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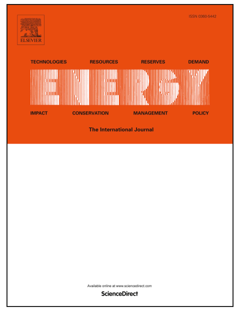

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OPTIMIZATION OF REGIONAL WATER - POWER SYSTEMS UNDER COOLING CONSTRAINTS AND CLIMATE CHANGE

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Article Impact Statement: How do cooling constraints on thermal power production affect the water-energy nexus on the Iberian Peninsula ?

Abstract

Thermo-electric generation represents 70% of Europe's electricity production and 43% of water withdrawals, and is therefore a key element of the water-energy nexus. In 2003, 2006 and 2009, several thermal power plants had to be switched off in Europe because of heat waves, showing the need to assess the impact of climate change on cooling constraints of thermal power plants. An integrated water-power model of the Iberian Peninsula was developed in this study. It includes a physical hydrologic representation, spatially and temporally resolved water demands, management of water infrastructure and a simple power system model. The system was evaluated under present and future climatic conditions using different climate change scenarios. The cost of cooling constraints is found to increase by 220 to 640 million € /year, for the period 2046-2065 depending on the climate change scenario. Average available capacity of freshwater-cooled thermal power plants is reduced by 16 to 30% while production is reduced by 5 to 12% in summer. The power production is shifted from plants equipped with once-through cooling systems (-5 to -14%) towards plants using closed-circuit cooling systems (+41 to +95%).

1. Introduction

Water and energy systems are strongly interdependent: while water is used for energy production through hydropower, extracting and refining combustibles and cooling of thermal power plants, energy is used to extract, treat and supply water as well as collect and treat wastewater

[1]. Thermo-electric generation represents 70% of Europe's electricity production [2] and 43% of water withdrawals [3]. Its dependence on freshwater resources has to be considered when defining energy strategies or building new thermal power plants that have a lifetime of around 30-60 years [4]. In order to protect ecosystems, the amount of heat that can be discharged into rivers and lakes by thermal power plants is regulated by law. During recent droughts in Europe, high water temperature combined with water scarcity, forced thermal power plants to reduce their production [5]. For similar reasons, the US energy sector has started to shift production towards power plants

requiring less water withdrawals [6]. As climate change will reduce water availability and increase temperature [7], it is necessary to assess its impact on the cooling constraints of thermal power plants and the performance of the system.

Chandramowli et al. [8] presented a literature review on climate change impacts on the power system. The review covers demand-side variation linked to temperature-sensitive demands, risks of extreme climatic events on the physical infrastructure, impacts of changing climatic conditions on renewable energy sources and impacts of reduced freshwater availability on hydropower production and cooling requirements of thermal power plants. Koch and Vögele [9] proposed a method to model shortages in thermal production linked to water availability and temperature constraints. The method, combined with a hydrological and water-temperature model, was applied to assess the impact of climate change on nuclear power plants in several studies. For Germany, Koch and Vögele [10] and Koch et al. [11] estimated available capacity reduction for nuclear power plants. At the global scale, Vliet et al. [4] found that more than 80% of all thermal power plants would face available capacity reductions in the period 2040-2069. A more optimistic study by Wang et al. [12] found that the expected improvement in the efficiency of generation technologies could lead to some water savings; however, this study did neither consider climate change nor the spatio-temporal distribution of water demand. In these studies impacts are evaluated in terms of the available capacity and not in terms of the actual production, as the power system is not simulated jointly with the hydrological system. Nuclear power plants are typically operated at full capacity, and the available capacity is therefore a good indicator for the production. In contrast, coal and gas power plants have a more flexible production schedule and use on average only a fraction of their capacity. While available capacity remains a useful indicator, the whole power system needs to be considered, taking into account interactions between the different power producers and power demand, in order to assess the impact of climate change on the actual thermal production. Khan et al. [13] presents a literature review on integrated water-energy models. In general, these models have a more detailed representation of the power system, considering the various steps of power production and more diverse power producers. However, as pointed out in the review, among the 16 reviewed integrated water-energy models, only two take into account cooling water constraints, and only one (Dubreuil et al., [14]) has hydrological constraints. But these two last models are not spatially and temporally disaggregated and may therefore oversee the spatial or temporal scarcity of cooling water identified by the previously mentioned studies. Khan et al. [15] used an integrated water-energy model for Spain to illustrate the importance of the linkages between the energy and water systems when planning infrastructures. However, the impact of river temperature on thermal power-plants was limited to efficiency reduction, disregarding shortages related to environmental regulations. Alternatively, recent studies focus on the trade-offs between environmental constraints and energy production: Gjorgiev et al. [16] finds that relaxing the environmental constraints in extreme events prevents significant capacity curtailments using a basin scale model for a synthetic case study. Logan et al. [17] presents a methodology combining a hydrodynamic-temperature model and a risk assessment for fish species to refine the environmental constraints for individual power plants.

The objective of the present study is to develop an integrated water-power management model including diverse power producers and cooling constraints of thermal power plants, in which water allocation is a decision variable and is connected to a spatially and temporally disaggregated hydrological model. The case study is the Iberian Peninsula, where the thermal power sector represents 47% of total electricity production (OMIE [18]), 17% of freshwater withdrawals (MMA [19]) and where climate change is expected to have severe impacts on water availability (IPCC [7]). The model is used to assess the impact of climate change on the cooling constraints of the water-power system of the Iberian Peninsula.

2. Material and methods

The study constructed a regional joint water-power management optimization model. Water availability is estimated using a rainfall-runoff model developed by Pereira-Cardenal et al. [20]. River network and hydraulic infrastructure are represented in a physical flow-path network approach (Cheng et al. [21]). Available water can be allocated to the water users (agriculture, domestic, electricity production), used for thermo-electric and hydropower generation and be stored/released from hydropower reservoirs. The links between the water and power system are the hydropower and thermal power plants using freshwater resources. They produce electricity in a simple representation of the power system adapted from Pereira-Cardenal et al. [22]. The power system is represented as one single power pool covering the entire Iberian Peninsula where the electricity generated by different producers has to meet the peninsular power demand per time-step. Other power producers are the “special regime”, representing producers having a special agreement (among others renewable energy producers), and the seawater-cooled thermal power plants. Water allocation and power production are represented as decision variables with associated marginal costs, subject to different physical and economic constraints implemented through linear programming [23]. The system is evaluated for the reference period 1971-1990 and under four climate change scenarios for the period 2046-2065. In both periods, the system is considered with and without cooling constraints to assess their impact on the water and power system.

Joint water and power management is formulated as a hydro-economic optimization problem. Hydro-economic models enable integration of economic principles in decision making, as they couple economic concepts to a hydrological representation. Each decision is characterized by its marginal benefit or cost and the optimal management becomes a single-objective problem, solved by maximizing (/minimizing) the economic benefit (/cost). Hydro-economic modelling is frequently used to assess the economic impact of alternative scenarios or strategies ([20], [24]) and is therefore highly suitable for the present study.

