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«Hydrogen and electricity system planning under water scarcity constraints: Insights from France»

by

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Highlights

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- We propose an energy model integrating constraints on water resource availability.
- We compare decisions with and without considering climate change impacts on water.
- Investments in PV and PtG are higher when anticipating water scarcity situations.
- Adapting investments to a pessimistic view on water availability minimizes regrets.

Hydrogen and electricity system planning under water scarcity constraints: Insights from France

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Abstract

As the global transition toward low-carbon energy systems intensifies, Power-to-Gas (PtG) technology plays a crucial role in converting surplus electricity into hydrogen via water electrolysis. However, scaling up renewable hydrogen production presents environmental challenges, particularly concerning freshwater resources, which are expected to decline due to climate change. While the integration of water considerations has been explored in electricity systems, they have received little attention in the context of hydrogen systems.

This article examines how climate-induced water availability constraints affect joint electricity and hydrogen planning. We employ a linear programming model to optimize investment and operating decisions. A regret-minimizing approach is used to compare planning decisions with and without considering water availability constraints. We focus on a French case study at a river basin scale.

Results indicate that incorporating climate impacts on water resources leads to increased investments in renewables and PtG capacity, helping offset reductions in hydro and nuclear production and ensuring adequate hydrogen supply during summer. The regret-minimizing approach demonstrates that proactively considering the impacts of climate change on water resources in electricity and hydrogen planning minimizes regrets. This findings highlight the importance of integrating water constraints in energy system models and contribute to the broader dialogue on climate change adaptation planning.

Keywords: *Water scarcity, Power-to-Gas, Energy system modeling, Hydrogen, Sector coupling*

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1. Introduction

The energy sector plays a crucial role in curbing climate change, with 43% of global CO_2 emissions in 2021 stemming directly from energy combustion (IEA). Absent any action, these emissions are projected to increase due to the upward trajectory of global energy consumption. Deep decarbonization efforts are imperative to counter this trend. In Europe, the revised Renewable Energy Directive targets at least 42.5% of renewable energy sources in the EU's overall energy mix by 2030 (EC, 2023).

In most decarbonization scenarios, large-scale deployment of renewable electricity plays a central role in reaching climate neutrality (DeAngelo et al., 2021). Yet, given the non-dispatchable nature of Variable Renewable Energy (VRE) sources such as solar and wind, their deployment needs to be complemented by flexibility assets (Kondziella and Bruckner, 2016). Electricity is also unsuited for some sectors such as aviation or industrial processes, which require other decarbonization methods. In this context, Power-to-Gas (PtG), a technology that converts electricity into hydrogen, is seen as a crucial energy vector for providing flexibility to the power system and substitute for fossil-based gases in sectors where energy needs cannot be met by electricity (Seck et al., 2022). In France, targets for 2030 include a 40% share of renewable electricity in power generation and a production of around 600 kt of hydrogen from electricity per year to meet the needs of industry and new usages (French Government, 2020, 2024).

However, scaling up renewable-based energy production poses technical, economic, and environmental challenges. Among these hurdles are the concerns about the availability of sufficient water resources. Water is essential in energy production, whether for cooling nuclear and thermal power plants, powering hydraulic turbines, or supplying PtG for hydrogen production. In France, power plant cooling represents approximately 500 million m^3 annually, or 16 % of total water consumption (French Government, 2023). As for hydrogen, the envisioned production of 600 kt of hydrogen per year would represent an incremental consumption of around 12 million m^3 of freshwater (IRENA, 2023).

The availability of water resources is a growing global concern. According to the Intergovernmental Panel on Climate Change (IPCC), the population at risk of increased water stress due to climate change can reach as high as 2 billion in 2040 (IPCC, 2014). In 2022, Europe's driest year in 500 years, nuclear plants were partially shut down because cooling water temperatures were too high (EC, 2022). In this context, water scarcity considerations could have an impact on the operation of future electricity and hydrogen capacities. This, in turn, requires comparing electricity and hydrogen production technologies in terms of their water use (JRC, 2018; IRENA, 2023) and integrating water considerations into energy development plans.

The joint management of energy and water resources, mentioned as early as 1979 (Buras, 1979), has developed exponentially in recent years to address the strong nexus between water, energy, and climate (Hamiche et al., 2016). Khan et al. (2017) review the literature on integrated water and energy modeling, and highlight the benefits to be gained and drawbacks of neglecting water-energy links for policymakers and planners. In particular, they show that ignoring water constraints in energy planning can lead to developing energy pathways with a strong impact on future water resources. In a Spanish case study, the same authors show that proactive investments to manage future water shortages are more cost-effective than dealing with the consequences of not investing. Torrajo et al. (2020) examine four carbon-free electricity narrative scenarios for California and rate them according to economic (cost) and environmental (freshwater consumption) criteria. They show that incorporating both economic and environmental criteria shifts the mix from cost-favored dispatchable technologies with high capacity factor to less water-intensive options like wind, solar, and hydropower. One study on the Beijing-Tianjin-Hebei region shows that adjusting the power mix can ease water stress, and recommend a coordinated energy and water resources plan (Sun et al., 2018). Another study seeks to explain why the decarbonization of the US electricity system between 2010-2018 has paradoxically led to an increase in water resources, and shows that the generation mix structure was a predominant factor in escalating water consumption (Xu et al., 2024).

A vast literature studies the implications of climate-induced water constraints on power systems (Emodi et al., 2021). At the global scale, van Vliet et al. (2016) found that more than 80% of all thermal power plants and more than 60% of hydropower plants would face available capacity reductions in 2040–2069. van Vliet et al. (2013) and Behrens et al. (2017) investigate the impact of water availability and temperature changes on the European power supply. van Vliet et al. (2013) show that under future climate scenarios, thermoelectric and hydropower generating potential is projected to decrease for most parts of Europe, except for the most northern countries. Behrens et al. (2017) further note that despite Europe's renewable-energy policies, the number of regions experiencing some reduction in power availability due to water stress is projected to increase by 15% between 2014 and 2030. Other studies have investigated the impact of water constraints on the power mix of specific regions, including the United States (Liu et al., 2019), the Iberian Peninsula (Khan et al., 2016; Payet-Burin et al., 2018), Great Britain (Qadrdan et al., 2019), China (Huang et al., 2017; Zhang et al., 2020), and Saudi Arabia (Parkinson et al., 2016).

In contrast, the consideration of water resources in hydrogen systems is still in its early stages. The debate on the importance of water for hydrogen production is ongoing: Beswick et al. (2021) argue that water for hydrogen production should not be of concern, given that the volume of water required to meet all future renewable hydrogen needs would represent only 1.5 ppm of Earth's freshwater. However, freshwater is unevenly distributed, and regions with high renewable energy potential and space for green hydrogen plants are also areas where water stress is a growing concern (Ellersdorfer et al., 2025; IRENA, 2023). In this context, several recent studies have examined water demand for hydrogen production in relation to available resources. Tonelli et al. (2023) build a country-by-country reference scenario for hydrogen demand in 2050 and compares it with land and water availability. They show that land and water scarcity pose challenges for several countries,[1] which may have to rely on importing electrolytic hydrogen from other nations to meet their electrolytic hydrogen demand. Ellersdorfer and al quantify water demand for two types of electrolysers (dry vs evaporating cooling) in multiple countries. They show that evaporating cooling requires more water than dry cooling, and highlight

[1]These countries include Western Europe, Japan, the Dominican Republic, Trinidad and Tobago, and South Korea.

that three of the ten countries studied lack sufficient resources to meet even 10% of their hydrogen demand. To the best of our knowledge, no study has yet integrated water constraints into a model optimizing hydrogen systems.

In this context, our paper aims to contribute to the literature by examining how climate-induced water constraints can influence electricity and hydrogen planning. To do this, we develop a partial-equilibrium, linear programming model to optimize both electricity and hydrogen investment and operating decisions. We take France as a case study and focus on 2030, for which quantified targets for hydrogen development have been set. We model the French electricity and hydrogen system at the river basin scale to account for regional and temporal water availability constraints. Following (Khan et al., 2016) methodology, we divide the optimization process into two stages: the investment phase, during which the planner forecasts the investments to be made based on anticipated available water resources, and the operation phase, during which the production fleet operates given the water resources present. We consider two anticipation options during the investment phase: assuming that water resources will remain similar to historical levels or anticipating a decrease due to climate change. We study the impact of these investment choices based on the anticipation that materializes during the operational phase. Finally, we discuss the importance of incorporating water constraints into energy optimization models through a regret analysis, based on the economic results obtained with our model (Chen et al., 2014; Nicolle and Massol, 2023).

Our findings indicate that the model invests in more VRE and PtG capacity when it anticipates a decline in water resources compared to when it does not. In cases where water shortage materializes, these additional capacities partly offset the decrease in hydroelectric and nuclear production and ensure that hydrogen demand in the south of France can be met in summer. Conversely, in cases where water resources are similar to historical levels, the costs associated with these investments are partially offset by increased revenues from additional exports enabled by the augmented supply. The regret minimizing approach demonstrates that proactively considering the influence of climate change on water resources is a regret-minimizing decision. This study emphasizes the importance of accounting for water constraints in energy system models. It contributes to the broader discussion on climate change adaptation planning, which is essential to move from crisis management to structural management of water resources.

Our document is organized as follows. Section 2 provides further information on France's hydrogen strategy and stresses the importance of water resource considerations. Section 3 details our modeling framework and associated equations. Section 4 describes our case study, and Section 5 the scenarios examined and our evaluation strategy. The results are presented in Section 6, and discussed in Section 7.

2. Background

2.1. France's hydrogen strategy for 2030 - an ambitious deployment without consideration of water use

In 2021, French hydrogen consumption reached 430 kt. The proposed 2024 revision of the French National Hydrogen Strategy (FNHS) projets that future hydrogen needs for industry and new uses will reach 770 kt in 2030 and 1000 kt in 2035 (French Government, 2024). On the supply side, the FNHS forecasts the production of 600 kt of hydrogen by 2030 and 1000 kt by 2035.

To produce this hydrogen, the FNHS relies on installing 6.5 GW of PtG, powered by the French electricity mix or dedicated renewable-electricity production facilities. France's electricity mix, based on nuclear power and renewable energy (hydroelectricity, solar, wind), has one of the lowest emission rates in Europe (RTE, 2024). Using electrolysis to produce hydrogen from electricity available in the power grid enables the strategic arrangement of production sites based on demand. In the medium term, the FNHS calls for deploying PtG close to areas of high consumption. By 2030, the plan envisions to establish hydrogen production and transportation facilities within regional hubs, gradually expanding to a nationwide hydrogen network. The FNHS emphasizes the goal of strengthening France's energy independence by focusing on domestic hydrogen production, with minimal reliance on neighboring countries.

