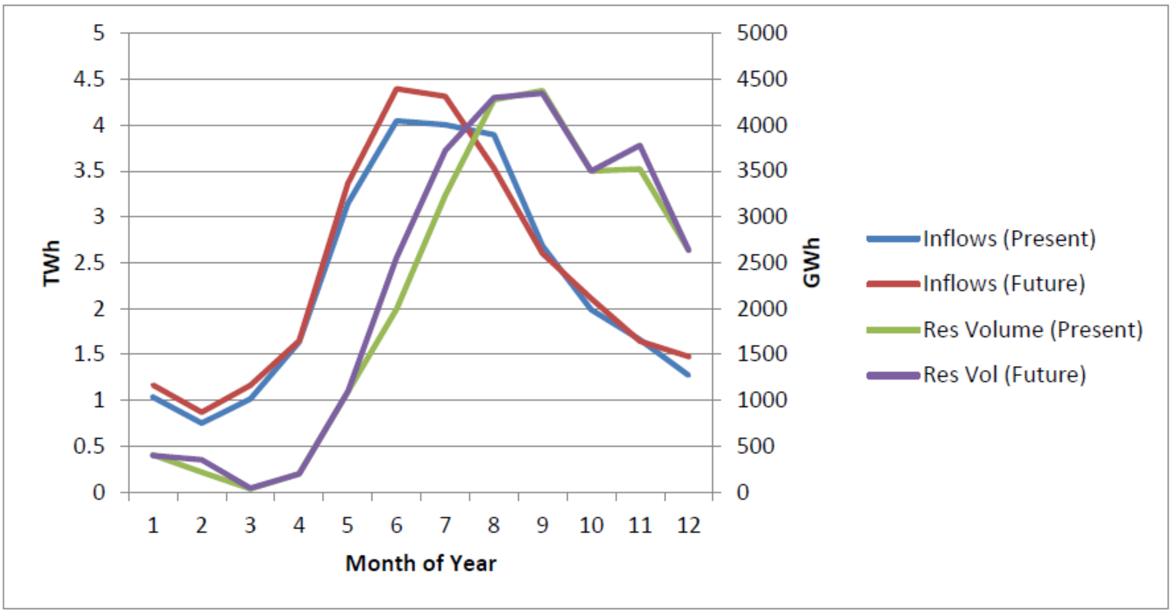


Figure 4.1: Inflows (primary axis) and reservoir volume (secondary axis) for CH

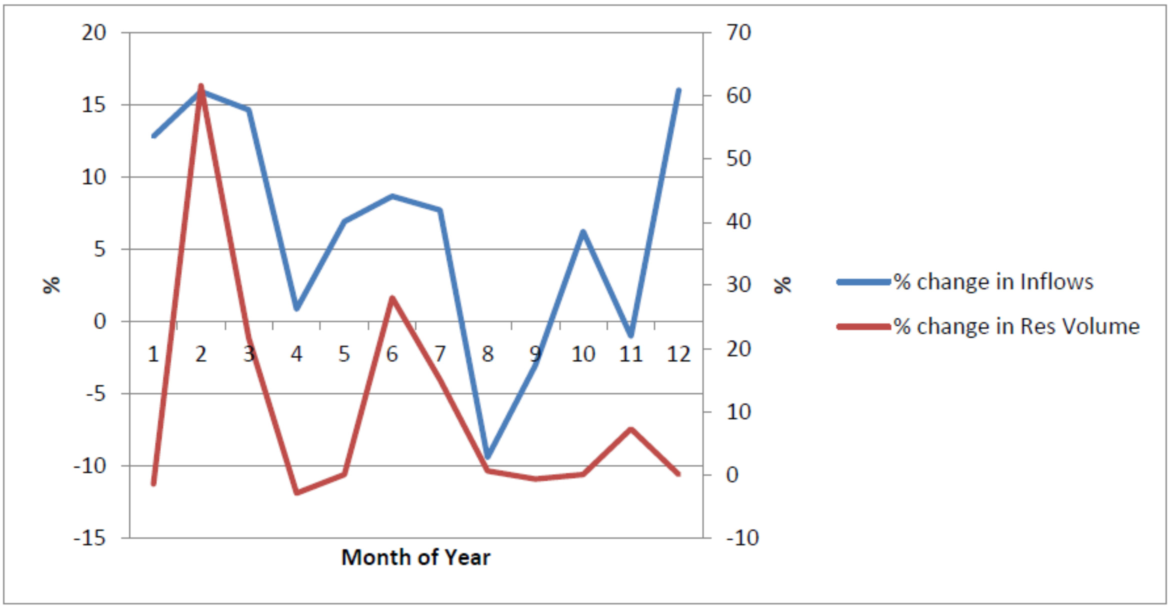


Figure 4.2: Change in inflows (primary axis) and reservoir volume (secondary axis)

From the point of view of the electricity producer, winter months are periods of scarcity since inflows are low and electricity demand (Fig 4.3) is high. Therefore, each unit of stored water has a higher value i.e. winter-time water values are high as compared to summer values (Fig 4.4). This is related to the behaviour of the reservoir volume (Fig 4.1 and 4.2). At the beginning of winter, there is a high volume of water stored in the reservoir, to meet the high electricity demand in winter. Water values continue to remain high through the winter. As winter moves to spring, in anticipation of the inflows, the reservoirs are drawn down (i.e. water is turbined to generate electricity) and the water values start to decrease. There is another factor to consider; at the end of winter, concern shifts to avoiding spillage (violating the reservoir upper bound) which also leads to depressed water values since it is now better to turbine the water. During spring and summer, inflows arrive and the reservoirs fill up, and since this is a period of low demand as well, water values remain low. The model optimizes storage levels such that, as summer goes into autumn, enough water remains to meet the high winter demand in a low inflow situation. Thereafter, the cycle repeats - water values increase, remaining high through the winter. An extensive discussion on this can be found in Read [16].

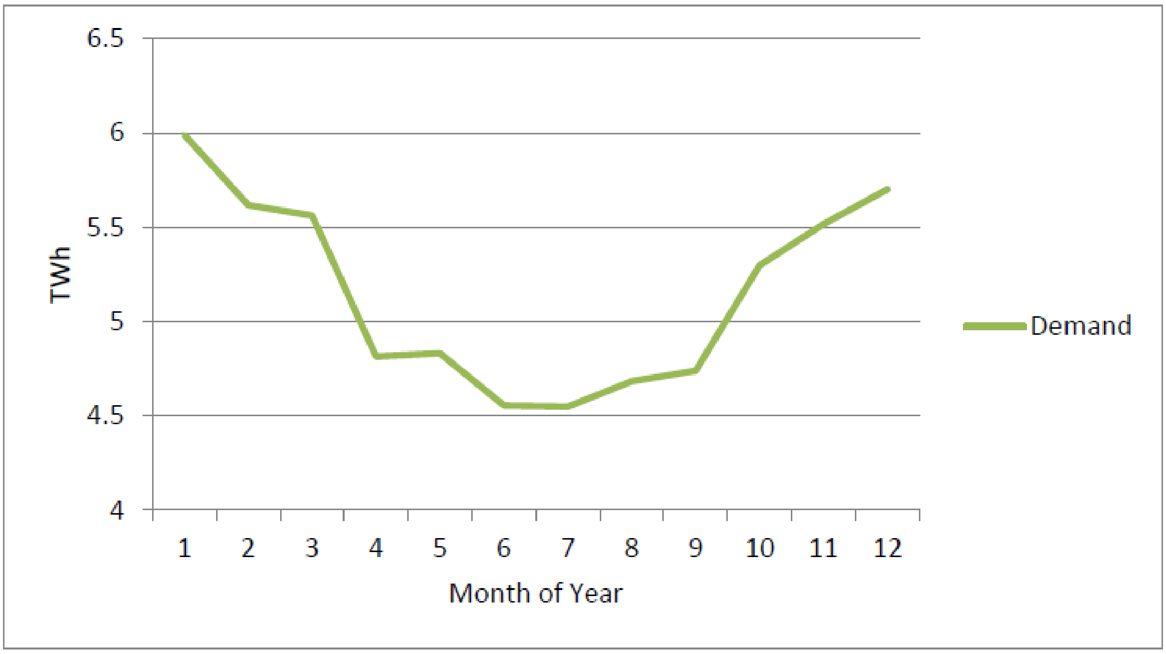


Figure 4.3: Monthly electricity demand for Switzerland

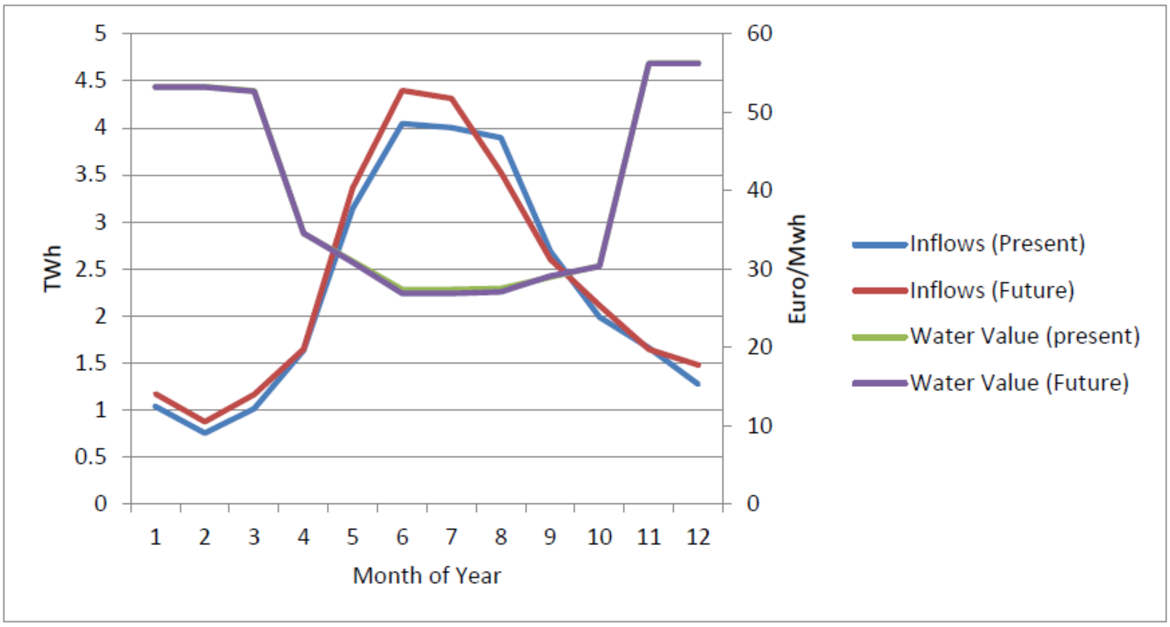


Figure 4.4: Inflows (primary axis) and water values (secondary axis) for the Present and the Future scenarios for Switzerland

Since there are more inflows in the future scenario, just before the beginning of summer, the reservoir is drawn down more in anticipation of the higher inflows. The increase in the inflows is such that throughout the rest of the year, there is an increase in stored water (Fig 4.2). This is reflected in the behaviour of the water values. If inflows increase, the reservoir balance constraint is relaxed and water values decrease. Thus, between the present and future scenarios, the future scenario has lower water values throughout (Fig 4.5, a maximum of 2% decrease). The difference is starker in the summer when the inflows are high. The reverse is true for when the inflows decrease, therefore water values in the future are higher in autumn as compared to the present.

