ACCREU

Assessing Climate Change Risk in EUrope

GA number: 101081358, Funding type: HORIZON-CL5-2022-D1-07-two-stage

Deliverable number (relative in WP)	**D2.6**
Deliverable name:	Climate change impacts in EU's energy systems
WP / WP number:	WP2
Delivery due date:	Project month 30 (30/11/2025)
Actual date of submission:	19/03/2026
Dissemination level:	PUBLIC
Lead beneficiary:	CYI
Responsible scientist/administrator:	Theodoros Zachariadis
Contributor(s):	Constantinos Taliotis, Elias Kousoulos, Ioanna Konstantinou (CYI); Francesco Pietro Colelli, Giacomo Falchetta, Enrica De Cian (CMCC)
Internal reviewer:	Francesco Pietro Colelli, Francesco Bosello

Funded by the European Union. Views and opinions expressed are however those of the author(s) only and do not necessarily reflect those of the European Union. Neither the European Union nor the granting authority can be held responsible for them.

Changes with respect to the DoA

Due to the delay in the finalization of the Grant Agreement Amendment to include The Cyprus Institute (CYI) as a new partner in the consortium, the delivery date of the present deliverable was delayed by three months in agreement with the Project Officer.

1. Dissemination and uptake

Insights from the deliverable can directly inform energy planners at national and regional levels of the need to account for climate impacts both on supply and demand. Results from the assessed scenarios can be used by the relevant stakeholders (i.e., policymakers, national authorities, Transmission System Operators) to allocate the necessary funds to ensure cost-effective supply of electricity and safeguard security of supply across the EU.

The OSeMOSYS code used for the analysis and the assessed scenarios, which include projected climate impacts on final electricity demand, renewable energy generation, and thermal power plant outages, are made available through a dedicated Zenodo repository (link) for future use by the scientific community, policymakers and other interested stakeholders.

2. Short Summary of results

ACCREU's estimates of climate impacts and adaptation in the **energy sector** with a specific focus on 2050 include:

a. Projections on differences in hourly electricity demand at a national level across the EU, driven by temperature differences due to climate change (RCP2.6, RCP4.5, RCP7.0) and the level of assumed adaptation.

b. Projections on how the aforementioned demand variation and impacts on energy supply, due to thermal power plant outages and projected differences in renewable energy generation, affect the generation mix of each EU member state. This in turn leads to changes in the projected carbon dioxide emissions.

c. Comparison of the cost incurred on electricity supply by the respective changes in electricity demand and generation technology availability.

Adaptation in the energy sector is characterized in terms of 1) **autonomous adaptation (e.g.** adjustments made by households and firms through a more or less intensive use of energy-using appliances) and 2) planned adaptation (e.g. increased adoption of energy-using appliances, such as air conditioning, and planned changes in their power plant maintenance operations resulting in a **planned power outage** as a response to extreme weather events, in order to avoid the possibility to incur in more costly forced power outages). Low, medium, and high adaptation scenarios are identified for residential energy demand and residential air conditioning adoption and use.

3. Evidence of accomplishment

Manuscripts in preparation:

- Colelli F., Sue Wing I., Future temperature variability around climatic shifts exacerbates global energy demand impacts of warming.
- Kousoulos-Kovachian E., Taliotis C., Colelli F., Konstantinou I., Cian E., Zachariadis T., Assessing climate change impacts on Europe's electricity supply.

Published Manuscripts:

- Sergio, A., & Colelli, F. P. (2025). Weather-induced power plant outages: Empirical evidence from hydro and thermal generators in Europe. *Energy Economics*, *148*, 108549. https://doi.org/10.1016/j.eneco.2025.108549
- Falchetta, G., Cian, E.D., Pavanello, F. et al. Inequalities in global residential cooling energy use to 2050. Nat Commun 15, 7874 (2024). https://doi.org/10.1038/s41467-024-52028-8.

Published datasets:

- Falchetta, G., Pavanello, F., De Cian, E., & Sue Wing, I. (2024). Global gridded scenarios of residential cooling energy demand to 2050 [Data set]. In Nature Communications. Zenodo. https://doi.org/10.5281/zenodo.12697821
- Kovachian Kousoulos, E., Taliotis, C. & Konstantinou, I. (2026). Climate change impacts in EU's energy systems - Energy Systems Model [Data set]. Zenodo. https://doi.org/10.5281/zenodo.18771646

Table of Contents

1. Introduction

This deliverable reports on the objectives outlined in ACCREU's Deliverable 2.6 "Climate change impacts in EU's energy systems", providing a detailed account of the work conducted and the progress made towards achieving the deliverable's objectives. The present deliverable builds on the work conducted in Task 2.2 and especially on climate impacts and adaptation on energy demand and supply.

This report presents an overview of the advancements made in the technoeconomic modelling of climate impacts on energy demand and supply. It assesses the level of resilience that is expected by national energy systems across the EU, considering official projections of the electricity supply system setup. A technoeconomic model is used to compile relevant climate impacts on demand and supply, and assess their combined effect on the generation mix and electricity supply costs.

Section 2 of the report describes the state-of-the-art in the literature projections of climate impacts on energy systems, indicating the advancements made in the present effort. The methodological approach followed in projecting climate impacts on energy demand and supply, which are then incorporated into a single modelling framework, is described in section 3 of the report. Section 4 reports on the modelling results that relate directly to the objectives of the deliverable as follows:

- Impact of climate change on final electricity demand (section 4.1.1)
- Impact of climate change on the energy mix and carbon dioxide emissions (sections 4.1.2-4.1.4)
- Impact of climate change on electricity supply costs (section 4.2)

The report concludes with some key messages for policymakers and energy planners in Section 5. Limitations of the present effort and potential future enhancements are also discussed in this section.

2. Literature background

The vulnerability of energy systems to climate change is an aspect that is widely recognised in the literature (Schaeffer et al., 2012), but is currently largely missing from official long-term national planning. Climate change can lead to increases in electricity demand due to space cooling requirements, directly affect electricity supply (e.g., through reduced water availability for hydropower or for thermal power plant cooling), change variable renewable energy output (e.g., solar PV and wind), improve access to fossil fuel resources (e.g., due to retreating ice cover) or result in supply outages in extreme weather events that can damage critical infrastructure (Ciscar and Dowling, 2014). As the shares of renewable energy increase in the system, power systems will become increasingly vulnerable to extreme events, such as hurricanes or heatwaves, leading to imbalances between supply and demand (Xu et al., 2024). Such risks are exacerbated by the gradual electrification of all sectors, as there is an increasing reliance on electricity supply (Xu et al., 2025).

There are numerous studies examining the impact of climate change on energy systems. Typically, these focus on specific supply technologies (Cronin et al., 2018) or on aspects related to energy demand (van Ruijven et al., 2019). Overall, energy system assessments expect that cooling demand will increase on a global level, heating demand will decrease, whereas hydropower and thermal power plant capacity will be negatively affected (Yalew et al., 2020).

Most of the literature focuses on the supply-side impacts of climate change. For instance, Zapata et al. employed two integrated assessment models and projections from four climate models to assess climate impacts on the output of specific renewable energy technologies (i.e., biomass, hydropower, solar, and wind) under low (RCP2.6) and medium (RCP6.0) climate forcing in each world region for the period 2071-2100 (Zapata et al., 2022). In addition, the impact of high temperatures on thermal power plant capacity availability and efficiency has been evaluated for a grid network in the USA using a production cost and unit commitment model (Ke et al., 2016).

Furthermore, a relevant analysis by the Joint Research Centre of the European Commission focused on the quantification of impacts of climate change on electricity supply, and concluded that most of the long-term supply impacts will relate to water availability for hydropower production and thermal power plant cooling, while the impact to wind and solar generation is estimated to be negligible (Després and Adamovic, 2020). Likewise, in another study the impact of three concentration pathways (RCP2.6, RCP4.5, RCP8.5) on hydropower across Europe was assessed assuming electricity consumption levels remain constant till 2050 (Gøtske and Victoria, 2021). This study also recognises the need for hydropower to transition from a baseload technology to a more balancing role, as wind and solar generation shares increase. Also, Kopica et al. used eight regional climate models to assess the impact of two climate scenarios (RCP4.5 and RCP8.5) on wind and solar energy across Europe, identifying the risk for periods of renewable energy droughts in certain regions (Kapica et al., 2024).

A separate study of the potential development of a 100% renewable electricity system in Germany adopted the use of a cost-optimisation model to estimate storage requirements, considering extreme weather events and using multi-year time series data to address climate uncertainty (Ruhnau and Qvist, 2022); this study focuses on variability in generation from solar photovoltaics and wind.

Besides impacts arising from climate change in the long-term, energy system models need to be able to capture inter-annual weather variability (Pfenninger, 2017). The impact of weather variability on electricity supply in Europe has been demonstrated for a set of electricity demand and renewable capacity scenarios using an electricity dispatch model (Collins et al., 2018); this study examined how solar and wind variability affect electricity supply cost, interconnection flows, and variable renewable energy curtailment, as their shares gradually increase across Europe. Schlachtberger et al. illustrated the impact of weather and load variability on average system costs, using multi-year historical weather data in a cost-optimisation model (Schlachtberger et al., 2018). Another Europe-focused study employed an energy systems optimisation model (PyPSA-Eur) to assess near-optimal scenarios for the development of the electricity supply system of the continent in 2030, taking into account 41 years of weather data and ensuring resilience to weather variability (Grochowicz et al., 2023). Similarly, Zeyringer et al. applied a soft-linking approach that uses a long-term energy systems model and a short-term power systems model to assess the impact of inter-annual weather variability on a system with high shares of variable renewable energy in Great Britain (Zeyringer et al., 2018).

The impact of extreme weather on energy systems is another area of interest, as the frequency of such events is expected to increase with climate change (Seneviratne et al., 2023). Bennett et al. adopted the Temoa optimisation model to evaluate the risk posed by extreme weather events, such as hurricanes, on the energy system of Puerto Rico and how these affect cost of electricity (Bennett et al., 2021); in this case, each year of the modelling horizon was represented by two days with 24 hour resolution. In a relevant analysis, a high-spatial resolution power systems model was coupled with a water distribution model to assess critical infrastructure's vulnerability to hurricanes, again for the case of Puerto Rico (Montoya-Rincon et al., 2023). Moreover, the reliability of electricity supply networks under extreme winters in Texas was evaluated through a coupling of climate modelling and simplified power systems modelling, illustrating the risk for blackouts in the future (Zheng et al., 2023). Another study adopted the PyPSA-Eur power systems model to identify extreme weather periods during which the European power system is most under stress, assuming a fully decarbonised system by 2030 and using 40 years of weather data (Grochowicz et al., 2024); in this case, the focus was on the winter season.

Looking at analyses focusing on the demand side impacts of climate change, Deroubaix et al. applied their methodology to thirty climate model simulations to indicate that on a global scale cooling demand is expected to increase, whereas heating demand is projected to decline, despite the admitted uncertainties in regards to climate (Deroubaix et al., 2021). A Computable General Equilibrium (CGE) model was used for another study to assess the macroeconomic impacts of climate change on energy demand across the European Union for a combination of SSPs-RCPs (Standardi et al., 2023).

Other national studies examine both demand and supply impacts. For example, Perera et al. developed a stochastic-robust optimisation methodology to quantify climate change impact in urban energy systems for 30 cities in Sweden, in an effort to address uncertainty in both renewable energy generation and energy demand (Perera et al., 2020). A Norway-focused analysis concluded that climate will lead to higher hydropower generation and lower electricity demand, as a result of lower space heating needs, while impacts on solar and wind are expected to be negligible (Haddeland et al., 2022). Finally, Gøtske et al. (2024) used 62 years (1960-2021) of historical weather data to examine the impact of weather variability on solar PV, wind, and hydropower generation, as well as heating demand and heat pump efficiency. They employ the PyPSA-Eur model to assess the robustness of the optimum capacity expansion for each of these weather years against the remaining 61 weather years, in order to provide insights into the design of a robust energy system. However, the study does not take into account future climate projections, which are expected to lead to cascading cooling demand needs across the continent.

The need to assess multiple climate impacts in modelling efforts has been identified in the literature (Cronin et al., 2018). Additionally, the disconnect between energy and climate modelling communities, along with the need to use climate data in energy system models has also been highlighted (Craig et al., 2022). The present analysis contributes to this research gap. It utilizes projections from a range of climate scenarios (RCP2.6, RCP4.5, RCP7.0) and a combination of macroeconomic and technoeconomic models to assess the resilience of the European energy system, incorporating relevant impacts on variable renewable energy (i.e., solar and wind), hydropower output, thermal power plant availability, heating and cooling demand. Official capacity projections from ENTSO-E (ENTSO-E and ENTSOG, 2025), which are informed directly from national planning authorities, are stress-tested against these impacts to illustrate the significance of coupling climate projections into energy planning processes.

3. Methods

This section presents the methodological approach used to conduct an analysis of the impacts of climate change on the EU's energy systems. It also includes an overview of the key assumptions.

3.1. Socioeconomic trends

The Shared Socioeconomic Pathways (SSPs) are five scenario narratives, developed between 2013 and 2017, that represent alternative trajectories for global socioeconomic development and climate change mitigation. These narratives, spanning a wide range of future development patterns and climate ambitions, were published in Global Environmental Change (O'Neill et al., 2017; van Vuuren et al., 2017) and have since become a widely used tool in the climate research community. Rather than predicting future trends, the SSPs provide "storylines" that explore how societal changes may unfold under different climate scenarios.

While the SSPs have been instrumental in climate scenario assessments over the past decade, their original framework assumes future projections starting from 2005, which creates the need for updates. In January 2024, version 3.0 of the SSP GDP and population projections was released after comprehensive internal and external reviews. These updates incorporate revised assumptions about technological, societal, and environmental factors. The updated population and GDP projections have been applied in ACCREU scenario modelling to ensure more relevant modelling of future socioeconomic trends.

3.2. Modelling framework

An existing OSeMOSYS model is used to examine the resilience of EU's energy systems to climate in 2050. More information on the model structure and the main assumptions is provided in the subsections below. It should also be mentioned that energy system-related results from Deliverable 2.2 have been used to inform the present analysis.

3.2.1. Final electricity demand and hourly load projections

Load projections for Deliverable 2.6 are based on a new econometric analysis that expands the approach adopted in Deliverable 2.2 developing a high frequency (hourly) assessment of EU country level electricity demand. Hourly load data for the period 2015 to 2023 are extracted from (ENTSO-E, 2026a) and matched with daily mean temperatures. The empirical specification includes seasonal and country specific high dimensional fixed effects to account for systematic temporal patterns and time invariant heterogeneity. The dataset is further complemented with country level residential air conditioning prevalence developed in Deliverable 2.2.

The main specification (1) introduces an interaction term between the linear spline of temperature intervals and air conditioning prevalence, allowing the electricity demand response to heat to vary with the level of adaptation:

$$\text{Load}_{cht} = \sum_k \beta^k T_{c,t}^k \; + \sum_k \gamma^k T_{c,t}^k \; \times \; AC_c + \mathbf{X}'_{cht}\gamma + \alpha_{ch} + \delta_{s(t)} + \varepsilon_{cht} \quad (1)$$

where:

- Load_{cht} denotes hourly electricity demand in country c, hour h, and day t;
- $T_{c,t}^k$ is the daily mean temperature, binned into k-th intervals, in country c on day t;
- AC_c is residential air conditioning prevalence in country c;
- $\mathbf{X}_{cht}$ is a vector of additional controls;
- α_{ch} are country by hour fixed effects, absorbing time invariant differences in hourly load profiles across countries;
- $\delta_{s(t)}$ are seasonal fixed effects;
- ε_{cht} is the error term.

The coefficients β^k capture the baseline semi elasticity of load with respect to k temperature bins, while γ^k identify how this semi elasticities vary with the level of air conditioning prevalence. Results of the panel regression model shown in Equation (1) are presented in Table 1.

Table 1. Semi elasticities of load to temperature and air conditioning prevalence.

Dependent Variable:	log (hourly load per capita)	
Model:	(1)	
Variables	Estimate	AC interaction
T < 0°C	0.1055*** (0.0006)	0.0016*** (2.66×10^{-5})
T 0 - 3°C	0.0683*** (0.0006)	0.0011*** (2.06×10^{-5})
T 3 - 6°C	0.0521*** (0.0005)	0.0009*** (1.72×10^{-5})
T 6 - 9°C	0.0334*** (0.0005)	0.0008*** (1.50×10^{-5})
T 9 - 12°C	0.0148*** (0.0004)	0.0005*** (1.31×10^{-5})
T 12 - 15°C	0.0029*** (0.0004)	0.0002*** (1.13×10^{-5})
T 18 - 21°C	0.0032*** (0.0004)	0.0002*** (1.18×10^{-5})
T 21 - 24°C	0.0074*** (0.0005)	0.0007*** (1.43×10^{-5})
T 24 - 27°C	0.0162*** (0.0006)	0.0013*** (1.75×10^{-5})
T 27 - 30°C	0.0325*** (0.0008)	0.0019*** (2.18×10^{-5})
T >30°C	0.0459*** (0.0012)	0.0029*** (2.75×10^{-5})
Fixed-effects		
iso3-hour-month	Yes	
iso3-year	Yes	
Fit statistics		
Observations	2,354,669	
R^2	0.90002	
Within R^2	0.04603	
IID standard-errors in parentheses		
*Signif. Codes: ***: 0.01, **: 0.05, *: 0.1*		

Figure 1 shows the estimated average change in hourly load due to different temperature levels from the reference of 15-18°C, varying by residential AC prevalence rates (high 60%, medium 30% and low 10%). AC substantially amplify the effect of temperatures.

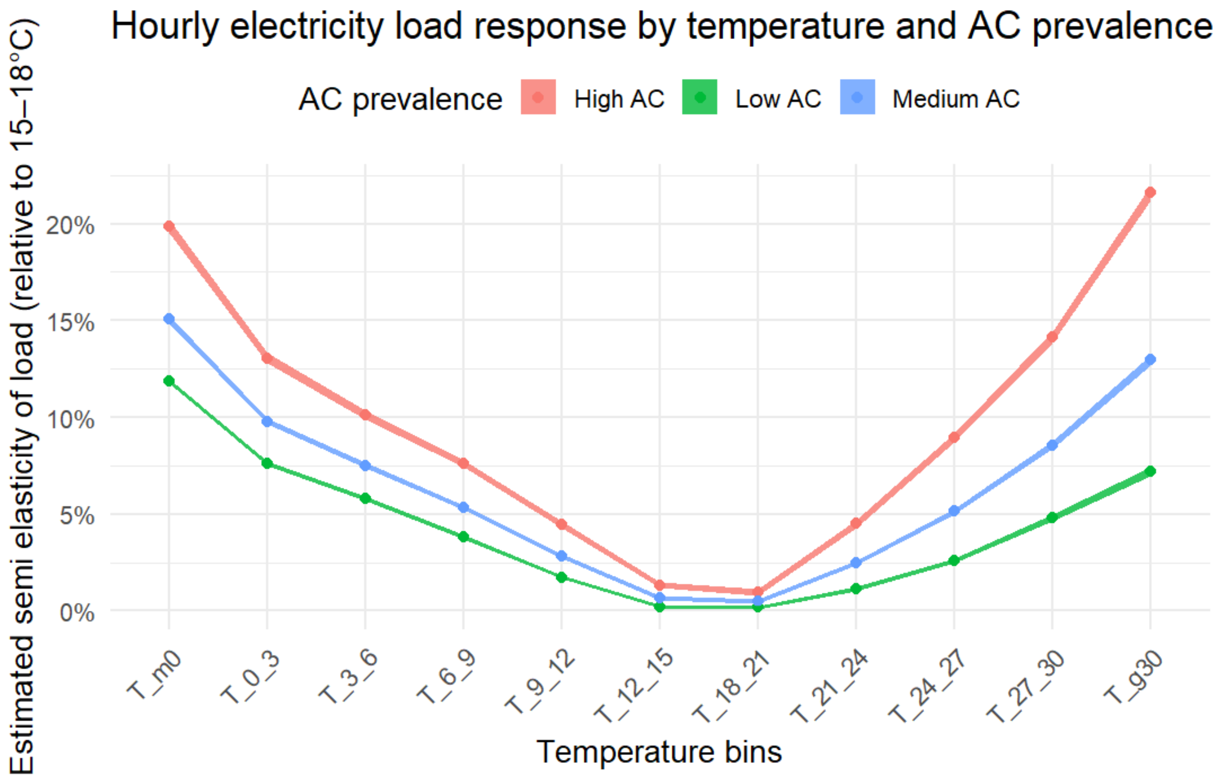


Figure 1. Estimated average change in hourly load at different temperature levels and residential AC adoption rates.

The estimated semi elasticities are then combined with projections of daily temperatures and air conditioning prevalence from the ACCREU model suite to derive hourly load projections for 2050 under low, medium, and high adaptation scenarios. Future air conditioning prevalence rates are taken from Deliverable 2.2 and are applied consistently across high, medium and low adaptation scenarios. Once hourly load projections were generated, the difference in hourly load projected for each of the adaptation levels (high, medium, low) was compared against the equivalent load without adaptation.

As a subsequent step, in order to maintain consistency across the model assumptions, and since the future generation and storage capacity is based on the latest European Systems' Ten-Year Network Development Plan (TYNDP), the no-adaptation scenario projections of final electricity demand at a yearly level are calibrated to this source as well (ENTSO-E and ENTSOG, 2025). Finally, the difference in load calculated for each adaptation case is added to the hourly load without adaptation to produce three distinct adaptation loads for 2050 for each Representative Concentration Pathway (RCP2.6, RCP4.5, RCP7.0).

More detail on the incorporation of adaptation in the assessed scenarios is provided in Deliverable 2.2; an extract of the relevant information is provided in Annex A of the present report also.