While the FNHS details the types of electricity that can be used to produce hydrogen, it is noteworthy that it does not cover the issue of water resources. This is a notable omission given that water is essential for the production of hydrogen by electrolysis, and is likely to be depleted by climate change.

2.2. Water resources in France - once abundant but now under spatio-temporal stress due to climate change.

Freshwater resources include surface water (rivers, lakes) and groundwater. In Metropolitan France, an average volume of 211 billion m^3 is renewed each year (average 1990-2020), supplied both by precipitation and by rivers from neighboring territories.[2] Only a fraction of this volume can be withdrawn for human use, and a significant proportion must be left for natural ecosystems.

Freshwater is used for domestic (drinking water) and economic (agriculture, industry, power-plant cooling, recreation) purposes. The volume of water consumed, which represents the portion of water withdrawn that is not returned to the aquatic ecosystem, is around 4 billion m^3, or 2% of annual water resources (average 2010-2020). However, this ratio varies greatly depending on the season. Indeed, the impact of water use is most significant in summer (June to August), when 60% of water consumption takes place, while rivers provide only 15% of annual runoff (average 2008-2016).

Moreover, the pressure on water resources differs significantly from one region to another. In the Adour-Garonne river basin, located in southwestern France, current summer water withdrawals already exceed the renewable water available (resources that can be used to satisfy human needs without compromising the aquatic environment and future needs) over more than a third of its surface area (Comité de bassin Adour-Garonne, 2015). This situation will likely worsen in the coming years due to the consequences of global warming.

Climate change already affects water resources: in Metropolitan France, the average volume of renewable water available for human uses fell by 14% between the 1990-2001 average

[2] Where not specified, the statistics presented in this sub-section are taken from the French government's websites (French Government, 2023, 2019).

and the 2002-2018 average (Cour des Comptes, 2023). The Explore 2070 project (Chauveau et al., 2013) examined the impact of climate change on water resources in France to 2070, using seven climate models and two hydrological models. The results indicate a downward trend in summer precipitation across the entire country and a significant overall decrease in average annual flows across the territory, from 10% to 40%.

2.3. Measuring and regulating water use: no formal restrictions, but growing interest in water scarcity indicators

Water policy in France is framed by the European Water Framework Directive (Directive 2000/60/EC of the European Parliament). This directive requires Member States to achieve good status in all bodies of surface water and groundwater by 2027. Good status comprises good ecological, chemical, and quantitative status. In this article, we focus on quantitative status. Good quantitative status can be defined as a situation in which human needs (drinking water supply, agricultural irrigation, industry, energy production, etc.) can be met without exceeding the renewal capacity of the water resource.

Several water scarcity indicators have been created to assess the status of a water exploitation system (Pedro-Monzonis et al., 2015). Among them, the Water Exploitation Index + (WEI+) measures total water consumption as a percentage of the renewable freshwater resources available for a given territory and month. WEI+ is receiving increasing interest as it highlights water stress monthly and regionally (Sondermann and Proença de Oliveira, 2022). In the absence of Europe-wide agreed formal targets, values above 20% are generally considered to be a sign of water scarcity, while values equal to or greater than 40% indicate severe water scarcity, meaning the use of freshwater resources is unsustainable[3].

2.4. Integrating climate-induced water constraints on electricity and hydrogen planning and operation

Given the water intensive nature of water electrolysis, one can wonder how the impact of climate change on water resources could affect the development of hydrogen production by

[3] https://www.eea.europa.eu/en/analysis/indicators/use-of-freshwater-resources-in-europe-1

electrolysis. Ignoring climate-induced water constraints may result in building production plants in areas that will suffer from water shortages in the future or overestimating energy production from water-constrained technologies. According to an IRENA study on water requirements for hydrogen production (IRENA, 2023), 30% of the hydrogen projects currently planned for 2040 in France are located in areas with a high level of water stress, and 9% in areas with an extremely high level of water stress.

Against this background, a combined approach that jointly considers water and energy is needed. In this study, we investigate how incorporating water-resource constraints into an energy model impacts investment and operating decisions. As in (Khan et al., 2016), we account for the regional and seasonal specificities of water resources by disaggregating water and energy demands and constraints in both space and time. We conducted this study at the scale of river basins, the level at which water resources are managed in France. The river basins under consideration are described in Figure 2 in section 4.

3. Methodology

3.1. Model overview

We develop a linear programming (LP) model representing the investment and operation decisions made by a benevolent social planner — equivalently, a myriad of economic actors in a perfectly competitive landscape (Biggar and Hesamzadeh, 2014)— in a integrated electricity-hydrogen system. The model uses an hourly resolution and aims to minimize total system costs over the year while satisfying a series of constraints. System costs include investment costs, fixed and variable operation and maintenance costs (O&M), transport costs, and Value of Lost Load (VoLL). Water considerations are integrated through a constraint described in section 3.2.5 (equation 20).

As described in Figure 1 the proposed electricity system includes VRE sources (solar, onshore wind, and offshore wind), run-on-river (RoR) plants, hydropower, nuclear power plants, open cycle gas turbines (OCGT), and combined-cycle gas turbines (CCGT). The import and export of electricity from neighboring countries are allowed. Hydrogen is produced from electricity using PtG assets. Energy can be stored either as electricity in pumped-hydro storage (PHS) and batteries or hydrogen in pressurized tanks. The model can be run allowing new investments or not. When authorized, new investments are limited to new renewable capacities (wind, solar), PtG, and storage[4].

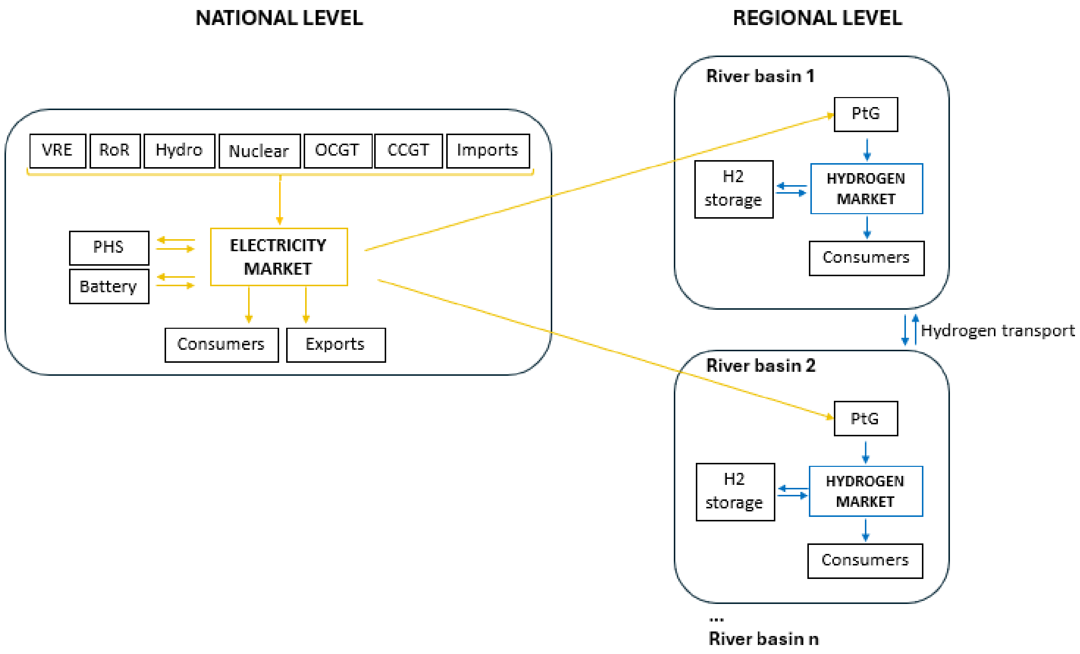


Figure 1: Model overview

We consider hourly electricity and hydrogen demands. We assume that the hydrogen market will not be a nationally integrated market by 2030 and that each water basin has a hydrogen demand. The electricity market is integrated, and electricity demand is national.

The notation used in this paper is introduced progressively in the following paragraphs, and listed in a nomenclature in Appendix A. We denote all the technologies considered (generation plus storage) by tec. We index the generating technologies by gen and the storage technologies by str. River basins are denoted by the indices bas, and hours by the indices $h \in (1, ..., 8760)$. $hydro$ refers to hydropower plants, imp to imports, and exp to exports. Where necessary, variables and parameters linked to the electricity system are

[4]Nuclear power plants are not considered investment candidates, as their investment decisions are primarily political. Additionally, the new nuclear power plants planned by the French government will not be operational before 2035 due to the lengthy construction timeline.

denoted by the letter E and those pertaining to the hydrogen system by H.

In this model, the central planner mains decision variables are:

- $K^{new}_{tec,bas}$ new installed capacity of technology tec in basin bas (GW);
- $G_{gen,bas,h}$ hourly generation of technology gen in basin bas (GWh);
- $G^{E}_{imp,h}$ and $G^{E}_{exp,h}$ hourly imports and exports of electricity (GWh);
- $G^{+/-}_{str,bas,h}$ hourly discharging (+) or charging (-) from/to storage str in basin bas (GWh);
- $G^{H,trsp}_{bas,bas',h}$ hydrogen transported from basin bas to basin bas' during hour h (GWh);
- f^{E}_{h}, $f^{H}_{bas,h}$, unsatisfied demand for electricity and hydrogen (Lost Load) (GWh).

Finally, $P_{str,bas,h}$ and $P_{hydro,bas,h}$ are state variables that account for the filling level of storage assets and hydro reservoirs, respectively.

From a computational perspective, the model is implemented in GAMS v37.1.0 and solved using the CPLEX solver with default settings. We use a standard personal computer (2.10 GHz CPU, 48 gigabyte RAM). The solution time for each scenario is about 1h.