The interplay of water values and inflows allows the explanation of energy generation from hydro (Fig 4.6). In general, generation from HRES plants is influenced by two factors - generating profits when electricity prices are high in periods of high demand, and respecting reservoir constraints. Thus, critical situations are in times of high demand-low inflow and low demand-high inflow. As explained previously, the use of water for generation is therefore optimized such that enough water is retained in the reservoir to earn profits in all periods

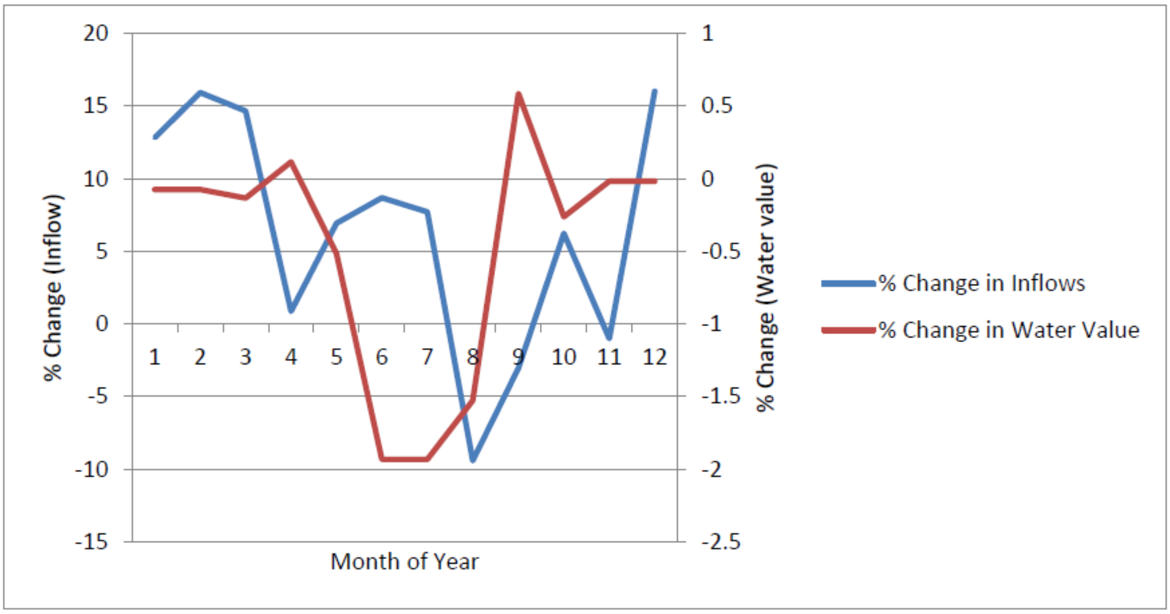


Figure 4.5: Change in inflows (primary axis) and water values (secondary axis) for the Present and Future scenarios for Switzerland

while meeting reservoir constraints. Since the modelling methodology used for this analysis is deterministic, the pattern of generation is driven strongly by the inflows. Comparing generation between the future and present, the fact that generation is driven by inflows is borne out again in that total annual generation in the future is increased by the same magnitude as the amount of the increase in inflows. Since an end-of-the-year storage target for the reservoir is specified in the model and the inflows are enough to reach (and exceed) this target, the increased inflows will lead to higher generation from hydro in the future scenario (Fig 4.7). In the same figure it can be observed that the increased inflows in future are alternately conserved (reflected in the change in reservoir volume) and used for generation. An interesting observation can be made for generation in June which is lower in the future scenario. The water was conserved to recoup the decrease in autumn inflows.

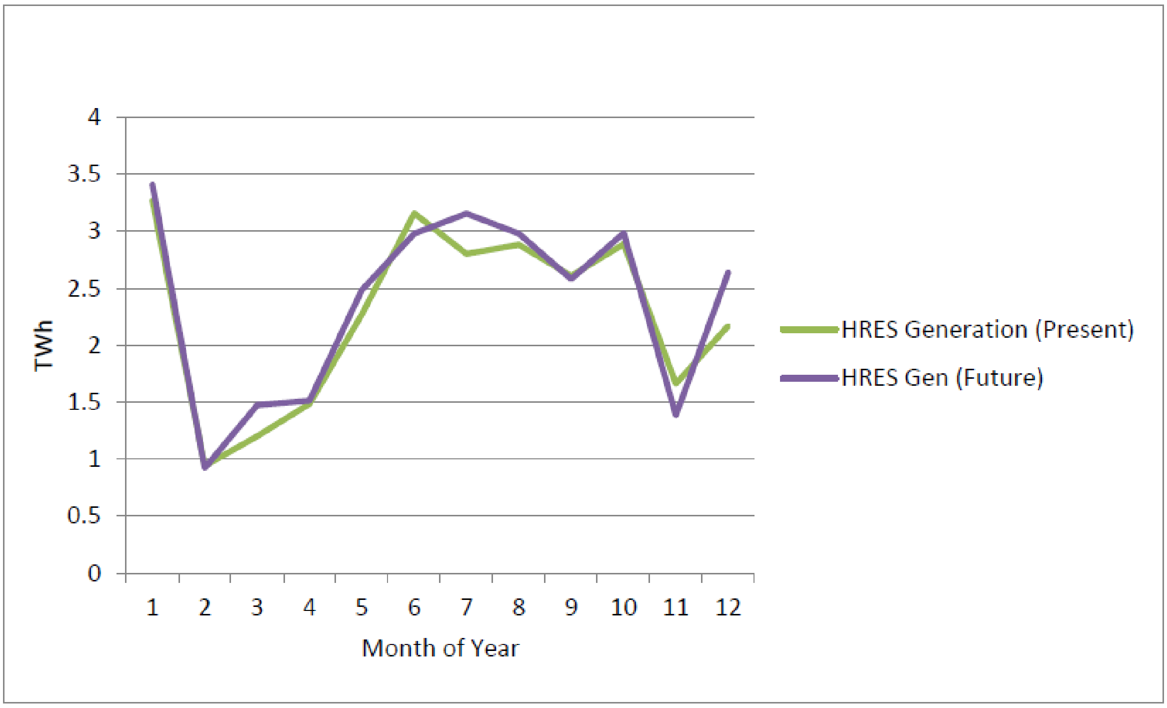


Figure 4.6: Generation from HRES for the Present and Future scenarios for Switzerland

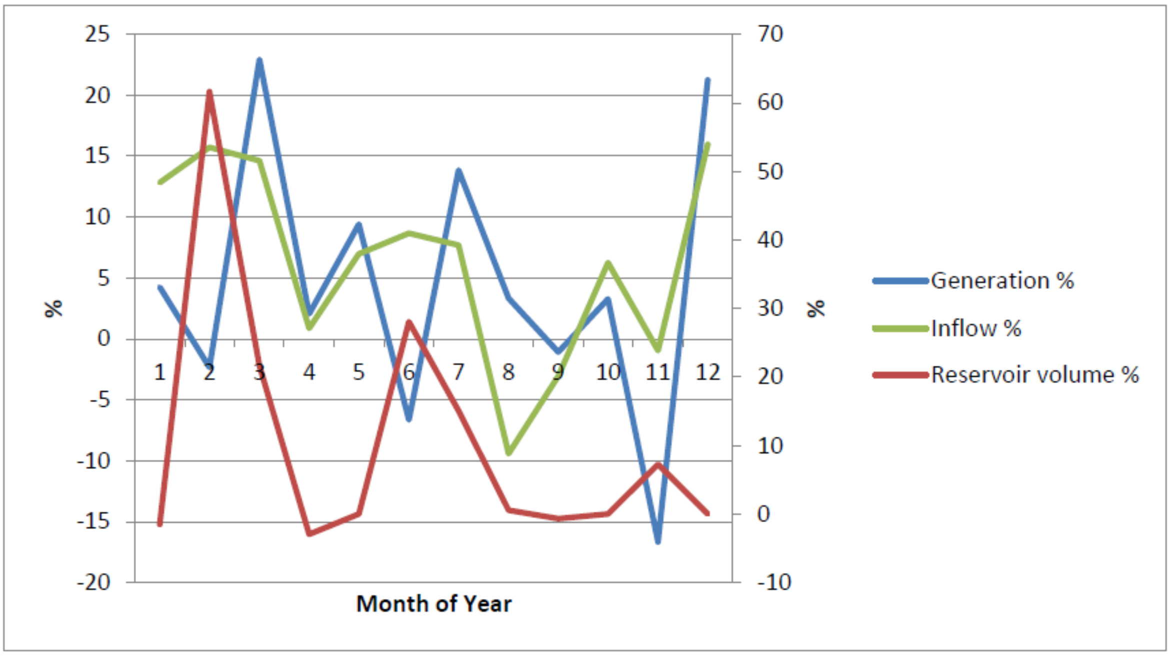


Figure 4.7: Comparison of change in inflows, generation (primary axis) and reservoir volume (secondary axis) for the Future and Present scenarios

4.2 Water value and SMP

Fig 4.8 shows the monthly average System Marginal Price[21] (SMP) for Switzerland for the future and present scenarios. Roughly following the shape of the demand, SMP is high in the winter and low in the summer. Since hydropower forms a large share of Switzerland's electricity supply, the SMP is close to the water value (Fig 4.9) throughout the year. Comparing future and present scenarios (Fig 4.10), it can be seen that the change in the SMP is in step with the change in water value. Since water is worth less in the future in periods of high inflow, and the market is supplied with cheap hydropower, the SMP in the future is lesser in these periods. In the summer months, one can also see a larger divergence between the change in SMP and change in water value. This is because even though water values decrease, the increase in hydropower is largely exported since it is a cheaper option for the neighbouring countries than using their more expensive domestic sources. The effect of this is to prevent the prices in the local market i.e. Switzerland to be affected by increased inflows in the future. For reference, the monthly SMP of all five countries for the future and present scenarios are given in Figures 4.12 and 4.11, and the change in SMP in future is given in Fig 4.13. It can be seen that the SMP in other countries has a similar shape as in Switzerland - high winter demand and low summer demand causes high and low prices in winter and summer respectively. Comparing the two scenarios, it can be seen that for other countries, the magnitude of change is smaller than for Switzerland and follows the same pattern over time. This is an influence of the change in inflows in Switzerland and the subsequent change in exports. This issue of trade will be discussed further in the next two sections.