2.1 Water system representation

The modelled area covers the seven major river basins of the Iberian Peninsula: Tajo, Ebro, Duero, Guadiana, Guadalquivir, Mino-Sil and Jucar. They extend over 400800 km^2 in Spain and Portugal, representing around 70% of the Peninsula. Using a digital elevation model (European Environmental Agency [25]) the 7 basins were divided into a total of 123 watersheds corresponding to the 116 major hydropower plants (**Figure 1**). The hydropower plants characteristics are obtained from Pereira-Cardenal et al. [20]. Their cumulated storage capacity is 46 000 $10^6 m^3$ out of the total 56 000 $10^6 m^3$ installed capacity regulating around 40% of the flow [26].

The river network and the hydraulic infrastructure are represented in a physical flow-path network approach [21] where water can be allocated from sources (reservoirs, run-off, and groundwater) to sinks (reservoirs, thermal power plants, agriculture, domestic and industrial demand) (**Figure 1**). Precipitation, surface runoff and groundwater recharge for the period 1971-1990 are obtained from the rainfall-runoff model developed in [20]. Generally the data is processed at the daily and weekly resolution; this issue is discussed later in the results. For each watershed groundwater is represented as a lumped linear reservoir subject to the following equations:

$$GWout_t = GWout_{t-1} \cdot e^{-dt/k_g} + GWin_t \cdot (1 - e^{-dt/k_g})$$

$$GW_{t+1} = GW_t + GWin_t - GWout_t - GWall_t$$

Where t is the present time step, dt (days) the length of the time step, k_g ($days^{-1}$) is the linear reservoir constant, $GWout$ (m^3) represents the groundwater outflow to the river, $GWin$ (m^3) the groundwater recharge, GW (m^3) the groundwater volume in the aquifer and $GWall$ (m^3) the allocated groundwater to water users. An air-water temperature model from Mohseni et al. [27] is implemented in order to convert the weekly-daily air temperature data from [20] into weekly-daily river temperatures. The relation is formulated as follows:

$$T_r = c_4 + \frac{c_1 - c_4}{1 + e^{c_3(c_2 - T_a)}}$$

where T_r and T_a represent respectively the river and air temperature in °C, c_1, c_2, c_3 and c_4 are the calibration parameters. The calibration was performed for one basin only and can be found in section A of supplementary materials. No dynamic representation of river water temperature is included in the study.

The main water user of the IP is agriculture, accounting for 75% of the total water consumption, up to around 90% in the Ebro, Duero, Guadiana and Guadalquivir basins but only 25% in the Mino-Sil basin [19]. Irrigation water demands are calculated as local crop water requirements minus precipitation on irrigated land. Only consumptive uses are considered, return flows are not modelled. Mean yearly crop water requirements and irrigated area are based on Wriedt et al. [28], who produced a dataset for Europe with a 10x10 km resolution grid. The yearly averages were distributed over the months and then downscaled to the days-weeks, using the monthly distribution of the local evapotranspiration obtained from the MODIS-16 gridded actual evapotranspiration product [29]. The year 2000 was considered as a reference year in [28] and therefore used to calculate the monthly distribution, the distribution pattern can be found in the section B of supplementary materials. The cost associated to the deficit in irrigation water demand, also called "curtailment cost" is approximated by the marginal benefit of the cultivated land and is available per basin in MMA [19]. National yearly domestic and industrial water demand (excluding electricity generation) from [19] are distributed to the watersheds using LandScan population data (Bright et al., [30]) and then equally split among the weeks-days. The curtailment cost of domestic and industrial demand is arbitrarily set to five times higher than the agricultural curtailment cost and these demands are therefore always fulfilled first. In order to simplify the modelling process, minimum environmental requirements are calculated according to the Montana method, i.e are set to 10% of the natural annual flows [31].

2.2 Power system representation

In 2007, the Portuguese and Spanish electricity markets were merged into the MIBEL (Iberian Electricity Market) which is a common market for both countries. It is a deregulated energy market where electricity is sold and purchased at the short and longer term by means of a buy and bid system [22]. The power market is represented by the peninsular power demand that has to be met on the weekly-daily basis and by the different producers (thermal power, hydropower and special regime). The production of the different power-units depends therefore on their marginal costs and water-linked external costs and constraints.

The power demand is represented by a synthetic weekly-daily time series based on observed weekly-daily power demand from the years 2008 to 2015 from OMIE [18] randomly shuffled and repeated (2009 was excluded because heavily impacted by low oil prices). The power demand under climate change was calculated in Pereira-Cardenal et al. [22] according to the cooling and heating degree-day approach from Valor et al. [32].

Thermal power is the main electricity production source in the peninsula and accounts for 47% of total electricity production with 68 main thermal power plants including 5 active nuclear power plants. Santa Maria de Garona nuclear power plant which has been shut down since 2013 was included in the study because it has not been finally decommissioned yet. Only the main 25 thermal power plants that are situated in the modelled area are individually modelled with water requirements and power production and called “freshwater-cooled thermal power plants”. Among them, 5 out of 6 Nuclear power plants are represented as only the Vandellos nuclear power plant is located on the coast. A list of the modelled thermal power plants and characteristics can be found in section C of the supplementary materials. General information about power plants, such as location, type of fuel, cooling technology and installed capacity were found partly on Global Energy Observatory [33], and partly on the producer's or power plant's websites such as [34], [35]. For Nuclear power plants, the efficiency was extracted from World Nuclear Association [36] as the ratio of the design and thermal capacity. For the other thermal power plants, average data per technology was used, available for Spain and Portugal in IEA [37]. Most of the thermal power plants outside the modelled area are located along the coast (**Figure 1**) and use seawater for cooling purposes; according to [19] they represent less than 5% of total cooling water withdrawals. They are represented as a single aggregated thermal producer called "seawater-cooled thermal production" and assumed to be disconnected from the freshwater resource. The power production capacity of the seawater-cooled thermal production is evaluated as the observed maximal daily total thermal power production from [18] minus the average yearly share of thermal production by the freshwater-cooled power plants (based on the years 2006-2008, data from [33]); it is estimated at 400 GWh per day or 2800 GWh per week.