3.2. Model equations

3.2.1. Objective function

The objective function minimizes the total system cost C^{tot}, composed of the annualized investment costs ($c^{annuity}_{tec}$) and fixed O&M costs (c^{fOM}_{tec}) for production and storage capacities, variable O&M costs for generating technologies (c^{vOM}_{gen}), import and export costs (c^{E}_{imp}, c^{E}_{exp}), injection cost for storage technologies (c^{inj}_{str}), hydrogen transport costs ($c^{H,trsp}_{bas,bas'}$), and the VoLL. The initial installed capacity of the various technologies is represented by $k^{ini}_{tec,bas}$. The cost function is detailed in equation (1).

$$\begin{aligned}
C^{tot} =& \sum_{tec}\left[c^{annuity}_{tec} \cdot K^{new}_{tec,bas} + c^{fOM}_{tec} \cdot (K^{new}_{tec,bas} + k^{ini}_{tec,bas})\right] \\
&+ \sum_{h}\Bigg[\sum_{gen,bas}\left(c^{vOM}_{gen} \cdot G_{gen,bas,h}\right) + \sum_{str,bas}\left(c^{inj}_{str} \cdot G^{-}_{str,bas,h}\right) \\
&+ \sum_{bas,bas'}\left(c^{H,trsp}_{bas,bas'} \cdot G^{H,trsp}_{bas,bas',h}\right) + c^{E}_{imp} \cdot G^{E}_{imp,h} - c^{E}_{exp} \cdot G^{E}_{exp,h}\Bigg] \\
&+ \sum_{h} VoLL^{E} \cdot f^{E}_{h} + \sum_{bas,h} VoLL^{H} \cdot f^{H}_{bas,h}
\end{aligned} \tag{1}$$

3.2.2. Constraints on electricity and hydrogen investments and production

Constraints are implemented to account for the physical limitations governing the electricity systems. The hourly production of VRE technologies (solar, onshore wind, and offshore wind) is equal to the product of their overall installed capacity ($K^{new}_{VRE,bas} + k^{ini}_{tec,bas}$) and their hourly availability factor $\delta_{VRE,bas,h}$. The hourly production of run-of-river power plants is fixed and equal to the energy supplied by the hourly flow of water $w_{river,bas,h}$.

$$G_{VRE,bas,h} = (K^{new}_{VRE,bas} + k^{ini}_{VRE,bas}) \cdot \delta_{VRE,bas,h} \qquad \forall VRE, bas, h \tag{2}$$

$$G_{river,bas,h} = w_{river,bas,h} \qquad \forall bas, h \tag{3}$$

Each dispatchable technology *disp* (nuclear, OCGT, CCGT) is bounded by its resource availability, given by the product of its installed capacity $k^{ini}_{disp,bas}$ and its availability factor $\delta_{disp,bas,h}$ (Equation (4)). In addition, hourly variations in the power supplied by the nuclear fleet are capped by ramp-up constraints, described in Equation (5).

$$G_{disp,bas,h} \leq k^{ini}_{disp,bas} \cdot \delta_{disp,bas,h} \qquad \forall disp, bas, h \tag{4}$$

$$|G_{nucl,bas,h+1} - G_{nucl,bas,h}| \leq k^{ini}_{nucl,bas} \cdot r_{nucl} \qquad \forall bas, h \tag{5}$$

Equation (6) is an intertemporal constraint linking the energy stocks of hydroelectric reservoirs between different time steps. At each hour $h + 1$, the energy stock in the hydraulic reservoir is equal to the energy stock at hour h, plus the additional energy supplied by the inflow of water to the reservoirs $w_{hydro,bas,h}$, minus the hourly production of hydraulic power. Equation (7) is a closure constraint that requires the energy present in the hydraulic reservoirs at the end of the year to be equal to that present at the beginning of the year. The energy stored in hydroelectric reservoirs is bounded by the reservoir's capacity $k_{res,bas}$ (Equation (8)).

$$P_{hydro,bas,h+1} - P_{hydro,bas,h} = w_{hydro,bas,h} - G_{hydro,bas,h} \qquad \forall bas, h \in [\![1, 8759]\!] \quad (6)$$

$$P_{hydro,bas,1} - P_{hydro,bas,8760} = w_{hydro,bas,8760} - G_{hydro,bas,8760} \qquad \forall bas \quad (7)$$

$$P_{hydro,bas,h} \leq k_{res,bas} \qquad \forall bas, h \quad (8)$$

Restrictions (9,10) imply that imports and exports of electricity and hydrogen are constrained by interconnection capacity k^{E}_{imp} and k^{E}_{exp}.

$$G^{E}_{imp,h} \leq k^{E}_{imp} \quad \forall h \quad (9)$$

$$G^{E}_{exp,h} \leq k^{E}_{exp} \quad \forall h \quad (10)$$

Equation (11) ensures that hydrogen production using PtG is limited by the installed capacity of PtG.

$$G_{PtG,bas,h} \leq (K^{new}_{PtG,bas} + k^{ini}_{PtG,bas}) \qquad \forall bas, h \quad (11)$$

Ultimately, the maximum capacities for installing renewable technologies and storage assets face various constraints, including land availability, geological factors, social acceptance, and political goals. Equations (12) take these limitations into account by restricting investment potential in renewable energies and storage. The calibration of the maximum integration capacity level for each technology is described in the Application Section (Section 4.1).

$$K^{new}_{tec,bas} \leq k^{new,max}_{tec,bas} \quad \forall tec \in \{VRE, str, PtG\}, bas \quad (12)$$

3.2.3. Constraints on storage

Regarding storage technologies, Equations (13)–(14) state that charging and discharging decisions are bounded by the storage charging/discharging capacity[5] ($K^{new}_{str,bas} + k^{ini}_{str,bas}$). The energy stored is limited by the storage capacity, equal to the product of the charg-

[5] We assume that pumping and turbine capacities are equal for each storage facility.

ing/discharging capacity and the storage duration[6] τ_{str}.

$$G^{+}_{str,bas,h} \leq (K^{new}_{str,bas} + k^{ini}_{str,bas}) \qquad \forall str, bas, h \tag{13}$$

$$G^{-}_{str,bas,h} \leq (K^{new}_{str,bas} + k^{ini}_{str,bas}) \qquad \forall str, bas, h \tag{14}$$

$$P_{str,bas,h} \leq (K^{new}_{str,bas} + k^{ini}_{str,bas}) \cdot \tau_{str} \qquad \forall str, bas, h \tag{15}$$

Finally, the energy stored in each storage at hour h is linked to those of the subsequent time step by equation (16). During each hour $h+1$, the energy stock is equal to the energy stock at hour h plus the amount of energy charged minus the amount of energy discharged from storage. γ_{str} denotes the round-trip efficiency of storage str. Equation (17) is a closure constraint that requires the energy present in the storage at the end of the year to be equal to that present at the beginning of the year.

$$P_{str,bas,h+1} = P_{str,bas,h} + \gamma_{str} \cdot G^{-}_{str,bas,h} - G^{+}_{str,bas,h} \qquad \forall str, bas, h \in [\![1, 8759]\!] \tag{16}$$

$$P_{str,bas,1} = P_{str,bas,8760} + \gamma_{str} \cdot G^{-}_{str,bas,8760} - G^{+}_{str,bas,8760} \qquad \forall str, bas, \tag{17}$$

3.2.4. Supply-demand balance

As the model optimizes hydrogen and electricity systems simultaneously, we require it to satisfy the supply-demand equilibrium for both commodities. In the electricity system, condition (18) ensures that, for each hour, the total electricity supply exceeds the total electricity demand.

$$\begin{aligned} &\sum_{gen,bas} G^{E}_{gen,bas,h} + \sum_{str,bas} G^{E,+}_{str,bas,h} + G^{E}_{imp,h} + f^{E}_{h} \\ &\geq d^{E}_{h} + \sum_{str,bas} G^{E,-}_{str,bas,h} + \sum_{bas} \frac{G^{H}_{PtG,bas,h}}{\gamma_{PtG}} + G^{E}_{exp,h} \quad \forall h \end{aligned} \tag{18}$$

On the demand side, d^{E}_{h} is the exogenous electricity demand, $\sum_{str,bas} G^{E,-}_{str,bas,h}$ the electricity charged into electricity storage, $\sum_{bas} \frac{G^{H}_{PtG,bas,h}}{\gamma_{PtG}}$ the electricity used for hydrogen production, and $G^{E}_{exp,h}$ the electricity exported to neighbouring countries. On the supply side, $\sum_{gen,bas} G^{E}_{gen,bas,h}$ is the sum of the electricity produced by electricity generation

[6]Storage duration is the time during which the storage can deliver maximum power from a full load. It is defined by the ratio between energy storage capacity and maximum power.

units, $\sum_{str,bas} G^{E,+}_{str,bas,h}$ the electricity discharged from electricity storage, $G^{E}_{imp,h}$ the electricity imported from neighbouring countries, and f^{E}_{h} the unsupplied electricity.

In the hydrogen system, condition (19) ensures that, for each hour and each river basin, the total hydrogen supply exceeds the total hydrogen demand. As explained in subsection 3.1, the hydrogen supply-demand balance must be satisfied in each river basin.

$$\begin{aligned} & G^{H}_{PtG,bas,h} + \sum_{str} G^{H,+}_{str,bas,h} + \sum_{bas' \neq bas} G^{H,trsp}_{bas',bas,h} + f^{H}_{bas,h} \\ & \geq d^{H}_{bas,h} + \sum_{str} G^{H,-}_{str,bas,h} + \sum_{bas' \neq bas} G^{H,trsp}_{bas,bas',h} \quad \forall bas, h \end{aligned} \tag{19}$$

On the demand side, $d^{H}_{bas,h}$ is the exogenous hydrogen demand in river basin bas, $\sum_{str} G^{H,-}_{str,bas,h}$ the hydrogen charged into hydrogen storage, and $\sum_{bas' \neq bas} G^{H,trsp}_{bas,bas',h}$ the hydrogen transported from the river basin in consideration to other river basins. On the supply side, $G_{PtG,bas,h}$ is the hydrogen produced using PtG, $\sum_{str} G^{H,+}_{str,bas,h}$ the hydrogen discharged from hydrogen storage, $\sum_{bas,bas'} G^{H,trsp}_{bas',h}$ the hydrogen transported from other river basins to the river basin in consideration, and $f^{H}_{bas,h}$ the unsupplied hydrogen.

3.2.5. Water requirements

Constraint (20) imposes, for each river basin and each month, that the Water Exploitation Index WEI+ must be below the threshold value of $WEI^{max}_{+} = 40\%$. We denote $w^{res}_{bas,m}$ the available freshwater resources per basin bas and month m. Water consumption is divided into two categories: non-energy-related water consumption $w^{cons,NonE}_{bas,m}$, which covers agricultural, domestic, and industrial water consumption, and energy-related water consumption. $w^{cons,NonE}_{bas,m}$ is an exogenous monthly parameter, while energy-related water consumption depends on optimization decisions. For each technology, we introduce a water consumption parameter $\omega^{cons}_{tec,bas}$, which gives the volume of water consumed per technology and per GWh of energy produced.

$$\frac{w^{cons,NonE}_{bas,m} + \sum_{h \in m} \left(\omega^{cons}_{tec,bas} \cdot G_{tec,bas,h} \right)}{w^{res}_{bas,m}} \leq WEI^{max}_{+} \quad \forall bas, m \tag{20}$$

4. Application: Data and model calibration

We apply our methodology to the future French power and hydrogen system in 2030. We consider the six river basins of metropolitan France: Artois-Picardie (PIC), Rhin-Meuse (RHI), Loire-Bretagne (LOI), Seine-Normandie (SEI), Rhône-Mediterranée (RHO), and Adour-Garonne (GAR), detailed in the map shown in Figure 2.