[21] An System marginal price (SMP) is the shadow price on the demand constraint. See Section 3.3.2 for details

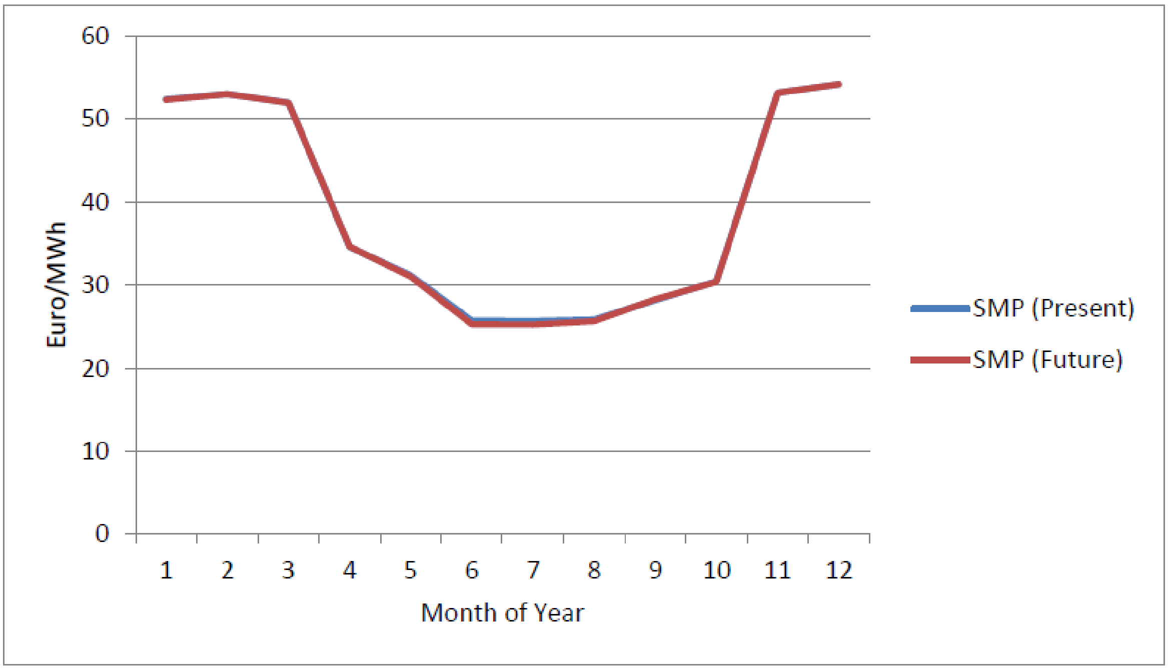


Figure 4.8: Monthly average system marginal price for Switzerland

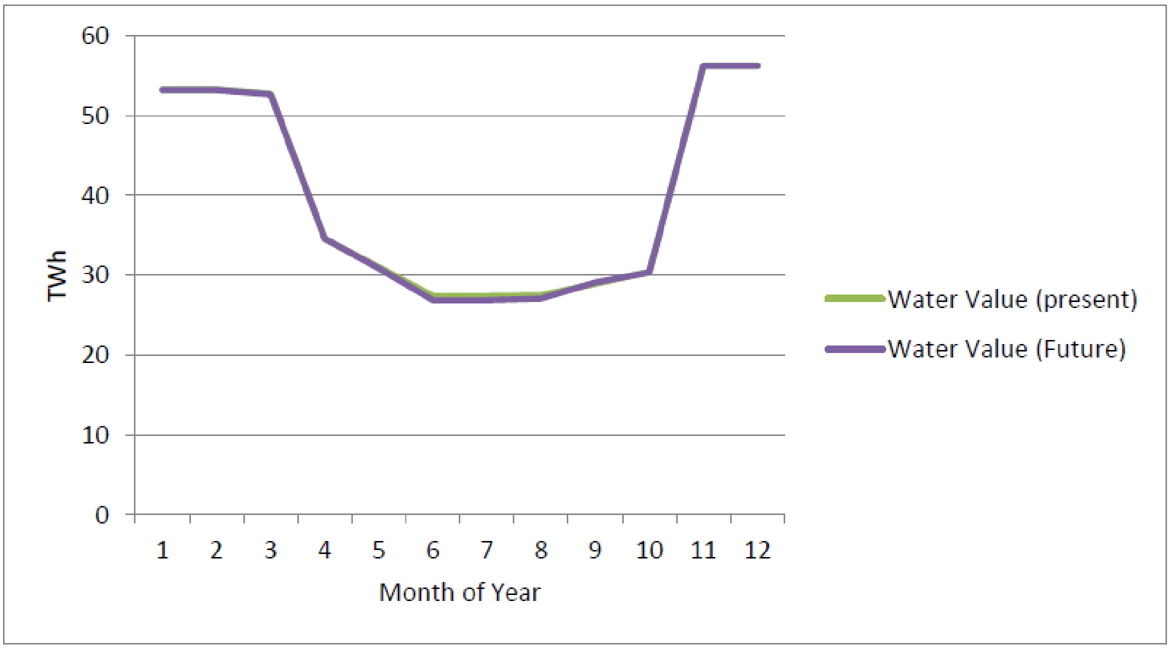


Figure 4.9: Monthly average water value for Switzerland

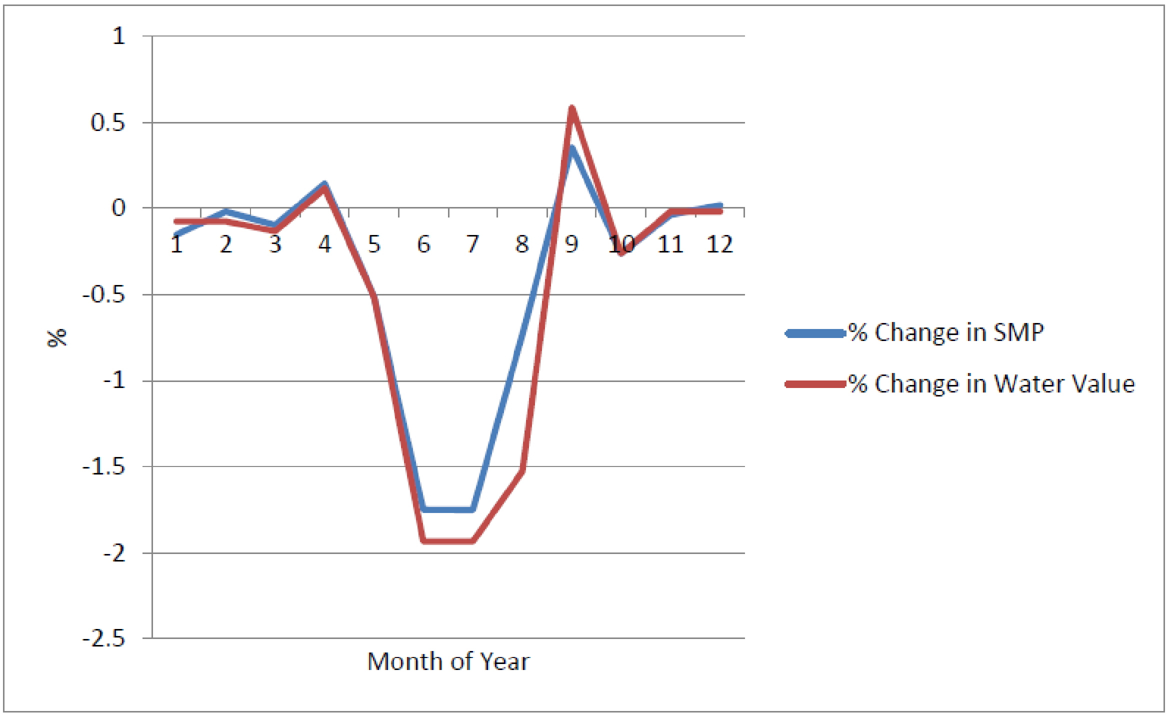
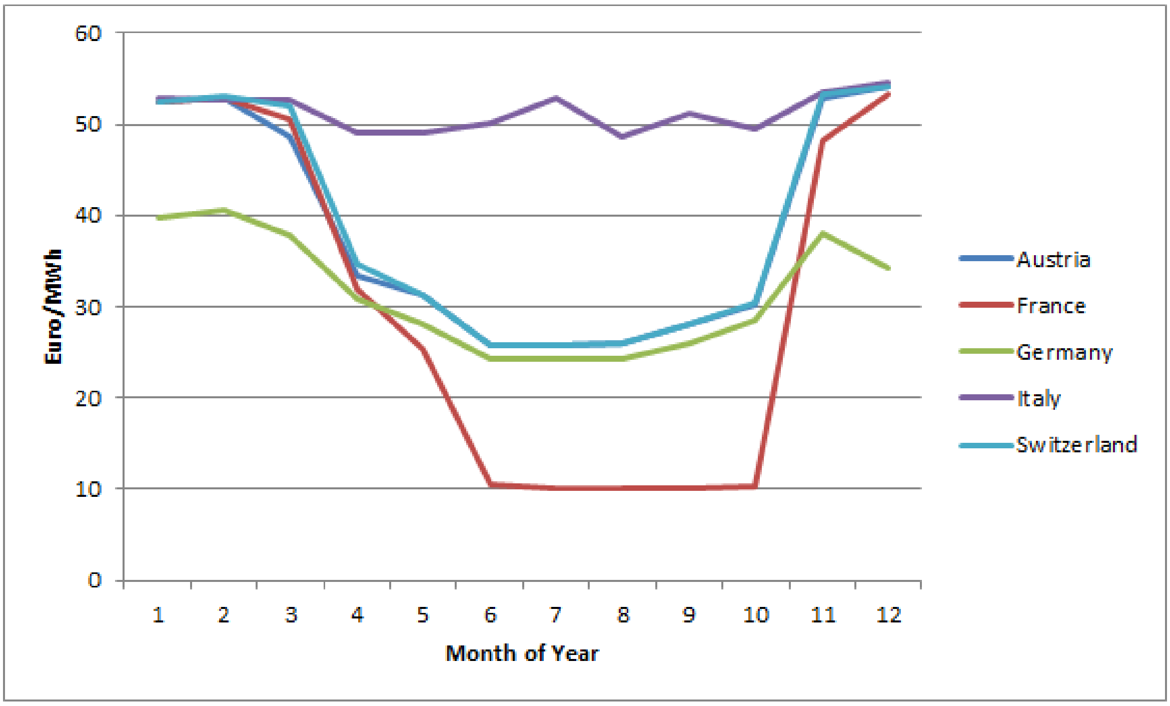


Figure 4.10: Change in SMP and WV in the Future compared to the Present scenario for Switzerland