Marginal costs of power producers are confidential and unavailable, but they can be estimated. The CNE (Commission Nacional de Energia) provides estimated costs per technology [38], the marginal cost of nuclear production is estimated at 18€/MWh, while gas and coal power plants have a marginal cost of around 58€/MWh. However these costs are variable between individual power plants, therefore an alternative approach was selected. For the seawater-cooled thermal production, the marginal costs are derived from the empirical "thermal supply curve". This method, detailed and validated in [22], exploits the correlation of observed daily power production and market price and was shown to produce more reasonable supply elasticity than fixed or seasonally variable power production costs. The single aggregated sea-water cooled thermal power production is segmented into 10 equal segments with an associated increasing marginal cost from 0 to 70 €/MWh corresponding to the supply curve. The supply curve is represented in section D of the supplementary materials. The marginal costs of freshwater-cooled thermal power plants MC are estimated as follow:

$$MC = (FC \cdot {}^{1}/_{e_{th}} + O\&M) \cdot {}^{1}/_{1-\gamma}$$

where FC (€/MWh) is the fuel cost (gas or coal), e_{th} is the thermal efficiency, $O\&M$ (€/MWh) the variable operation and maintenance costs and γ the penalty factor for own electricity consumption induced by the cooling system. As for the power demand, a synthetic weekly-daily time series of fuel prices is generated based on monthly fuel prices from the years 2008 to 2015 from EIA [39]. The operation and maintenance costs from EIA [40] are assumed to be representative for the Iberian Peninsula, although they were derived from the US power system. Average values per cooling technology for γ are derived from [41] and range from 1.5% for once-through cooling systems to 7.2% for dry cooling systems. As fuel costs for nuclear power plants do not vary significantly, the average marginal cost of 18€/MWh from [38] was used.

The so called "special regime", accounting for 37% of total electric production, is a mix of energy sources of which 60% are renewable (mainly wind and solar), these producers have special agreement and the electricity is always cleared at a special price [22]. A synthetic special regime production time-series was constructed out of observed weekly-daily data from 2008 to 2015 extracted from OMIE [18] by repeating the observed time-series through the simulated years. It is subtracted from the total power demand to get the "net power demand" that has to be satisfied by thermal production and hydropower.

There are 208 hydropower plants in Spain and 38 in Portugal with a capacity over 10MW accounting for a total capacity of more than 20 GW [20]. The hydropower sector fulfilled on average 14% of the peninsular power demand between 2008 and 2015 [18]. The 116 main hydropower plants are modelled and represent 85% of the installed capacity in the peninsula; characteristics are obtained from [20]. Their production rates were calibrated in [20] to meet the total peninsular hydropower production. The marginal cost of hydropower production is estimated at 3 €/MWh [38] and hydropower is thus the cheapest electric production source.

2.3 Cooling constraints of thermal power plants

The cooling of thermal power production mainly uses "wet cooling systems" [9]. In the "once-through" technology water is taken from a river/reservoir, heated and directly discharged back into the river which leads to high withdrawals but low consumption. If cooling towers are installed, cooling water is fully (in closed circuit) or partially (once-through with cooling towers) evaporated, which leads to higher consumption but lower withdrawals [9].

The method to represent the cooling constraints of thermal power plants was adapted from Koch et al. [9]. The waste heat generated H_w (GWh) is linked to the production P (GWh) by the thermal (e_{th}) and net (e_n) efficiency:

$$H_w = \frac{1 - e_{th}}{e_n} \cdot P$$

The amount of waste heat discharged to the environment is constrained by the thermal capacity of the river:

$$H_w \leq \frac{Q \cdot \rho \cdot c_P \cdot dT}{(1 - \beta) \cdot (1 - \alpha)}$$

where Q (m^3) is the weekly-daily flow in the river, ρ (kg/m^3) the density of water, c_P (GWh/kg/K) the specific heat of liquid water, dT (K) the maximum temperature increase in the mixed river which is prescribed by environmental legislation, β is the share of waste heat dissipated through the cooling tower (evaporation) and α the share of waste heat dissipated through other parts of the system. To simplify the model and data collection, the net efficiency was assumed to be equal to the thermal efficiency ($e_n = e_{th}$) and additional heat losses in the system where neglected ($\alpha = 0$). The share of heat dissipated through the cooling towers (β) is the most sensitive parameter. It is assumed to be 0 for once-through cooling systems without cooling towers and 100 % for recirculating cooling systems. Data of water withdrawals of the 4 main water withdrawing thermal power plants (Nuclear power plants Asco, Almaraz and Santa Maria de Garona, and thermal power plant Acceca [19]), was used to calibrate β for these thermal power plants. These four power plants represent 80% of total water withdrawals for cooling purposes (4173 out of 5169 $10^6 m^3$ per year) and Asco Nuclear power plant alone represents 46% of them [19]. The parameter β is hard to estimate for once-through cooling systems with cooling towers. Literature (Macknick et al., [42]; NETL, [43]) distinguishes only two categories among the three: once-through systems or closed circuit systems (ambigously also called “cooling tower systems”) but points out that cooling water requirements for the same cooling technology can be variable. Macknick et al. [42] reported withdrawals by once-through cooling systems varying from 40 to 240 m^3/MWh. The value of β of thermal power plants equipped with once-through cooling systems with cooling towers was calibrated in order to match the total observed water withdrawals in the Iberian Peninsula [19]. Water withdrawals V_w(m^3) are calculated as follow:

$$V_w = \frac{(1-\beta)\cdot(1-\alpha)\cdot H_w}{\rho \cdot c_P \cdot DT}$$

where DT (K) is the temperature increase in the withdrawn water, which is between 5 and 15 K according to [44]. It was assumed to be 10 K on average and calibrated in the cited range for some power plants to match observed values. The water consumption by thermal power plants V_c (m^3) is calculated using a similar heat balance as:

$$V_c = \frac{H_w \cdot \beta}{\rho \cdot L_e}$$

where L_e (GWh/kg) is the latent evaporation heat of water.

The Spanish regulation *Reglamento de Dominio Público Hidráulico* states that if no ecologic requirements are specified, the maximum increase in the downstream mixed river temperature is 3 °C, up to a maximum of 28 °C according to the European freshwater fish directive (Carrillo et al., [45]), while the discharged water to lakes and reservoirs should not exceed 30 °C. This implies that the maximum temperature increase dT in the mixed downstream river can be formulated as follow:

$$dT = max(0, min(3, 28 - T_r))$$

where T_r is the water temperature in the river. This constraint and consumptive water requirements are the only binding cooling constraints, limits in water withdrawal capacity and temperature increase in the withdrawn water are not considered. There is no dynamic representation of the river temperature (the loss heat is not accumulated in the river) but power plants of a same watershed share the thermal capacity of the river.

2.4 Climate change scenarios

Three Regional Climate Models (RCM) from the ENSEMBLES Project (van der Linen et al., [46]) were employed in the model to generate possible climate change scenarios. These models use the IPCC A1B emission scenario, based on rapid economic growth, a population peak by 2050, a rapid spread of new technologies and a balanced use of energy sources. Models are: RACMO2 [47], CLM [48] and REMO [49]. A set of monthly change factors (CF) was computed for each one of the three RCMs in order to generate precipitation and temperature time series for the future scenario in [20] and used in this study. A fourth scenario was constructed as an average of the three RCMs [20], and is referred to as "3RCM" or "average scenario". More details about the RCMs can be found in section E of supplementary materials and in [20].