3.2.2. Thermal power plant outages

The impact of climate change on thermal power plant outages is drawn from (Sergio and Colelli, 2025). Projections are provided for each day in 2050 across the three climate scenarios (RCP2.6, RCP4.5, RCP7.0) for key generation technologies; coal, gas and nuclear. The initial screening identifies 14 countries[1] for which impacts could potentially be expected. Since the analysis is using as a starting point the existing stock of thermal units to estimate the possibility of outages, this is converted into an estimated share of capacity lost, which can then be applied to the projected power plant capacity to be assessed in the OSeMOSYS model. It should be mentioned that even though Sergio and Colelli's work provide a probability of each outage event for each day, the OSeMOSYS model is deterministic and cannot incorporate these probabilities. Nonetheless, since the present analysis attempts to assess the resilience of the EU's energy systems under extreme conditions, the identified capacity outages can be considered to represent the worst-case scenarios.

3.2.3. Climate impacts on renewable energy

As illustrated in section 2, climate change is projected to alter energy generation from renewable sources such as hydropower, solar PV and wind. Impacts on these technologies are extracted from previous CMCC analyses (Antonini et al., 2024).

In the case of hydropower, the study provides hydropower generation projections for run-of-river and dam infrastructure options for 2010, 2030 and 2050, assuming a static hydropower capacity. The relative change in generation per country and hydropower technology between 2010 and 2050 is extracted from this information (i.e., percentage increase/decrease). Historical statistics for 30 climatic years (1981-2010) (Stoop, 2023) are then used to calculate projections on country- and technology-specific hourly capacity factors which are lacking.

[1] Considering the geographical scope of the OSeMOSYS model adopted in the analysis, impacts on thermal power plant outages for fourteen countries across the EU are identified. These countries are: Austria, Belgium, Bulgaria, Czech Republic, France, Germany, Greece, Hungary, Italy, Latvia, Netherlands, Portugal, Romania, Spain.

3.2.4. Representation of European national energy systems within OSeMOSYS

Climate impacts on energy supply and demand from sections 3.2.1-3.2.3 are incorporated into an energy systems optimisation model and used to assess the climate resilience of 30 European countries. The following subsections provide details on the adopted model and its key assumptions.

3.2.4.1. OSeMOSYS-Europe model development

The model developed in this analysis utilises the OSeMOSYS modelling framework, which is an open-source, bottom-up, energy system optimization tool used for national, regional, and global analyses (Gardumi et al., 2018; Sridharan et al., 2019; Taliotis et al., 2020). It is suitable for the evaluation of long-term energy planning scenarios. Its transparency and modular structure make it well-suited for long-term planning and for capturing the complexities of national and transcontinental energy systems. OSeMOSYS operates by minimising the total discounted system cost, meaning that it identifies the most cost-effective configuration for the entire modelled region, rather than optimising each national system independently. As a result, investment decisions or instantaneous generation output may be concentrated in countries with the most competitive energy resources, such as those with abundant low-cost renewables, with electricity then exported to neighbouring systems. This enables lower-cost supply for importing regions compared to domestic alternatives. Furthermore, the model can represent trade flows that balance generation surpluses or deficits across the interconnected network, such as exporting excess electricity during low demand or meeting peak demand shortfalls elsewhere. In this way, cross-border trade supports deferred investments and improved system-wide efficiency.

The model input incorporates a range of statistics and assumptions, including final energy demand, existing and planned generation infrastructure, trade infrastructure, projected technoeconomic characteristics, fuel price trajectories, fossil fuel reserves, renewable resource availability, and national energy and climate policy targets. The principal outputs generated by the model include technology-specific electricity generation, cross-border electricity flows, system cost breakdown (Capital, Fixed and Variable Operation & Maintenance (O&M), Fuel, Emission costs), carbon dioxide emissions by fuel type, and resource use (i.e., fuel combustion or renewable energy utilisation). These outputs are extracted in detail for each country, enabling the comparative assessment of scenarios in terms of cost, emissions, and trade dynamics.

This study applies an extended version of an OSeMOSYS model (Kousoulos, 2025) applying the AETOS model, which represents the electricity supply systems of seventy-eight countries in Africa and Europe. The European energy system is extracted, consisting of the 27 EU member states, Norway, Switzerland, and United Kingdom. It is then updated to consider national energy system infrastructure projections. In the present study the OSeMOSYS model is fed with official projections on generation and storage capacity from the latest European Systems' Ten-Year Network Development Plan (TYNDP) (ENTSO-E and ENTSOG, 2025)[2].

3.2.4.2. Temporal resolution

The analysis focuses on the climate impacts from each of the assessed scenarios for 2050. This is considered a more interesting and informative year compared with 2030 that features lower projected climate impacts, overcapacity of electricity supply systems across Europe and most of fossil fired power plants not yet decommissioned.

In order to adequately capture the impact of extreme climate on national energy systems and address one of the key limitations of long-term optimisation models (Niet et al., 2022) representative weeks for each season (i.e., autumn, winter, spring, summer) are modelled with an hourly resolution. Furthermore, two additional weeks are included to better capture the most energy-demanding periods during Summer and Winter. These "extreme weeks" are selected based on the observed level of impacts in the data utilised for the projections on final electricity demand, thermal power plant outages and renewable energy generation.

Table 2. Definition of temporal resolution used in adopted OSeMOSYS model.

Week	1	2	3	4	5	6
Season	Autumn	Winter (typical)	Winter (extreme)	Spring	Summer (typical)	Summer (extreme)
Dates in 2050 (RCP2.6)	01/09-30/11	01/12-10/12 18/12-28/02	11/12-17/12	01/03-31/05	01/06-27/07 04/08-31/08	28/07-03/08
Dates in 2050 (RCP4.5)	01/09-30/11	01/12-27/01 04/02-28/02	28/01-03/02	01/03-31/05	01/06-24/07 01/08-31/08	25/07-31/07
Dates in 2050 (RCP7.0)	01/09-30/11	01/12-08/02 16/02-28/02	09/02-15/02	01/03-31/05	01/06-31/07 08/08-31/08	01/08-07/08

The extreme periods are identified at the system level using a seven-day window applied to daily indicators of climate impacts. Demand extremes are based on the cumulative increase in electricity load

[2] This is done to assess the ability of official projections of the future EU energy systems to cope with the aforementioned impacts, which are to be expected due to climate change in each scenario. This approach also addresses the limitation of perfect foresight, which relates to long-term energy systems model having perfect information about the conditions of the respective problem for the entire modelling horizon and adjusting their outlook accordingly (Keppo and Strubegger, 2010). In such a case, a greenfield optimisation of capacity expansion would consider the climatic conditions of the year in question and ensure that investments in generation and storage technologies would be structured in a way that climate impacts would be entirely manageable and the respective energy demand would be met at the lowest possible cost.

relative to the reference case, while outage extremes are defined based on the total unavailable thermal capacity. The summer extreme weeks correspond to periods where high demand increases and outages occur simultaneously, whereas the winter extreme weeks are defined primarily by peak demand increases. The exact timing of the extreme weeks varies across RCPs, reflecting differences in the projected climatic impacts. In total, 1008 time-slices are used to represent each modelled year; i.e. 6 representative weeks with an hourly resolution (Table 2).

3.2.4.3. Underlying model assumptions

Data on energy projections are retrieved from the latest TYNDP from the European Transmission System Operators (ENTSO-E and ENTSOG, 2025), which is preferred to the EU Reference Scenario, whose latest assessment was published in 2021 (European Commission - Directorate General for Energy. et al., 2021). The projected generation and storage infrastructure capacities are taken from the National Trends+ scenario, which is largely based on the first round of national energy and climate plans (NECPs) submitted by EU member states. The revised NECPs submitted at the end of 2024 and early 2025 are yet to be compiled into TYNDP 2026, which is still under development (ENTSO-E, 2025). Therefore, the adopted scenario may not be fully aligned with the latest climate targets set by the European Green Deal (European Commission, 2021), but it may be closer to a middle-of-the-road scenario and the SSP2 assumptions of the Shared Socioeconomic Pathways (O'Neill et al., 2017).

The technoeconomic parameters of generation and storage technologies, including capital cost, fixed and variable operation and maintenance costs, and efficiencies, are compiled from multiple sources to reflect regionally consistent and policy-relevant assumptions. Primary sources include the EU Reference Scenario 2020 (European Commission - Directorate General for Energy. et al., 2021) and datasets from a previous version of the OSeMOSYS-Europe (OSeMBE) model (Henke et al., 2022). Pumped hydro storage costs are disaggregated into power capacity and energy storage components. Similarly, battery storage systems are disaggregated into energy storage and inverter components, reflecting distinct cost drivers (IRENA, 2017).

Furthermore, fossil fuel price projections are based on the latest World Energy Outlook of the International Energy Agency (IEA, 2025). In addition, the Emissions Trading System (ETS) for carbon emissions from energy-intensive industries is already implemented across the EU, directly affecting the cost of electricity supply. Even though, as indicated in Deliverable 2.2, a global carbon price pathway is available from MESSAGE for each of the Representative Concentration Pathways included in the analysis (RCP2.6, RCP4.5, RCP7.0), it is deemed more relevant to adopt EU-specific assumptions. As such, the ETS price projection utilised is based on the latest recommendations by the European Commission (European Commission - DG CLIMA, 2024). Two separate price projections are provided by the European Commission: one for a scenario "With Existing Measures" (WEM), and one for a scenario "With Additional Measures" (WAM). The former scenario's ETS price projections are adopted in the present analysis, as it is more aligned with the SSP2 narrative. The relevant fuel and ETS price assumptions are provided in Table 3.

Table 3. International fuel and ETS price projections.

	Oil	Natural gas	Coal	ETS
Unit	EUR2021/barrel	EUR2021/MBtu	EUR2021/tonne	EUR2021/tCO2
2024	61	8.0	86.8	82
2035	62	5.0	60.5	86
2050	59	6.5	51.2	164

The possibility for electricity exchange in periods of imbalanced demand and supply provides flexibility to grid networks. This flexibility is rapidly gaining importance as shares of variable renewable energy increase. As such, incorporation of the future interconnection levels across European countries is required in the present analysis. Representation of grid interconnections in Europe is based on a combination of existing and planned infrastructure. Existing cross-border transmission links are sourced from the original OSeMBE model (Henke et al., 2022) and European Network of Transmission System Operators for Electricity (ENTSO-E) Transparency Platform (ENTSO-E, 2026b), while planned and candidate interconnectors are drawn from the latest information of the relevant TYNDPs (ENTSO-E, 2025; ENTSO-E and ENTSOG, 2025). Line lengths have been recorded for each interconnector to facilitate the calculation of associated capital and operational expenditures. Where possible, values are cross-validated using multiple sources, including National Energy and Climate Plans (NECPs) (European Commission, 2025), which are systematically reviewed for all EU Member States. A symmetric exchange capacity is assumed for all modelled interconnectors, which means that bidirectional electricity flow is allowed at equal capacities. Further detail on the represented grid interconnections is provided in Annex B.

3.2.5. Scenarios investigated within OSeMOSYS

Based on the information available for the projected climate impacts across the three Representative Concentration Pathways (RCP2.6, RCP4.5, RCP7.0) and the three levels of adaptation assessed for the load projections (low, medium, high), the relevant climatic impacts on the European electricity supply system are analysed for a total of 9 future pathways. These alternative futures are compared against a Baseline scenario, where no climatic impacts are introduced and no adaptation affecting electricity demand is assumed.

4. Quantification of climate impacts in EU energy systems

4.1. Impact of climate change on the energy mix

The following section presents and discusses the energy relevant projections to provide a broader understanding of the climate change impacts on EU's electricity supply system.

4.1.1. Impact on final electricity demand

Since OSeMOSYS is a demand-driven model, it is important to comprehend the dynamics implemented in the model as a result of the changes in the electricity load foreseen by the respective adaptation scenarios discussed in section 3.2.1. As indicated in Figure 2, there are distinct trends observed when comparing the various pathways. These vary across adaptation levels, RCPs, as well as seasons, as opposing trends arise in terms of cooling and heating demand. Figure 2 indicates the level of change in the total projected load for meeting residential space cooling (assumed to occur between May-September) and space heating needs (assumed to occur between November-March) satisfied by air conditioners in each EU member state; a comparison between the low and high adaptation levels and across each RCP is conducted against a reference scenario without adaptation.

Overall, the general trends seem to agree with existing literature, as heating demand is projected to decrease while cooling demand is expected to increase. However, the extent of these changes varies greatly across countries. In terms of absolute difference, the biggest variation is observed in large energy systems. A reduction in electricity demand for residential heating of up to 4.4 TWh occurs in Germany, 2.9 TWh in France, 2.1 TWh in Italy, and 1.8 TWh in Poland and Sweden. On the other hand, an increase in electricity demand for residential cooling of up to 5.7 TWh is projected in Italy, 4.9 TWh in Spain, 3.2 TWh in France, and 1.3 TWh in Germany and Greece.

As we move from lower to higher radiative forcing (i.e. from RCP2.6 towards RCP7.0), while keeping the adaptation level constant, electricity demand for space heating in the winter months decreases. Equivalently, electricity demand for space cooling in the summer months increases. As such, the largest differences in both cases are observed in the case of RCP7.0. It is interesting to observe that in certain countries RCP7.0 leads to greater load decreases for space heating requirements rather than load increases for space cooling. This is especially the case for countries that have a high heating demand in the winter period due to their geographical location and predominant climatological conditions.

Similarly, when keeping the RCP constant, the higher the level of adaptation, the greatest is the electricity demand, as the adoption of residential air-conditioning grows. In the case of cooling demand in summer, this means that the increase of electricity demand is higher in the High Adaptation scenario, while in the case of heating demand in winter, the largest load reductions are observed in a low adaptation scenario.

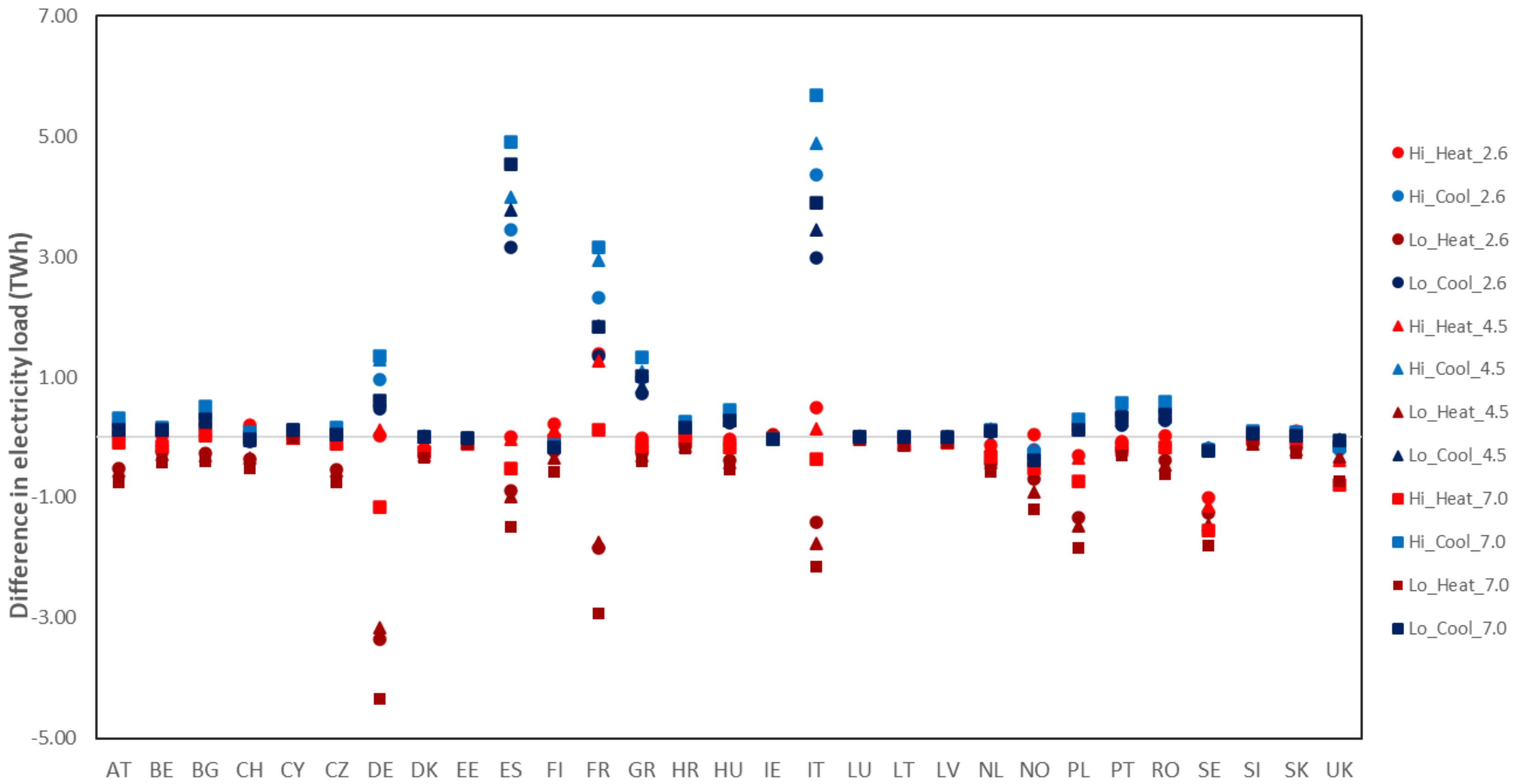


Figure 2. Difference in electricity load for residential heating (November-March) and cooling (May-September) in each country across RCPs (RCP2.6, RCP4.5, RCP7.0) and air-conditioning adoption rates (high and low) as compared to the equivalent load from a scenario without adaptation.

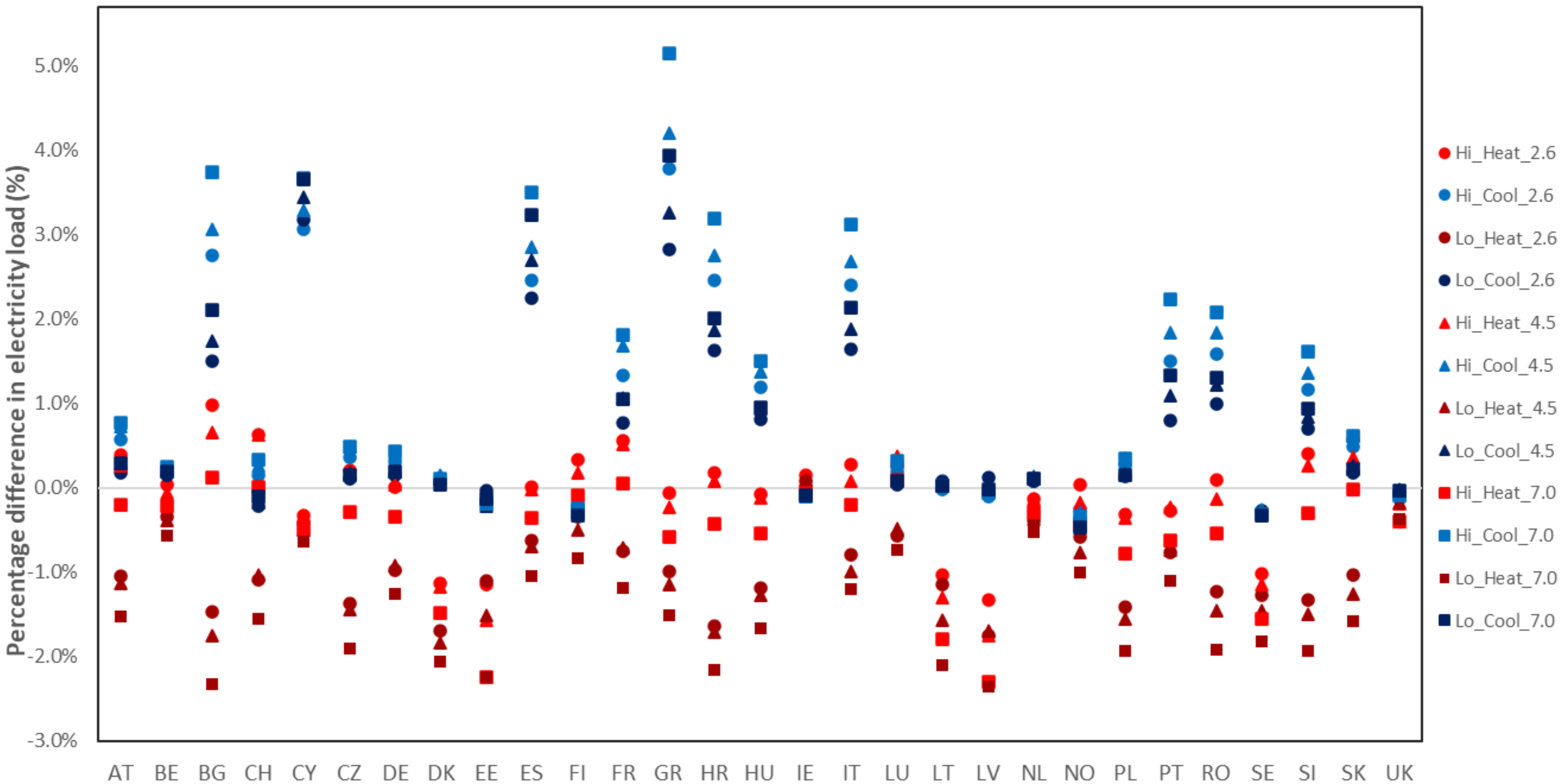


Figure 3. Percentage difference in electricity load for residential heating (November-March) and cooling (May-September) in each country across RCPs (RCP2.6, RCP4.5, RCP7.0) and air-conditioning adoption rates (high and low) as compared to the equivalent load from a scenario without adaptation.

When looking at the relative difference in load for residential heating and cooling (Figure 3), additional remarks can be made. Firstly, the largest increases in cooling demand are observed in South European countries, such as Greece, Bulgaria, Cyprus, Spain, Croatia, and Italy. Correspondingly, the largest reductions occur in countries with cold winter, such as Denmark, Estonia, Latvia, Lithuania. As in the case of the absolute differences, the largest variations appear in RCP7.0.