hi

Figure 4.11: SMP for all countries in the Present scenario

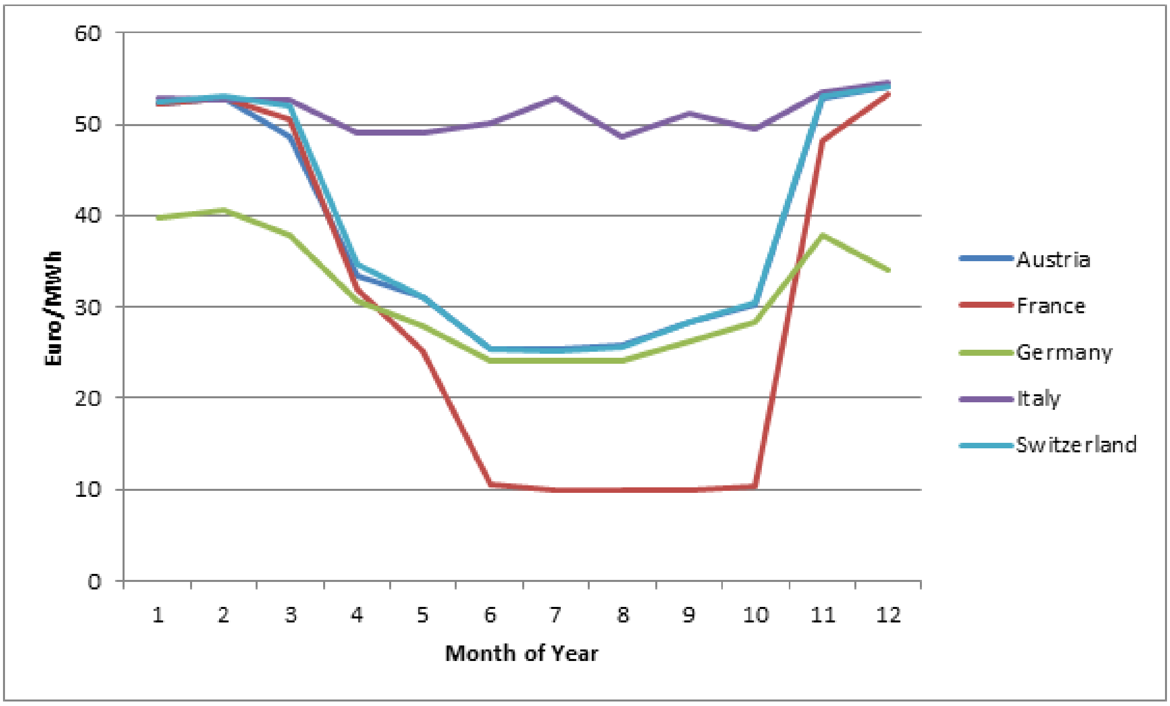


Figure 4.12: SMP for all countries in the Future scenario

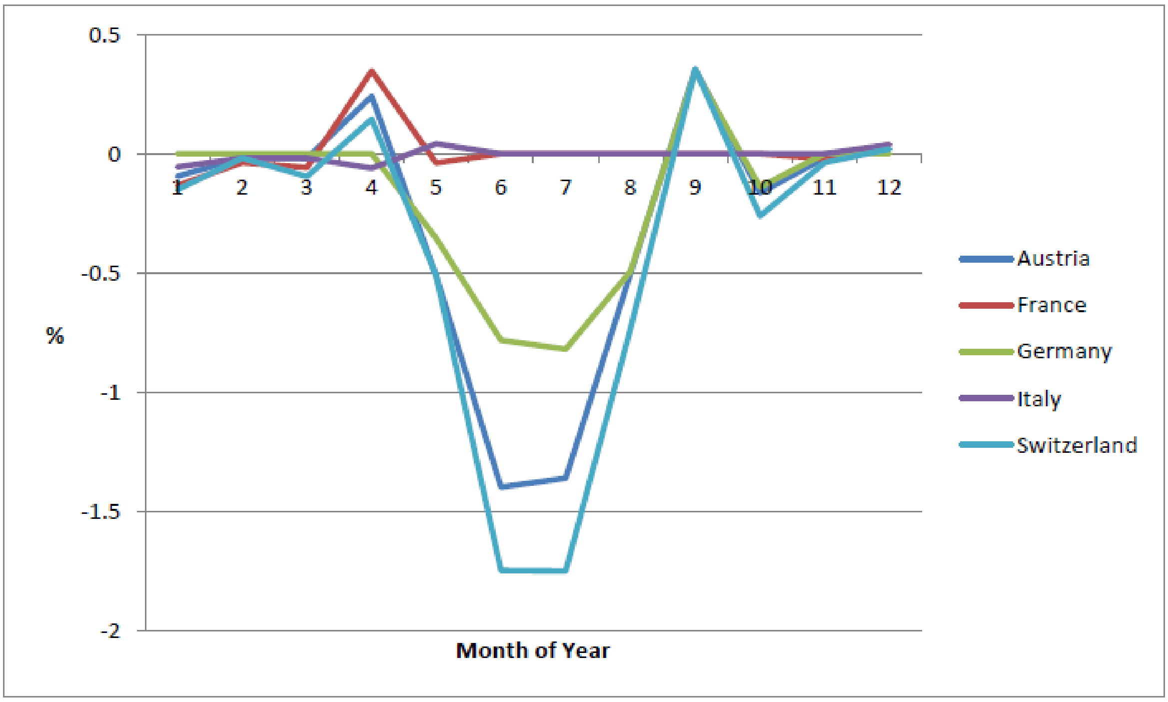


Figure 4.13: Change in SMP in the Future compared to the Present scenario for all countries

4.3 Change in trade - annual net exports of all countries

The annual net exports and the percentage change in exports of the five countries considered in the analysis are presented in Fig 4.14 and Fig 4.15. Annual exports are given in energy units, where positive values indicate exports and negative values are imports. Austria and Italy are net importers while France, Germany and Switzerland are net exporters. In the future scenario, the sign on the exports does not change which is not surprising given that no change was made to the installed generation capacity. However, the point that was raised in Section 4.2, that increased inflows in Switzerland are mostly used to export hydroelectricity to the neighbouring markets, can be clearly seen in Fig 4.15. Austria and Italy see a slight increase of about 1.4% in imports while France and Germany see a decrease in electricity exports by 0.15% and 4.4% respectively in the future scenario. However, the exports of Switzerland rise drastically by almost 81%. Since demand has been held constant for both scenarios, it can be concluded that this increase in exports is due to an increase in hydro generation caused due to increased inflows. Switzerland's exports will be examined in more detail in the next section.

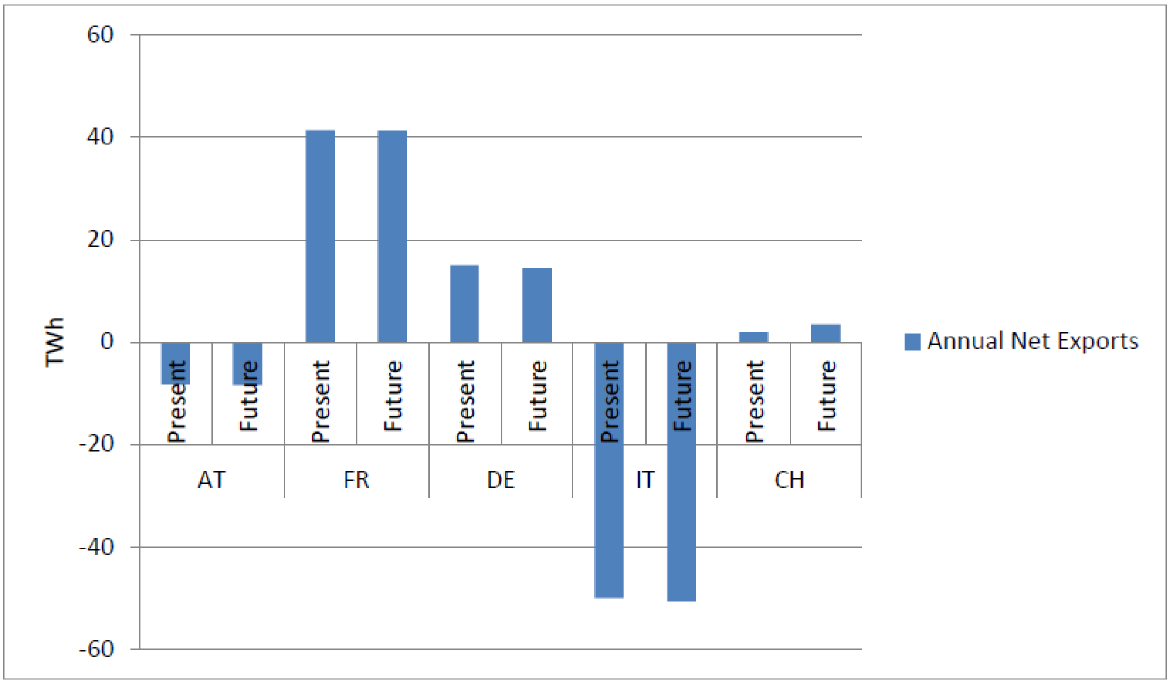


Figure 4.14: Change in annual net exports of electricity for the five countries

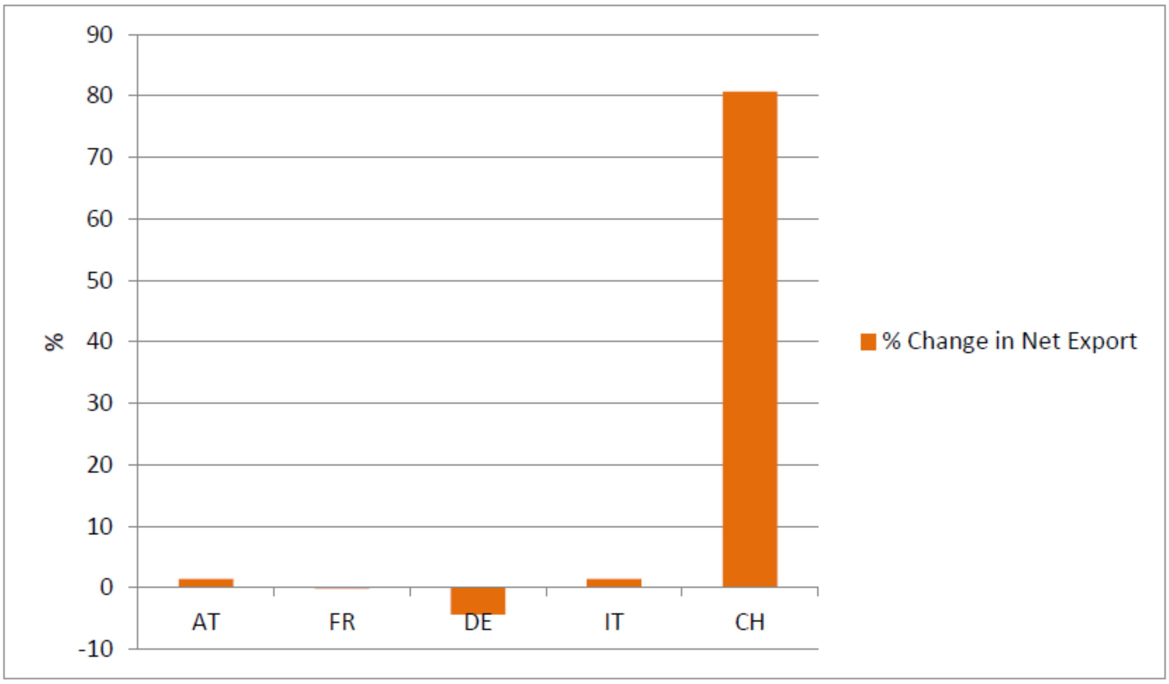


Figure 4.15: Percent change in annual net exports of electricity for the five countries

4.4 Effect on Swiss exports

Switzerland's export revenues[22] (Fig 4.16) follow the pattern of generation from HRES - this implies that the extra generation (due to increased inflows) is primarily exported. In periods of high inflows (i.e. summer) in the future, both export energy and revenues increase but the percentage increase in export revenues is smaller than the former. In the rest of the year, since prices are already high[23], export revenues increase in step with the increase in exported energy. Of course, both these quantities decrease when the inflows decrease in November (again pointing to how strongly Switzerland's exports are driven by inflows). On an annual level, the net effect is an increase in export revenues and contributes significantly to the net system value of the electricity system. This will be discussed in the following two sections.

[22]Export revenues are calculated by multiplying the amount of energy exported by Switzerland to a particular country, by the SMP of that country. The quantity referred to here is the sum of exports to all countries.

[23]Refer Figures 4.11 through 4.13.

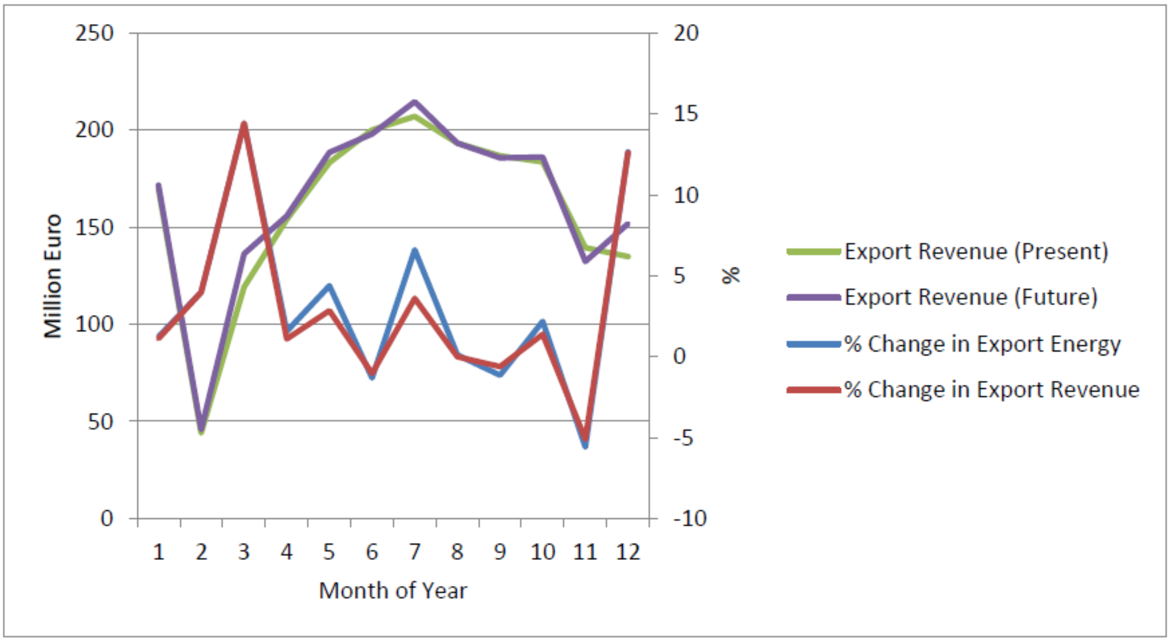


Figure 4.16: Export revenues (primary axis) and change in export revenues and energy (secondary axis)

4.5 Change in Switzerland's electricity system cost

The total cost of the electricity system is an important metric by means of which the change in the economics of the system can be evaluated. The electricity system optimization model calculates generation levels of each generating plant in the system such that the total system cost is minimized. An accompanying result is the marginal price of electricity (the SMP). Thus, the total system cost can be obtained by multiplying the total generation by the SMP. In economic terms, it is the revenue earned by producers or conversely the price paid by consumers. Fig 4.17 shows the change in electricity system cost between the present and the future scenario for Switzerland. The pattern observed is the same as that of the change in SMP (Fig 4.10). Due to increased inflows and increased supply of (cheap) hydropower in summer, the system cost decreases by about 1.5%. The decreases are more modest in the winter months since the water values are high during that period due to scarcity, with small increases in April and September due to an increase in the SMP.