In the future scenario only the hydrological changes linked to climate change are considered, economic growth, technology transition or societal changes are not considered. The future power demand is impacted only by temperature changes. Crop water demands are assumed to be constant, however irrigation water demands increase with decreasing precipitation. The power system is assumed to be unchanged, however the power demand pattern changes with temperature as described in section 3.2. This is not representative for a future scenario as the power system is expected to change considerably. However this approach provides robust insights into the role of cooling constraints in the current power system and potential adaptation needs.

2.5 Linear optimization

A deterministic dynamic optimization is performed using linear programming (Mikosch et al., [23]) to find the optimal water resource allocation that results in the minimum global cost for the simulated period. The model was setup in MATLAB R2012a and uses the linear solver from the CPLEX optimization studio [45]. The problem is a classical linear problem and is formulated as follow:

$$\min_{\boldsymbol{x}} \phi(\boldsymbol{x}) = \boldsymbol{c} \cdot \boldsymbol{x}$$

$$A_{eq}\, \boldsymbol{x} = \boldsymbol{b_{eq}}$$

$$A\, \boldsymbol{x} \leq \boldsymbol{b}$$

Where ϕ is the objective function to minimize, $\boldsymbol{x}$ the decision variables (water allocations, power productions) and $\boldsymbol{c}$ the associated costs (curtailment costs, marginal power production costs). All decision variables are non-negative, $\boldsymbol{A}$ and $\boldsymbol{A_{eq}}$ are the inequality and equality matrices and $\boldsymbol{b}$, $\boldsymbol{b_{eq}}$ the constant terms of the linear constraints. They represent the different mass balances (freshwater mass balance, groundwater mass balance, and power equilibrium), the reservoir capacities, the agricultural and domestic demands fulfillment, the hydropower and thermal production capacities and water demands, the environmental flows, and the cooling constraints. The constraints are detailed in section F of supplementary materials. Over the 20 year period the weekly model has 2.684.800 decision variables subject to 528.320 equality and 932.880 inequality constraints. For the reference period and climate change scenarios, the model is run with and without cooling constraints.

3. Results and discussion

This section is structured in the following way: first the model is validated against observed data; subsequently we assess the impact of climate change on cooling constraints and discuss some adaptation measures; finally a sensitivity analysis is presented.

3.1 Validity of the model

The water and power balances of the model are presented in **Table 1**. The water balance is compared to data from other sources than the ones used to parametrize the model. Small differences appear, the total available water resource (based on the rainfall-runoff model of Pereira-Cardenal et al., [20]) is higher than the one calculated by FAO [51]. Cooling water consumption is underestimated, however this has a very small impact on the total costs and water balance (<0.5%) and cooling constraints are mainly linked to water withdrawals as presented later. International transfers (<2% of total power production) are ignored in the model and are therefore balanced by a slightly higher thermal and hydropower production in the model. The average yearly pattern of modelled and observed thermal and hydropower production is presented in **Figure 2**. The deterministic approach of the model (i.e climatic conditions, water and power demands are anticipated) results in water management decisions that are not representative for a reality in which future conditions can only be forecasted over the short-term. Combined with other features that are not represented in the model, such as flood management or evaporation losses in reservoirs, it may explain the observed differences between model results and reality. Therefore results are not shown as absolute values, but as relative changes between different scenarios (reference period against climate change and with cooling constraints against without cooling constraints).

3.2 Climate change impact on cooling constraints

Climate change has combined negative effects on the cooling water requirements as it increases the average temperature of water (+1.7 to +2.4 °C) and decreases the average peninsular freshwater inflow (-8 to -26%) (**Figure 3**). Both phenomena are enhanced in summer (+2 to 2.5°C and -20 to -35% average inflows). Furthermore it shifts power demand to summer months (+3%), which induces higher cooling requirements while other competing users have an increased demand, such as agricultural water demand (+6 to +10% during summer month).

The combination of these factors explains the increased costs of cooling constraints (**Table 2)**, defined as the difference in total costs between the scenario with and without cooling constraints. The average yearly cost of cooling constraints increases from 100 M€ (million euro) per year in the reference period (1971-1990) to 330-740 M€ per year in the future (2046-2065) depending on the climate change scenario. On average 97 % of the cost increases are linked to the water withdrawal requirements, consumptive water use has a minor cost impact (3%). These values are of the same order of magnitude as future agriculture curtailments costs, increasing by around 410 to 1230 M€ per year.

The power system is affected by the reduction in hydropower production (-15 to -33%) and power production by freshwater-cooled thermal plants (-0.5 to -3%). This is compensated by seawater-cooled thermal power production (+15% to +38%). Among freshwater-cooled thermal power plants, power production is shifted towards power plants having closed circuit cooling systems (+41 to +95%) while once-through cooling systems (with and without cooling towers) face a decreased production (-5 to -14%). As a result, cooling water withdrawals decrease by 10 to 30% and average electricity price increases by 9 to 23%. The impact on the average water value (defined as the shadow price of water availability) and electricity price is shown **Figure 4**.

The average available capacity of freshwater-cooled thermal power plants (calculated as the thermal capacity of the river divided by the maximum heat loss of the thermal power plant) decreases with climate change by 6 to 18%. As seen on **Figure 5** the main reduction is found during the summer months (-16 to –30 % from June to August) and is less important in the winter month (-1 to -12 % from December to February). The most affected cooling system is once-through (-11 to -16% on yearly average, -31 to 40% during summer months) while closed circuit has an almost unchanged capacity (<-0.5%). These results can be compared to Vliet et al. [2] who found a summer average decrease in capacity of thermal power plants in Europe of 6.3 to 19% in 2040 depending on the cooling system. Hoffman, [3] found summer available capacity reduction between 7 and 26% for thermal power plants equipped with once-through cooling systems in Germany. While the reduction of available thermal power capacity is rather high (-6 to -18%), the reduction in freshwater-cooled thermal power production is lower (-0.5 to -3%). Impacts are shown in terms of power production in **Figure 6**. Similar trends are found, however the once-through cooling system with cooling towers faces the biggest production reduction. This is linked to the fact that several impacted nuclear power plants are equipped with this cooling system.

The impact of climate change on the Iberian Peninsula varies in the different basins (**Table 3**). Main power production reductions are in the Ebro (-6800 GWh per year), the Tajo (-3900 GWh per year) and Duero basin (-1800 GWh per year). In the Ebro the decrease is mainly linked to the decreased production of two nuclear power plants (Asco and Santa Maria de Garonna) while in the Duero the reduction in power production is linked to decreased hydropower production (-4600 GWh per year) despite the higher thermal power production (+2800 GWh per year). The Ebro is also the basin where the cooling constraints have the biggest impact on the water value as shown in **Figure 7**. The model assumes unlimited transmission capacity and zero transmission losses throughout the power system, coastal thermal power plants using seawater can therefore compensate for the decreased power production of hydropower and freshwater dependent power plants in other basins. Including transmission constraints and losses into the power system model is an interesting avenue for future research.