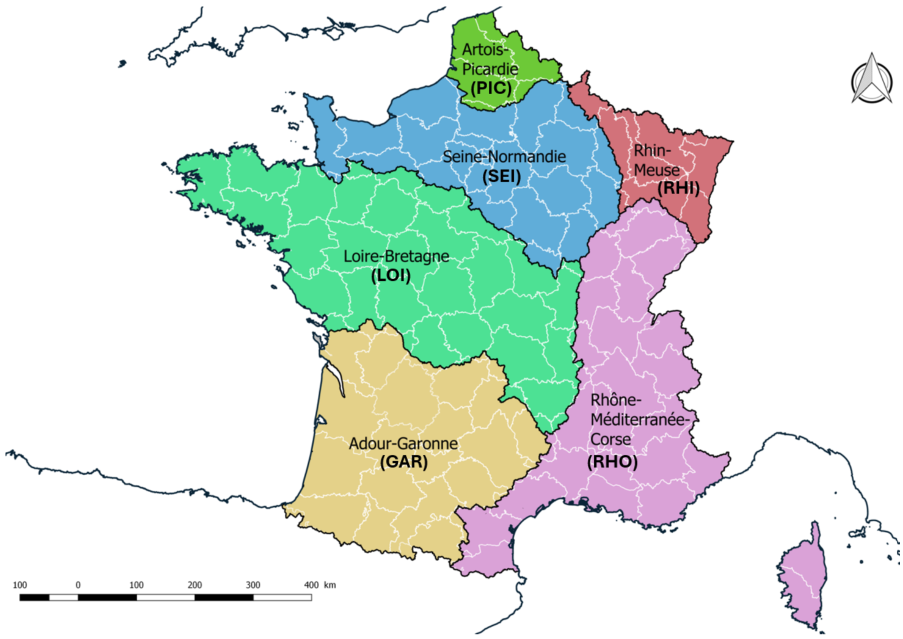


Figure 2: River basins in Metropolitan France. (Source: Wikimedia, CC BY-NC-SA)

4.1. Assumptions on existing capacities

Table 1 shows the existing generation capacities per river basin $k^{ini}_{tec,bas}$. Existing electricity generation and storage capacities are taken from the ORE Agency's 2023 national register of electricity generation and storage facilities (Agence ORE, 2023). We suppose that all these capacities will remain in 2030. We assume that no PtG or hydrogen storage capacity is installed initially.

PHS storage capacity is taken from the JRC hydropower database (JRC, 2019). The calculation of lake-type water-storage reservoir capacities is based on the national hydraulic stock given by the French TSO RTE, which gives a maximum stock of 3,600 GWh (RTE, 2024). We have divided this stock between the two river basins containing the majority of hydroelectric dams, RHO and GAR. Since we had no data on the location of the batteries and since their operation is not affected by them, we arbitrarily placed the storage capacities of the batteries in the PIC basin.

	PIC	RHI	LOI	SEI	RHO	GAR
Solar	0.34	0.95	4.48	1.77	5.88	5.84
Wind onshore	4.17	1.22	5.23	7.79	2.05	1.47
Wind offshore	0	0	0.98	0.50	0	0
Nuclear	5.46	8.20	14.62	13.14	13.57	6.26
OCGT	0.58	1.28	1.91	1.74	0.74	0.2
CCGT	1.82	1.76	1.34	0	1.90	0
PtG	0	0	0	0	0	0
Hydropower						
Generation	0	0	0	0	5.50	3.20
Reservoir (GWh)	0	0	0	0	2700	900
4-h Battery storage						
Charging/Discharging	0.84	0	0	0	0	0
Storage (GWh)	3.36	0	0	0	0	0
PHS						
Charging/Discharging	0	0.8	0	0	3.30	0.9
Storage (GWh)	0	4.5	0	0	42.5	36.4
Hydrogen storage tank						
Charging/Discharging	0	0	0	0	0	0
Storage (GWh)	0	0	0	0	0	0

Table 1: Installed capacity assumptions in GW (based on installed capacity in 2023)

		PIC	RHI	LOI	SEI	RHO	GAR
Solar	GW	1.7	0.6	1.5	0.2	14.6	7.7
Wind onshore	GW	4.8	1.4	6.4	1.0	8.6	7.0
Wind offshore	GW	0	0	4.0	6.5	0	1.0
PHS	GW/GWh	-	-	-	-	2.0/34.4	-

Table 2: Assumptions on maximum integration capacities for renewable and storage technologies

We assume an electricity import (respectively export) capacity from neighboring countries of 22 GW (respectively 27 GW) based on RTE (2021) calculations for 2030. According to RTE's study, interconnections' contribution to France's supply security is projected to decline from 80% of import capacity to 60% by 2050 due to shifts in neighboring countries' generation mix. To accommodate this, we incorporate a 73% derating factor for electricity imports and exports in our study, maintained constant annually for simplicity.

Table 2 describes the maximum integration capacities for renewable and storage technologies. The maximum installable solar and wind power capacities are taken from Tlili et al. (2022), and those of PHS from Shirizadeh and Quirion (2023). No limit is imposed on the installable capacities of PtG, battery, and hydrogen storage tanks.

4.2. Cost assumptions

Table 3 details the cost assumptions for electricity and hydrogen generating technologies, mainly taken from RTE (2021) (constant prices, reference year 2020). The main changes or additions made to RTE assumptions are described in Appendix B.1. The annuity is calculated by multiplying the CAPEX by the capital recovery factor of each technology, assuming a discount rate of 5% per year. Regarding the variable cost of hydrogen production from PtG technology, we assume that this cost is determined solely by the cost of generating the electricity used for this conversion process. VoLL is set at €10,000/MWh for electricity and hydrogen. Following Lebeau (2024), the import price is assumed to be set by foreign CCGTs whose efficiency is slightly lower than that of the domestic fleet (c^E_{imp}=90€/MWh), and the export opportunity cost is assumed to correspond to CCGTs whose efficiency is slightly higher than that of the domestic fleet (c^E_{exp}=50€/MWh).

	CAPEX (€/kW)	Lifetime (yr)	Annuity (€/kW/yr)	fO&M existing / new asset (€/kW/yr)	vO&M (€/MWh)
Solar	760.5	30	49.47	153 / 10	0
Wind onshore	1228.5	30	79.92	161 / 35	0
Wind offshore	2900	25	205.76	69 / 69	0
Nuclear	-	-	-	186	10
OCGT	-	-	-	71	112.75
CGGT	-	-	-	101	77.65
Hydropower	-	-	-	121	0
Run-of-River	-	-	-	121	0
PtG	1000	20	80.24	12	*endogenous*

Table 3: Cost assumptions for electricity and hydrogen generating technologies

Table 4 details the cost and technical assumptions for electricity and hydrogen storage technologies. CAPEX and O&M costs and lifetime parameters are taken from RTE for PHS and batteries, and from (France, 2024) for hydrogen storage tanks. Injection costs are fixed at 1 €/MWh to avoid simultaneous charging and discharging.

	CAPEX (€/kW)	Lifetime (yr)	Annuity (€/kW/yr)	fO&M (€/kW/yr)	vO&M (€/MWh)	Round-trip efficiency
PHS	1000	50	54.78	15	1	0.8
4-h battery	1101	15	106.07	30	1	0.9
12-h H_2 storage tank	396	30	68.35	39.6	1	0.98

Table 4: Cost assumptions for electricity and hydrogen storage technologies

The development of inter-regional hydrogen transport and inter-seasonal hydrogen storage is currently the subject of several recent studies in France (France, 2024; RTE, GRT Gaz, 2023), and the extent to which these infrastructures will be developed by 2030 is still being determined In this context, we take a conservative approach in this study and suppose these infrastructures will not yet be deployed in 2030. We assume that inter-regional hydrogen transport will only be possible by truck. The cost of transporting hydrogen by truck between two river basins is obtained by multiplying the transport cost per km driven by the road distance between the industrial centers of the river basins. We took the transport cost per km driven in (France, 2024) and calculated the distances between hubs using Google Maps. The transport costs obtained are described in Table 5.

		Origin					
		PIC	RHI	LOI	SEI	RHO	GAR
Destination	PIC	0	0.07	0.07	0.03	0.09	0.11
	RHI	0.07	0	0.11	0.06	0.06	0.12
	LOI	0.07	0.11	0	0.05	0.09	0.07
	SEI	0.03	0.06	0.05	0	0.06	0.09
	RHO	0.09	0.06	0.09	0.06	0	0.07
	GAR	0.11	0.12	0.07	0.09	0.07	0

Table 5: Cost assumptions for hydrogen inter-regional transport (M€/GWh /1000km)

4.3. Technical assumptions

The hourly availability factors of VREs are based on hourly availability factors time series from the ERAA database (De Felice, 2021). These coefficients are regionalized to account for the greater sunshine in southern river basins and the greater wind in northern river basins (see Appendix B.2 for details). The nuclear availability factors are obtained by scaling the hourly time series of historical data (RTE, 2024). The same methodology is applied at the river basin level to derive regionalized capacity factors. Appendix B.2 illustrates the hourly availability factor of VREs and nuclear assets. The remaining technical parameters are detailed in Appendix B.1.

4.4. Demand related parameter

We generate hourly time-series data for electricity demand by combining the hourly time-series from the ERAA database (De Felice, 2021) with RTE's 2030 projections (RTE, 2023). According to RTE's 2023-2035 estimates, the expected total electricity consumption in 2030 is projected to reach 535 TWh, with 25 TWh allocated for hydrogen production. Deducting this portion, we estimate France's final annual electricity demand, excluding hydrogen production, to be 510 TWh. Hourly time series for electricity demand are obtained by homothetically scaling the 2030 times series from (De Felice, 2021) to targeted value. Appendix B.3 illustrates the load profile obtained.

Regarding hydrogen demand, we assume a total annual hydrogen demand of 21 TWh, following the French strategy for the development of green hydrogen (French Government, 2024). This demand is distributed across the river basins, in line with the assumptions in a study on hydrogen infrastructure development in France (RTE, GRT Gaz, 2023). Finally, we assume that the hydrogen demand remains constant throughout the year. The values obtained are detailed in Table 6.

	PIC	RHI	LOI	SEI	RHO	GAR
Hourly hydrogen demand	0.34	0.21	0.34	0.75	0.68	0.21

Table 6: Assumptions on hourly hydrogen demand allocation per river basin (GWh)

4.5. Water related parameters

Figure 3 shows the monthly water resources $w_{bas,m}^{res}$ considered in our study. It shows that, except the RHO basin, water resources are highest in winter (December to March) and lowest in summer (July to September). The RHO basin shows a slightly different pattern, with maximum water resources in April-May and minimum in September due to the melting ice from the Alps. We describe our approach for computing water resources in Appendix B.4.