The relative difference in load may appear to be small on a seasonal basis. However, this grows substantially at the hourly level. For instance, even though the electricity demand in the scenario High Adaptation-RCP7.0 in Italy increases due to cooling in summer by about 6%, there are instances when the difference is much higher. Actually, the highest relative difference is observed in the first hour of the 15th of August, reaching an increase of 19%; this translates to an additional hourly load of 5.3 GW.

In the short-term, accurate projections of the level of variation in load at the hourly level is very important for maintaining grid stability and ensuring adequate capacity is available online to meet the expected demand. Furthermore, in the longer-term, additional investments in electricity supply infrastructure (i.e., generation, storage, grids) may be needed.

4.1.2. Impact on electricity generation

The developed scenario results indicate that the capacity outlooks of EU member states assessed in the present analysis indicate a satisfactory level of resilience against the climate impacts included in the model. We can reach this conclusion as there is no indication of an imbalance in supply and demand in any of the scenarios. However, the generation mix changes across Europe, as climate impacts are implemented. Figures 4-6 show differences in generation by technology across countries for each of the nine scenarios, as compared to a baseline scenario without climatic impacts. The susceptibility to generation changes varies substantially between scenarios and countries.

As expected, the lowest impact is observed in RCP2.6. This is due to a lower effect of climate change on demand, thermal power plant outages and renewable energy output. With a greater radiative forcing the climate impacts on electricity generation amplify in RCP4.5 and RCP7.0. In fact, these two cases are almost identical within each adaptation case with only minor differences observed. This is due to the fact that in the absence of RCP7.0 projections on renewable energy output, the assumed capacity factors of hydropower, solar PV and wind are kept constant to those of RCP4.5. In essence, this also indicates that the differences observed across RCPs are primarily driven by changes in the renewable energy output. This is an anticipated outcome in the relevant scenarios, as capacity outlooks with high shares of renewable energy are adopted for the analysis.

When looking at the differences in generation in each country across scenarios, interesting patterns emerge. Firstly, a greater radiative forcing enables greater renewable energy output in certain countries. For instance, Germany's solar PV and wind generation is higher in RCP4.5 compared to RCP2.6, while the same applies for solar PV in Spain. Similarly, hydropower generation increases in the cases of Sweden and Norway.

ACCREU
Assessing Climate Change Risk in EUrope

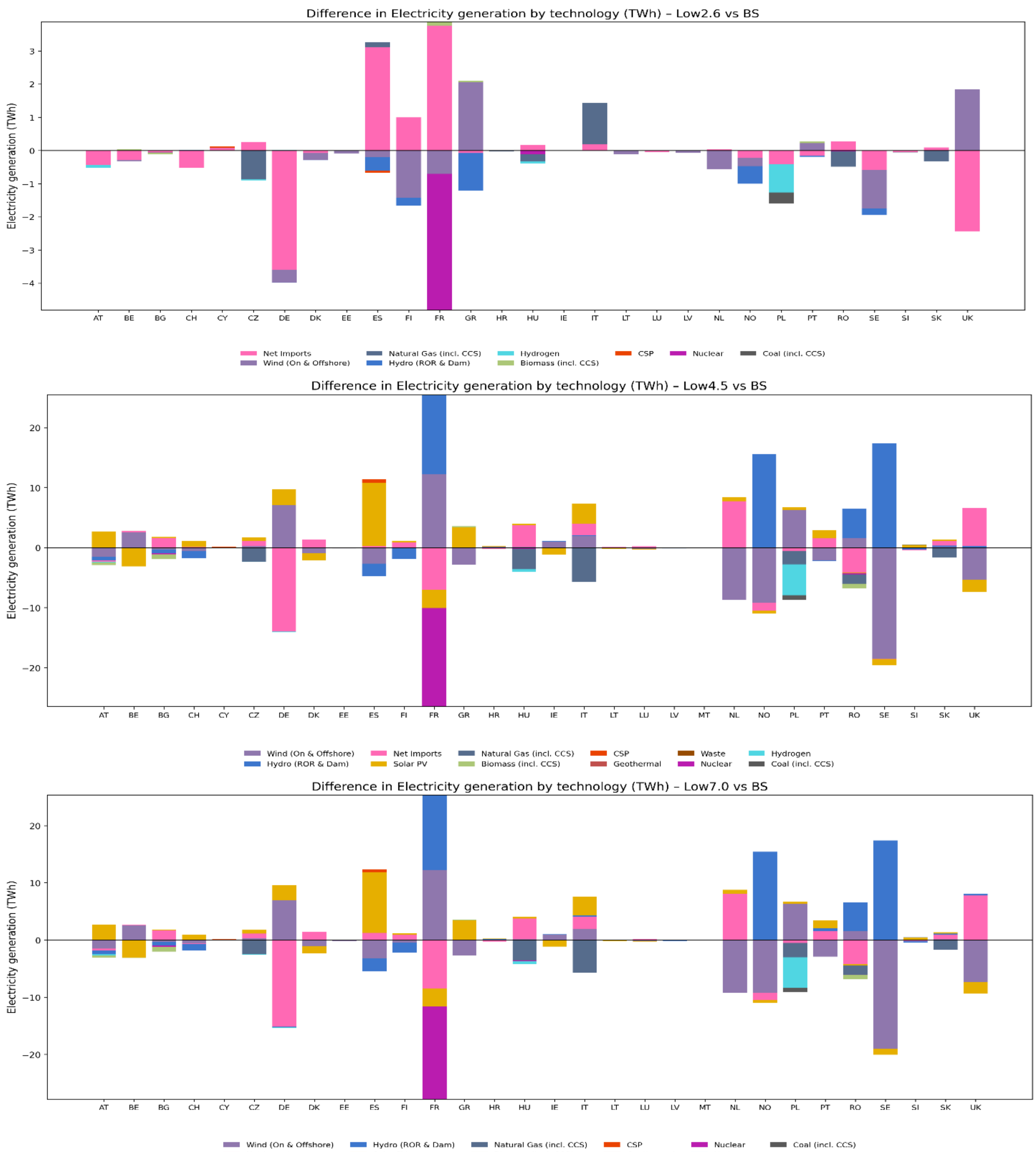


Figure 4. Difference in electricity generation by technology in each country in the Low adaptation case for RCP2.6 (top), RCP4.5 (middle) and RCP7.0 (bottom), as compared to a baseline scenario (BS) without climate impacts and adaptation.

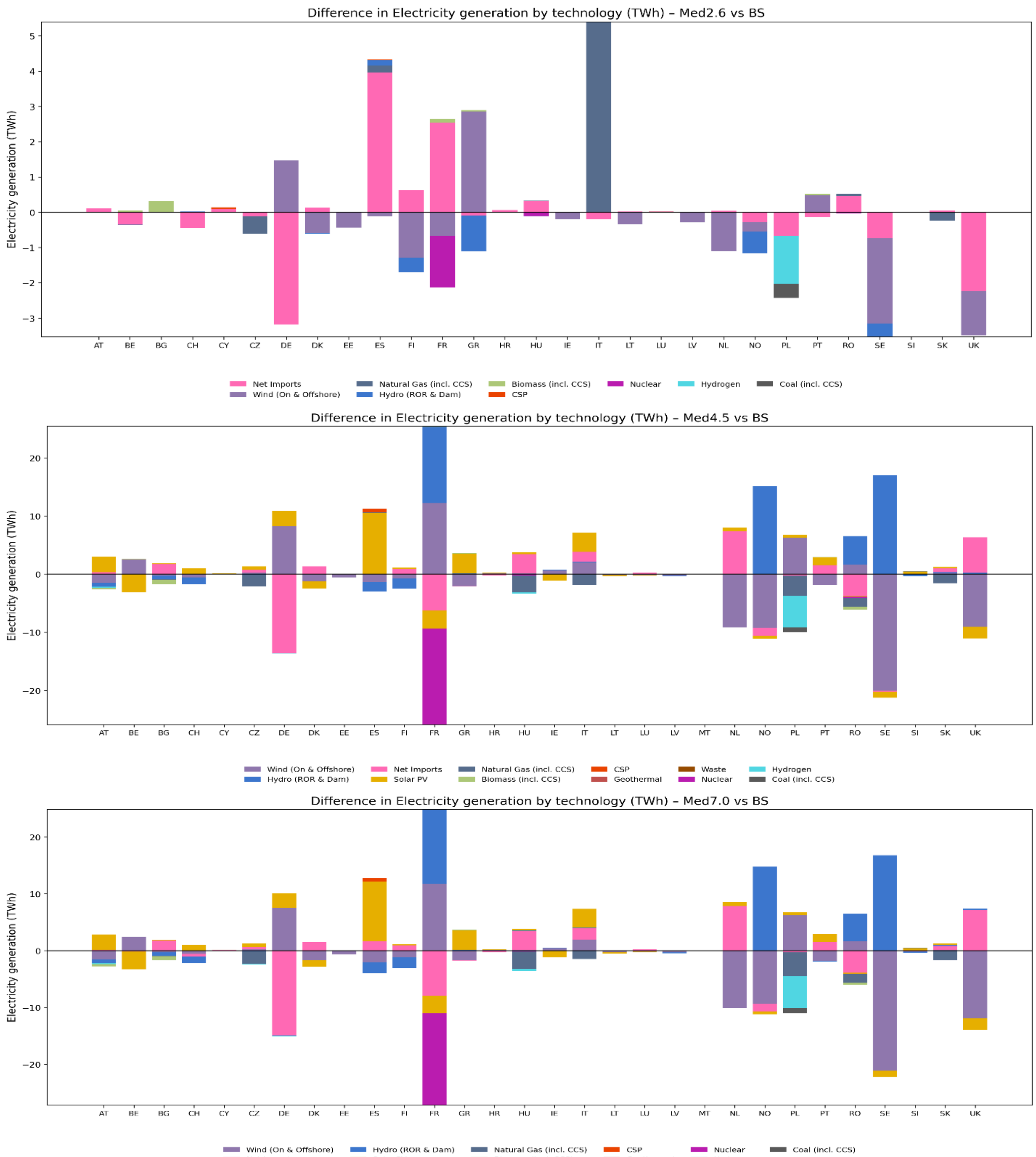


Figure 5. Difference in electricity generation by technology in each country in the Medium adaptation case for RCP2.6 (top), RCP4.5 (middle) and RCP7.0 (bottom), as compared to a baseline scenario (BS) without climate impacts and adaptation.

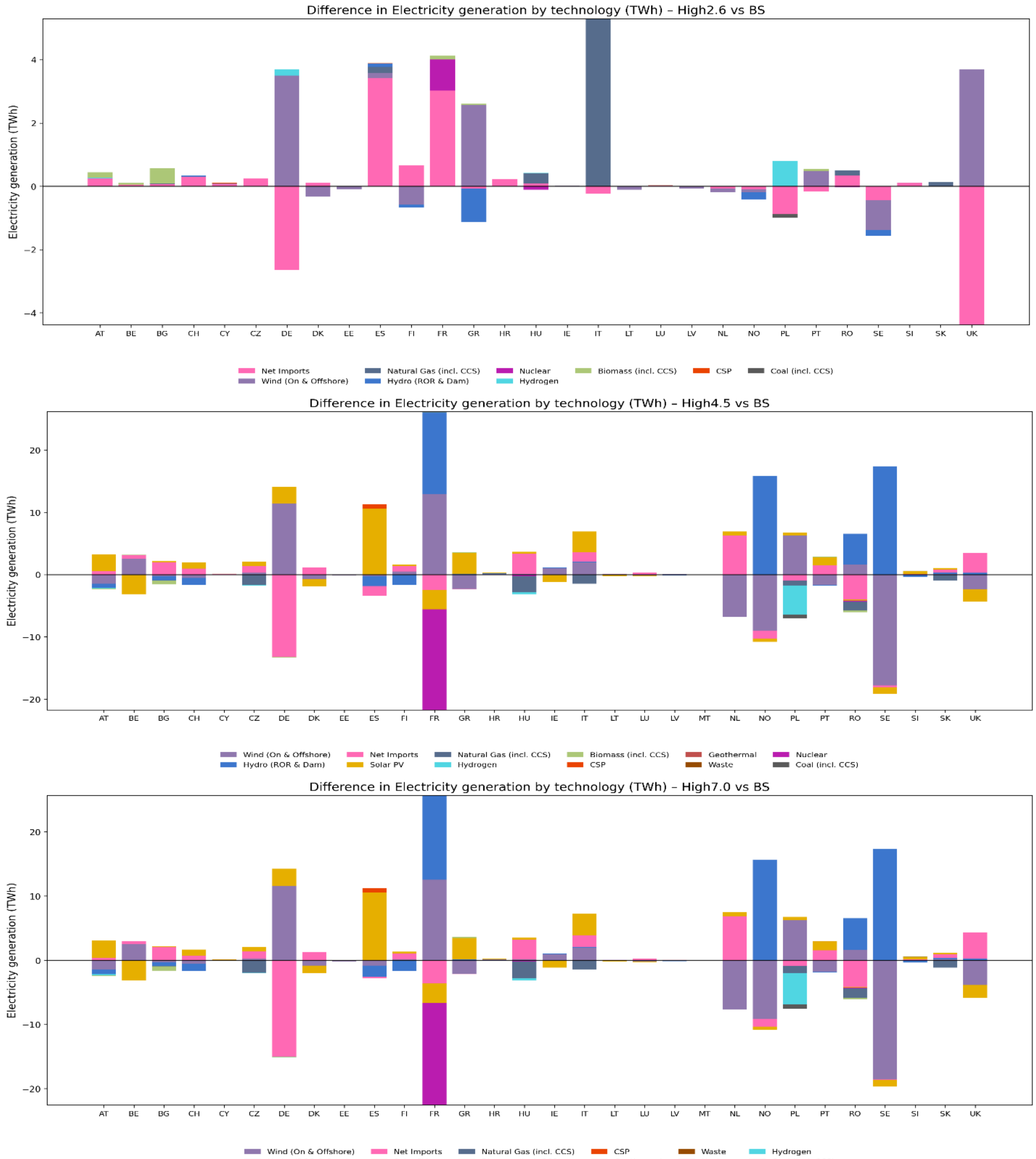


Figure 6. Difference in electricity generation by technology in each country in the High adaptation case for RCP2.6 (top), RCP4.5 (middle) and RCP7.0 (bottom), as compared to a baseline scenario (BS) without climate impacts and adaptation.

On the other hand, a greater radiative forcing increases the risk for thermal power plant outages, often affecting large shares of capacity. This aspect affects nuclear generation in France, which is however substituted by hydropower and wind generation, as indicated in RCP4.5 and RCP7.0. Natural gas generation in Italy also appears to be substantially affected by climate change, as it has the highest capacity of a given technology at the risk of an outage; the relevant capacity at risk exceeds 28 GW in mid-August.

Useful insights can be extracted when looking at the hourly generation mix, as variability in renewable energy output is more evident. For example, in the case of Portugal and the High Adaptation-RCP4.5 scenario, the system relies solely on renewable energy technologies. In instances during the evening hours when wind generation is projected to be erratic, the electricity demand is met using renewable hydropower and electricity stored during the day in pumped hydro facilities (Figure 7).

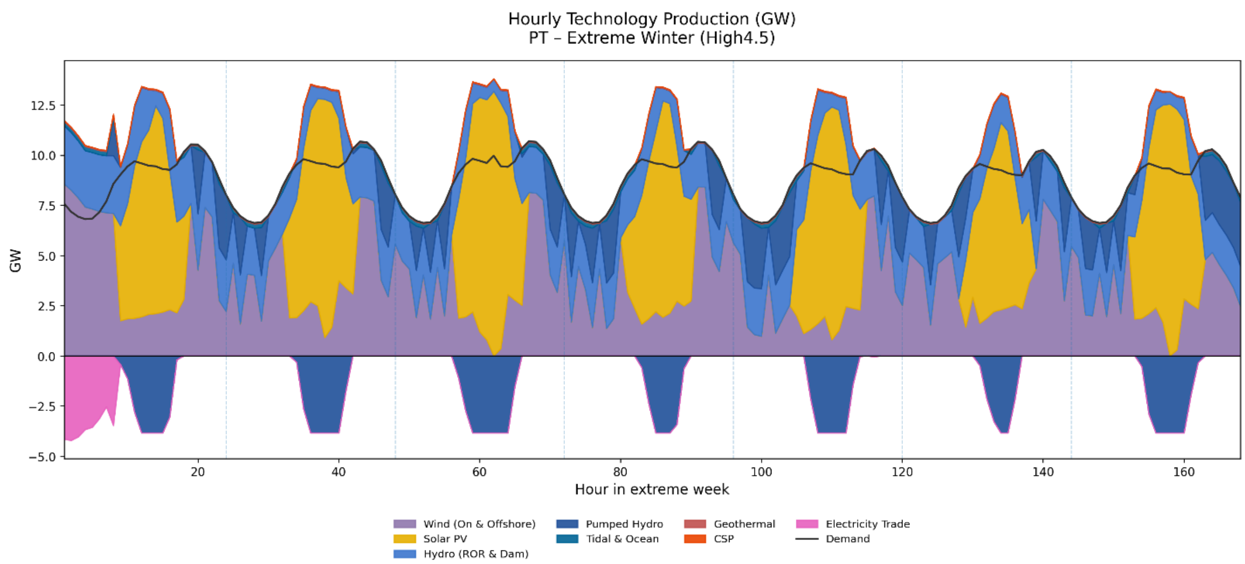


Figure 7. Projected generation profile in Portugal in the High Adaptation-RCP4.5 scenario in the period 28/01/2050-03/02/2050.

Similarly, in a more diversified system, the electricity of Czech Republic in wintertime relies on a technology mixture of solar PV, nuclear, biomass, natural gas and imported electricity, while batteries enables storage of cheap electricity during the day so that it can be used in the evening; small volumes of hydrogen-fired generation are also projected (Figure 9). In this specific case, there are periods where fast-response gas-fired units need to be ramped up or down (e.g. between hours 100-120); this may be driven by sudden shifts in the output of solar PV. However, the rate at which this ramping occurs exerts additional strain on the thermal units and incurs additional costs, which are not captured by the adopted modelling framework.

The two national examples shown here highlight the importance of flexibility options in a future highly decarbonised system. The importance of adequate storage is illustrated in both cases, while the need for grid interconnector availability is shown in the case of Czech Republic. Additionally, thermal generators with fast response times are needed. In the case of a fully decarbonised system, this may mean additional investments in units firing biofuels, green hydrogen, or fossil-fuels coupled with Carbon Capture and Storage.

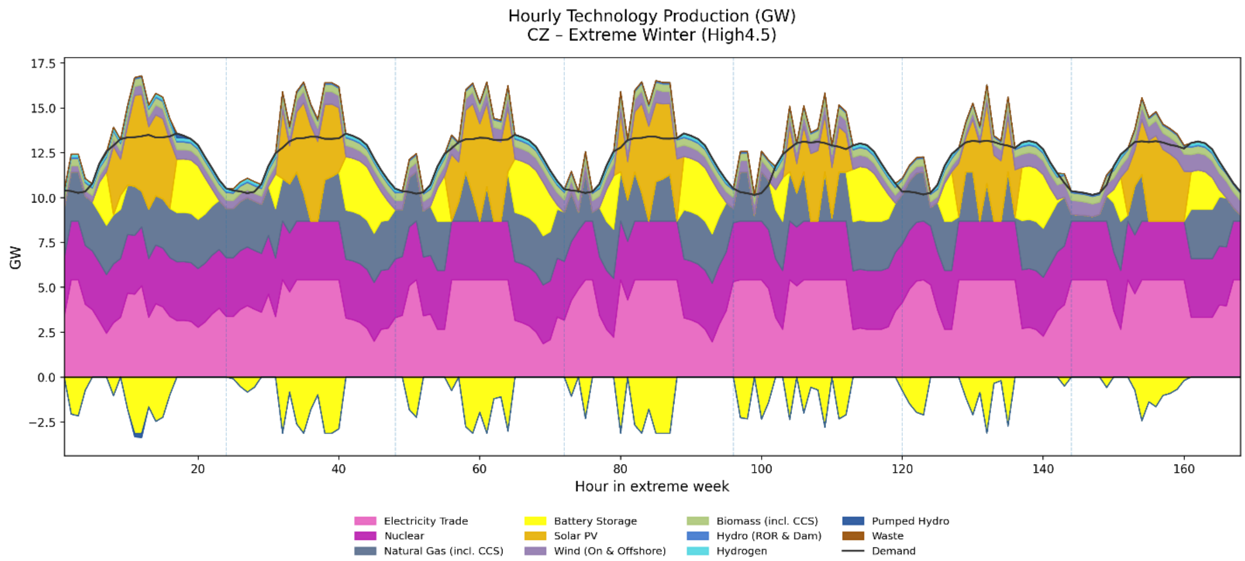


Figure 8. Projected generation profile in Czech Republic in the High Adaptation-RCP4.5 scenario in the period 28/01/2050-03/02/2050.

4.1.3. The importance of electricity trade

The flexibility offered by grid interconnections to national electricity supply is of great significance. To illustrate the extent of this importance, a sensitivity scenario is developed and run within the OSeMOSYS-Europe model. In this scenario, operation of grid interconnections is blocked throughout 2050 to examine whether any issues regarding shortage of supply arise at any given time across the national electricity supply systems. This stressor is implemented on a scenario with climate change impacts; specifically, the High Adaptation-RCP7.0 scenario is chosen due to its higher degree of variation compared to the baseline scenario.

As indicated in Table 4, in a hypothetical scenario without electricity trade across national borders, the level of unserved energy is significant in certain countries. For instance, in the extreme case of Luxembourg, which is currently heavily dependent on electricity imports, its unserved electricity demand reaches about 75% of its projected needs. In other countries, such as Croatia and Malta, the level of unserved energy is much smaller. It should be noted that in the baseline scenario, which does not include climate impacts and electricity trade is enabled, no unserved energy is observed across the EU; this also applies to the rest of the scenarios, where electricity trade is allowed.