3.3 Adaptation measures

Adaptation strategies are not modelled here but can be considered based on model results. According to Byers et al. [41], replacing a once-through cooling system with a recirculating system results in a net efficiency penalty of 1 to 4% (because the plant itself consumes more electric power). According to EPRI [52], the capital cost of a recirculation cooling tower is around 12 000 € per MW of loss heat capacity (9 million $ for a $2.5 \cdot 10^9$ btu/hr capacity tower). Considering a thermal efficiency of 0.35 (average value for coal or nuclear power plants) this corresponds to a capital cost of 22 300 € per MW of power production capacity. If an average work load of 40% is assumed (average observed for non-nuclear thermal power plants), an interest rate of 3% on the capital and a life-time of 20 years for the cooling tower (lower estimate), this represents an additional cost of 0.57 € per produced MWh or an increase of 1% in the observed marginal cost of non-nuclear thermal production (evaluated at 58€/MWh in CNE [38]). These numbers are far below the calculated increase in the electricity price, estimated between 9% and 23% depending on the scenario, making the investment profitable for some thermal power plants that would have reduced production otherwise.

For dry cooling systems, the efficiency penalty is estimated between 2.5 to 9% compared to once-through cooling systems or around 1.5 to 5% compared to “wet” closed-circuit [41]. Based on average water consumption by wet recirculating systems of 2.5 m^3/MWh (Macknick et al., [42]) and an average electricity production marginal cost of 58 €/MWh, the water price where a dry cooling systems becomes profitable to compensate a loss of 1.5% in efficiency is 0.35 €/ m^3 (assuming the same investment and maintenance costs). According to the model, this value of water will be reached in different areas of the Peninsula as presented in **Figure 8**. The actual decision to install a dry or wet recirculation cooling system will depend on other parameters such as the location, investment costs, local regulations and specifics of the planned power plant, however dry cooling may become a profitable option in some cases. In the current situation, only one power plant in the river basins was equipped with a dry cooling system. The expected costs of cooling constraints calculated in the study can be reduced by adapting the power system and investing in more water efficient cooling technologies. Vliet et al. [4] shows that decoupling 10% of the most vulnerable power plants from freshwater is an efficient strategy to mitigate impacts of climate change at the European scale.

3.4 Sensitivity analysis and time step

A sensitivity analysis was carried out to assess the robustness of the results with respect to uncertainty in some parameters. The analysed parameters are the freshwater resource availability, the total power demand, the “special regime” production, the fuel prices and β the share of waste heat evacuated through the cooling tower(s) for closed-circuit and once-through cooling systems with cooling towers. Results are shown for the average climate change scenario on **Figure 9**. As expected, impacts of cooling constraints are stronger if the available water resource decreases or the power demand increases. However, the impacts are linear in terms of the parameter change and the results can be considered as robust. The less sensitive result is the average available thermal capacity as it only directly depends on the water system and not the power system. The most sensitive parameter is β, as an increase in 10% in the parameters decreases the total costs of cooling constraints by 25%. Since β was calibrated to match observed total water withdrawals, the results at the peninsula average can be considered robust. However it shows that, at a scale of the individual power plant, the actual β value is very sensitive.

The main part of the analysis is carried out at the weekly time step. However as shown in Koch and Vögele [10], it is more appropriate to model impacts of cooling constraints using daily time steps. This was not performed for the entire study as (1) the flow-path method adopted assumes that water can flow from all connected sources and sinks in one time-step, which is not realistic at the daily time step; (2) pump and storage of hydropower reservoirs and elasticity in the power demand are not represented, these two features are negligible at the weekly time-step but may play an important role at the daily time-step; (3) it results in highly increased computational time (around 3 cpu-hours for the weekly model, and 1150 cpu-hours for the daily model for one simulation over 20 years). To assess the validity of the weekly results the analysis was performed at the daily time step on a reduced period (2051-2055). Results for both temporal resolutions are compared in terms of freshwater dependent thermal power production and average available capacity in **Figure 10**. At the daily time-step, costs of cooling constraints only increase by 5%, average available thermal capacity does not change and freshwater dependent production decreases by 1%. Cooling constraints are slightly more important at the daily time step, but results do not change dramatically. The results of the weekly analysis can therefore be validated and be considered as a lower-bound estimate.

4. Conclusion

An innovative integrated water-power model has been developed for the Iberian Peninsula. This model includes thermal and hydropower production, cooling constraints of thermal power plants, a simple power system model and a spatially and temporally disaggregated hydrological representation. The model was used to assess the impact of climate change on cooling constraints of thermal power plants in the Iberian Peninsula. Given future expected climate conditions, cooling constraints will increase particularly in summer, and largely affect once-through cooling systems. The calculated impacts (on average 30 to 40% available capacity reduction for once-through cooling systems during summer) are higher than similar studies carried over Europe or Germany. The investment in more water-efficient cooling technologies, such as recirculating or dry cooling systems may be profitable in some cases and should attenuate the impact of climate change on the power system. The present analysis was carried out on the current power system and did not take into account future technology development, economic growth or new regulations such as CO_2 taxes. Renewable energies are expanding on the peninsula and will probably reduce the share of thermal power in the total production, however intermittence in the power production will also increase, and thermal power plant may play an essential role in peak production. The adoption of constraining CO_2 pricing policies should shift production towards more efficient power plants (such as combined cycle gas power plants) less affected by cooling constraints but should on the other hand increase the use of carbon capture systems that have cooling needs exceeding the ones of the steam cycle. To quantitatively assess the impact of policies, climate change, or socio-economic development on the complex water-energy nexus, the development of such integrated water-power models are therefore of high interest.

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Tables

Table 1: Water and Power balance of the model compared to observed data. The sources are: a FAO [51], b MMA [19], c OMIE [18].

Water balance (1000 $10^6 m^3/y$)	model	observed total Peninsula	**Power balance**	model	observed total Peninsula
Total Inflow	161	149[a]	Power demand (1000GWh/y)	298	294[c]
Agriculture consumption	20	23[a]	Hydropower production	15%	14%[c]
Domestic and industrial demand	4.8	4.7[a]	Thermal production	48%	47%[c]
Cooling water consumption	0.15	0.25[b]	Special regime	36%	37%[c]
Downstream flow	135	-	International	-	1.4%[c]
Balance	0.00	-	**Balance**	100%	100%
Cooling water withdrawals	5.2	5.2[b]	Average electricity price (€/MWh)	38	48[c]

Table 2: Peninsular scale impacts of climate change on the water-power system. Best case refers to the RACMO scenario while worst case refers to the CLM scenario.