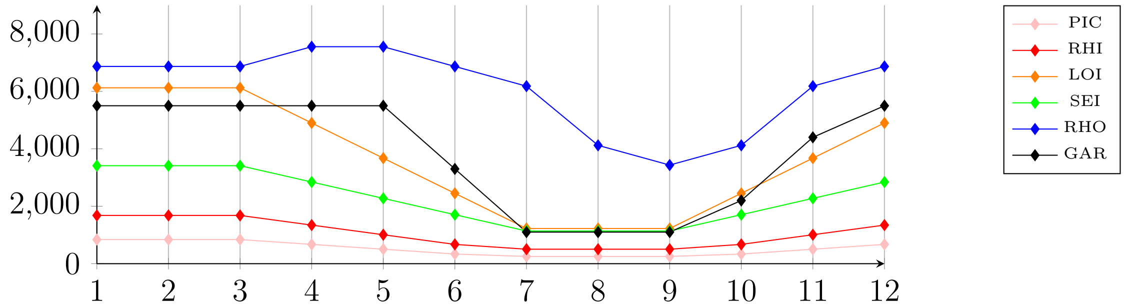


Figure 3: Water resource availability by month and water basin in million m^3, based on historical levels
month 1=january, month 12=december

The energy supplied by water inflows to run-of-river plants $w_{river,bas,h}$ and the energy supply provided by the inflow of water into hydroelectric reservoirs $w_{hydro,bas,h}$ are derived from the hourly time series from the ERAA database (De Felice, 2021). Water consumption factors of energy generation technologies other than hydropower and run-of-river are listed in Table 7. They are extracted from (JRC, 2018) for power generation technologies, and from (IRENA, 2023) for hydrogen generation technologies. Since the water consumption factor of a nuclear power plant's output depends on the plant's cooling system (tower or once-through), we calculate the average water consumption factor per river basin, taking into account the cooling system of the nuclear power plants in each basin. These factors are detailed in Table 8.

Technology	VRE	Nuclear	OCCGT	CCGT	PtG
Value	0	*see Table 8*	2.02	0.69	0.6

Table 7: Water consumption factors for energy generation technologies (m^3/MWh)

	PIC	RHI	LOI	SEI	RHO	GAR
Water consumption factor of nuclear	0	2.54	2.54	0.51	1.63	1.66

Table 8: Water consumption factor of nuclear generation per river basin (m3/MWh)

Finally, we consider water consumption for agriculture, industry and drinking water to be non-energy-related. Non-energy-related water consumption by river basin is taken from (French Government, 2023) and is assumed to be identical in all scenarios. These parameters are detailed in Table 9. To divide these annual values into monthly values, we assume that industrial and drinking water consumption is evenly distributed over the year. We presume that agricultural water consumption is evenly distributed over the summer months (June to August).

	PIC	RHI	LOI	SEI	RHO	GAR
Agricultural consumption	41	96	569	142	658	854
Industrial consumption	10	46	10	42	58	13
Drinking water	66	69	162	234	353	158

Table 9: Non-energy-related water consumption per river basin in million m^3 (Average 2010-2020)

5. Assessment strategy and calibration of water resources data

5.1. Assessment strategy

This paper aims (i) to investigate how integrating climate-induced water constraints can influence the investment and operating decisions of an electricity and hydrogen planner and (ii) to examine the relevance of integrating them into an energy model. To do this, we divide the planning process into two stages: the investment phase, during which the planner forecasts the investments to be made based on anticipated available water resources, and the operation phase, during which the production fleet operates given the water resources present.

For the investment phase, we consider that the planner can make two possible anticipations. The first one posits that water resources in 2030 will be similar to historical values ("Historical" anticipation), whereas the second accounts for the foreseen impact of climate change on water resources ("Climate Change" anticipation). In the operation phase, one of these two anticipations materializes. The "No Water Stress" scenario corresponds to the case where water resources are similar to historical levels, and the "Water Stress" scenario to the case where they are reduced due to climate change (see section 5.2).

The scenarios "No Water Stress" and "Water Stress" can be viewed as two potential futures. The "Historical" and "Climate Change" anticipation strategies are choices made by the planner regarding whether or not to integrate these potential futures into decision-making. Table 10 describes how the model is applied to simulate these four cases. The off-diagonal entries correspond to the cases in which the scenario differs from the anticipation.

	Historical anticipation	Climate Change anticipation
No Water Stress scenario	The model optimizes both investments and operations in the scenario without water stress.	Investments are fixed and set equal to those made in the scenario with water stress. The model optimizes operations in the scenario without water stress.
Water Stress scenario	Investments are fixed and set equal to those made in the scenario without water stress. The model optimizes operations in the scenario with water stress.	The model optimizes both investments and operations in the scenario with water stress.

Table 10: Details of the four cases under consideration

5.2. Calibration of water resources data

As discussed in Section 5.1, the availability of water resources (the water resources available in each basin and the water flowing into hydroelectric reservoirs and run-of-river power stations) depends on the case and the stage considered. In the "Historical" anticipation and the "No Water Stress" scenario, water resource availability is based on historical trends using data from 1990-2020. These data are those detailed in Section 4. In contrast, the "Climate Change" anticipation and the "Water Stress" scenario include the effect of climate change and assume a reduction in water resources. The available water resources are here based on the results of Dayon (2015), who presents the evolution of the French continental hydrological cycle under different RCP scenarios[7]. We use the data obtained for the climate change scenario RCP 8.5, generally used as a basis for pessimistic climate change scenarios.

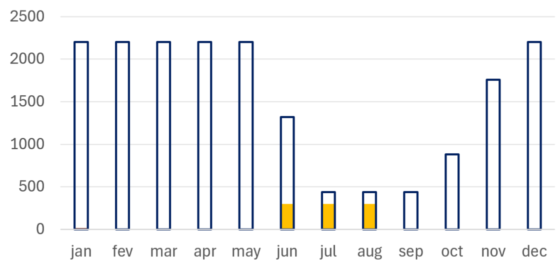
Table 11 shows the reduction in water resources due to climate change considered in our paper, compared to historical averages. We assume that the change in the water entering hydroelectric reservoirs and run-of-river power plants follows the same relative trends as that of the water resources. It highlights that changes in water resources are moderate in winter, except GAR, whose water resources are decreasing, and RHO, whose water resources are increasing (due to reduced snow cover in the Alps). In summer, changes are negative across the country, with more intense changes in the South than in the North. The GAR river basin is the region most impacted by climate change and deserves special attention.

Seasons	Winter	Spring	Summer	Autumn
Months	12 1 2	3 4 5	6 7 8	9 10 11
PIC			- 0.1	- 0.1
RHI			- 0.2	- 0.2
LOI		- 0.2	- 0.3	- 0.3
SEI		- 0.2	- 0.3	- 0.3
RHO	+ 0.1		- 0.5	- 0.4
GAR	- 0.2	- 0.2	- 0.5	- 0.4

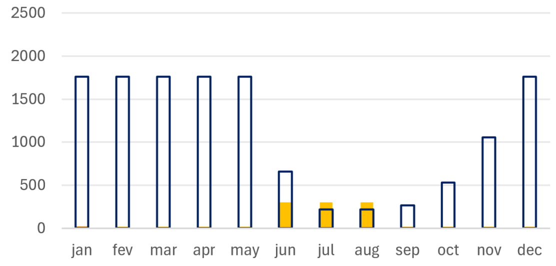
Table 11: Average seasonal differences in water resources when accounting for the impact of climate change compared to the historical average (%)

[7]RCP scenarios are greenhouse gas concentration trajectories adopted by the IPCC for climate modeling and research.

Figure 4: Water parameters in the GAR river basin (million m^3)



(a) When accounting for climate change



(b) Historical values

Water demand for non-energy sectors
Water available to maintain sustainable water consumption

Figure 4 compares the water available to maintain sustainable water consumption, set at 40% of total water resources as proposed in section 3.2.5, with water demand for non-energy sectors in the GAR river basin. Figure 4b shows that when accounting for the impact of climate change on water resources, meeting water demand for non-energy uses in July and August consumes more water than is available to maintain sustainable water consumption (54% of the basin's water resources). As the management of conflicts of use between economic sectors during periods of drought is outside the scope of this paper, we assume that the energy sector is the only sector to have to restrict its water consumption. The water resource available for energy production in the GAR river basin in July and August is set to 0 in the "Climate Change" anticipation and in the "Water Stress" scenario.

6. Results

6.1. Investment phase: investments in new capacities

Table 12 shows the investments made in the two anticipations. It shows that investments in PV capacity are higher under the "Climate Change" anticipation than under the "Historical" anticipation (17.96 GW vs 14.91 GW). More solar power plants are installed to compensate for the reduced electricity supplied by run-of-river and hydropower (see Section 6.2). Installed PtG capacity increases by 0.21 GW under the "Climate change" anticipation compared to the "Historical" anticipation, from 2.53 GW to 2.74 GW. There is no storage installed in either anticipation.

	Historical anticipation	Climate Change anticipation
PV	14.91	17.96
Wind onshore	27.86	27.86
Wind offshore	0	0
PtG	2.53	2.74
PHS	0	0
Battery	0	0
Hydrogen storage tank	0	0

Table 12: Investments in new capacities for each anticipation (GW)

Figure 5 details installed PtG capacities by river basin and shows that the increase in PtG capacity is concentrated in the RHO river basin. Under the "Historical" anticipation, the capacity installed in each river basin is equal to the hourly hydrogen demand of each basin (detailed in table 6). Under the "Climate Change" anticipation, additional PtG capacity is installed in the river basin closest to the GAR basin (RHO basin), enabling hydrogen to be produced and transported to the GAR basin during periods of water restriction in July and August. Appendix C.1 details investments in VRE per river basin.

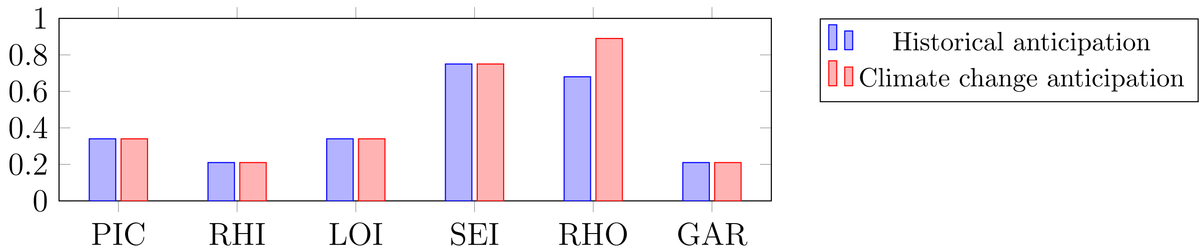


Figure 5: Investments in PtG capacity per river basin for each anticipation (GW)

6.2. Operation phase: energy production and water consumption

6.2.1. Operations of electricity and hydrogen production assets

Table 13 details the overall electricity and hydrogen mix in the "Historical anticipation - No Water Stress scenario" case and the changes observed under the three other cases. In the "Historical anticipation - No Water Stress scenario" case, the French electricity mix is 100% decarbonized (404.60 TWh from nuclear, 183.85 from wind and solar, and 57.54 from hydro). This production meets demand from French electricity consumers, PtG hydrogen producers and exports (510 TWh, 32.59 TWh and 103.76 TWh respectively). 0.36 TWh are lost when electricity is stored in PHS or batteries.