The peak load that is projected to be unserved in the affected group of countries is also of interest; this relates to the highest level of unserved energy observed throughout 2050 during a period of one hour. In this case, the highest instance is noticed in Poland and exceeds 8 GW which would correspond to roughly 26% of the country's peak demand (usually reached during the winter season). Note that Poland's capacity is assumed to be reliant on intermittent renewables in 2050, with 30 GW solar PV, 14 GW onshore wind, and 11 GW offshore wind, while dispatchable generation technologies (i.e., nuclear, coal, gas, biomass, hydropower) amount to about 20 GW and storage technologies to 1.6 GW. Accordingly, the additional flexibility of electricity interconnections is crucial. In this particular example, the loss of load does not arise directly from the assessed climate impacts on supply and demand, but from failure of such critical infrastructure as a result of extreme weather events.

Table 4. Estimation of unserved energy and peak load unserved in EU member states in a scenario without electricity trade in 2050 and climate change impacts (High Adaptation-RCP7.0).

	Unserved energy (GWh)	Peak load unserved (GW)
Austria	42,800	5.02
Belgium	5,627	5.48
Czech Rep.	19,241	3.67
Croatia	867	1.15
Hungary	13,676	4.37
Luxembourg	10,875	1.46
Malta	3	0.05
Poland	14,889	8.32

4.1.4. Impact on carbon dioxide emissions

The projected energy demand and energy mix differences across scenarios results in equivalent changes in carbon dioxide emissions from the electricity supply system across the EU member states (Figure 9). It is interesting to note that as we move from lower to higher radiative forcing (i.e. RCP2.6 to RCP7.0) – and keeping the adoption of residential air conditioners constant – the carbon dioxide emissions appear to decrease at an EU level. This can be attributed to overall lower heating demand across Europe, which means that the need for baseload fossil-fired generation units reduces in winter.

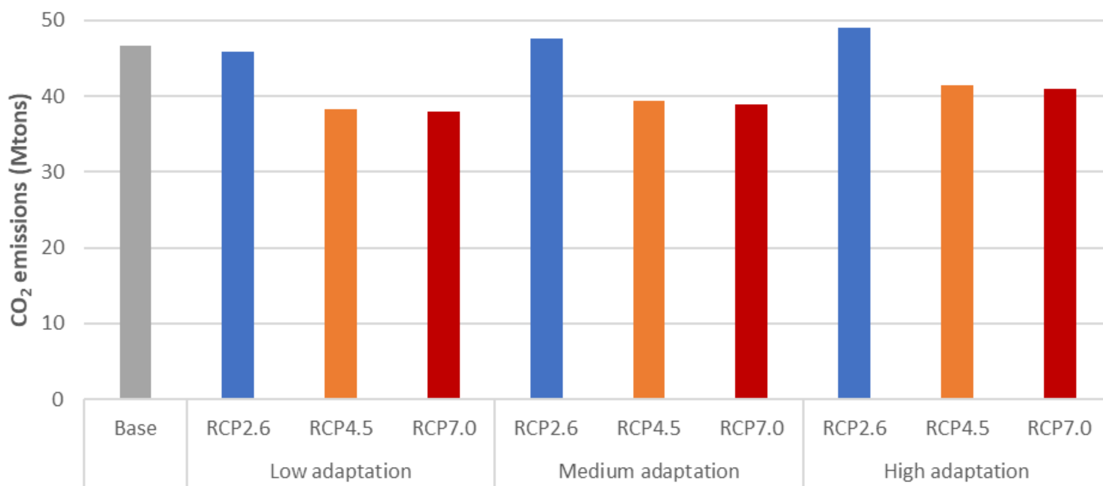


Figure 9. Total carbon dioxide emissions in the electricity supply sector in the EU across scenarios.

The second observation that can be made is that as the adaptation level increases and adoption of air conditioners rises within each RCP, carbon dioxide emissions also rise. This is an expected outcome, as final electricity demand grows to satisfy cooling and heating requirements, adding pressure to the existing system. Since the additional demand can be more easily satisfied with dispatchable generation technologies and fossil-fired units are more readily available than variable renewable energy technologies, higher adaptation levels lead to marginally higher carbon dioxide emissions.

It should be noted that the projected carbon dioxide emissions relate only to a few countries, as more than half of the EU member states are projected to rely fully on renewable energy for their electricity supply by 2050 across the scenarios. Specifically, almost all these emissions correspond to Poland, Italy, Hungary, Czech Republic and Slovakia. These countries continue to have relatively sizeable fossil-fired capacities that remain in the generation mix across scenarios. For instance, according to the adopted scenario projections, Italy and Poland have 46 and 6 GW of natural gas-fired power plants respectively in 2050. Another small group of countries (e.g. Austria, Germany, Romania, Slovenia) are projected to have negligible carbon dioxide emissions.

The carbon dioxide emission projections in each scenario are provided for each EU member state in Appendix C.

4.2. Impact of climate change on electricity supply cost

The variability in generation described in section 4.1.2 affects the overall cost of electricity supply. Since the assessed scenarios do not allow for investments in new infrastructure, changes in the supply cost relate to the level of variable operation and maintenance, fuel and ETS costs. As the differences in generation are largely marginal, the overall cost of electricity supply shows negligible variation on a regional level, especially at an annual level. However, there seems to be seasonal variability in the observed impacts (Figure 10). Even though the overall electricity supply cost decreases in winter, spring, and autumn with higher radiative forcing, the opposite trend occurs in the summer. On the other hand, as we move from a lower to a higher adaptation scenario within the same RCP, the electricity supply cost increases marginally across all seasons.

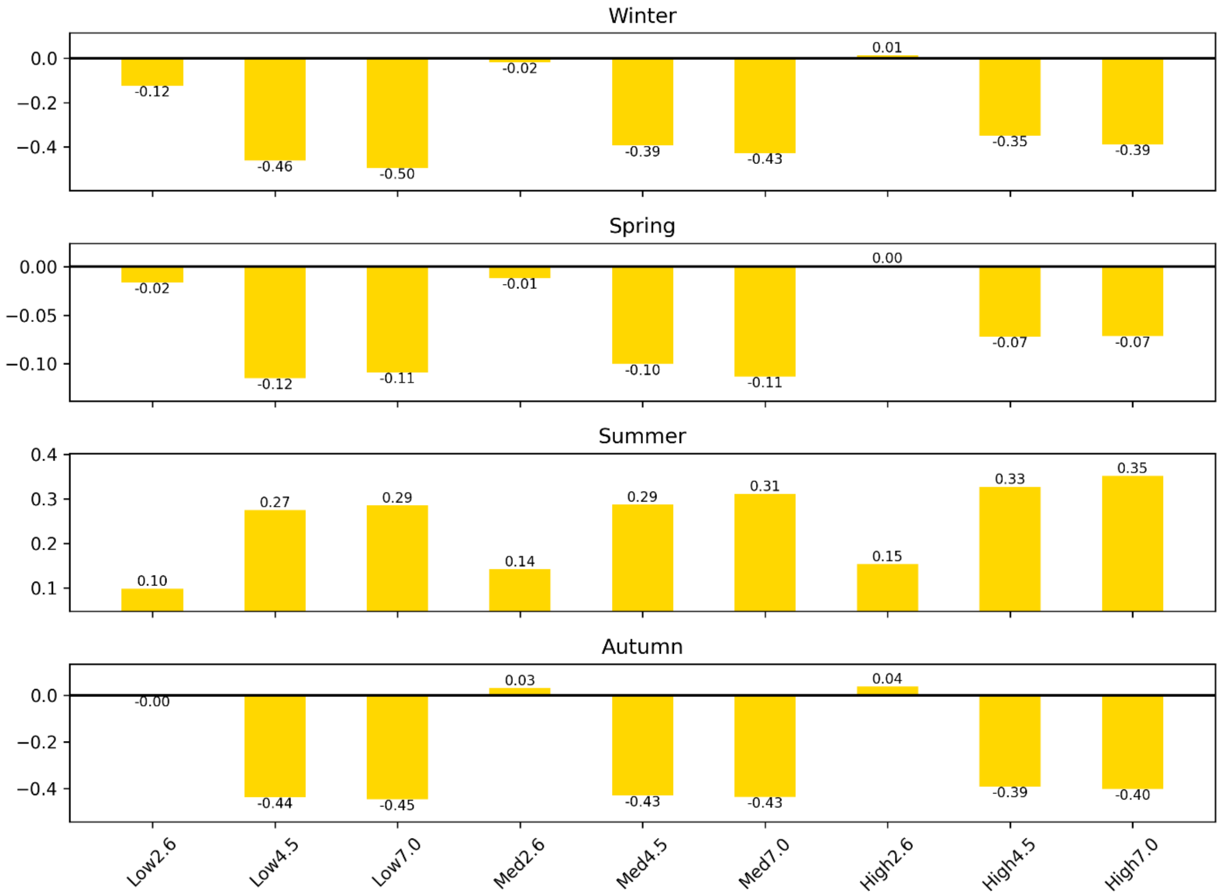


Figure 10. Absolute change in the EU electricity supply cost (EUR/MWh) across seasons, climate, and adaptation scenarios.

A comparison of North and South Europe illustrates that the climate impact on electricity supply cost is more pronounced in southern countries across all seasons (Figures 11-12). For instance, the maximum deviation observed in North Europe indicates an additional cost of 0.06 EUR/MWh in the High Adaptation-RCP7.0 scenario, whereas the corresponding value in South Europe is 0.93 EUR/MWh. A substantial deviation is also observed in the autumn period for the same scenario, but in the opposite direction, as electricity supply cost in South Europe for the same scenario decreases by 1.2 EUR/MWh.

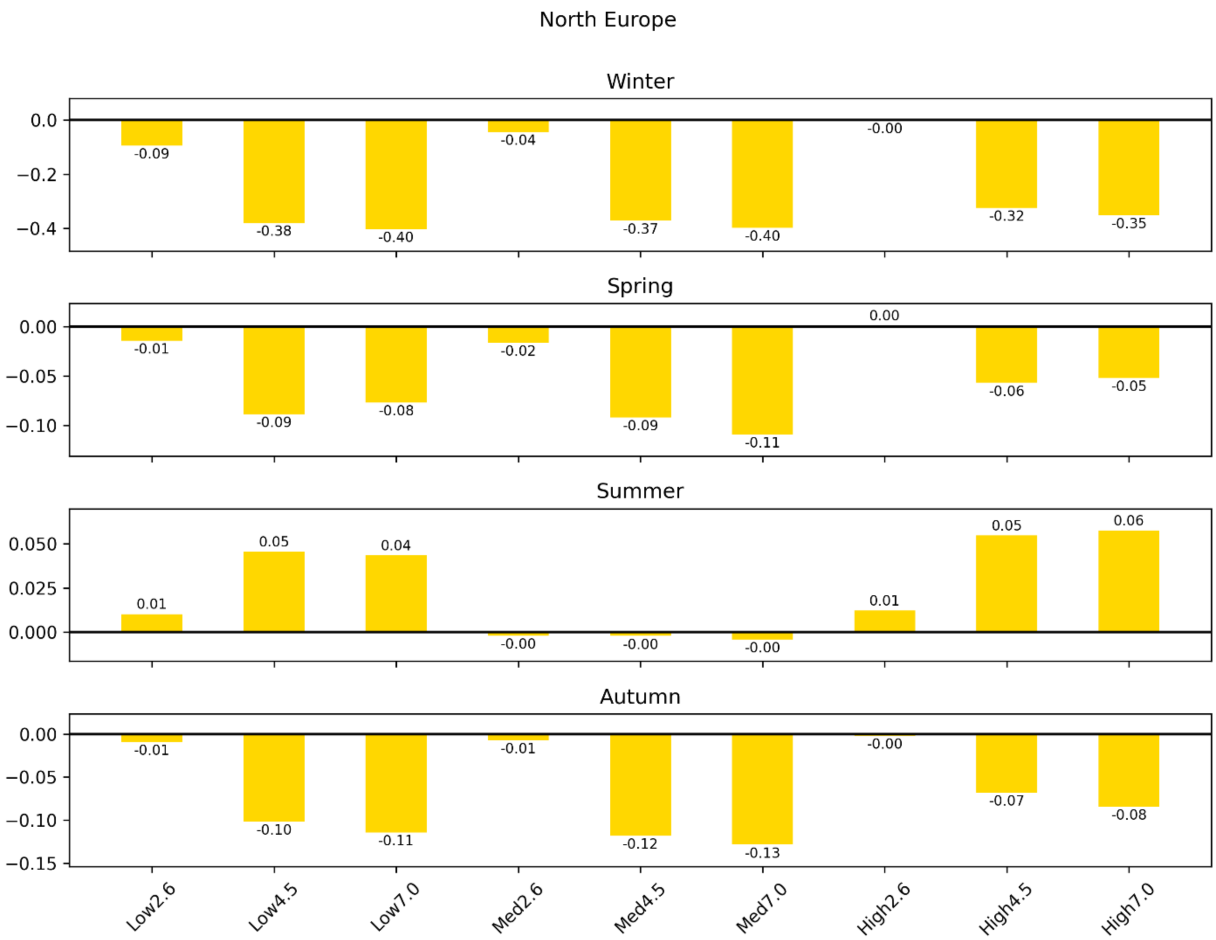


Figure 11. Absolute change in the electricity supply cost (EUR/MWh) in North EU countries[3] across seasons, climate, and adaptation scenarios.

[3] Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Ireland, Latvia, Lithuania, Luxembourg, Netherlands, Poland, Slovakia, Sweden.

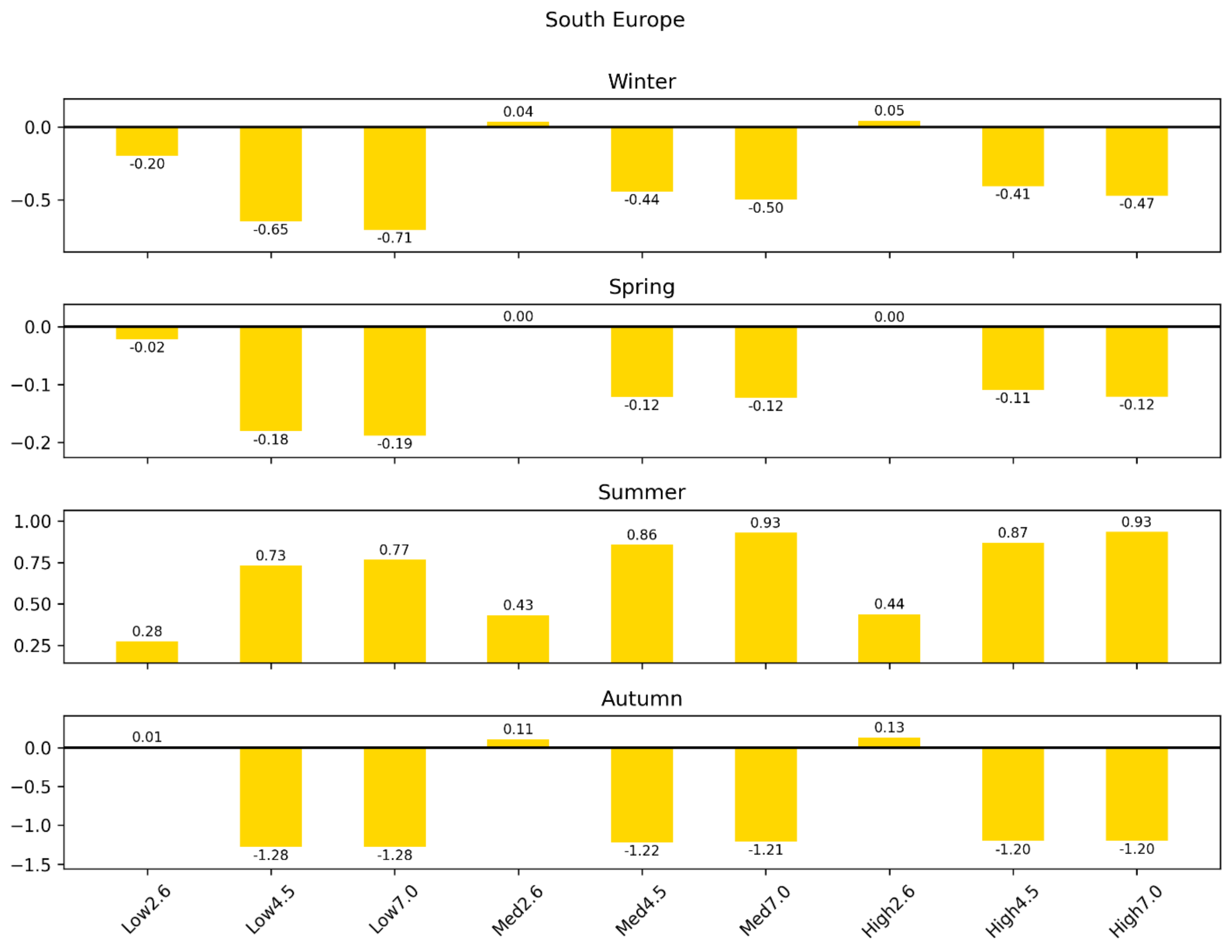
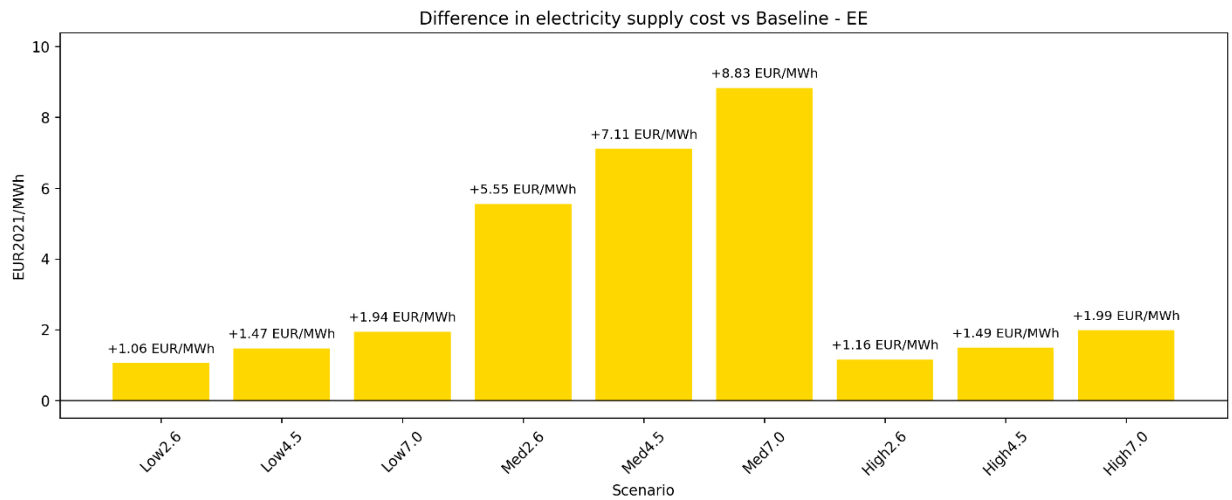


Figure 12. Absolute change in the electricity supply cost (EUR/MWh) in South EU countries[4] across seasons, climate, and adaptation scenarios.

Furthermore, greater variation can be noticed on a national level and especially for countries with small systems, such as Latvia and Estonia, reaching an increase of up to 5.1 and 8.8 EUR2021/MWh respectively in a Medium Adaptation-RCP7.0 scenario (Figure 13). In these specific cases, it is apparent that the cost of electricity supply increases with a higher radiative forcing (i.e. when moving from RCP2.6 to RCP 4.5 and RCP7.0). This can be explained by two factors: lower renewable energy generation and lower electricity demand. In the case of renewable energy generation hydropower (in Latvia) and wind (in

[4] Bulgaria, Croatia, Cyprus, Greece, Hungary, Italy, Malta, Portugal, Romania, Slovenia, Spain.

Estonia and Latvia) are affected by climate change. In the case of electricity demand, a higher radiative forcing results in lower demand for residential heating.



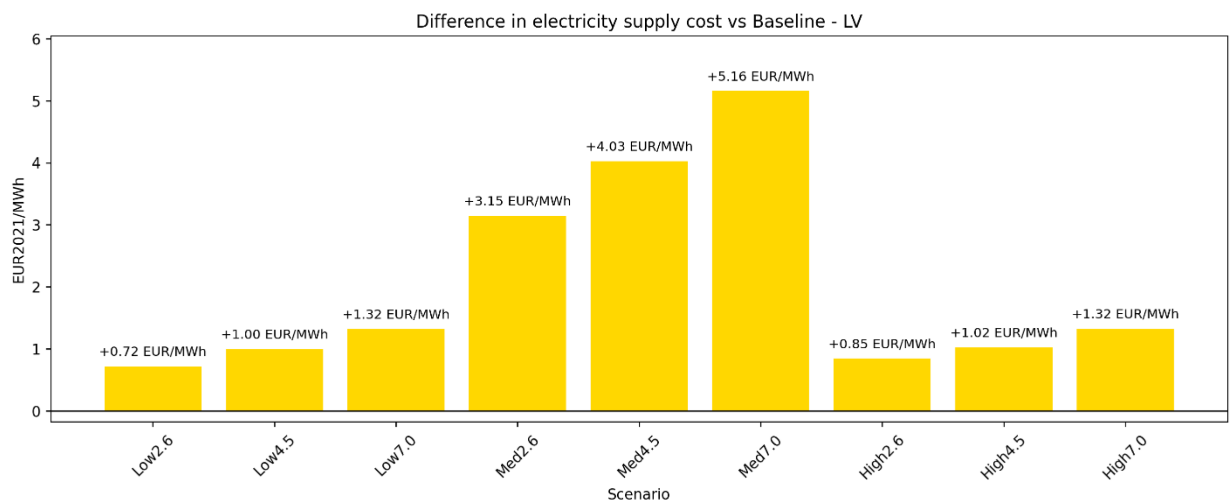


Figure 13. Absolute change in the electricity supply cost (EUR/MWh) across climate and adaptation scenarios in Estonia (top) and Latvia (bottom).