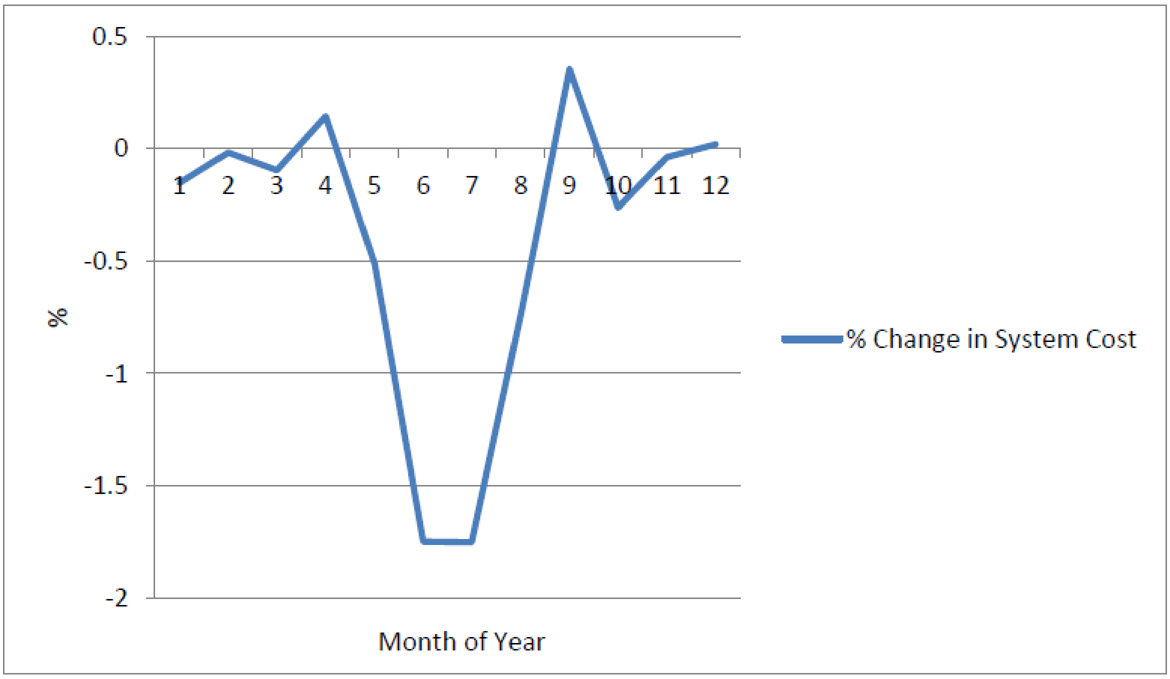


Figure 4.17: Change in electricity system cost of Switzerland in the Future scenario compared to the Present scenario

4.6 Effect on net electricity system value of Switzerland and other countries

In Section 4.4 and 4.5, it was shown that export revenues increase while system costs decrease for Switzerland. Defining the Net System Value (NSV) as the sum of the exports and system costs, it can be concluded that the NSV increases in the future scenario. The value of net exports increases by about 2.3% to approximately 2 billion Euros, and the system cost decreases by about 0.3% to approximately 2.5 billion Euros (Fig 4.18). The net effect is that the NSV increases by 0.9% i.e. about 38.03 million Euros (Fig 4.19).

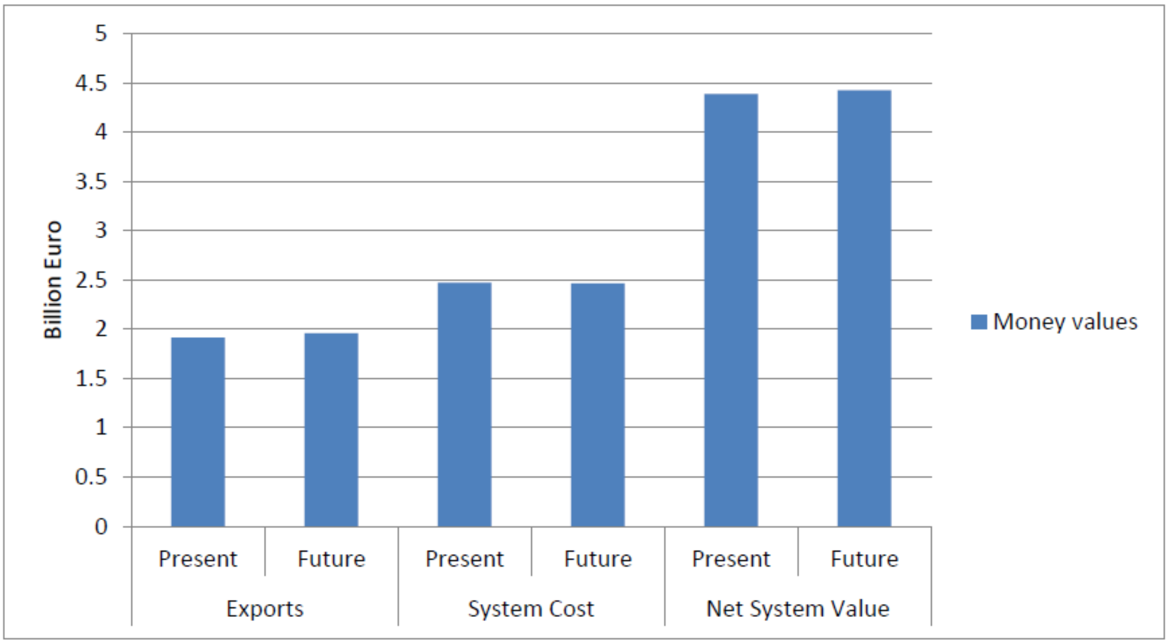


Figure 4.18: Export revenue, system cost and Net System Value for Switzerland, for the Present and the Future scenario

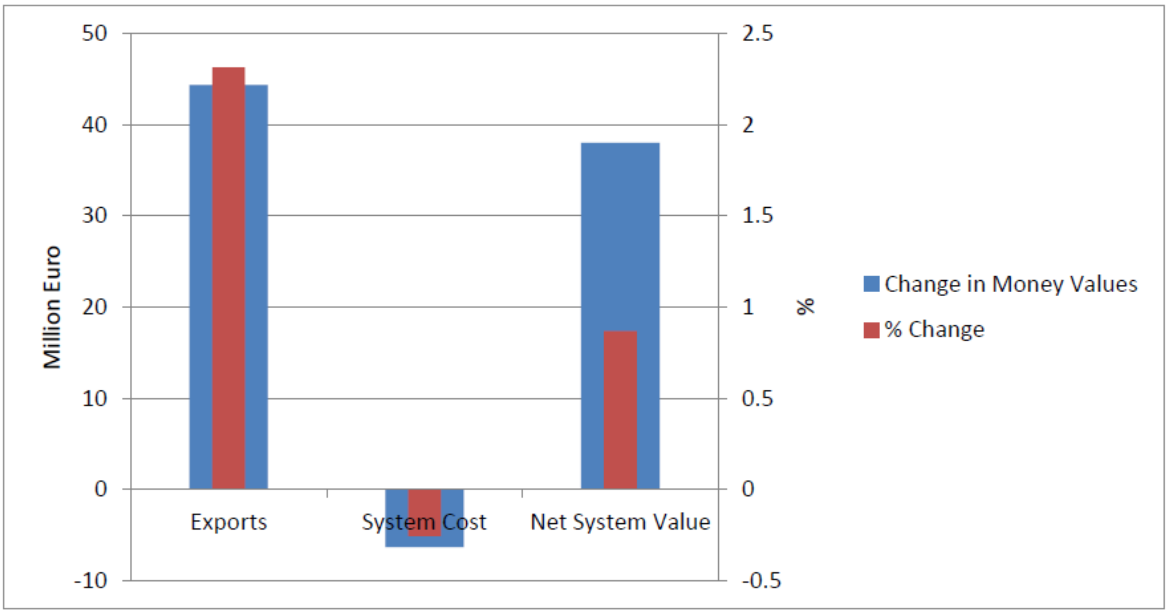


Figure 4.19: Change in export revenue, system cost and Net System Value for Switzerland in the Future scenario compared to the Present

In Section 4.3, it was shown that the increase in Swiss electricity exports is juxtaposed by a decrease in exports (or increase in imports) of other countries. This can be clearly demonstrated using the same NSV metric for AT, FR, DE and IT are shown in Fig 4.20 and Table 4.1.

Table 4.1: Change in Net System Value for the five countries in the Future scenario compared to the Present

	AT	FR	DE	IT	CH
Million Euro	-7.02315	-1.5195	-33.1291	-6.78978	38.02551
% Change	-0.22545	-0.00807	-0.17839	-0.04131	0.866898

The decrease in NSV for the future scenario was largest for Germany in absolute terms (33 million Euros) but modest for other countries. This shows the tight coupling of the German power market to the developments on the supply side in Switzerland.

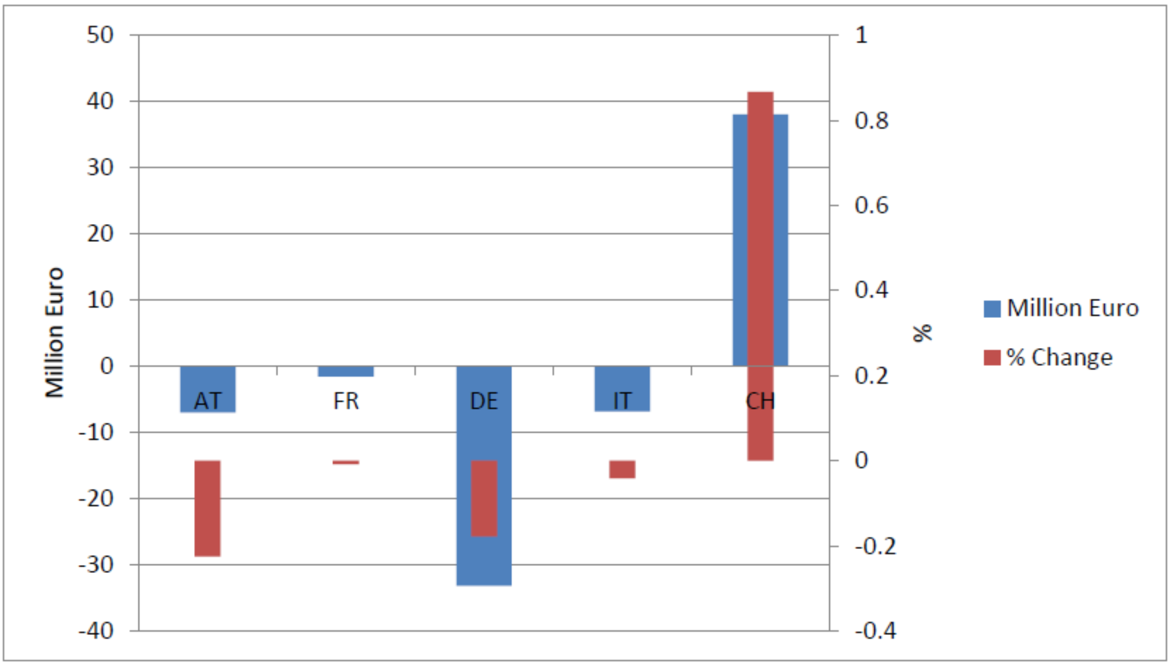


Figure 4.20: Change in Net System Value for the five countries in the Future scenario compared to the Present

4.7 Limitations of the analysis

The limitations of the modelling approach used in this analysis stem from the simplifications adopted to make the analysis tractable and soluble in the limited time-frame available for this thesis. The main caveats are explained below.