	Historical		Climate Change	
	No Water Stress	Water Stress	No Water Stress	Water Stress
Electricity supply and demand (TWh):				
PV	46.87	-	+4.14	+4.14
Wind onshore	130.69	-	-	-
Wind offshore	6.29	-	-	-
Nuclear	404.60	-6.00	-0.49	-6.38
OCGT	0.00	-	-	-
CCGT	0.00	≈ 0	-	≈ 0
Hydropower	18.04	-3.95	-	-3.95
Run-of-River	39.50	-7.42	-	-7.42
Imports	0.00	-	-	-
Unsatisfied Electricity demand	0.00	-	-	-
Electricity demand	510.00	-	-	-
Exports	103.76	-16.81	+3.49	-13.62
Hydrogen supply and demand (TWh):				
PtG	22.81	-0.31	-	-
Unsatisfied Hydrogen demand	0.00	+0.31	-	-
Hydrogen demand	22.81	-	-	-
Total energy charged into (TWh):				
PHS	2.41	-0.53	+0.67	+0.03
Battery	0.68	-0.14	+0.13	-0.03
Hydrogen storage tank	0.00	-	-	-

Table 13: Electricity and hydrogen production and storage levels observed in the "Historical anticipation - No Water Stress scenario" case and the changes observed under the three other cases

In the "Historical anticipation - Water Stress scenario" case, electricity production from hydraulic reservoirs and run-of-river power plants falls by 20%, from 57.54 TWh to 46.17 TWh. Nuclear production is also lower, as the nuclear power plants in the GAR river basin are shut down in July and August due to water restrictions. This drop in electricity production resulted in a significant drop in exports of -16.83 TWh. Water restrictions in the GAR basin also impact hydrogen production and demand. Hydrogen production by PtG is not authorized in this basin due to lack of water, and the PtG capacities installed in neighboring basins are not sufficient to offset this: the GAR basin's hydrogen demand of 0.31 TWh is not met in July and August.

The situation is different in cases with "Climate Change" anticipation, where PV and PtG capacities are higher, as discussed in section 6.1. In the "Climate Change - Water Stress scenario" case, the additional PV production reduces the drop in exports seen in the case with historical anticipation (-13.62 vs. -16.81 TWh). In addition, the increase in PtG capacity in the RHO basin enables hydrogen demand in the GAR basin to be satisfied during the dry periods of July and August, avoiding a situation of unsatisfied demand. Finally, in the "Climate Change - No Water Stress scenario" case, the additional PV production allows to increase electricity exports by 0.49 TWh. The use of storage facilities increases and the nuclear power generation decreases to integrate this additional renewable energy.

6.3. Costs and benefits of adaptation to climate-induced water constraints

6.3.1. Details of costs in the four cases considered

Table 14 describes the details of costs in the "Historical anticipation - No Water Stress scenario" case and the changes observed under the three other cases.

The "Historical anticipation - No Water Stress scenario" case is the case with the lowest total cost. In cases where climate change is anticipated, the total cost increases due to the investment and fixed costs of the additional solar and PtG capacities installed (+0.20 billion euros). In cases with water stress, total costs increase due to the reduction in export revenues. In these cases, not producing energy in the GAR basin in July and August reduces variable costs by 0.06 billion euros. In the "Climate Change anticipation - Water Stress scenario" case, the cost of transporting hydrogen from the RHO basin to the

	Historical		Climate Change	
	No Water Stress	Water Stress	No Water Stress	Water Stress
Total costs	23.58	+3.90	+0.02	+0.83
Investment costs	3.17	-	+0.17	+0.17
Fixed costs of new capacities	1.15	-	+0.03	+0.03
Fixed costs of existing capacities	20.39	-	-	-
Variable generation costs	4.05	-0.06	-	-0.06
Storage injection costs	≈ 0	-	-	-
Hydrogen transport costs	0.00	-	-	0.02
Import costs	0.00	-	-	-
VoLL Electricity	0.00	-	-	-
VoLL Hydrogen	0.00	+3.12	-	-
Export revenues	5.19	-0.84	+0.17	-0.68

Table 14: Detail of costs in the "Historical anticipation - No Water Stress scenario" case and the changes observed under the three other cases (billion euros)

GAR basin adds an extra 0.02 billion euros, while in the "Historical anticipation - Water Stress scenario" case, failure to meet hydrogen demand adds 3.12 billion euros.

6.3.2. Value of integrating water considerations into an energy model

We adopt the minimax regret criterion[8] to evaluate the value of integrating the impact of climate change on water resources into our energy model. Similar to Chen et al. (2014) and Nicolle and Massol (2023), we establish the regret $R(a, s)$ for a given anticipation $a \in A$; with A the set of feasible anticipations, and a scenario $s \in S$, with S the set of uncertain scenarios. This regret quantifies the deviation from the anticipation that minimizes costs for a given scenario: $R(a, s) = C_s(a) - min_{\alpha \in A} C_s(\alpha)$ where $C_s(a)$ is the cost associated with anticipation a in scenario s. The regret measures the additional cost incurred when selecting an anticipation other than the optimal one for that water resource scenario. We define the minimax regret criterion as : $min_{a \in A} max_{s \in S}(R(a, s))$.

For a given anticipation a, the "worst-case" scenario is defined as the scenario with the highest regret in the minimax regret criterion. In our study, the set of feasible anticipa-

[8]We compare the regrets rather than the total costs because the water stress scenario will lead to higher costs regardless of the anticipated decision. In such cases, as Chen et al. (2014) have already pointed out, a more insightful approach from a decision-making point of view is to compare the relative costs for each scenario by calculating regrets rather than comparing costs in absolute terms.

tions is {Historical anticipation, Climate Change anticipation}, and the set of uncertain scenarios is {No Water Stress, Water Stress}. Table 15 describes the total cost in the four cases, and 16 computes the regret associated with each anticipation in each water resource scenario.

	Historical anticipation	Climate Change anticipation
No Water Stress scenario	23.58	23.60
Water Stress scenario	27.48	24.41

Table 15: Total cost incurred in the four cases (billion euros)

	Historical anticipation	Climate Change anticipation
No Water Stress scenario	0.00	0.02
Water Stress scenario	3.07	0.00
Max regret	3.07	0.02

Table 16: Regret associated with each anticipation in each water resource scenario (billion euros)

The Minimax Regret decision rule recommends implementing the anticipation that minimizes the worst-case regret. We compare the values of the Max regret presented in Table 16 and pick the smallest one to obtain the minimax regret decision. In our setting, the decision to minimize the worst-case regret is to anticipate the impact of climate change on water resources. This anticipation reduces the maximum regret by more than 3 billion euros compared to an anticipation that overlooks the impact of climate change on water resources.[9]

[9]It should be noted that the cost difference between the 'historical anticipation - water stress scenario' case and the other cases largely depends on the value assigned to the VoLL for hydrogen, which is set at €10,000/MWh in this study. To assess how sensitive our results are to this parameter, we conducted an ex-post cost-benefit analysis. This analysis indicates that the minimum VoLL required to justify investment in additional PtG capacity — thereby avoiding penalties for unmet hydrogen demand — is €120/MWh. Therefore, our minimax regret results are relatively insensitive to variations in the VoLL level for hydrogen

7. Discussion

Building upon Khan et al. (2016), our study highlights the value of incorporating climate-induced water constraints into energy planning. This section examines several aspects for better integration of this issue into energy optimization models, including the integration of water considerations into the national hydrogen strategy (7.1), the provision of prospective scenarios of water resource availability (7.2), and the implementation of policies to manage conflicts of use (7.3).

7.1. Develop economically and technically feasible adaptation solutions - integrating water consideration into the hydrogen strategy

Our study shows that although hydrogen production represents only 0.3% of France's total water consumption, ignoring water constraints during the planning phase leads to unsatisfied hydrogen demand in cases where water shortages materialize. In our study, adapting to these constraints involved investing in additional PtG capacities. However, other solutions may also be relevant and could be explored in future studies. For instance, hydrogen imports or seasonal storage could replace or supplement PtG production during periods of water scarcity. These options are already being discussed in the national hydrogen strategy and are under investigation for their technical and economic feasibility. Our paper emphasizes the importance of integrating water constraints into such studies to size these solutions optimally.

From an economic perspective, investing in hydrogen production to mitigate the risk of diminishing water resources is not profitable. In our scenarios, the additional PtG capacities are never used in the "Climate Change adaptation - No Water Stress scenario" case and are only used for two months of the year in the " Climate Change adaptation - Water Stress scenario " case. This suggests that climate resilience subsidies or pricing mechanisms are necessary for investors to consider climate-related risks in their decision-making process.

7.2. Agree on common future scenarios - from a worst-case scenario to a comparison of contrasting narratives

Understanding the future evolution of water resources spatially and seasonally represents a significant challenge for developing effective adaptation strategies. In our study, we relied on the work of Dayon (2015). Dayon's results are obtained by multi-model climate averaging. This approach provides global hydrological trends, but does not capture certain regional climatic phenomena, which may vary from one model to another.

The ongoing Explore 2 project (OFB, 2024) seeks to address this limitation by presenting distinct narratives outlining contrasting potential futures for climate and water conditions in France. Recently published, these findings could enhance our study by enabling comparisons of adaptation strategies across divergent future scenarios. Additionally, this project is complemented by a study quantifying anthropogenic pressures and water demands, considering demographic shifts, socioeconomic developments, and the influence of climate change. These insights can be used to refine our assumptions regarding water consumption in other sectors.

7.3. Establish political measures to preserve water resources and manage conflicts of use

The European Water Framework Directive and the French Environment Code (law no. 92-3 of January 3, 1992) recognize water as a common heritage. Today, French water policy strives to harmonize two fundamental principles: one emphasizing the equal importance of all water uses (law no. 64-1245 of December 16, 1964) and another advocating for an integrated management of water resources to safeguard ecosystems (law no. 92-3 of January 3, 1992). However, the effects of climate change are reducing the availability of renewable water. As a result, meeting the demands of all current water uses increasingly conflicts with the imperative of resource and environmental preservation.