The aspect of electricity demand affects the cost of electricity when moving across adaptation scenarios as well. If domestic generation increases to satisfy a rise in electricity demand, the average cost of electricity supply is dependent on the source of this electricity. If it is generated by thermal power plants, which have a high variable cost component, then the average cost will increase. If, however, the demand is met with available variable renewable energy sources, which have primarily high capital and fixed cost components, such as hydropower, wind and solar PV, then the electricity supply cost is pushed down.

In the larger energy systems of France, Germany, Italy and Spain, the impact of climate on electricity supply costs appears to be negligible; projections for all countries in two of the scenarios are provided as examples in Figure 14. The small changes observed in large systems may be attributed to the fact that the generation mix in these countries is typically more diverse than that of smaller EU economies in terms of generation and storage infrastructure. Greater diversity in energy supply means that failure of a specific unit, for instance a power outage of a thermal power plant or loss of a grid interconnector, and reduced generation from variable renewable energy sources, such as wind and solar PV, due to climate impacts can be managed more effectively without endangering security of supply.

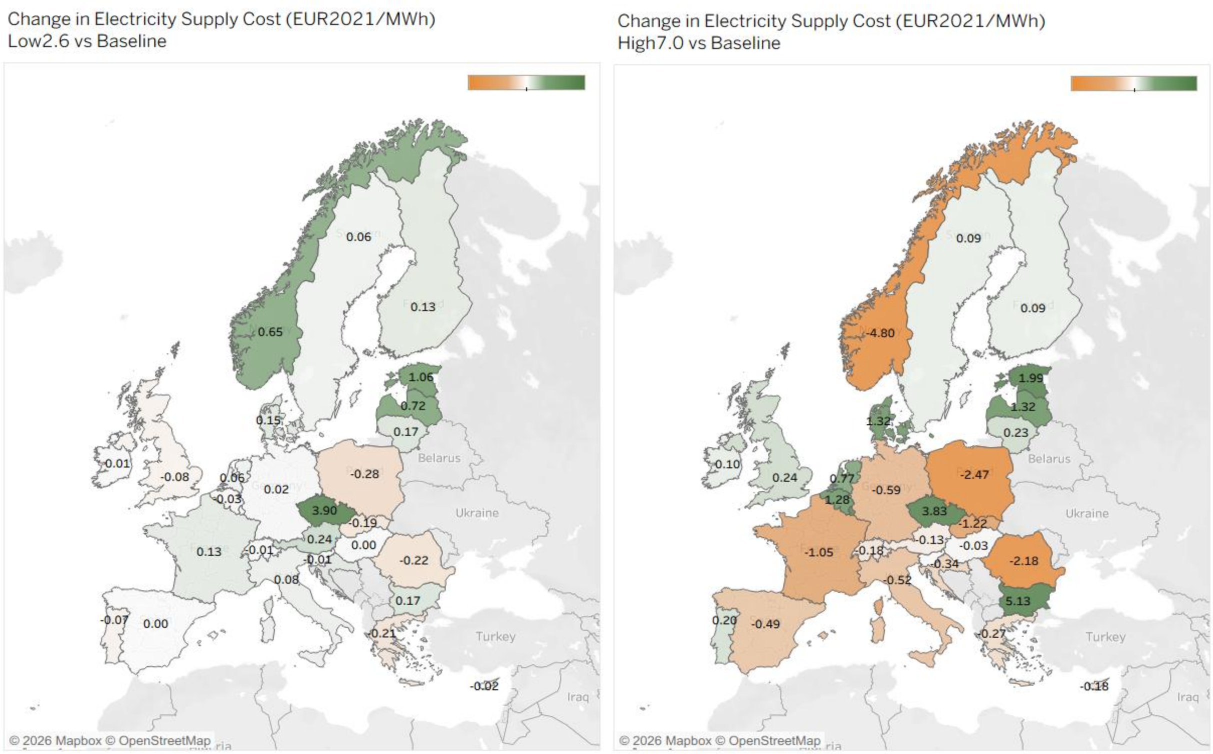


Figure 14. Changes in the cost of electricity supply across Europe in the Low Adaptation-RCP2.6 (left) and High Adaptation-RCP7.0 (right) scenarios.

Additional figures comparing the cost of electricity supply in each country across scenarios are provided in Annexes D and E.

5. Conclusions

The present analysis provides insights into the climate impacts in Europe's energy systems. Specifically, impacts arising from changes in renewable energy generation, thermal power plant outage frequency, and additional electricity demand due to air-conditioning have been assessed in a unified framework.

Scenario results from three Representative Concentration Pathways in combination with three adaptation levels distinctly indicate that the generation outlook of Europe's energy systems will be affected by climatic change. Impacts are observed in both demand and supply, clearly identifying the need for the incorporation of climate uncertainty in official energy planning efforts at the national and regional level. Differences in demand are highly seasonal and are driven by changes in heating and cooling requirements. For instance, lower residential space heating needs may lead to reductions in final electricity demand of up to 4.4 TWh in Germany and 2.9 TWh in France by 2050. On the other hand, higher cooling needs can increase final electricity demand up to 5.7 TWh in Italy and 4.9 TWh in Spain.

Changes in power plant availability and renewable energy generation output affect the choice of technology supplying electricity for up to 22 TWh in France, 20 TWh in Sweden and 15 TWh in Spain by 2050 in RCP7.0, whereas changes are observed in almost all of the modelled countries. Even though no serious imbalances in energy supply and demand have been identified in the assessed scenarios, periods of extended pressure on the energy system, such as prolonged heat waves, may compromise grid stability and create the need for additional investments in generation, storage or grid network infrastructure.

In terms of climate impacts on the cost of electricity supply, in regional terms these are projected to be negligible. However, smaller systems appear to be more vulnerable to supply and demand variations, reaching additional costs of up to 9 EUR/MWh and 5 EUR/MWh in Estonia and Latvia respectively, which means policymakers and energy planners in relevant countries need to take climate projections into account when designing the future development of their respective systems. Nonetheless, it should be mentioned that although the annual variation in electricity supply cost appears to be small, this may vary substantially at the daily or hourly level, as it is directly affected by the availability of relevant domestic generation technologies. An attempt to quantify such daily or intra-day variation can be pursued in future enhancements of the present effort.

Furthermore, inherent limitations of the present effort are identified so that they can be addressed in future enhancements of the analysis. Firstly, in relation to the thermal power plant outages, the existing stock of thermal units will be largely decommissioned or potentially retrofitted (e.g., with Carbon Capture and Storage), as a result of relevant decarbonisation efforts. These units may also be replaced by other thermal power plants, such as biomass- or hydrogen-fired units. However, since we do not have information of the location of such potential investments, it is difficult to assess the extent and possibility of potential outages of this infrastructure.

In addition, the analysis focused on the impacts of climate change on the demand and supply side of electricity systems considering the operational characteristics of contemporary grid networks. However, with the potential evolution of smart grids, there are additional measures that could be pursued for increased flexibility and adaptation of energy systems to climate change, such as demand side management (Panda et al., 2023). Such flexibility options are also missing from typical energy modelling efforts that support EU member state official planning. These technology options have not been incorporated into the developed modelling framework, but they could be addressed in future research efforts.

Similarly, the adopted modelling framework does not consider limitations in short-term operational characteristics of thermal power plants (e.g. ramping rates, minimum stable operation levels, minimum up or down times, start-up costs), which can substantially amplify the cost of climate impacts. These are greatly important when investigating scenarios with high shares of intermittent renewable energy sources, and especially so in the assessment of net-zero emission scenarios. As such, the authors recommend the future expansion of the present work and linking this assessment with relevant power systems models. Nonetheless, this creates the need for detailed assumptions at the unit level of plants, which was not available for the present effort.

6. References

Antonini, E.G.A., Di Bella, A., Savelli, I., Drouet, L., Tavoni, M., 2024. Weather- and climate-driven power supply and demand time series for power and energy system analyses. Sci. Data 11, 1324. https://doi.org/10.1038/s41597-024-04129-8

Bennett, J.A., Trevisan, C.N., DeCarolis, J.F., Ortiz-García, C., Pérez-Lugo, M., Etienne, B.T., Clarens, A.F., 2021. Extending energy system modelling to include extreme weather risks and application to hurricane events in Puerto Rico. Nat. Energy 6, 240–249. https://doi.org/10.1038/s41560-020-00758-6

Ciscar, J.-C., Dowling, P., 2014. Integrated assessment of climate impacts and adaptation in the energy sector. Energy Econ. 46, 531–538. https://doi.org/10.1016/j.eneco.2014.07.003

Collins, S., Deane, P., Gallachóir, B.Ó., Pfenninger, S., Staffell, I., 2018. Impacts of Inter-annual Wind and Solar Variations on the European Power System. Joule 2, 2076–2090. https://doi.org/10.1016/j.joule.2018.06.020

Craig, M.T., Wohland, J., Stoop, L.P., Kies, A., Pickering, B., Bloomfield, H.C., Browell, J., Felice, M.D., Dent, C.J., Deroubaix, A., Frischmuth, F., Gonzalez, P.L.M., Grochowicz, A., Gruber, K., Härtel, P., Kittel, M., Kotzur, L., Labuhn, I., Lundquist, J.K., Pflugradt, N., Wiel, K. van der, Zeyringer, M., Brayshaw, D.J., 2022. Overcoming the disconnect between energy system and climate modeling. Joule 6, 1405–1417. https://doi.org/10.1016/j.joule.2022.05.010

Cronin, J., Anandarajah, G., Dessens, O., 2018. Climate change impacts on the energy system: a review of trends and gaps. Clim. Change 151, 79–93. https://doi.org/10.1007/s10584-018-2265-4

Deroubaix, A., Labuhn, I., Camredon, M., Gaubert, B., Monerie, P.-A., Popp, M., Ramarohetra, J., Ruprich-Robert, Y., Silvers, L.G., Siour, G., 2021. Large uncertainties in trends of energy demand for heating and cooling under climate change. Nat. Commun. 12, 5197. https://doi.org/10.1038/s41467-021-25504-8

Després, J., Adamovic, M., 2020. Seasonal impacts of climate change on electricity production: JRC PESETA IV project : Task 4. Publications Office, LU. https://doi.org/10.2760/879978

ENTSO-E, 2026a. Power Statistics [WWW Document]. URL https://www.entsoe.eu/data/power-stats/ (accessed 2.13.26).

ENTSO-E, 2026b. Transparency Platform [WWW Document]. URL https://transparency.entsoe.eu/ (accessed 2.16.26).

ENTSO-E, 2025. Explore the TYNDP 2026 draft project portfolio: 178 transmission and 49 storage projects now published [WWW Document]. URL https://www.entsoe.eu/news/2025/10/29/explore-the-tyndp-2026-draft-project-portfolio-178-transmission-and-49-storage-projects-now-published/ (accessed 2.13.26).

ENTSO-E, ENTSOG, 2025. ENTSOs TYNDP 2024 Scenarios. URL https://2024.entsos-tyndp-scenarios.eu/download/ (accessed 1.16.26).

European Commission, 2025. National energy and climate plans 2021-2030 [WWW Document]. URL https://commission.europa.eu/energy-climate-change-environment/implementation-eu-countries/energy-and-climate-governance-and-reporting/national-energy-and-climate-plans_en#national-energy-and-climate-plans-2021-2030 (accessed 7.2.25).

European Commission, 2021. Delivering the European Green Deal [WWW Document]. URL https://commission.europa.eu/topics/climate-action/delivering-european-green-deal_en (accessed 1.28.26).

European Commission - DG CLIMA, 2024. EC recommended parameters for GHG projections 2025 [WWW Document]. Eionet Portal. URL https://epanet.eea.europa.eu/Eionet/reportnet/docs/govreg/projections/govregart18_ec_parameters_projections_2021.zip/view (accessed 7.7.25).

European Commission - Directorate General for Energy., European Commission - Directorate General for Climate Action., European Commission - Directorate General for Mobility and Transport., 2021. EU Reference Scenario 2020: Energy, Transport and GHG emissions : Trends to 2050. Publications Office, LU.

Gardumi, F., Shivakumar, A., Morrison, R., Taliotis, C., Broad, O., Beltramo, A., Sridharan, V., Howells, M., Hörsch, J., Niet, T., Almulla, Y., Ramos, E., Burandt, T., Balderrama, G.P., Pinto de Moura, G.N., Zepeda, E., Alfstad, T., 2018. From the development of an open-source energy modelling tool to its application and the creation of communities of practice: The example of OSeMOSYS. Energy Strategy Rev. 20, 209–228. https://doi.org/10.1016/j.esr.2018.03.005

Gøtske, E.K., Andresen, G.B., Neumann, F., Victoria, M., 2024. Designing a sector-coupled European energy system robust to 60 years of historical weather data. Nat. Commun. 15, 10680. https://doi.org/10.1038/s41467-024-54853-3

Gøtske, E.K., Victoria, M., 2021. Future operation of hydropower in Europe under high renewable penetration and climate change. iScience 24. https://doi.org/10.1016/j.isci.2021.102999

Grochowicz, A., van Greevenbroek, K., Benth, F.E., Zeyringer, M., 2023. Intersecting near-optimal spaces: European power systems with more resilience to weather variability. Energy Econ. 118, 106496. https://doi.org/10.1016/j.eneco.2022.106496

Grochowicz, A., van Greevenbroek, K., Bloomfield, H.C., 2024. Using power system modelling outputs to identify weather-induced extreme events in highly renewable systems. Environ. Res. Lett. 19, 054038. https://doi.org/10.1088/1748-9326/ad374a

Haddeland, I., Hole, J., Holmqvist, E., Koestler, V., Sidelnikova, M., Veie, C.A., Wold, M., 2022. Effects of climate on renewable energy sources and electricity supply in Norway. Renew. Energy 196, 625–637. https://doi.org/10.1016/j.renene.2022.06.150

Henke, H.T.J., Gardumi, F., Howells, M., 2022. The open source electricity Model Base for Europe - An engagement framework for open and transparent European energy modelling. Energy 239, 121973. https://doi.org/10.1016/j.energy.2021.121973

IEA, 2025. World Energy Outlook 2025. International Energy Agency, Paris.

IRENA, 2017. Electricity storage and renewables: Costs and markets to 2030 132.

Kapica, J., Jurasz, J., Canales, F.A., Bloomfield, H., Guezgouz, M., De Felice, M., Kobus, Z., 2024. The potential impact of climate change on European renewable energy droughts. Renew. Sustain. Energy Rev. 189, 114011. https://doi.org/10.1016/j.rser.2023.114011

Ke, X., Wu, D., Rice, J., Kintner-Meyer, M., Lu, N., 2016. Quantifying impacts of heat waves on power grid operation. Appl. Energy 183, 504–512. https://doi.org/10.1016/j.apenergy.2016.08.188

Keppo, I., Strubegger, M., 2010. Short term decisions for long term problems – The effect of foresight on model based energy systems analysis. Energy 35, 2033–2042. https://doi.org/10.1016/j.energy.2010.01.019

Kousoulos, E., 2025. AETOS-model at v1.0.0 [WWW Document]. GitHub. URL https://github.com/ekousoulos/AETOS-model (accessed 2.17.26).

Montoya-Rincon, J.P., Mejia-Manrique, S.A., Azad, S., Ghandehari, M., Harmsen, E.W., Khanbilvardi, R., Gonzalez-Cruz, J.E., 2023. A socio-technical approach for the assessment of critical infrastructure system vulnerability in extreme weather events. Nat. Energy 8, 1002–1012. https://doi.org/10.1038/s41560-023-01315-7

Niet, T., Arianpoo, N., Kuling, K., Wright, A.S., 2022. Increasing the reliability of energy system scenarios with integrated modelling: a review. Environ. Res. Lett. 17, 043006. https://doi.org/10.1088/1748-9326/ac5cf5

O'Neill, B.C., Kriegler, E., Ebi, K.L., Kemp-Benedict, E., Riahi, K., Rothman, D.S., van Ruijven, B.J., van Vuuren, D.P., Birkmann, J., Kok, K., Levy, M., Solecki, W., 2017. The roads ahead: Narratives for shared socioeconomic pathways describing world futures in the 21st century. Glob. Environ. Change 42, 169–180. https://doi.org/10.1016/j.gloenvcha.2015.01.004

Panda, S., Mohanty, S., Rout, P.K., Sahu, B.K., Parida, S.M., Samanta, I.S., Bajaj, M., Piecha, M., Blazek, V., Prokop, L., 2023. A comprehensive review on demand side management and market design for renewable energy support and integration. Energy Rep. 10, 2228–2250. https://doi.org/10.1016/j.egyr.2023.09.049

Perera, A.T.D., Nik, V.M., Chen, D., Scartezzini, J.-L., Hong, T., 2020. Quantifying the impacts of climate change and extreme climate events on energy systems. Nat. Energy 5, 150–159. https://doi.org/10.1038/s41560-020-0558-0

Pfenninger, S., 2017. Dealing with multiple decades of hourly wind and PV time series in energy models: A comparison of methods to reduce time resolution and the planning implications of inter-annual variability. Appl. Energy 197, 1–13. https://doi.org/10.1016/j.apenergy.2017.03.051

Ruhnau, O., Qvist, S., 2022. Storage requirements in a 100% renewable electricity system: extreme events and inter-annual variability. Environ. Res. Lett. 17, 044018. https://doi.org/10.1088/1748-9326/ac4dc8

Schaeffer, R., Szklo, A.S., Pereira de Lucena, A.F., Moreira Cesar Borba, B.S., Pupo Nogueira, L.P., Fleming, F.P., Troccoli, A., Harrison, M., Boulahya, M.S., 2012. Energy sector vulnerability to climate change: A review. Energy 38, 1–12. https://doi.org/10.1016/j.energy.2011.11.056

Schlachtberger, D.P., Brown, T., Schäfer, M., Schramm, S., Greiner, M., 2018. Cost optimal scenarios of a future highly renewable European electricity system: Exploring the influence of weather data, cost parameters and policy constraints. Energy 163, 100–114. https://doi.org/10.1016/j.energy.2018.08.070

Seneviratne, S.I., Zhang, X., Adnan, M., Badi, W., Dereczynski, C., Di Luca, A., Ghosh, S., Iskander, I., Kossin, J., Lewis, S., Otto, F., Pinto, I., Satoh, M., Vicente-Serrano, S.M., Wehner, M., Zhou, B., 2023. Weather and Climate Extreme Events in a Changing Climate (Chapter 11), in: Masson-Delmotte, V., Zhai, P., Pirani, A., Connors, S.L., Péan, C., Berger, S., Caud, N., Chen, Y., Goldfarb, L., Gomis, M.I., Huang, M., Leitzell, K., Lonnoy, E., Matthews, J.B.R., Maycock, T.K., Waterfield, T., Yelekçi, K., Yu, R., Zhu, B. (Eds.), IPCC 2021: Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 1513–1766.

Sergio, A., Colelli, F.P., 2025. Weather-induced power plant outages: Empirical evidence from hydro and thermal generators in Europe. Energy Econ. 148, 108549. https://doi.org/10.1016/j.eneco.2025.108549

Sridharan, V., Broad, O., Shivakumar, A., Howells, M., Boehlert, B., Groves, D.G., Rogner, H.-H., Taliotis, C., Neumann, J.E., Strzepek, K.M., Lempert, R., Joyce, B., Huber-Lee, A., Cervigni, R., 2019. Resilience of the Eastern African electricity sector to climate driven changes in hydropower generation. Nat. Commun. 10, 302. https://doi.org/10.1038/s41467-018-08275-7

Standardi, G., Dasgupta, S., Parrado, R., De Cian, E., Bosello, F., 2023. Assessing Macro-economic Effects of Climate Impacts on Energy Demand in EU Sub-national Regions. Environ. Resour. Econ. 86, 173–201. https://doi.org/10.1007/s10640-023-00792-4

Stoop, L.P., 2023. Hydropower dataset of hourly inflow values for European bidding zones for ACDC-ESM. https://doi.org/10.5281/zenodo.7766457

Taliotis, C., Giannakis, E., Karmellos, M., Fylaktos, N., Zachariadis, T., 2020. Estimating the economy-wide impacts of energy policies in Cyprus. Energy Strategy Rev. 29, 100495. https://doi.org/10.1016/j.esr.2020.100495

van Ruijven, B.J., De Cian, E., Sue Wing, I., 2019. Amplification of future energy demand growth due to climate change. Nat. Commun. 10, 2762. https://doi.org/10.1038/s41467-019-10399-3 van Vuuren, D.P., Riahi, K., Calvin, K., Dellink, R., Emmerling, J., Fujimori, S., Kc, S., Kriegler, E., O'Neill, B., 2017. The Shared Socio-economic Pathways: Trajectories for human development and global environmental change. Glob. Environ. Change 42, 148–152. https://doi.org/10.1016/j.gloenvcha.2016.10.009

Xu, L., Feng, K., Lin, N., Perera, A.T.D., Poor, H.V., Xie, L., Ji, C., Sun, X.A., Guo, Q., O'Malley, M., 2024. Resilience of renewable power systems under climate risks. Nat. Rev. Electr. Eng. 1, 53–66. https://doi.org/10.1038/s44287-023-00003-8

Xu, L., Lin, N., Perera, A.T.D., Poor, H.V., Guo, Q., Sun, H., Oppenheimer, M., 2025. Cross-sector energy system resilience and interdependence in a changing climate. Joule 9. https://doi.org/10.1016/j.joule.2025.101967

Yalew, S.G., van Vliet, M.T.H., Gernaat, D.E.H.J., Ludwig, F., Miara, A., Park, C., Byers, E., De Cian, E., Piontek, F., Iyer, G., Mouratiadou, I., Glynn, J., Hejazi, M., Dessens, O., Rochedo, P., Pietzcker, R., Schaeffer, R., Fujimori, S., Dasgupta, S., Mima, S., da Silva, S.R.S., Chaturvedi, V., Vautard, R., van Vuuren, D.P., 2020. Impacts of climate change on energy systems in global and regional scenarios. Nat. Energy 5, 794–802. https://doi.org/10.1038/s41560-020-0664-z

Zapata, V., Gernaat, D.E.H.J., Yalew, S.G., Santos da Silva, S.R., Iyer, G., Hejazi, M., van Vuuren, D.P., 2022. Climate change impacts on the energy system: a model comparison. Environ. Res. Lett. 17, 034036. https://doi.org/10.1088/1748-9326/ac5141

Zeyringer, M., Price, J., Fais, B., Li, P.-H., Sharp, E., 2018. Designing low-carbon power systems for Great Britain in 2050 that are robust to the spatiotemporal and inter-annual variability of weather. Nat. Energy 3, 395–403. https://doi.org/10.1038/s41560-018-0128-x

Zheng, X., Xie, L., Lee, K., Fu, D., Wu, J., 2023. Impact of climate simulation resolutions on future energy system reliability assessment: A Texas case study. iEnergy 2, 222–230. https://doi.org/10.23919/IEN.2023.0014

7. Annexes

A. Incorporation of adaptation in the energy system scenarios

In this section, we describe how autonomous and planned adaptation strategies are included in the energy sector under different climate change scenarios—namely, the **high adaptation** and **low adaptation** pathways. Energy for adaptation can be categorized into three levels: low, where no new technology is adopted with respect to the historical baseline, and responses are limited to short-term adjustments (intensive margin); medium, where climate alone drives long-term technological changes; and high, where both climate and higher income drive greater technological adoption and adaptability over time. In the short run, households and firms mainly adjust **energy use** through the intensive margin, while long-term climate shifts lead to **changes in durable goods** (extensive margin).