Limitations of hydrology modelling

- Only one scenario, produced by the ETHZ modelling group during the ENSEMBLES project, is used to drive the hydrology model. Thus, only the SRES A1B CO_2 emissions scenario from one climate model is accounted for in this study. The ETHZ climate model output used in this thesis is one of the warmer scenarios and therefore would form the upper bound of the results from the full ensemble of models.
- Only six representative hydrological regimes were modelled and the inflows were then aggregated using the procedure described in Section 3.3.1. This leads to the possibility that the behaviour of some catchment areas was left out of the final inflow result.
- The hydrology model simulates the behaviour of hydrological processes, many of which are non-linear. Moreover, as with all models, since the processes are parametrised there is an inherent limitation of not representing them to their fullest and most exact detail.
- The representative periods for the present and future scenarios for the hydrology modelling were chosen to be 2008-2013 and 2045-2050 i.e. 5 year long simulations were run. Since the model runs at a high time-resolution (hourly or ten-minute, depending on the modelled catchment), some extreme precipitation events which occurred during the selected time-frame might be over-represented. Another source of spurious model behaviour could be the use of the Delta-Change method of reconstructing future scenarios,

due to the inherent limitations of the same[24].

Limitations of electricity system modelling methodology

– The electricity market optimization model used here simulates an idealized market. Generation levels and electricity prices are calculated using a least cost optimization approach. In comparison, real electricity markets are operated in a way that the prices are determined by generators and consumers submitting bids to the market operator, who then aggregates the bid and ask curves. This procedure is carried out at several levels - one day in advance, one week in advance etc. and it is also updated in real time. In addition market participants can trade in other instruments such as forward and option contracts which can be either purely financial or physical. These aspects are not considered in the modelling procedure. Thus, the impact on real-world markets may be different.

– The results are not representative of an actual future scenario since they do account for the evolution of the electricity sector, nor do they involve any modelled interaction with the rest of the economy. For example, in the long-run, electricity demand will increase or decrease and new technologies with potentially different costs will enter the market. In fact even at present, Germany is undergoing a transition of its energy system (termed as Energiewende). There is a large uptake of renewable sources of energy which is causing an upheaval in the structure and organisation of the electricity sector. In addition, the phasing out of nuclear energy has begun in some states (e.g. Germany and Switzerland), and is being debated in others post the Fukushima nuclear accident. All these factors will contribute to an electricity system that will, in all likelihood, look very different from

[24]Based on the methodology adopted for creating future climate scenarios, described in footnote 10, it can be reasoned that some statistical errors may result. Moreover, the Delta-Change method itself has some limitations which are described in Bosshard et al. [4].

that of today. To capture these effects, several scenarios need to be developed and the electricity simulation model run for each year from now until 2050 to make any concrete conclusions of expected behaviour and the uncertainties involved.

– The results depend on the model parameters. For example, the results were obtained by running the model at a step size of five months (at hourly resolution). This step size was the largest that could be chosen with regard to computational limitations, while still allowing for a seasonal characterisation of the hydropower characteristics. Changes to the step size might change the results but were not tested. Another example is that detailed technical characteristics of individual power plants are not represented. For example, marginal cost can vary strongly with generation levels beyond a certain output range - such non-linear behaviour is not modelled in this analysis.

General limitations

– The modelling approach used in this analysis is deterministic. In reality both hydrological processes and electricity supply and demand are stochastic. The stochastic nature of these processes influences real-world decision by plant managers, ultimately leading to higher volatility in prices in real-world electricity markets.

– Geographical scope: This analysis looked at the change in Switzerland's hydrology. The geographical scope needs to be increased to increase the accuracy of the models.

– Sensitivity and uncertainty analyses are not performed. To test how sensitive the models are to parameter values, simulations will have to be performed for various sets of both hydrological parameters and technical characteristics of generating plants. Uncertainty analyses will need the simulations to be performed using several scenarios.

– While there were advantages to using proven, commercially available software tools for modelling - namely robustness, ease-of-use and computational efficiency - it leads to a somewhat opaque analytical methodology which may not be easily accessible in its entirety. Thus, while the models were used as 'black-boxes', this could be a limitation and a truly transparent solution would be to use available open source models or develop them from scratch.

The above limitations are the product of several factors. The most important reason is that the focus of the project was to explore the broader economic response of the electricity system to changes in hydrology without getting into complex technical details of electricity generating plants, since these do not strongly influence broad price movements. Moreover, commercial software tools and publicly available data have been used for both hydrology and electricity market modelling and they constrained the flexibility of input and output data. Secondly, time available for completing this work was a major constraining factor. However, expert advice and judgement has been used for both the hydrology and electricity system modelling to include the most critical aspects and prevent unrealistic results. Hence, the level of detail included in the study was deemed acceptable.

The results of this analysis are therefore to be considered in the context of the above limitations. Although the absolute numbers may be different from reality, the relative changes between present and future scenarios and the characteristics of the system response are consistent with expected behaviour from literature. Moreover, the methodology developed during the analysis can be easily extended to incorporate increased detail and therefore paves the way for future work.

Chapter 5

Summary and policy implications

A summary of the results, for Switzerland, of the analysis presented in this thesis is shown in Fig 5.1. The annual increase of about 4.6% in the inflows, with the associated seasonal patterns, leads to a decrease in electricity price (SMP) of approximately 0.4% in the summer and 0.03% in the winter. Increased supply of cheaper hydropower therefore leads to an increase in exports and reduction in imports, ultimately reducing system cost and increasing the net system value. Keeping in mind the limitations and caveats of the analysis (Section 4.7), it can be said that in the middle of the century, climate warming essentially leads to increased potential supply of hydropower leading to a net economic benefit for Switzerland. This comes at the cost to the interconnected markets of Austria, France, Germany and Italy all of whom see decreases in the money value of their electricity system. However, since the employed methodology does not incorporate the evolution of the electricity sector over the next fifty years, this is only a potential impact and the exact behaviour of the system can only be found by doing detailed scenario analyses.

Variant	Result Variable	% Change	Interpretation of the outcome
1	Annual Inflow	+ 4.26 %	More water available for generation
2	Water Value	Summer: -0.5% Winter: -0.03%	Larger decreases in high inflow periods
3	SMP	Summer: -0.36% Winter: -0.03%	Larger decreases in summer (in step with WV), not as high as WV due to export
4	Annual Trade	Exports: +2.3% Imports: -1.4%	Exports increase, imports decrease
5	System Cost	-0.26%	Decrease in system cost (due to more, cheap water)
6	Net System Value	+0.87%	Net increase in system value

Figure 5.1: Summary of results from the analysis

Thus, although the quantum of climate impacts on the electricity system can be judged from this analysis, one cannot accurately predict the magnitude of the impact several decades into the future. This lends a cautionary tone to the use of the results in making policy recommendations. However, the ENSEMBLES project predicts that as climate warming advances in the latter half of the century, only 25% of the present glacier volume will remain (van der Linden P. and Mitchell [22]). Given the precedents of the results presented here, it can be concluded that in the latter half of the century, there will therefore be a shortage in potential supply of hydropower, with a negative impact on the net system value. Thus, with these opposing impacts at two different points in time, one policy proposal that could be recommended to safeguard the security of supply as well as provide some insurance to suppliers is a revision in the water fees (*"Wasserzinse"*, in German) that hydropower producers pay to the Swiss cantons. Currently, hydropower producers have to pay a fee to the canton for the use of water, which is defined on the basis of the installed capacity of the power plant. These fees currently add up to about 300 million Swiss francs (total for Switzerland, according to Banfi et al. [2]). If these fees are charged on a variable basis - on the basis of available water, for example - the increase in water supply would lead to increased fees in mid-century which can be used to invest in measures to mitigate the impact of the loss of glaciers towards the end of the century. Of course, this is a complex, multidimensional issue involving a large number of diverse stakeholders and the solution is certainly not as simple as to be discussed in this work. For further reading on the issue of flexible water fees, readers are directed to Banfi and Filippini [1] which provides a good starting point for a discussion of this nature.

Chapter 6

Conclusion

Based on the strengths and weaknesses of the analysis methodology, various proposals for future work can be considered. Two significant improvements will be the incorporation of several climate scenarios and the evolution of the electricity over time. Both of these are not trivial issues and were therefore not attempted here in the interests of time. Another improvement will be to perform sensitivity analyses of both the hydrology and electricity system models. Further extensions could then be to simulate for longer time scales i.e. over the entire century, including the aforementioned uncertainty and sensitivity analyses.

In summary, the contribution of this thesis is a demonstration of the impact of climate warming on the economics of the electricity model by employing both detailed hydrology and electricity system models, which to the extent of the author's knowledge, has not been attempted for the countries in question. The response of the electricity system has been both qualitatively and quantitatively described, and potential policy implications explored. To achieve this, a repeatable and easily extensible methodology using commercially available tools and publicly available data has been used. The results obtained correspond to the expected behaviour of the electricity system obtained from the analytical model used as a reference. The results and conclusions have been carefully evaluated for strengths and weaknesses, and based on the limitations of the analysis recommendations for improvements have been made. Thus, this thesis builds on state-of-the-art research in this field and also extends the body of knowledge in many areas.

Appendix A

Hydrology modelling - selected catchments, regimes and their inflows

Figure A.1 shows the location of the three reservoirs whose inflows were modelled and later extrapolated based on the methodology explained in Section 3.3.1.

Figure A.1: Location within Switzerland of the three modelled reservoirs

The hourly inflows for the present and future case for each of these reservoirs is shown in Figure A.2 to Figure A.4. Hereafter in all figures, the future scenario for 2050 and the 2013 scenario are labelled 'future' and 'present' respectively.