Changes	Best case	Worst case
Costs of cooling constraints (M€/y)	+227	+638
Agriculture water curtailment costs (M€/y)	+417	+1229
Freshwater-cooled thermal production	-0.5%	-3%
Seawater-cooled thermal production	+15%	+38%
Hydropower production	-15%	-33%
Cooling water withdrawals	-10%	-30%
Average electricity price	+9%	+23%

Table 3: Local impacts of climate change on the water-power system. Values are represented as changes in the yearly averages per river basin.

River-Basin	Thermal production (GWh)	Available thermal capacity (%)	Hydropower production (GWh)	Water value (€/m^3)	Cooling water withdrawals ($10^6 m^3$)	Agriculture curtailments ($10^6 m^3$)
TAJO	-2021	-13%	-1861	+0.03	-146	+112
EBRO	-5499	-3%	-1284	+0.12	-1255	+915
DUERO	+2785	0%	-4585	+0.01	+136	+1
GUADALQUIVIR	+1689	-4%	-43	+0.05	+113	+876
GUADIANA	0	-	-259	+0.00	0	+320
JUCAR	-627	-5%	-79	+0.10	-12	+316
MINO-SIL	+2396	-2%	-1371	+0.01	+85	+0
Average/total Peninsula	**-1278**	**-7%**	**-9481**	**+0.05**	**-1079**	**+2541**

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Figures

Figure 1: Conceptual model of the Iberian Peninsula. The coloured area corresponds to the hydrologically modelled area. The right scheme is the conceptual representation of one watershed. [double column]

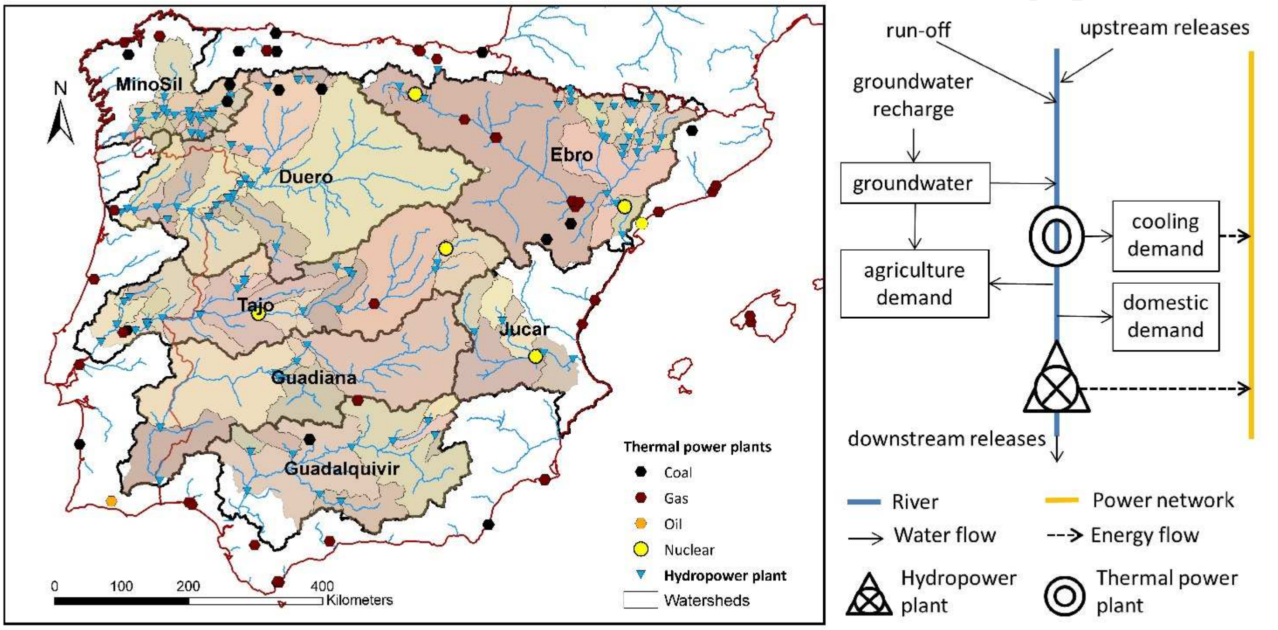


Figure 2: Average yearly pattern of modelled (mod.) and observed (obs.) total thermal and hydropower production on the Iberian Peninsula. [single column]

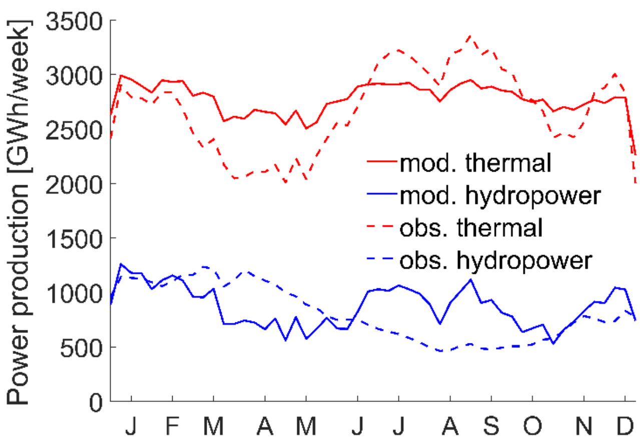


Figure 3: Climate scenarios and changes in the total Iberian water inflow, average water temperature, total Iberian irrigation water demand, and power demand. Only one future power demand scenario was considered. [double column]