Changes in energy demand are a consequence of different forms of adaptation across households and firms. In the context of energy demand, our focus is on **autonomous adaptation**, which refers to the adjustments made by households and firms, particularly through the more intensive use of adaptive appliances, and on **planned adaptation**, in terms of increased adoption of technologies and. Our empirical framework allows us to distinguish between two key forms of autonomous adaptation. First, people and firms respond to temperature shocks by adjusting their usage of energy-consuming goods like air conditioners. This immediate response, called the "intensive margin," reflects changes in the utilization of a fixed capital good. In the short-run, changes in the time allocation of a household has also unintended consequences on energy use. The lack of intention makes this form of adaptation, which is identified by short term adjustments to unexpected weather shocks autonomous.

Over longer periods, agents perceive repeated temperature regimes as climatic shifts, prompting more significant adjustments, such as households without air conditioning purchasing one, which can also be classified as a **planned adaptation response**. This response, known as the "extensive margin," unfolds more gradually. Since capital goods are fixed in the short run, responses to unexpected weather shocks predominantly occur through the intensive margin. In the macro-level energy demand estimation, technologically-constrained adaptation is implicit in the difference between short-term and long-term coefficients, highlighting how immediate responses differ from those that evolve over time. In the micro-level AC ownership and use model, the intensive margin is directly estimated based on the change in household-level electricity consumption based on interannual weather changes, conditional on the presence of AC shock. Second, adaptive capacity is reflected in how GDP per capita modulates the long-term coefficients, indicating that wealthier societies may adjust more effectively. Both in the macro-level and micro-level energy demand estimations, this effect is captured by the modulating effects of per capita income on these responses.

We exploit macro and micro level evidence to identify how adaptation levels can vary. Under **low adaptation**, no additional technology is adopted with respect to the level chosen by households and firms without climate change, and energy responses are restricted to the intensive margin alone. In other words, existing technologies are assumed frozen at historical climate conditions**. Medium adaptation** involves long-term technological adoption driven by climate changes alone, allowing more flexible responses. **High adaptation** represents a scenario where additional, long-term technology adoption is driven by climate shifts and amplified by higher income, reflecting an enhanced adaptive capacity to future climate risks.

In the context of energy supply, **planned adaptation** refers to the adjustments made by power system generator through the change in their power plant maintenance operations resulting in a **planned power outage** as a response to extreme weather events, in order to avoid the possibility to incur in more costly forced power outages. Adaptation costs in this setting are computed as the forgone profit. More details on the framework for the definition of adaptation scenarios are provided in Deliverable 2.2.

B. Grid interconnections across Europe

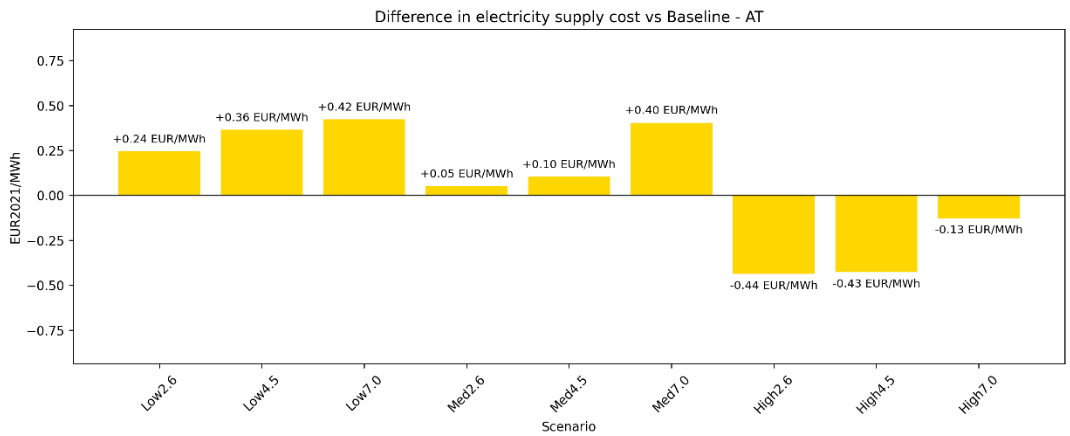
Existing Capacity			
Grid Interconnector	**MW**	**Grid Interconnector**	**MW**
Austria - Czech Republic	2900	Germany - France	4800
Austria - Germany	2900	Germany - Luxembourg	1950
Austria - Hungary	2000	Germany - Netherlands	6300
Austria - Italy	300	Germany - Norway	1400
Austria - Slovenia	1650	Germany - Poland	2100
Austria - Switzerland	2200	Germany - Sweden	600
Belgium - France	5000	Germany - UK	1400
Belgium - Germany	1000	Hungary - Romania	1500
Belgium - Luxembourg	720	Hungary - Slovakia	3500
Belgium - Netherlands	2400	Hungary - Slovenia	870
Belgium - UK	1012	Ireland - UK	500
Bulgaria - Greece	2000	Italy - Malta	200
Bulgaria - Romania	1800	Italy - Slovenia	1000
Czech Republic - Germany	2800	Lithuania - Latvia	1200
Czech Republic - Poland	2200	Lithuania - Poland	500
Czech Republic - Slovakia	2500	Lithuania - Sweden	700
Croatia - Hungary	1800	Netherlands - Norway	700
Croatia - Slovenia	1700	Netherlands - UK	1000
Denmark - Netherlands	700	Norway - Sweden	1200
Denmark - Norway	1700	Norway - UK	1400
Denmark - Sweden	2500	Poland - Slovakia	1353
Denmark - UK	1400	Poland - Sweden	600
Estonia - Finland	1016	Spain - France	7000
Estonia - Latvia	1447	Spain - Portugal	4700
Finland - Norway	100	Switzerland - France	5000
Finland - Sweden	2700	Switzerland - Germany	4600
France - Italy	4350	Switzerland - Italy	1200
France - Luxembourg	450	Greece - Italy	500
France - UK	2000	Germany - Denmark	600

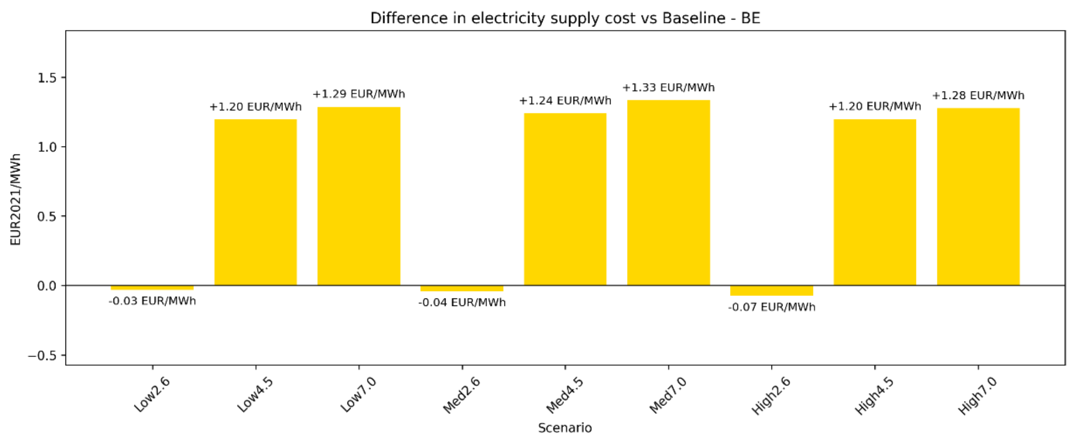
Planned Capacity					
Grid Interconnector	**MW**	**Year**	**Grid Interconnector**	**MW**	**Year**
Spain - Portugal	3000	2030	France - UK	1400	2030
Spain - France	2000	2027	Austria - Germany	3500	2027
Luxemburg-Germany	2600	2040	Italy - Slovenia	150	2026
Austria - Germany	600	2030	Austria - Slovenia	500	2035
France - Ireland	700	2027	Germany - Luxemburg	500	2035
Finland - Sweden	900	2025	UK - Ireland	750	2029
Belgium - UK	1400	2030	Austria - Italy	1100	2035
France - UK	1250	2031	Germany - UK	1400	2030
Lithuania - Poland	1000	2025	Sweden - Latvia	500	2037
Austria - Germany	1500	2030	Estonia - Latvia	1000	2035
Austria - Italy	300	2029	Belgium - Denmark	4000	2032
Cyprus - Greece	1000	2030	Estonia - Finland	700	2035
Finland - Sweden	800	2038	Finland - Sweden	900	2032
France - UK	2000	2028	Greece - Italy	1000	2031
Netherlands - UK	2000	2030	Netherlands - UK	1400	2031
Germany - Sweden	700	2035	Norway - Denmark - Germany - Belgium	1400	2035
Belgium - France	1000	2030	Lithuania - Latvia	1000	2035

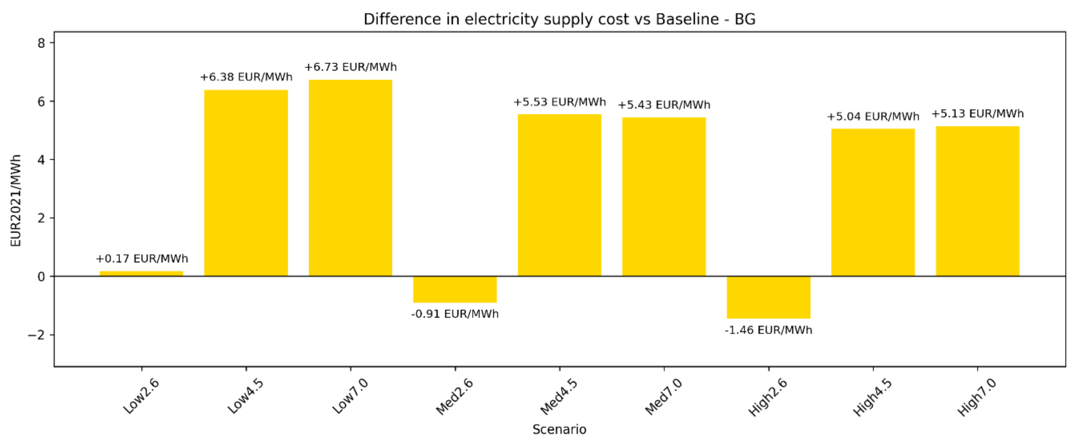
C. Carbon dioxide emissions from electricity supply in EU member states

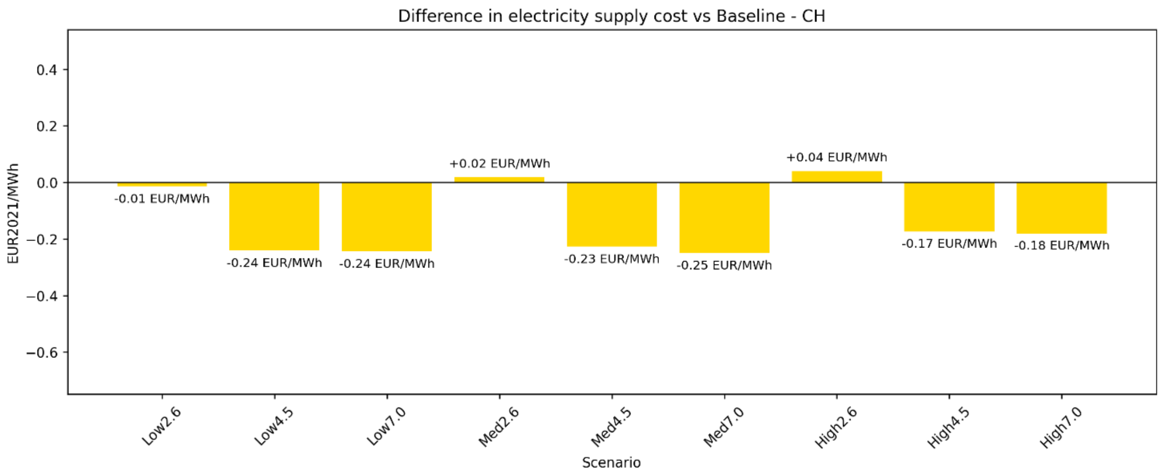
Mtons CO_2	Low adaptation			Medium adaptation			High adaptation		
Country	**RCP2.6**	**RCP4.5**	**RCP7.0**	**RCP2.6**	**RCP4.5**	**RCP7.0**	**RCP2.6**	**RCP4.5**	**RCP7.0**
AT	0.16	0.12	0.12	0.18	0.13	0.12	0.20	0.16	0.14
BE	0	0	0	0	0	0	0	0	0
BG	0.01	0	0	0.01	0	0	0.01	0	0
CY	0	0	0	0	0	0	0	0	0
CZ	1.42	0.94	0.87	1.56	1.02	0.92	1.73	1.16	1.07
DE	0.32	0.28	0.27	0.31	0.29	0.27	0.38	0.33	0.30
DK	0	0	0	0	0	0	0	0	0
EE	0	0	0	0	0	0	0	0	0
ES	0.05	0	0	0.07	0.01	0	0.07	0	0
FI	0	0	0	0	0	0	0	0	0
FR	0	0	0	0	0	0	0	0	0
GR	0	0	0	0	0	0	0	0	0
HR	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
HU	3.13	1.90	1.83	3.22	2.12	2.06	3.34	2.22	2.21
IE	0	0	0	0	0	0	0	0	0
IT	17.16	14.82	14.80	18.59	16.10	16.25	18.56	16.25	16.26
LT	0	0	0	0	0	0	0	0	0
LU	0	0	0	0	0	0	0	0	0
LV	0	0	0	0	0	0	0	0	0
MT	0	0	0	0	0	0	0	0	0
NL	0	0	0	0	0	0	0	0	0
PL	21.73	19.16	19.00	21.51	18.55	18.16	22.48	19.94	19.71
PT	0	0	0	0	0	0	0	0	0
RO	0.50	0.11	0.09	0.67	0.15	0.13	0.71	0.17	0.14
SE	0	0	0	0	0	0	0	0	0
SI	0	0.02	0.02	0.01	0.02	0.02	0.01	0.03	0.02
SK	1.39	0.95	0.92	1.42	0.97	0.91	1.55	1.17	1.10
Total EU	**45.9**	**38.3**	**37.9**	**47.6**	**39.4**	**38.8**	**49.1**	**41.4**	**41.0**

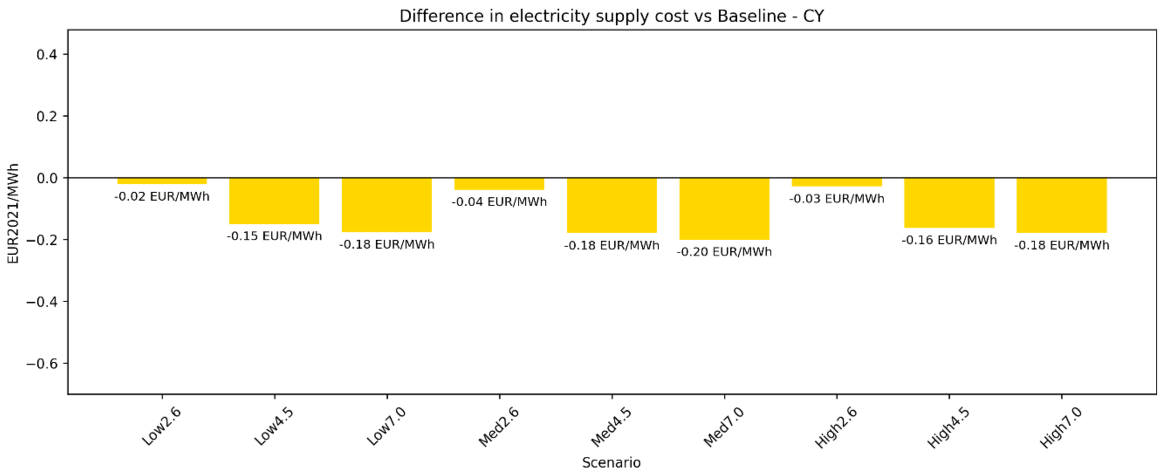
D. Difference in electricity supply cost due to assessed climate change impacts in each country

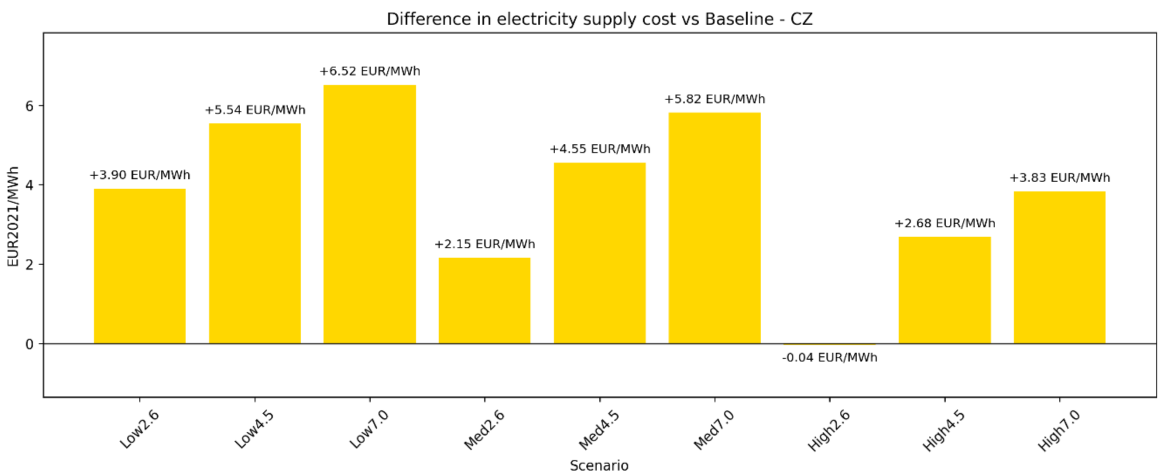


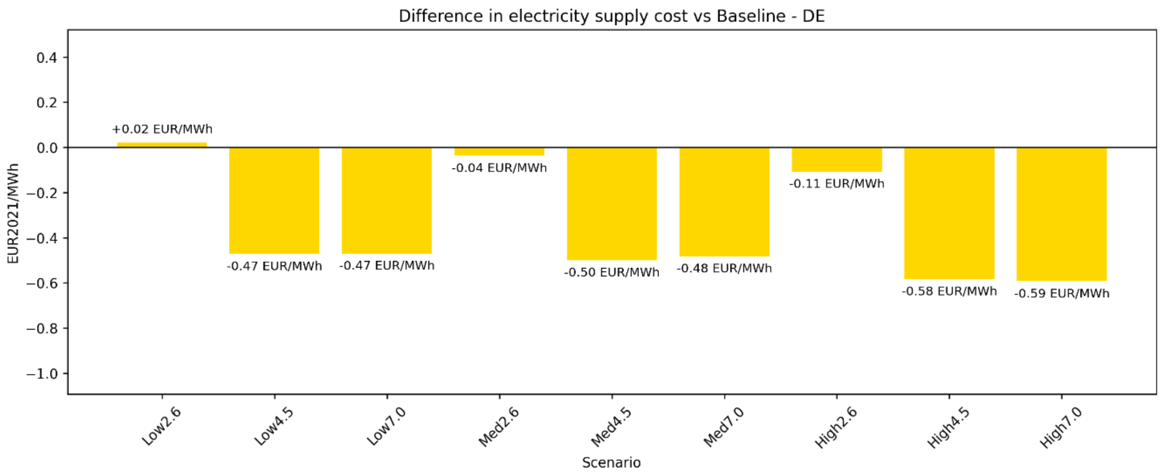


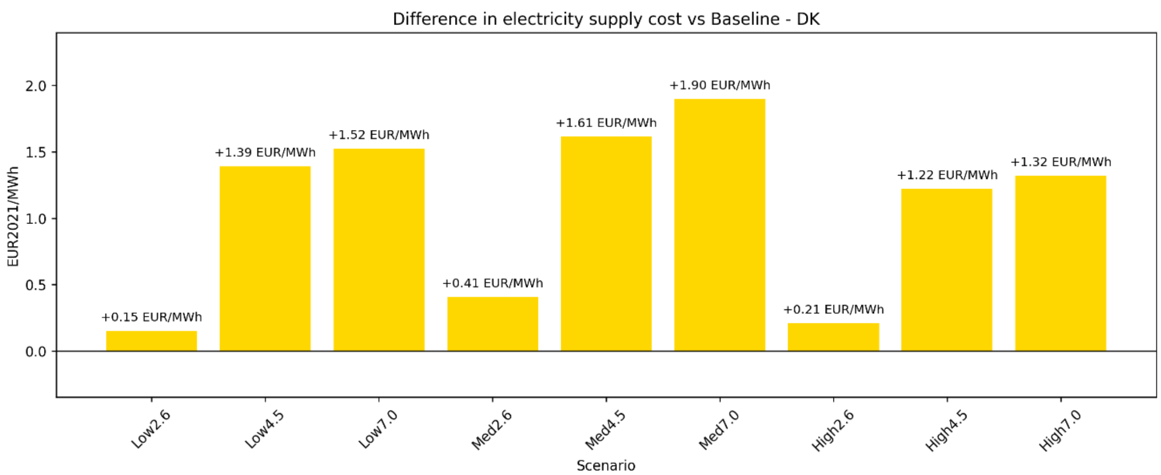


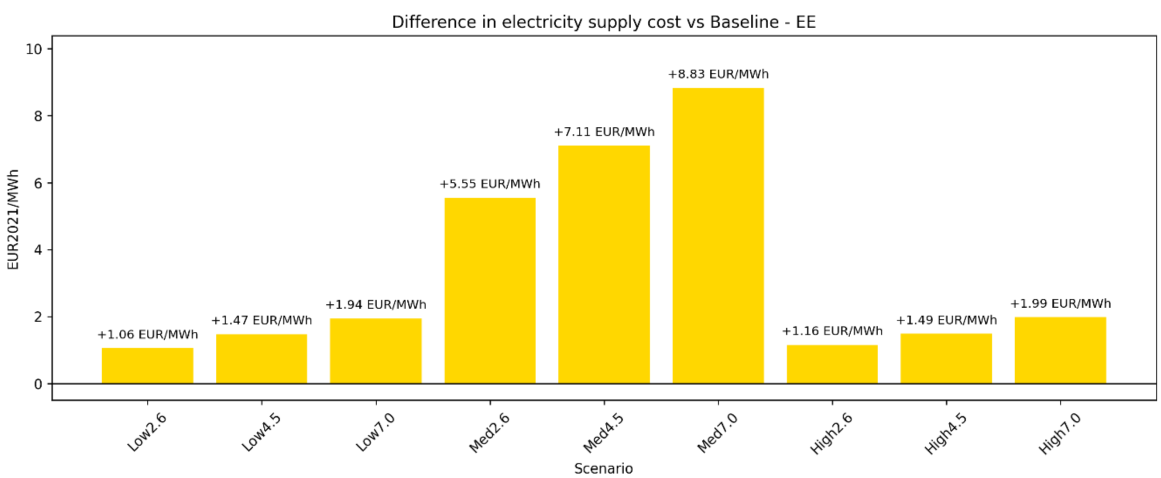

Difference in electricity supply cost vs Baseline - CH
EUR2021/MWh
Scenario
Low2.6
Low4.5
Low7.0
Med2.6
Med4.5
Med7.0
High2.6
High4.5
High7.0
-0.01 EUR/MWh
-0.24 EUR/MWh
-0.24 EUR/MWh
+0.02 EUR/MWh
-0.23 EUR/MWh
-0.25 EUR/MWh
+0.04 EUR/MWh
-0.17 EUR/MWh
-0.18 EUR/MWh