Without regulatory intervention, water use exemplifies the tragedy of the commons (Garrett, 1968), where individuals tend to overuse the resource, regardless of the negative impact this may have on others. To avoid this situation, several issues are currently on the agenda of government bodies to adapt French water policy to the new context of water scarcity. Firstly, the commitment to establish admissible water abstraction volumes, initially proposed in 2009 for water bodies considered out of balance, has been confirmed by decrees in 2021 and 2022 (Cour des Comptes, 2023). Secondly, a discussion regarding the necessity for a national framework to prioritize water usage emerged in an information report presented to the French National Assembly (Mission d'Information sur l'adaptation de la politique de l'eau au défi climatique, 2023). The objective is to prevent tense situations and to transition from crisis-oriented management to a more structural approach. If properly implemented and monitored, these two elements will help to clarify the rules governing quantitative water management in the context of climate change and facilitate the planning and adaptation work of the various water-consuming stakeholders.

Lastly, a recent water plan mandates water conservation measures for all involved parties, aiming for a 10% reduction in water withdrawal by 2030 (Ministère de la Transition Ecologique et de la Cohésion des Territoire, 2023). Although beyond the scope of this document, the above model can be extended to include water consumption reduction targets, likely to modify the investment and operating decisions of water consumers.

7.4. Limits and further work

While this study provides insights into the value of integrating climate-induced water concerns into energy planning, certain limitations warrant further investigation. First, further extensions to this study are feasible once the additional elements described in the discussion are available. By incorporating a more comprehensive array of scenarios, conducting more detailed modeling of interactions among various water-consuming sectors, and implementing a "user pays" pricing system, more nuanced adaptation strategies tailored to the impacts of climate change could be developed. Second, incorporating a more detailed representation of consumer behavior would enhance our economic analysis, as the valuation consumers place on different technologies can significantly influence demand patterns and, consequently, the optimal dispatch of electricity. This aspect is frequently overlooked in current models but has been recognized as a key challenge in energy system modeling (Pfenninger et al., 2014).

Moreover, certain assumptions made in our analysis could benefit from refinement, as they may either overestimate or underestimate the influence of climate change on investment decisions. For instance, our assumption that all water utilized in hydrogen production via PtG originates from freshwater overlooks the potential use of wastewater or treated seawater, thereby offering an avenue to reduce PtG's reliance on freshwater resources. Additionally, we have not accounted for the impact of climate change on water temperature, a critical factor for power plant cooling. Lastly, our energy system modeling overlooks electricity transmission infrastructures, precluding consideration of potential inter-regional transmission constraints. Addressing this limitation would enhance the accuracy and comprehensiveness of our analysis.

8. Conclusion and policy implications

As global efforts towards cleaner energy systems gain momentum, Power-to-Gas (PtG) technology emerges as a critical solution, converting surplus electricity into hydrogen through water electrolysis. However, expanding renewable-based hydrogen production presents technical, economic, and environmental challenges, notably the sustainable management of freshwater. While many studies have integrated water availability constraints into electricity planning models, the academic literature often overlooks these constraints in hydrogen planning.

This study aims to fill this gap by investigating how climate-induced water constraints impact electricity and hydrogen development. We focus on a French case study for 2030, modelling regional and temporal variations in water availability. We compare investment choices made when the model either does or does not include the effect of climate change on water resources and examine the relevance of including this consideration in an electricity and hydrogen model through a regret analysis.

Our findings underline the significant impact of integrating the effects of climate change on water resources in the investment phase. Including this consideration in investment choices results in increased investment in variable renewable electricity and PtG capacity. In cases where water stress materialize, these investments mitigate the decline in exported electricity and prevent shortages in hydrogen supply during summer. Conversely, in cases where water resources are similar to historical levels, the costs associated with these investments are partially offset by increased revenues from additional exports enabled by the augmented supply. A regret analysis confirms that proactively considering climate change's impact on water resources minimizes potential regrets in decision-making processes.

Two key conclusions emerge from the present work. First, adapting investment decisions to a pessimistic outlook on water availability minimizes future regrets. This result is particularly relevant in the context of France's hydrogen development strategy, which does not currently consider this issue. Secondly, adapting to climate change requires, on the one hand, a shared vision of future climatic and hydrological conditions and, on the other, a clear policy regarding abstractable water volumes and hierarchy of uses. This work emphasizes the importance of accounting for water constraints in energy system models. It contributes to the broader discussion on climate change adaptation planning, which is essential to move from crisis management to structural management of water resources. Future extensions may include contrasting future scenarios and future policy decisions on water use to propose detailed adaptation strategies for the electricity and hydrogen sectors.

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Appendix A. Nomenclature

Name	Description	Unit
Indices		
$h \in (1, ..., 8760)$	Hours	
$m \in (1, ..., 12)$	Months	
bas	River basins	
tec	Technology (generation and storage)	
gen	Generation technologies	
str	Storage assets	
imp	Electricity imports	
exp	Electricity exports	
$hydro$	Hydropower plants	
$river$	Run-of-river power plants	
Variables		
$K^{new}_{tec,bas}$	New installed capacity of technology tec in river basin bas	(GW)
$G_{gen,bas,h}$	Hourly generation of technology gen in river basin bas during hour h	(GWh)
$G^{E}_{imp,h}$	Imports of electricity during hour h	(GWh)
$G^{E}_{exp,h}$	Exports of electricity during hour h	(GWh)
$G^{+}_{str,bas,h}$	Hourly turbining into storage str in basin bas during hour h	(GWh)
$G^{-}_{str,bas,h}$	Hourly pumping from storage str in basin bas during hour h	(GWh)
$G^{H,trsp}_{bas,bas',h}$	Hydrogen transported from basin bas to basin bas' during hour h	(GWh)
f^{E}_{h}	Unsatisfied demand for electricity during hour h	(GWh)
$f^{H}_{bas,h}$	Unsatisfied demand for hydrogen during hour h	(GWh)
$P_{str,bas,h}$	Filling level of storage asset str in river basin bas during hour h	(GWh)
$P_{hydro,bas,h}$	Filling level of hydro reservoirs in river basin bas during hour h	(GWh)
Parameters		
$c^{annuity}_{tec}$	Annualized investment cost for technology tec	$(€/GW)$
c^{fOM}_{tec}	Fixed O&M costs for technology tec	$(€/GW)$
c^{vOM}_{gen}	Variable O&M costs for generation technology gen	$(€/GWh)$
c^{E}_{imp}	Import costs	$(€/GWh)$
c^{E}_{exp}	Export costs	$(€/GWh)$
$c^{H,transp}_{bas,bas'}$	Hydrogen transport costs	$(€/GWh)$
$VoLL$	Vallue of Loss Load	$(€/GWh)$
$k^{ini}_{tec,bas}$	Initial installed capacity of technology tec in river basin bas	(GWh)
k^{E}_{imp}	Import interconnection capacity	(GW)
k^{E}_{exp}	Export interconnection capacity	(GW)
$k_{res,bas}$	Capacity of hydroelectric reservoirs in river basin bas	(GW)
$k^{new,max}_{tec,bas}$	maximum investment potential in technology tec and river basin bas	(GW)
$w_{river,bas,h}$	Hourly flow of water in run of river plants in river basin bas	(GWh)
$w_{hydro,bas,h}$	Hourly inflow of water to the hydro reservoir in river basin bas	(GWh)
d^{E}_{h}	Exogenous electricity demand in hour h	(GWh)
$d^{H}_{bas,h}$	Exogenous hydrogen demand in river basin bas and hour h	(GWh)
$\delta_{gen,bas,h}$	Capacity factor of generation technology gen in river basin bas in hour h	
r_{nucl}	Maximum nuclear power ramp	$(\%)$
τ_{str}	Storage time of storage str	
γ_{str}	Round-trip efficiency of storage str	$(\%)$
$w^{res}_{bas,m}$	Available freshwater resources per river bas bas and month m	(m^3)
$w^{cons,NonE}_{bas,m}$	Non-energy related water consumption per river basin bas and month m	(m^3)
$w^{cons}_{tec,bas}$	Water consumption parameter for technology tec in river basin bas	(m^3/GWh)

Appendix B. Model parameterization

This appendix specifies certain assumptions used to calibrate the model.

Appendix B.1. Cost parameters

Cost assumptions detailed in (RTE, 2021) do not include gas and CO2 prices. We include them by assuming a gas price p^{gas} of €28/MWh as in (Pietzcker et al., 2021), and a CO2 price p^{CO2} of €90/tCO2.

Thermal production — Cost parameters The variable cost of thermal power generation is obtained using the following formula :

$$c_{CGT}^{vOM} = \frac{1}{\gamma^{CGT}} \cdot p^{gas} + \xi^{CGT} \cdot p^{CO_2}.$$

with γ^{CGT} the efficiency of gas-to-electricity conversion and ξ^{CGT} the CGT emission factor. The values of these parameters retained for OCGT and CCGT generation are detailed in Table B.17.

Table B.17: Cost parameters for OCGT and CCGT generation units

Parameter	Source	Value	Unit
CCGT conversion efficiency γ_{CCGT}	(Shirizadeh and Quirion, 2023)	0.57	
OCGT conversion efficiency γ_{OCGT}	(Shirizadeh and Quirion, 2023)	0.4	
CO_2 emission per unit of electricity			
generated by CCGT ξ^{CCGT}	(RTE, 2021)	0.32	(t_{CO_2}/MWh)
generated by OCGT ξ^{OCGT}	(RTE, 2021)	0.47	(t_{CO_2}/MWh)

Hydrogen production — Cost and technical parameters The values of the cost and technical parameters retained for hydrogen production are detailed in table B.19.

Table B.18: Hydrogen cost and technical parameters

Parameter	Source	Value	Unit
PtG investment cost	(Megy and Massol, 2023)	1000	(ton/MWh)
PtG lifetime	(Megy and Massol, 2023)	20	(yr)
PtG conversion efficiency	(Li and Mulder, 2021)	0.7	

Thermal and nuclear electricity production — technical parameters

The main technical parameters for thermal and nuclear power generation are detailed in Table B.19.