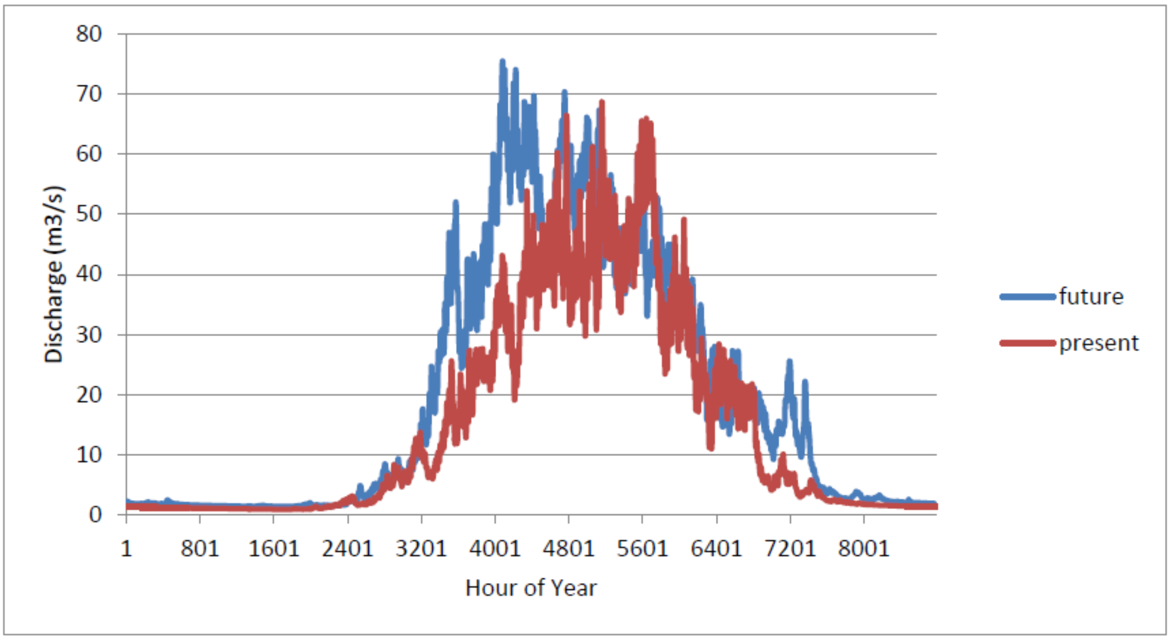


Figure A.2: Hourly inflows in the Massa reservoir

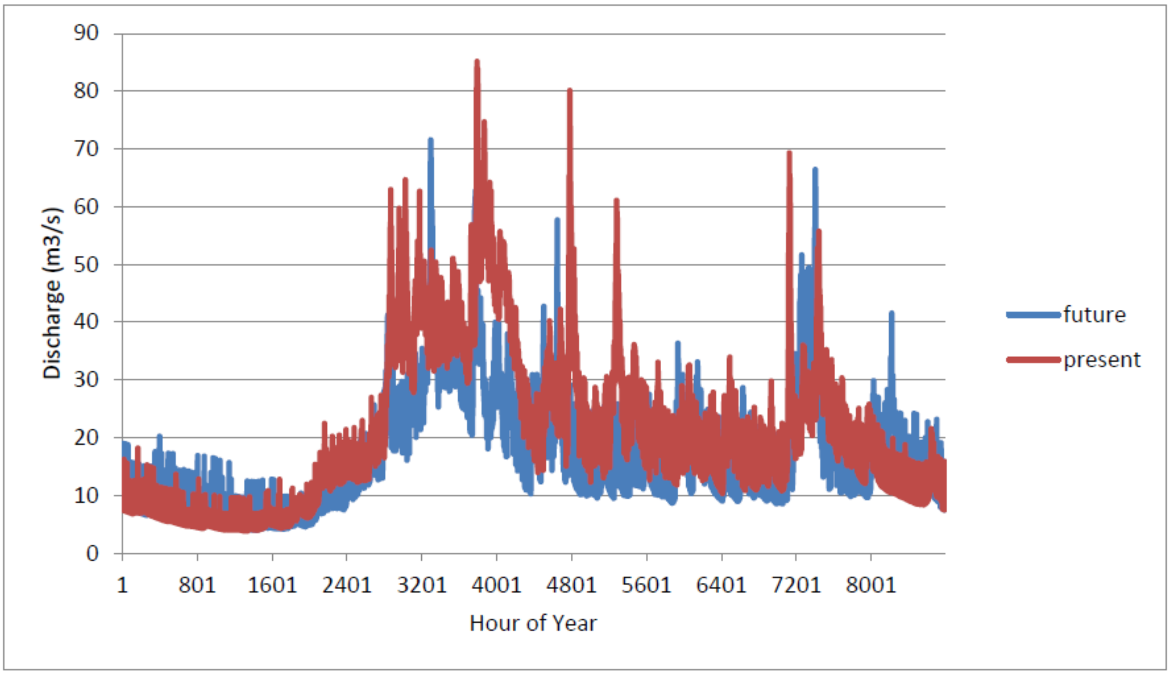


Figure A.3: Hourly inflows in the Isola reservoir

Figures A.5 to A.7 show the set of discharges for three representative river regimes that were modelled Aare, Rhine and Rhone respectively. These discharge values are not to be interpreted as ones at a particular point but a sort of global average in the watercourse.