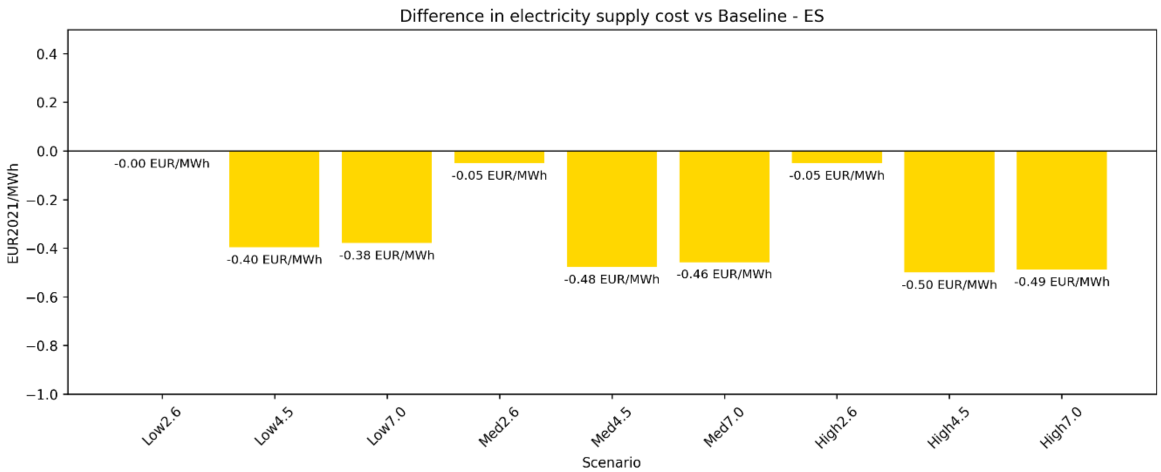

Difference in electricity supply cost vs Baseline - CY
EUR2021/MWh
Scenario
Low2.6
Low4.5
Low7.0
Med2.6
Med4.5
Med7.0
High2.6
High4.5
High7.0
-0.02 EUR/MWh
-0.15 EUR/MWh
-0.18 EUR/MWh
-0.04 EUR/MWh
-0.18 EUR/MWh
-0.20 EUR/MWh
-0.03 EUR/MWh
-0.16 EUR/MWh
-0.18 EUR/MWh

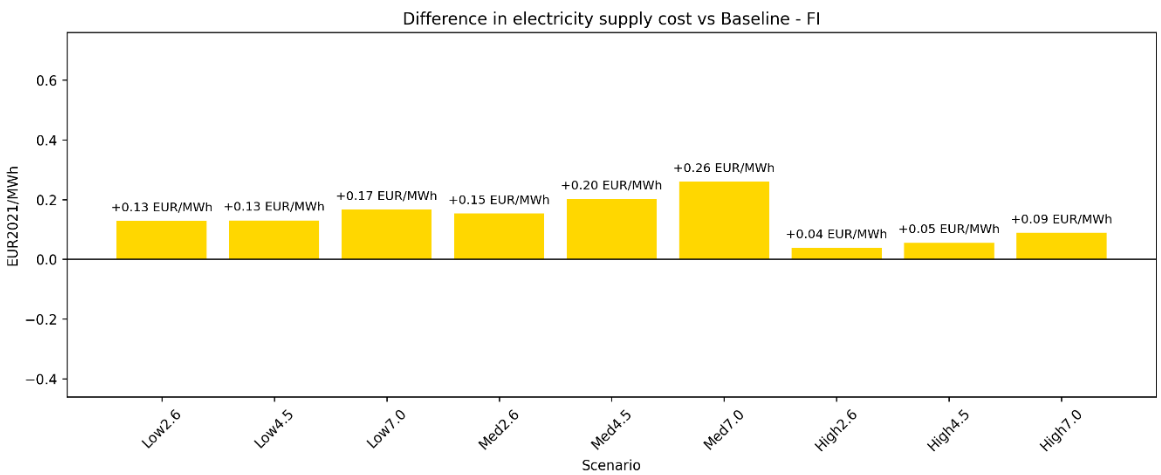

Difference in electricity supply cost vs Baseline - CZ
EUR2021/MWh
Scenario
Low2.6
Low4.5
Low7.0
Med2.6
Med4.5
Med7.0
High2.6
High4.5
High7.0
+3.90 EUR/MWh
+5.54 EUR/MWh
+6.52 EUR/MWh
+2.15 EUR/MWh
+4.55 EUR/MWh
+5.82 EUR/MWh
-0.04 EUR/MWh
+2.68 EUR/MWh
+3.83 EUR/MWh

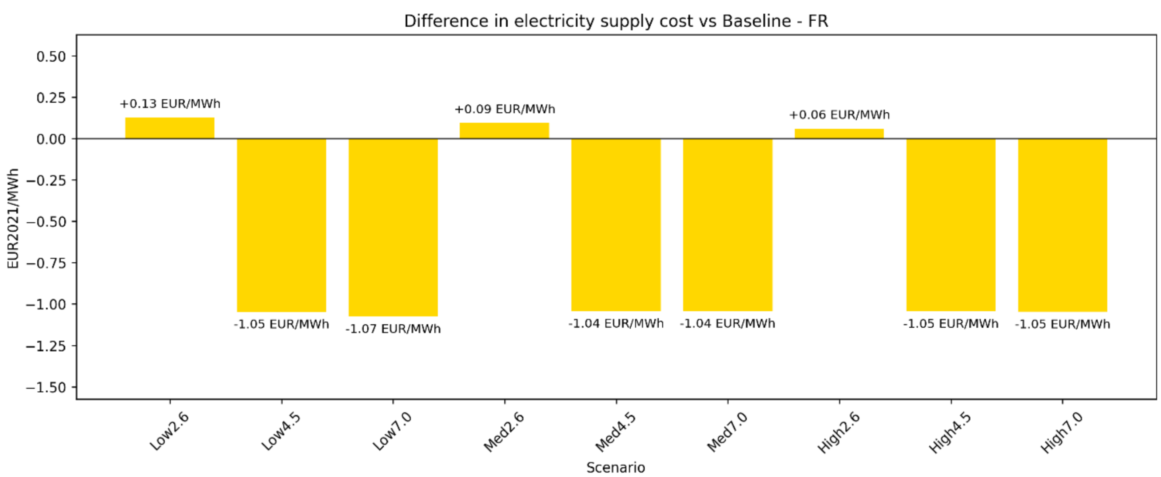

Difference in electricity supply cost vs Baseline - DE
EUR2021/MWh
+0.02 EUR/MWh
-0.47 EUR/MWh
-0.47 EUR/MWh
-0.04 EUR/MWh
-0.50 EUR/MWh
-0.48 EUR/MWh
-0.11 EUR/MWh
-0.58 EUR/MWh
-0.59 EUR/MWh
Low2.6
Low4.5
Low7.0
Med2.6
Med4.5
Med7.0
High2.6
High4.5
High7.0
Scenario

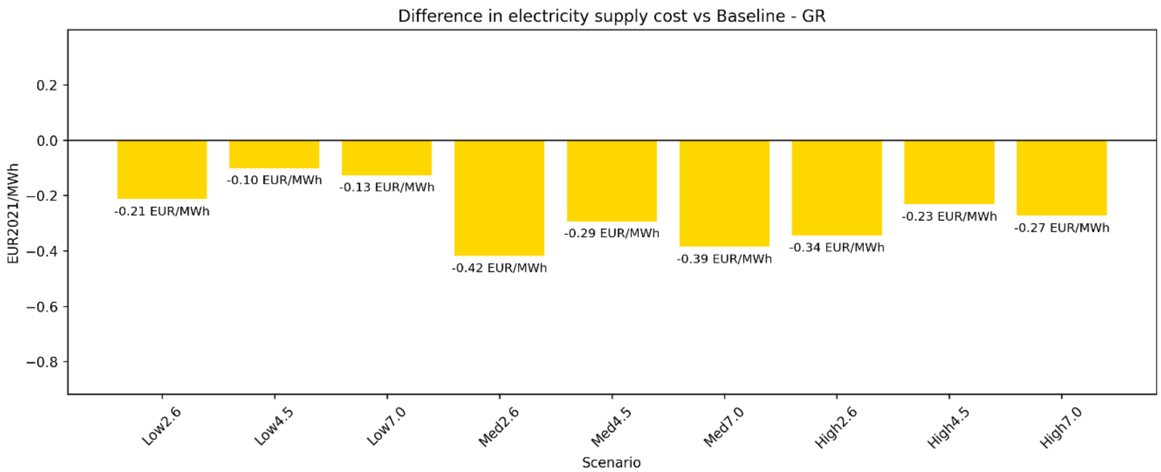

Difference in electricity supply cost vs Baseline - DK
EUR2021/MWh
+0.15 EUR/MWh
+1.39 EUR/MWh
+1.52 EUR/MWh
+0.41 EUR/MWh
+1.61 EUR/MWh
+1.90 EUR/MWh
+0.21 EUR/MWh
+1.22 EUR/MWh
+1.32 EUR/MWh
Low2.6
Low4.5
Low7.0
Med2.6
Med4.5
Med7.0
High2.6
High4.5
High7.0
Scenario

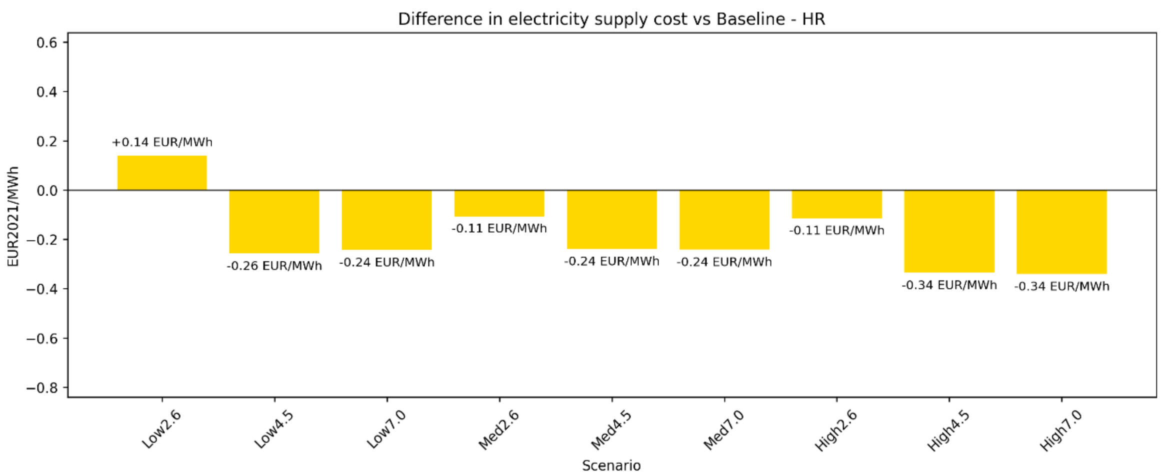

Difference in electricity supply cost vs Baseline - EE
EUR2021/MWh
+1.06 EUR/MWh
+1.47 EUR/MWh
+1.94 EUR/MWh
+5.55 EUR/MWh
+7.11 EUR/MWh
+8.83 EUR/MWh
+1.16 EUR/MWh
+1.49 EUR/MWh
+1.99 EUR/MWh
Low2.6
Low4.5
Low7.0
Med2.6
Med4.5
Med7.0
High2.6
High4.5
High7.0
Scenario

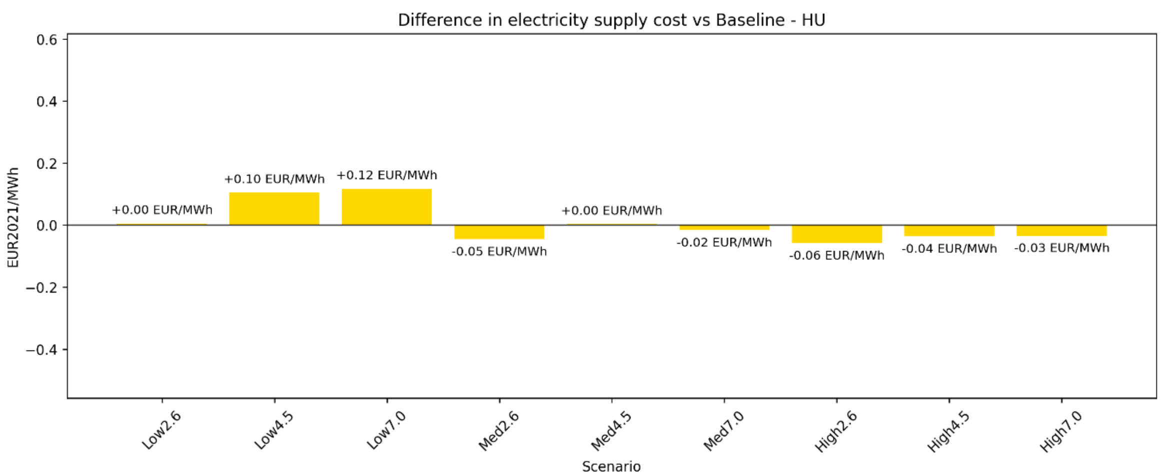

Difference in electricity supply cost vs Baseline - ES
EUR2021/MWh
Scenario
Low2.6
Low4.5
Low7.0
Med2.6
Med4.5
Med7.0
High2.6
High4.5
High7.0
-0.00 EUR/MWh
-0.40 EUR/MWh
-0.38 EUR/MWh
-0.05 EUR/MWh
-0.48 EUR/MWh
-0.46 EUR/MWh
-0.05 EUR/MWh
-0.50 EUR/MWh
-0.49 EUR/MWh

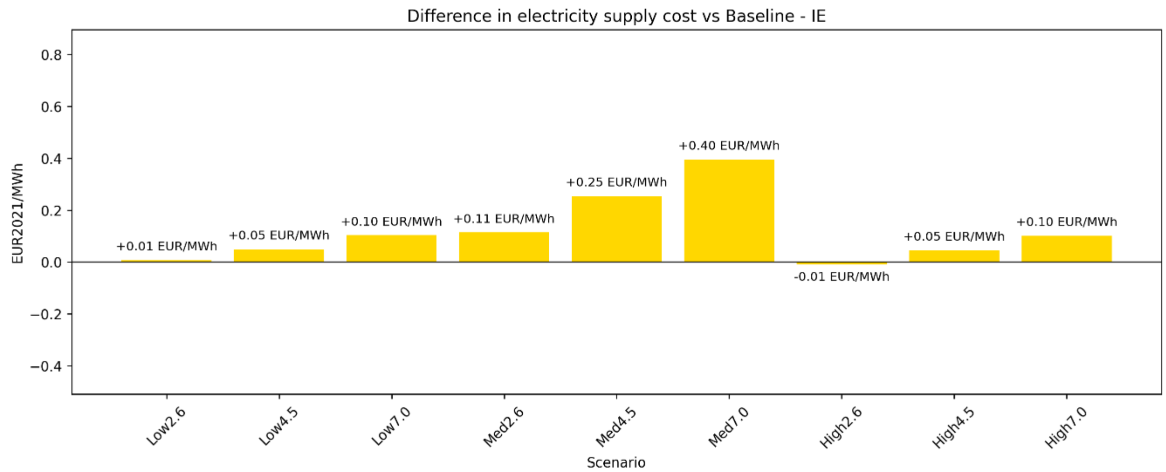

Difference in electricity supply cost vs Baseline - FI
EUR2021/MWh
Scenario
Low2.6
Low4.5
Low7.0
Med2.6
Med4.5
Med7.0
High2.6
High4.5
High7.0
+0.13 EUR/MWh
+0.13 EUR/MWh
+0.17 EUR/MWh
+0.15 EUR/MWh
+0.20 EUR/MWh
+0.26 EUR/MWh
+0.04 EUR/MWh
+0.05 EUR/MWh
+0.09 EUR/MWh

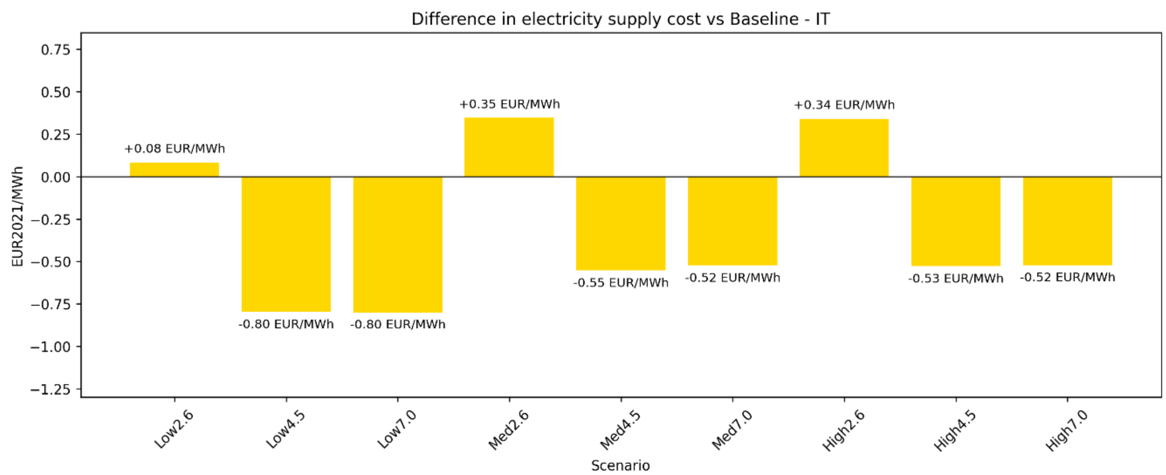

Difference in electricity supply cost vs Baseline - FR
EUR2021/MWh
Scenario
Low2.6
Low4.5
Low7.0
Med2.6
Med4.5
Med7.0
High2.6
High4.5
High7.0
+0.13 EUR/MWh
-1.05 EUR/MWh
-1.07 EUR/MWh
+0.09 EUR/MWh
-1.04 EUR/MWh
-1.04 EUR/MWh
+0.06 EUR/MWh
-1.05 EUR/MWh
-1.05 EUR/MWh