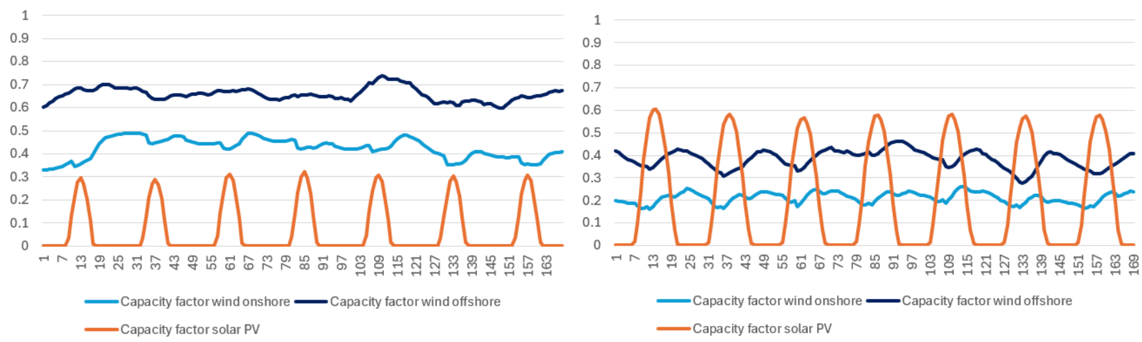
Table B.19: Technical parameters for thermal and nuclear electricity generation units

Parameter	Source	Value	Unit
CCGT capacity factor δ_{CCGT}	(IEA, 2020)	0.85	
OCGT capacity factor δ_{OCGT}	(IEA, 2020)	0.30	
Maximum nuclear power ramp r_{nucl}		0.07	

Appendix B.2. VREs and nuclear capacity factors

Illustration of VREs and nuclear national availability factors

Figure B.6: Wind onshore, wind offshore, and solar national availability factors for two representative weeks



(a) Winter week (January 1 - January 7)

(b) Summer week (July 1 - July 7)

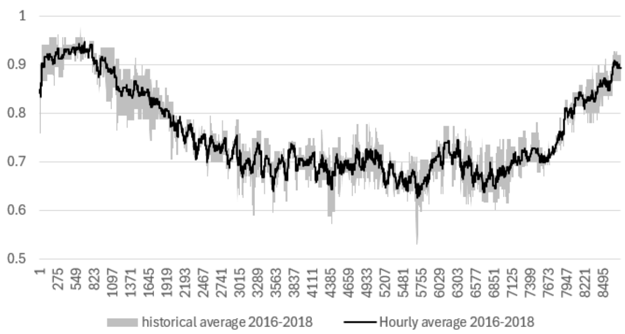


Figure B.7: Nuclear availability profile

Regionalization of VRE availability factors

VRE hourly availability factors time series from the ERAA database (De Felice, 2021) have been regionalized by applying a correction factor. This correction factor is defined as the percentage difference between the river basin's average VRE availability and the national average VRE availability. The average wind (respectively solar) availability is obtained in the global wind atlas (respectively global solar atlas) by calculating the mean wind power density (respectively mean specific photovoltaic power output) for each river basin. Wind and solar correction factors are described in Table B.20.

	PIC	RHI	LOI	SEI	RHO	GAR
Wind correction factor (%)	0.10	-0.13	-0.01	0	0.05	-0.02
Solar correction factor (%)	-0.12	-0.08	-0.03	-0.09	0.11	0.05

Table B.20: Correction factors applied to national wind and solar availability factors to obtain coefficients per river basin

Appendix B.3. Electricity load profile

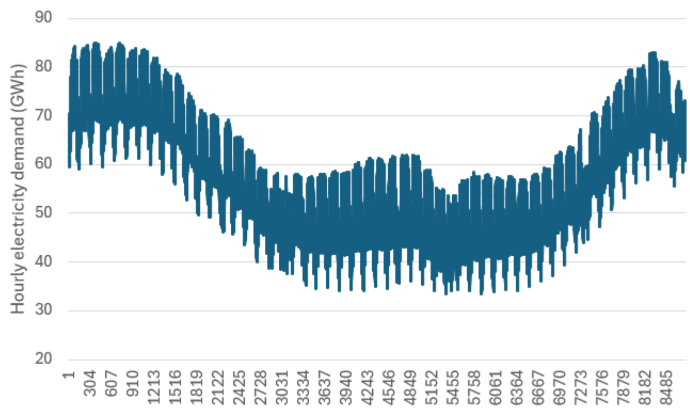


Figure B.8: Electricity load profile

Appendix B.4. Water resource availability by month and by river basin

As described in subsection 2.2, in metropolitan France, an average volume of 211 billion m^3 of freshwater resources is renewed each year. To obtain water resource values by river basin and month based on historical levels, we distribute this annual resource among the river basins based on government statistics, which give annual water resources by sub-basin from 1990 to 2020 (French Government, 2023). To divide these annual resources into monthly resources, we use the annual cycle of the major French rivers as a proxy, extracted from (Dayon, 2015). Table B.21 details the water resources obtained by month and by river basin.

Months	1	2	3	4	5	6	7	8	9	10	11	12
PIC	840	840	840	672	504	336	252	252	252	336	504	672
RHI	1680	1680	1680	1344	1008	672	504	504	504	672	1008	1344
LOI	6125	6125	6125	4900	3675	2450	1225	1225	1225	2450	3675	4900
SEI	3412	3412	3412	2844	2275	1706	1137	1137	1137	1706	2275	2844
RHO	6869	6869	6869	7556	7556	6869	6182	4121	3434	4121	6182	6869
GAR	5500	5500	5500	5500	5500	3300	1100	1100	1100	2200	4400	5500

Table B.21: Water resource availability by month and water basin based on historical levels (million m^3) - month 1: january, month 12: december

Appendix C. Further results

Appendix C.1. Investments in new capacities per river basin for each decision

	Historical water resources forecast						Reduced water resources forecast					
	PIC	RHI	LOI	SEI	RHO	GAR	PIC	RHI	LOI	SEI	RHO	GAR
PV	0	0	0	0	14.62	0.29	0	0	0	0	14.62	3.34
Wind onshore	4.83	0	6.39	1.04	8.57	7.03	4.83	0	6.39	1.04	8.57	7.03
Wind offshore	0	0	0	0	0	0	0	0	0	0	0	0
PtG	0.34	0.21	0.34	0.75	0.68	0.21	0.34	0.21	0.34	0.75	0.89	0.21

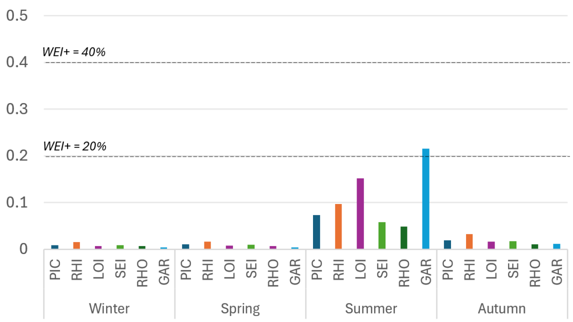
Table C.22: Investments in new capacities per river basin for each decision strategy (GW)

Appendix C.2. WEI+ per month and river basin for the four cases under consideration

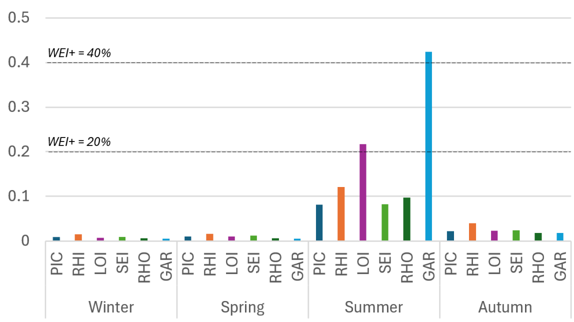
Figure 4 shows the WEI+ per season[10] for the six river basins and four cases considered. The monthly WEI+ have been averaged per season for ease of reading on the figure, but the monthly values are detailed in Tables C.23 and C.24. Comparing these four figures shows that the WEI+ is higher in the "Water Stress" scenario than in the "No Water Stress" scenario, especially in summer. In summer, in the "Water stress" scenario, the WEI+ of LOI exceeds 20%, and that of GAR exceeds 40%. The WEI+max constraint (20) is binding in the GAR river basin in summer, due to water consumption for agriculture, industry and drinking water production (see 5.2. Water consumption in the energy sector does not make (20) a binding constraint in other months and in other river basins.

[10] Appendix C.2

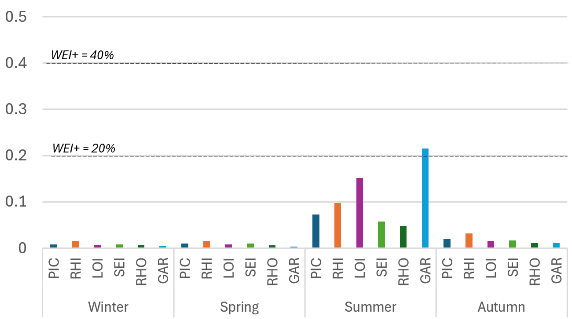
Figure C.9: WEI+ per season in the six river basins for the four cases under consideration



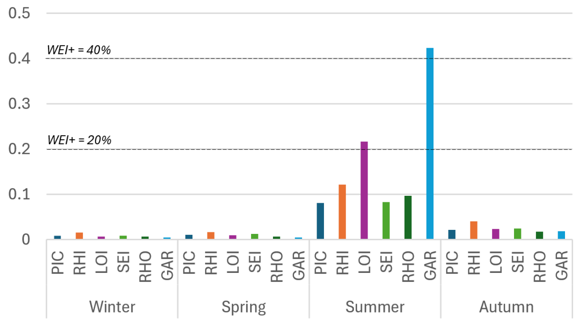
(a) Historical anticipation - No Water Stress scenario



(b) Historical anticipation - Water Stress scenario



(c) Climate Change anticipation - No Water Stress scenario



(d) Climate Change anticipation - Water Stress scenario

Months	1	2	3	4	5	6	7	8	9	10	11	12
PIC	0.8	0.8	0.8	1.0	1.3	6.0	8.0	8.0	2.6	1.9	1.3	1.0
RHI	1.5	1.4	1.3	1.5	2.0	8.1	10.8	10.3	4.2	3.1	2.3	1.8
LOI	0.7	0.6	0.6	0.7	1.0	9.1	18.2	18.2	2.6	1.3	0.9	0.8
SEI	0.8	0.8	0.8	0.9	1.2	4.3	6.5	6.5	2.3	1.5	1.2	1.0
RHO	0.7	0.7	0.7	0.6	0.6	3.8	4.3	6.4	1.4	1.1	0.7	0.7
GAR	0.4	0.4	0.4	0.4	0.4	9.2	27.7	27.7	1.8	1.0	0.5	0.4

Table C.23: WEI+ per month and river basin for the two cases with Historical Anticipation month 1: january, month 12: december

Months	1	2	3	4	5	6	7	8	9	10	11	12
PIC	0.8	0.8	0.8	1.0	1.3	6.6	8.9	8.9	2.9	2.1	1.4	1.0
RHI	1.5	1.4	1.3	1.5	2.0	10.1	13.5	12.8	5.3	3.8	2.8	1.8
LOI	0.7	0.6	0.8	0.9	1.2	13.0	26.0	26.0	3.7	1.9	1.3	0.8
SEI	0.8	0.8	1.0	1.2	1.5	6.2	9.3	9.3	3.3	2.2	1.7	1.0
RHO	0.7	0.6	0.7	0.6	0.6	7.7	8.6	12.9	2.3	1.8	1.2	0.6
GAR	0.5	0.5	0.5	0.5	0.5	18.4	54.4	54.4	3.0	1.7	0.8	0.5

Table C.24: WEI+ per month and river basin for the two cases with Climate Change Anticipation month 1: january, month 12: december