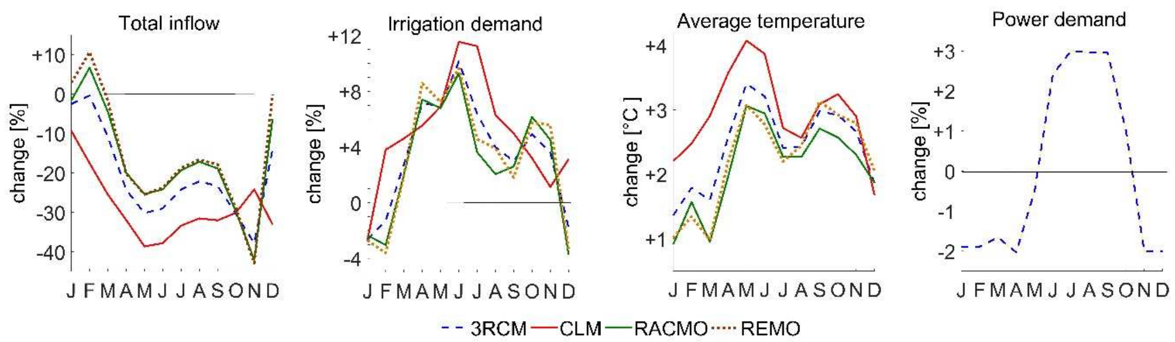
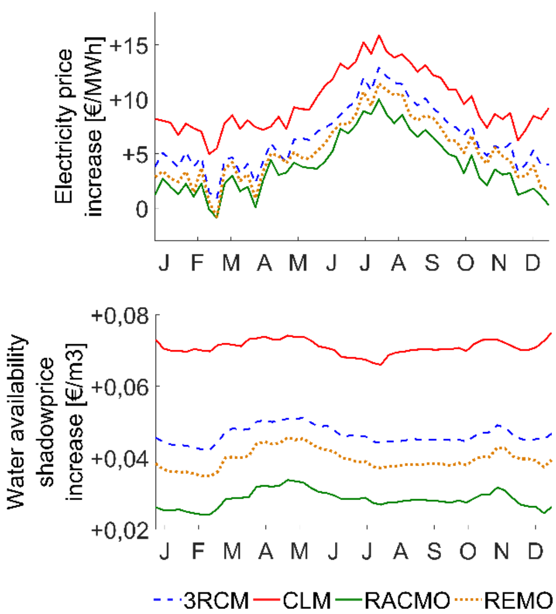
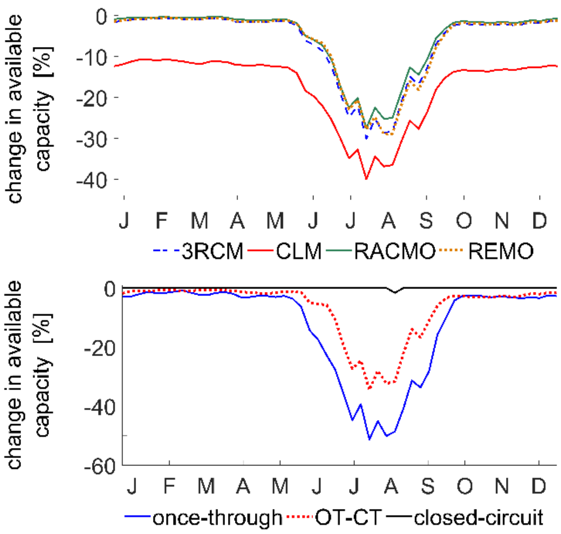


Figure 4: Average electricity price and water value increase. The water value is defined by the shadow price of water availability (i.e the economic benefit of an additional available cubic meter). It does not take in account water supply and treatment cost. [single column]



631 **Figure 5**: Average weekly available capacity reduction, per scenario and per cooling technology.
632 The reduction per cooling technology is shown for the 3RCM scenario (average climate change).
633 OT-CT stands for "once-through with cooling towers". [single column]

634 

635 **Figure 6:** Variation of thermal and hydropower production patterns under climate change.
636 Variation is shown in comparison to the reference period for freshwater and seawater-cooled
637 thermal power production and hydropower production. The variation in freshwater-cooled thermal
638 production is shown per cooling technology in the right upper figure. [double column]

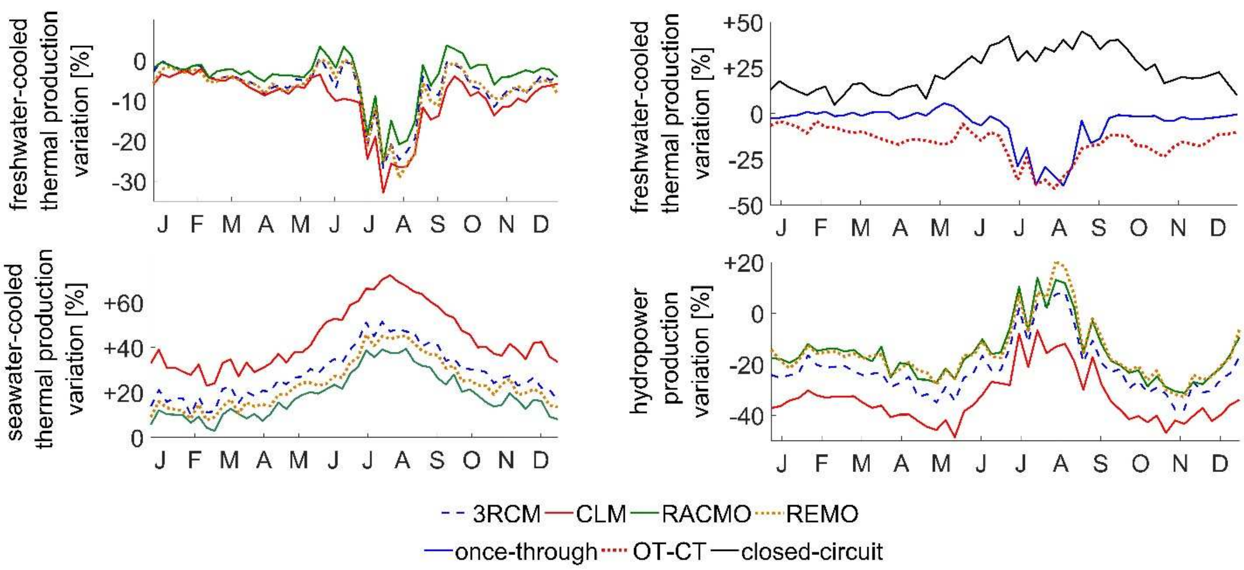
639 

Figure 7: Value of water linked to cooling purposes per watershed for the 3RCM climate change scenario. It is calculated by comparing the water value in the scenarios with and without cooling constraints. [1.5 column]

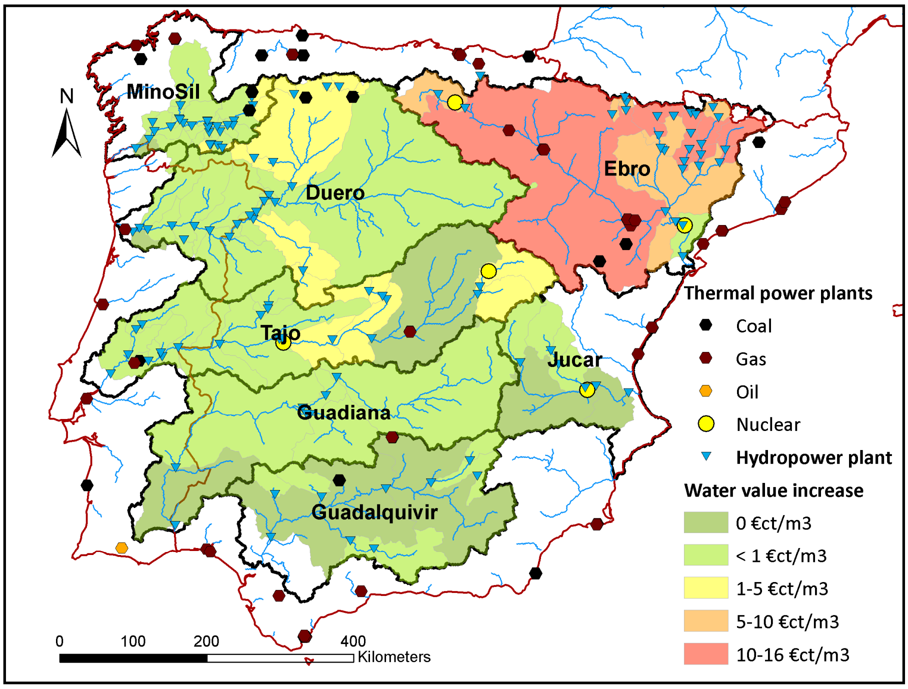


Figure 8: Average water value per watershed for the CLM climate change scenario. [1.5 column]