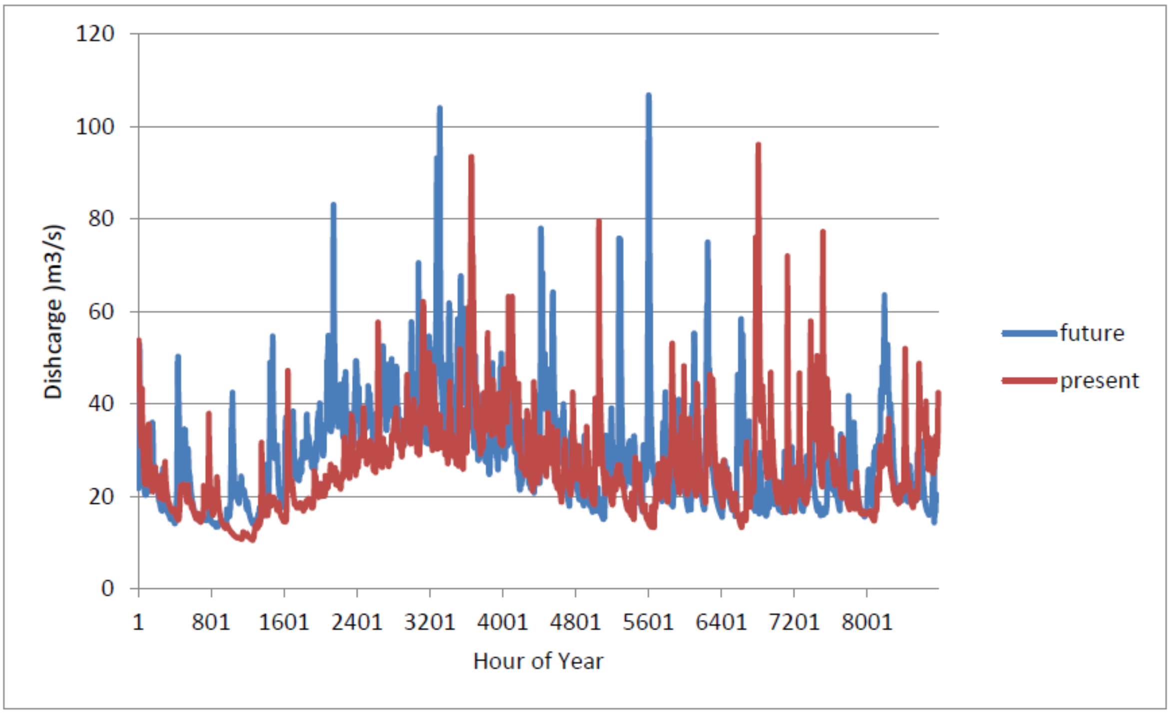


Figure A.4: Hourly inflows in the Gruyere reservoir

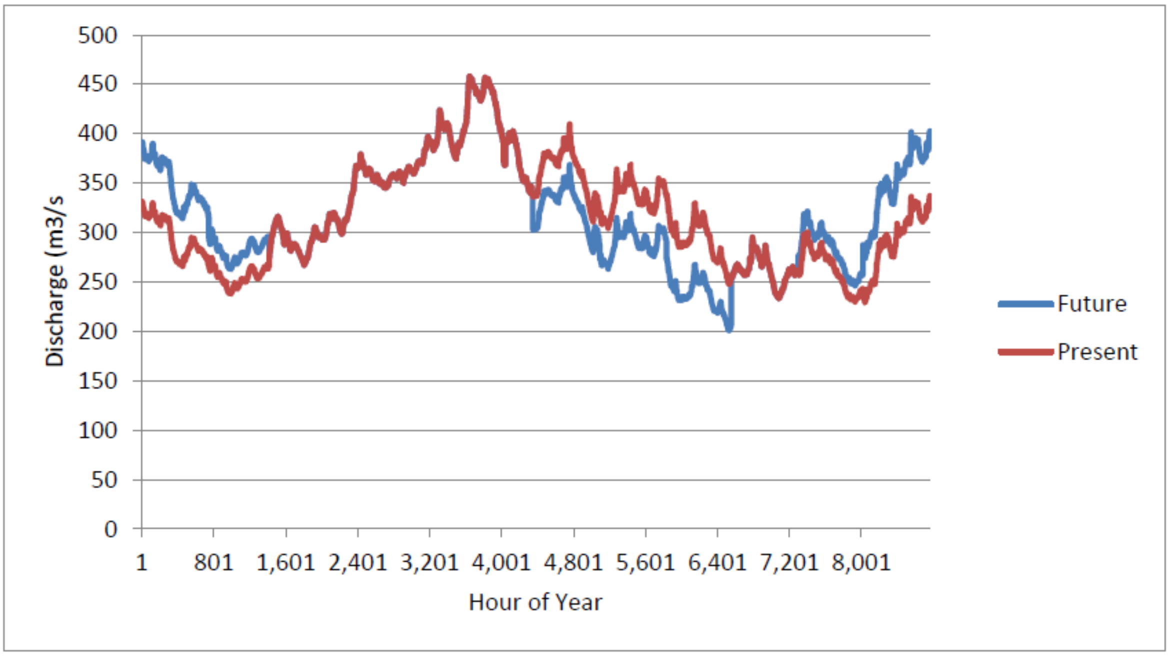


Figure A.5: Simulated discharge in the Aare river

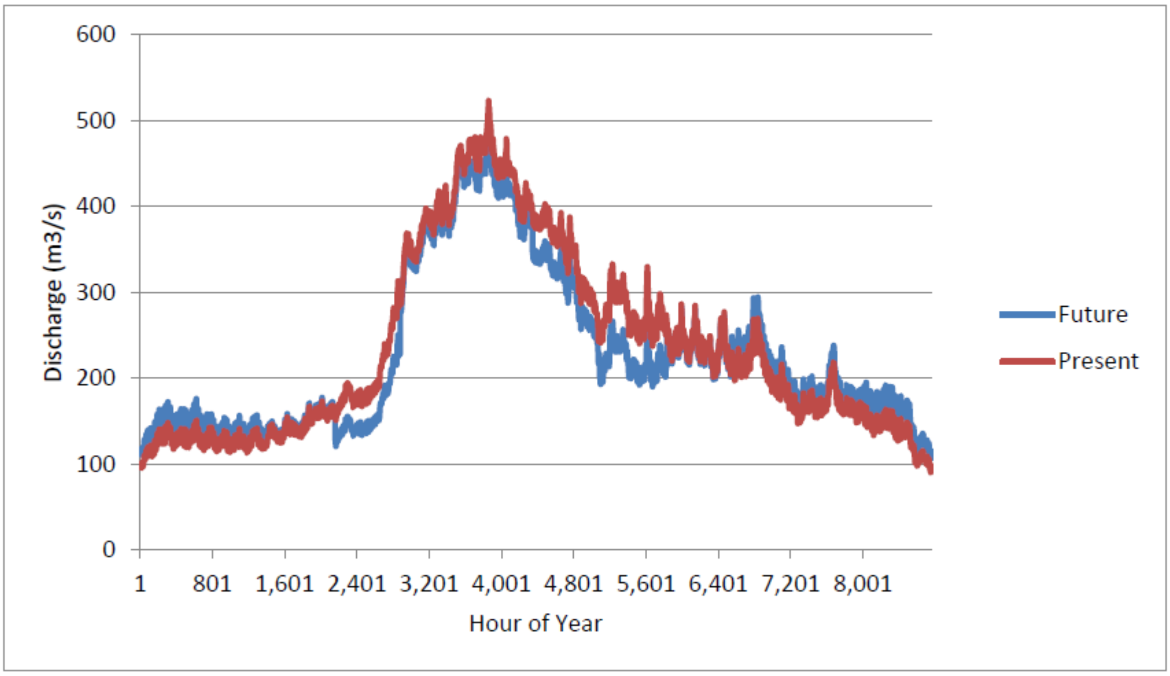


Figure A.6: Simulated discharge in the Rhine river

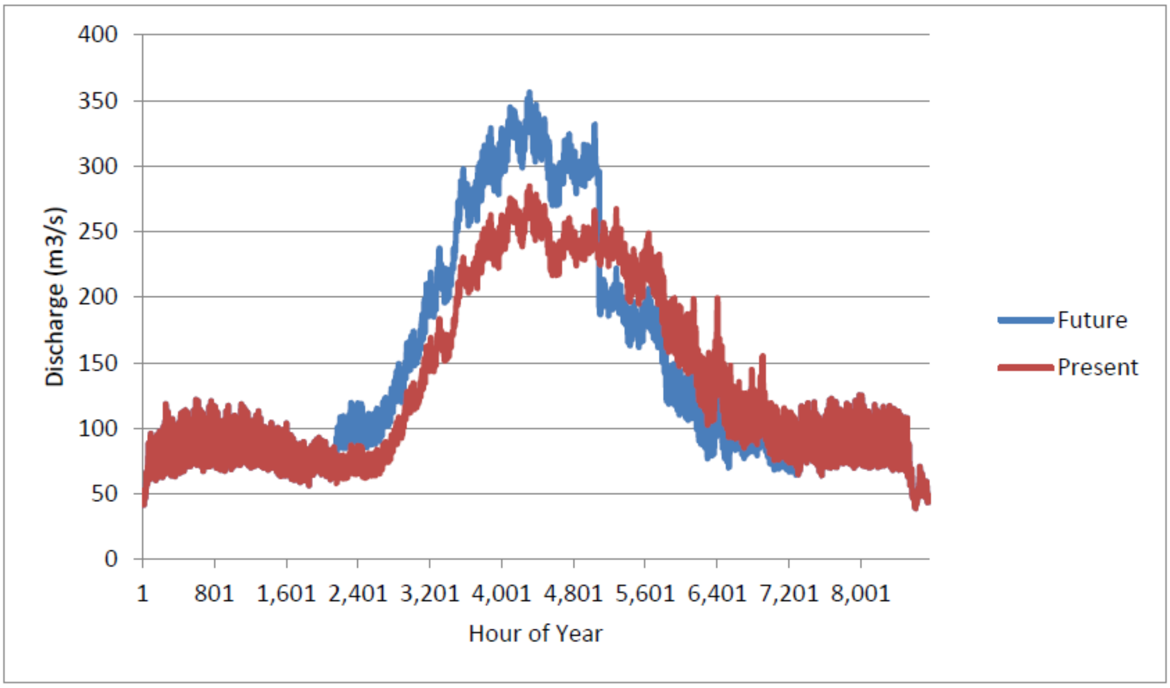


Figure A.7: Simulated discharge in the Rhone river

Appendix B

Generation optimization - Unit Commitment and Economic Dispatch

This section briefly outlines the Unit Commitment and Economic Dispatch problem, presented here as an adaptation of the one in Salam [17]. It is presented here in a simplified form applicable for a one-region model containing hydro and thermal plants. The optimization problem which is solved reads as the following:

$$\min \quad \sum_{g=1,t=1}^{M,T} Cost(Gen_{g,t}^{Th}) \tag{B.1}$$

$$\begin{aligned} \text{s.t.} \quad \sum_{g=1,t=1}^{M,T} Gen_{g,t}^{Th} + \sum_{g=1,t=1}^{H,T} Gen_{g,t}^{H} &= \sum_{t=1}^{T} Demand \\ R_t &= R_{(t-1)} + w_t - Gen_t^H \\ R_t &\leq \bar{R} \\ Gen\mathsf{L}^H &\leq Gen_t^H \leq Gen\mathsf{U}^H \\ Gen\mathsf{L}^{Th} &\leq Gen_t^{Th} \leq Gen\mathsf{U}^{Th} \end{aligned} \tag{B.2}$$

Where

M, H	: Set of thermal and hydro plants
Gen_t^{Th}, Gen_t^H	: Generation from thermal and hydro plants at time t
R_t, w_t	: Reservoir content and inflows, in energy units, at time t
$\bar{R}$, $Gen\mathsf{U}^{Th}$, $Gen\mathsf{U}^H$	: Upper bound on reservoir content and generation
$Gen\mathsf{L}^{Th}$, $Gen\mathsf{L}^H$	: Lower bound on generation

The objective function includes the cost function of thermal plants. Since hydropower plants have an insignificant marginal cost of generation, the objective function is essentially to minimize the cost of generation from thermal plants. In the first constraint of equation set B.2, it is stated that at all times, electricity demand should be balanced by the generation. Secondly, the hydro reservoirs must fulfil the second constraint in equation set B.2 which states that the amount of water in the reservoir at time t is the net of the amount of water in the previous period plus the inflows arriving in the current period minus the generation from the plant in the current period. The third and fourth constraints are reservoir and generation bounds.

The ELAN model used in this analysis solves a model similar, albeit more detailed and complex, than this one wherein several countries are included with their associated flows as well as a different marginal cost specification.

Bibliography

[1] S. Banfi and M. Filippini. Resource rent taxation and benchmarkinga new perspective for the swiss hydropower sector. *Energy policy*, 38(5):2302–2308, 2010.

[2] S. Banfi, M. Filippini, and A. Müller. An estimation of the swiss hydropower rent. *Energy policy*, 33(7):927–937, 2005.

[3] BFE. Elektrizitätstatistik. Technical report, BFE, Bern, 2012.

[4] .T Bosshard, S. Kotlarski, T. Ewen, and C. Schär. Spectral representation of the annual cycle in the climate change signal. *Hydrology and Earth System Sciences*, 15 (9):2777–2788, 2011.

[5] F. Forsund. *Hydropower Economics*. Springer, 2007.

[6] J. García Hernández, F. Jordan, J. Dubois, J.L. Boillat, and A. Schleiss. Routing system ii: Flow modelling in hydraulic systems. *Communication du Laboratoire de Constructions Hydrauliques*, 32, 2007.

[7] L. Gaudard, M. Gilli, and F. Romerio. Climate change impacts on hydropower management. *Water resources management*, 27(15):5143–5156, 2013.

[8] R. Golombek, S. Kittelsen, and I. Haddeland. Climate change: impacts on electricity markets in western europe. *Climatic change*, 113(2):357–370, 2012.

[9] IPCC. Special report on emissions scenarios. Technical report, IPCC, 2000.

[10] IPCC. Climate change 2007: Synthesis report. Technical report, IPCC, 2007.

[11] T.C. Koopmans. *Water storage policy in a simplified hydroelectric system*. Cowles Foundation for Research in Economics at Yale University, 1958.

[12] B. Lehner, G. Czisch, and S. Vassolo. The impact of global change on the hydropower potential of europe: a model-based analysis. *Energy Policy*, 33(7):839–855, 2005.

[13] M.G. Lijesen. The real-time price elasticity of electricity. *Energy economics*, 29(2): 249–258, 2007.

[14] J.D.C. Little. *The use of storage water in a hydroelectric system*. PhD thesis, Massachusetts Institute of Technology, 1955.

[15] E.G. Read. *Optimal operation of power systems*. PhD thesis, University of Canterbury, New Zealand, 1979.

[16] E.G. Read. Deterministic reservoir operation: an application of the economic principles. Technical report, New Zealand Ministry of Energy, Wellington, 1984.

[17] M. Salam. Solution to the short term unit committment problem. *Handbook of Power Systems I - Energy Systems*, pages 255–292, 2010.

[18] S. Stage and Y. Larsson. Incremental cost of water power. *Power apparatus and systems, part iii. transactions of the american institute of electrical engineers*, 80(3): 361–364, 1961.

[19] Swisselectric. Auswirkungen der klimaänderung auf die wasserkraftnutzung. Technical report, Hydrologische Kommission CHy der Akademie der Naturwissenschaften Schweiz SCNAT, 2011.

[20] J.P. Tipping, E.G. Read, and D. McNickle. The incorporation of hydro storage into a spot price model for the new zealand electricity market. In *Proceedings of the 6th IAEE European Conference*, 2004.

[21] B. Uhlmann, F. Jordan, and M. Beniston. Modelling runoff in a swiss glacierized catchmentpart ii: daily discharge and glacier evolution in the findelen basin in a progressively warmer climate. *International Journal of Climatology*, 33(5):1301–1307, 2013.

[22] van der Linden P. and J. Mitchell. ENSEMBLES: Climate change and its impacts:

Summary of research and results from the ensembles project. Technical report, Met Office Hadley Centre, Exeter, 2009.

[23] M. Van Vliet, S. Vögele, and D. Rübbelke. Water constraints on european power supply under climate change: impacts on electricity prices. *Environmental Research Letters*, 8(3):035010, 2013.

[24] R. Weingartner, B. Schädler, and P. Hänggi. Auswirkungen der klimaänderung auf die schweizerische wasserkraftnutzung. *Geogr. Helv*, 68:239–248, 2013.

[25] A. Wood and B. Wollenberg. *Power generation, Operation and Control*. John Wiley & Sons, USA, 1996.

Acknowledgements

Several individuals assisted me directly or indirectly with the work on my thesis. I would like to take the opportunity to thank them. Dr. Gunter Stephan, my thesis supervisor, provided invaluable and timely guidance right from the beginning of this undertaking. Dr. Ralph Winkler, with whom I had interesting discussions, provided helpful guidance in his capacity as my co-supervisor. Since I used commercial modelling software for my analysis, I am deeply indebted to Dr. Twan Vollebregt, CEO of Energy Fundamentals and Dr. Frédéric Jordan - Director, e-drich.ch, who graciously agreed to let me use the EPSI and RS3.0 modelling platforms respectively for my thesis. Also, without the technical guidance of Twan, Frédéric and Guillaume Artigue, I would not have made the rapid progress that I did. Dr. Ludovic Gaudard, who was close to finishing his PhD when I first contacted him for advice on my thesis, gladly gave his time in reviewing early results of my analysis and provided much needed feedback.

I also extend my thanks to my parents and my sister who provided constant encouragement, love and support throughout my time at the University of Bern and to Diego Sandoval, a dear friend, who was always there to hear my ideas. And last but not the least, I extend my sincerest gratitudes to Ananda Kambli and my guru Swami Samartha, without whose teachings of yoga and meditation, this endeavour would have been impossible.

Declaration

under Art. 28 Para. 2 RSL 05

Last, first name:	Godbole, Advait
Matriculation number:	12-124-673
Programme:	M.Sc. in Climate Sciences (Economics)
	Bachelor ☐ Master ☒ Dissertation ☐
Thesis title:	Climate change impacts on hydropower and the electricity market: A case study for Switzerland
Thesis supervisor:	Prof. Dr. Gunter Stephan

I hereby declare that this submission is my own work and that, to the best of my knowledge and belief, it contains no material previously published or written by another person, except where due acknowledgement has been made in the text. In accordance with academic rules and ethical conduct, I have fully cited and referenced all material and results that are not original to this work. I am well aware of the fact that, on the basis of Article 36 Paragraph 1 Letter o of the University Law of 5 September 1996, the Senate is entitled to deny the title awarded on the basis of this work if proven otherwise. I grant inspection of my thesis.

Bern, July 24, 2014 Signature