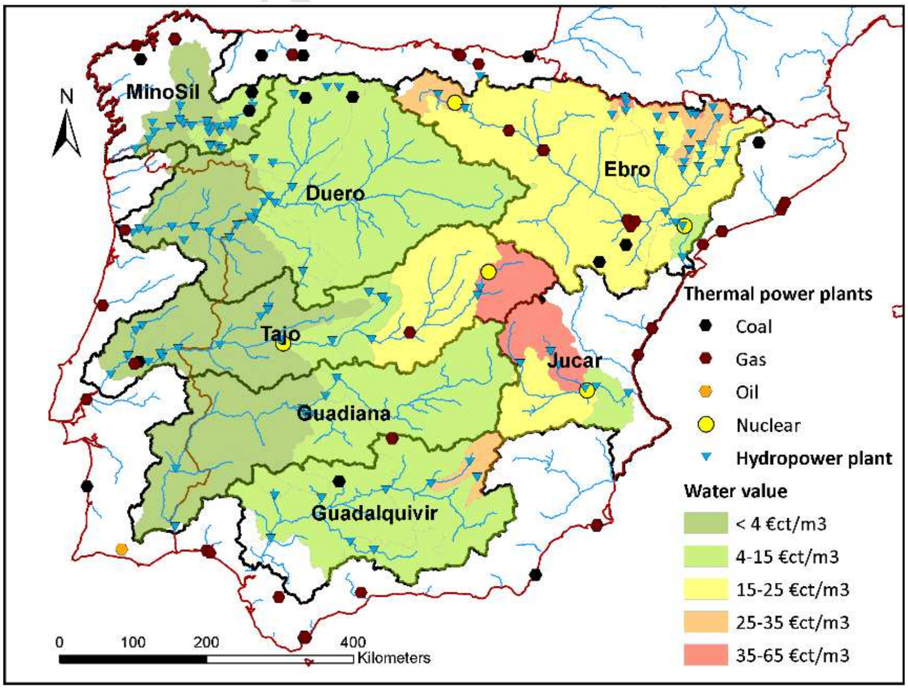


Figure 9: Sensitivity analysis of the model (scale sensitivity). The sensitivity analysis is carried on 5 parameters (total inflow, total power demand, total special regime production, thermal production price, beta) and is showed for 3 results (variation of cooling constraints costs, variation of closed-circuit thermal production, average available capacity of freshwater-cooled thermal power plants). [double column]

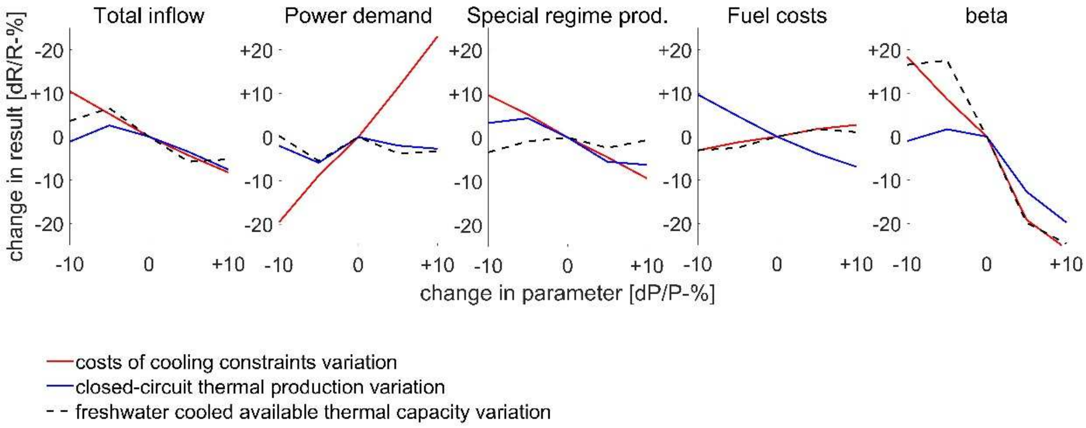
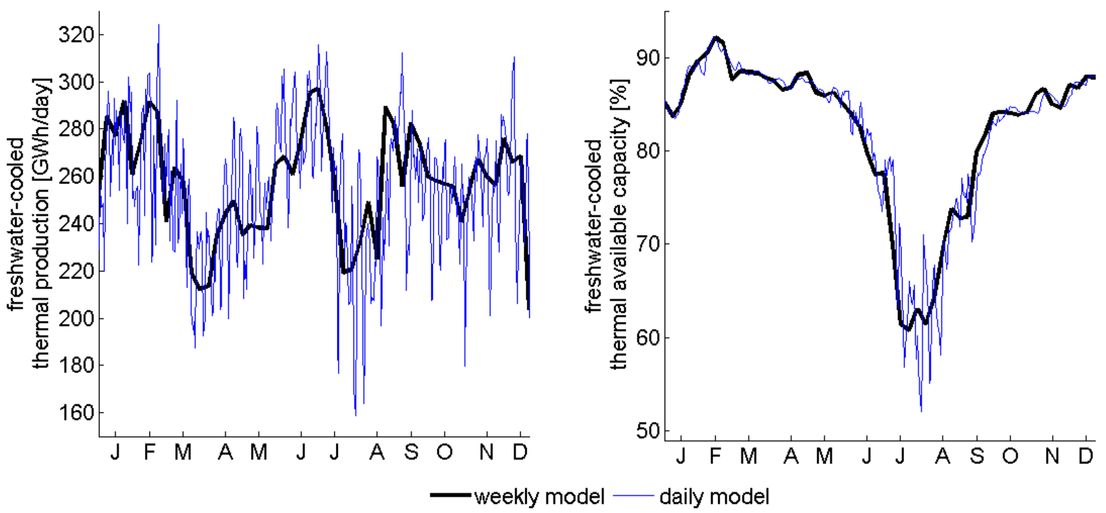


Figure 10: Model run for the weekly and daily time step in the average climate change scenario for the years 2051 to 2055. The left graph shows the freshwater-cooled thermal power production, the right graph shows available capacity of freshwater-cooled thermal power plants. [double column]



Highlights

An optimization model for joint water-power management on the Iberian Peninsula

Model includes cooling constraints on thermal power plants

Freshwater-cooled power plants are particularly impacted by climate change

Production is shifted away from freshwater cooled power plants and costs increase