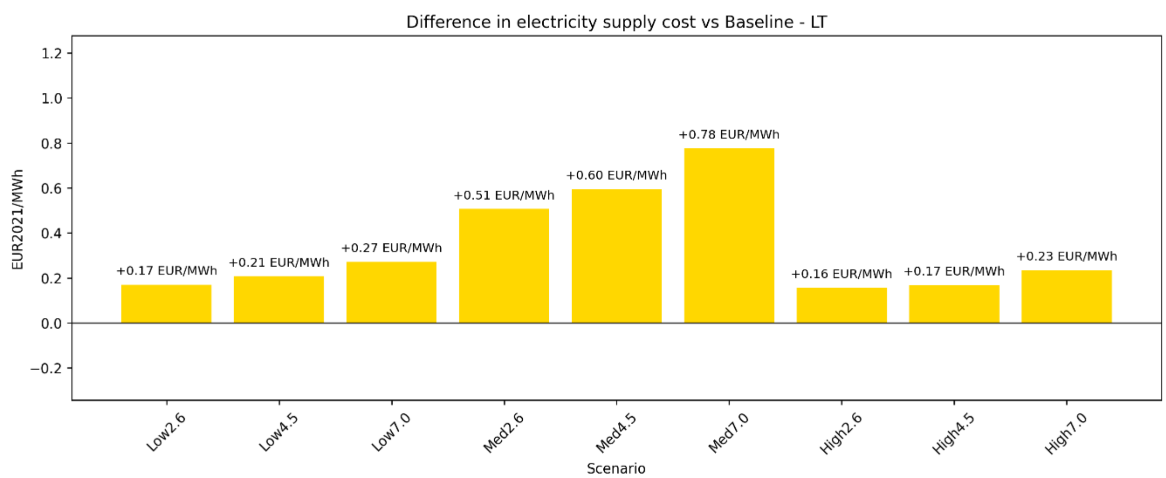

Difference in electricity supply cost vs Baseline - GR
EUR2021/MWh
0.2
0.0
−0.2
−0.4
−0.6
−0.8
-0.21 EUR/MWh
-0.10 EUR/MWh
-0.13 EUR/MWh
-0.42 EUR/MWh
-0.29 EUR/MWh
-0.39 EUR/MWh
-0.34 EUR/MWh
-0.23 EUR/MWh
-0.27 EUR/MWh
Low2.6
Low4.5
Low7.0
Med2.6
Med4.5
Med7.0
High2.6
High4.5
High7.0
Scenario

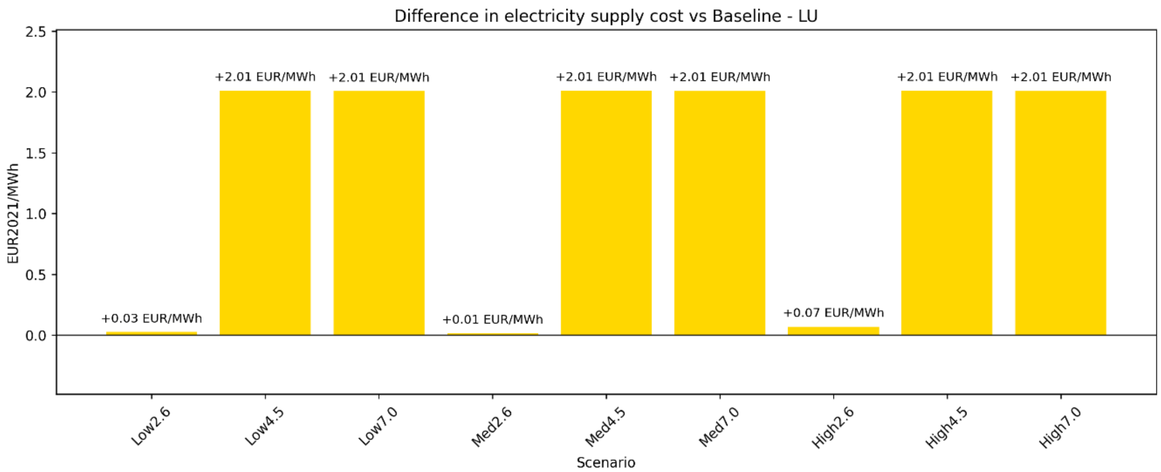

Difference in electricity supply cost vs Baseline - HR
EUR2021/MWh
0.6
0.4
0.2
0.0
−0.2
−0.4
−0.6
−0.8
+0.14 EUR/MWh
-0.26 EUR/MWh
-0.24 EUR/MWh
-0.11 EUR/MWh
-0.24 EUR/MWh
-0.24 EUR/MWh
-0.11 EUR/MWh
-0.34 EUR/MWh
-0.34 EUR/MWh
Low2.6
Low4.5
Low7.0
Med2.6
Med4.5
Med7.0
High2.6
High4.5
High7.0
Scenario

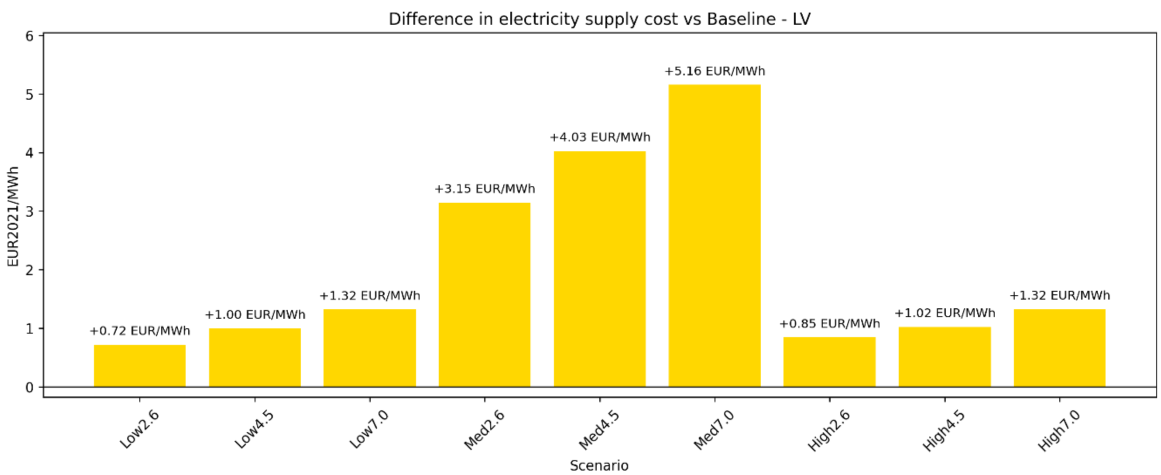

Difference in electricity supply cost vs Baseline - HU
EUR2021/MWh
0.6
0.4
0.2
0.0
−0.2
−0.4
+0.00 EUR/MWh
+0.10 EUR/MWh
+0.12 EUR/MWh
-0.05 EUR/MWh
+0.00 EUR/MWh
-0.02 EUR/MWh
-0.06 EUR/MWh
-0.04 EUR/MWh
-0.03 EUR/MWh
Low2.6
Low4.5
Low7.0
Med2.6
Med4.5
Med7.0
High2.6
High4.5
High7.0
Scenario

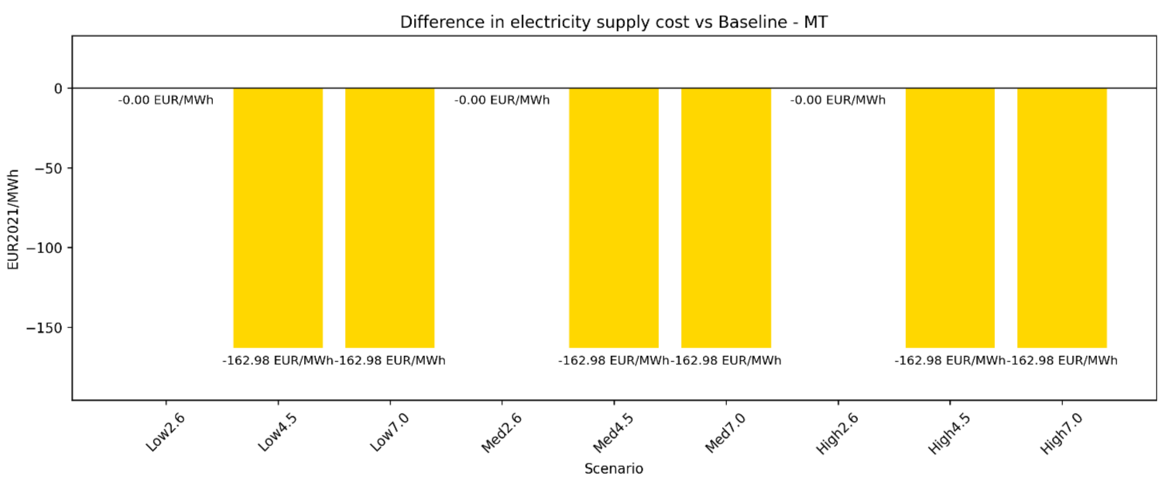

Difference in electricity supply cost vs Baseline - IE
EUR2021/MWh
0.8
0.6
0.4
0.2
0.0
−0.2
−0.4
+0.01 EUR/MWh
+0.05 EUR/MWh
+0.10 EUR/MWh
+0.11 EUR/MWh
+0.25 EUR/MWh
+0.40 EUR/MWh
-0.01 EUR/MWh
+0.05 EUR/MWh
+0.10 EUR/MWh
Low2.6
Low4.5
Low7.0
Med2.6
Med4.5
Med7.0
High2.6
High4.5
High7.0
Scenario

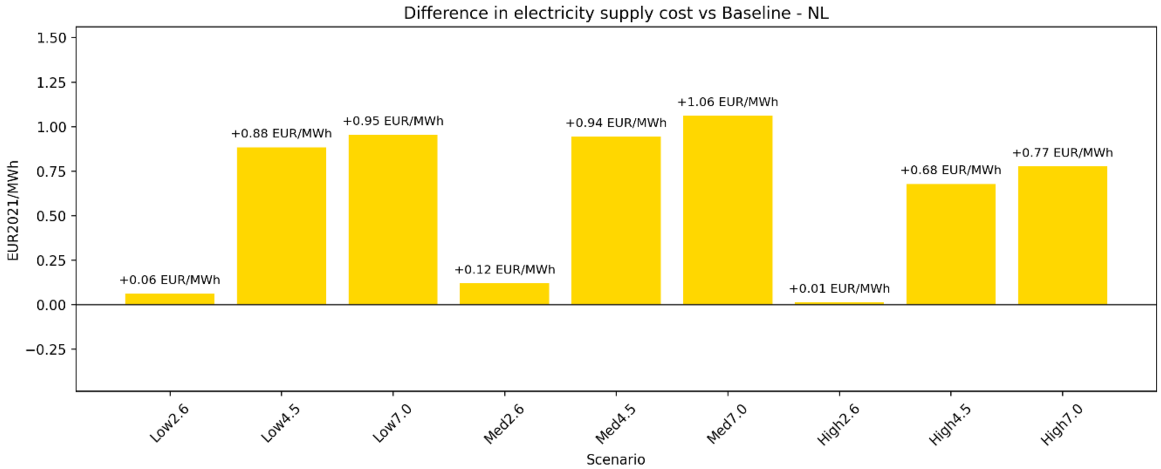

Difference in electricity supply cost vs Baseline - IT
EUR2021/MWh
0.75
0.50
0.25
0.00
−0.25
−0.50
−0.75
−1.00
−1.25
+0.08 EUR/MWh
-0.80 EUR/MWh
-0.80 EUR/MWh
+0.35 EUR/MWh
-0.55 EUR/MWh
-0.52 EUR/MWh
+0.34 EUR/MWh
-0.53 EUR/MWh
-0.52 EUR/MWh
Low2.6
Low4.5
Low7.0
Med2.6
Med4.5
Med7.0
High2.6
High4.5
High7.0
Scenario

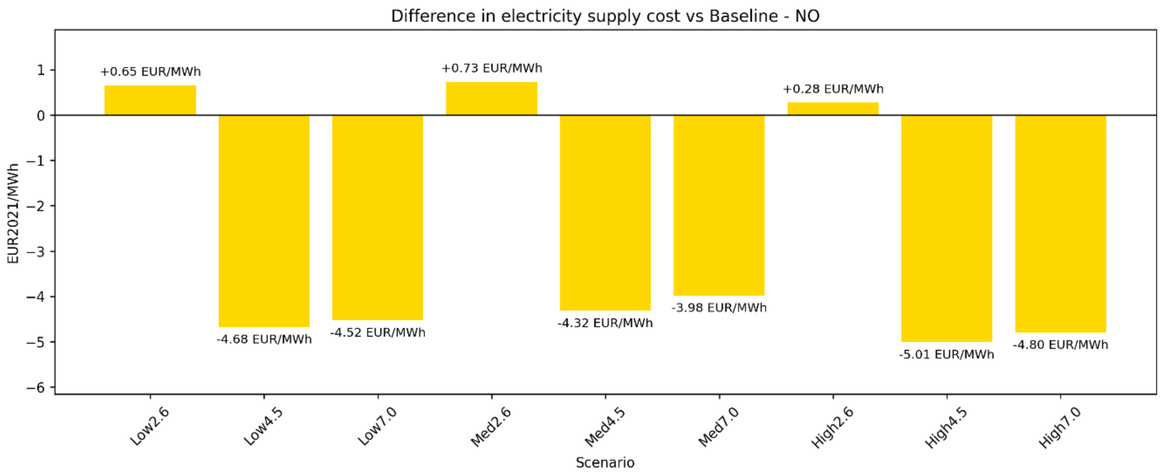

Difference in electricity supply cost vs Baseline - LT
EUR2021/MWh
1.2
1.0
0.8
0.6
0.4
0.2
0.0
−0.2
+0.17 EUR/MWh
+0.21 EUR/MWh
+0.27 EUR/MWh
+0.51 EUR/MWh
+0.60 EUR/MWh
+0.78 EUR/MWh
+0.16 EUR/MWh
+0.17 EUR/MWh
+0.23 EUR/MWh
Low2.6
Low4.5
Low7.0
Med2.6
Med4.5
Med7.0
High2.6
High4.5
High7.0
Scenario

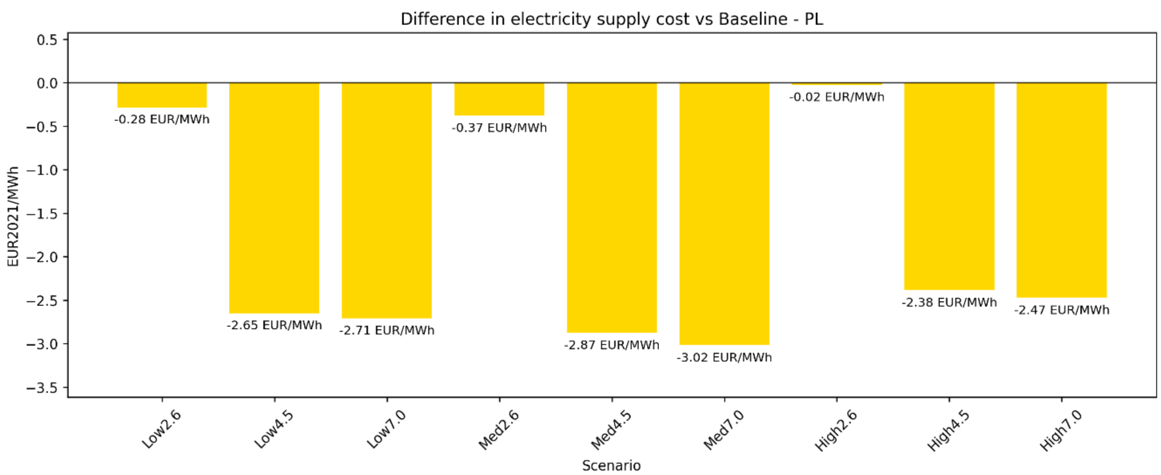

Difference in electricity supply cost vs Baseline - LU
EUR2021/MWh
Scenario
+0.03 EUR/MWh
+2.01 EUR/MWh
+2.01 EUR/MWh
+0.01 EUR/MWh
+2.01 EUR/MWh
+2.01 EUR/MWh
+0.07 EUR/MWh
+2.01 EUR/MWh
+2.01 EUR/MWh
Low2.6
Low4.5
Low7.0
Med2.6
Med4.5
Med7.0
High2.6
High4.5
High7.0

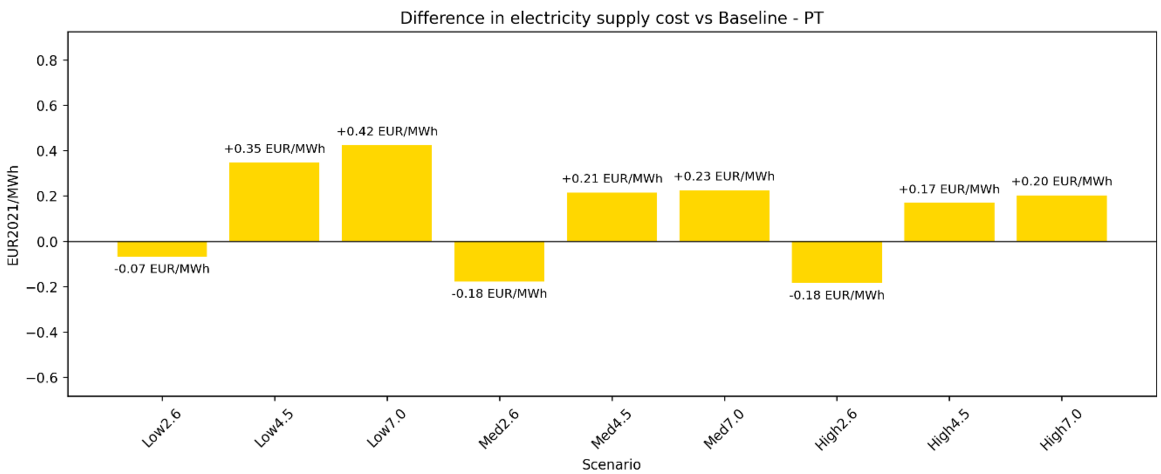

Difference in electricity supply cost vs Baseline - LV
EUR2021/MWh
Scenario
+0.72 EUR/MWh
+1.00 EUR/MWh
+1.32 EUR/MWh
+3.15 EUR/MWh
+4.03 EUR/MWh
+5.16 EUR/MWh
+0.85 EUR/MWh
+1.02 EUR/MWh
+1.32 EUR/MWh
Low2.6
Low4.5
Low7.0
Med2.6
Med4.5
Med7.0
High2.6
High4.5
High7.0

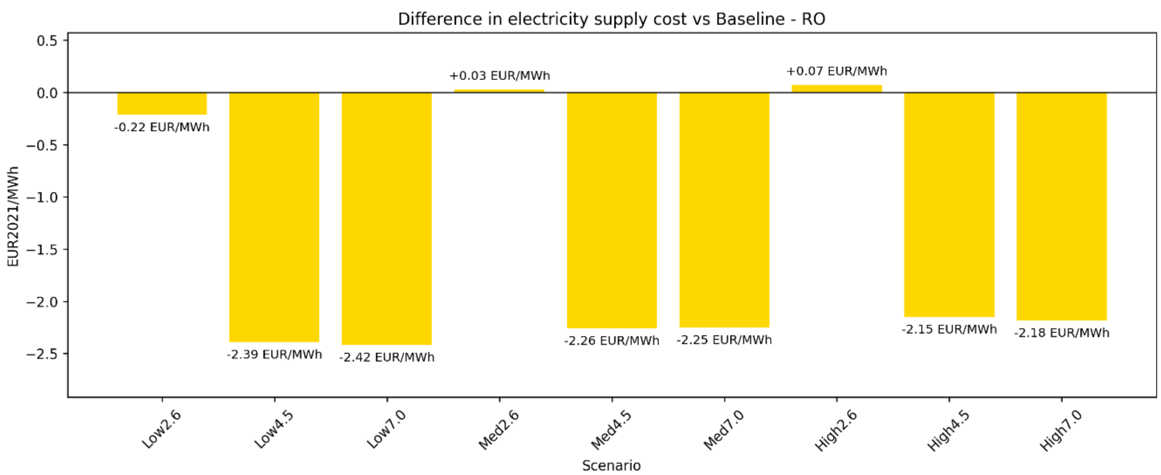

Difference in electricity supply cost vs Baseline - MT
EUR2021/MWh
Scenario
-0.00 EUR/MWh
-162.98 EUR/MWh
-162.98 EUR/MWh
-0.00 EUR/MWh
-162.98 EUR/MWh
-162.98 EUR/MWh
-0.00 EUR/MWh
-162.98 EUR/MWh
-162.98 EUR/MWh
Low2.6
Low4.5
Low7.0
Med2.6
Med4.5
Med7.0
High2.6
High4.5
High7.0

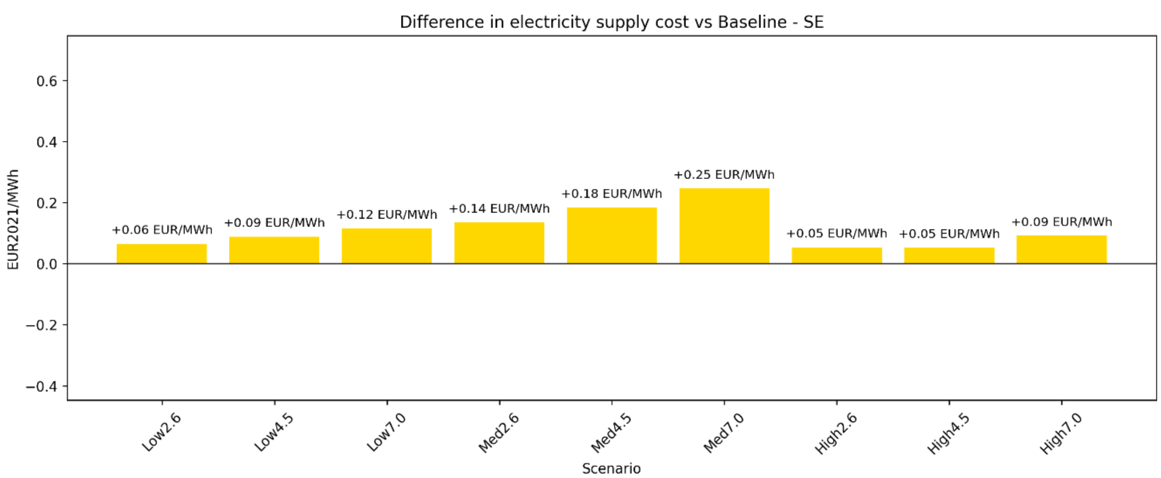

Difference in electricity supply cost vs Baseline - NL
EUR2021/MWh
Scenario
+0.06 EUR/MWh
+0.88 EUR/MWh
+0.95 EUR/MWh
+0.12 EUR/MWh
+0.94 EUR/MWh
+1.06 EUR/MWh
+0.01 EUR/MWh
+0.68 EUR/MWh
+0.77 EUR/MWh
Low2.6
Low4.5
Low7.0
Med2.6
Med4.5
Med7.0
High2.6
High4.5
High7.0

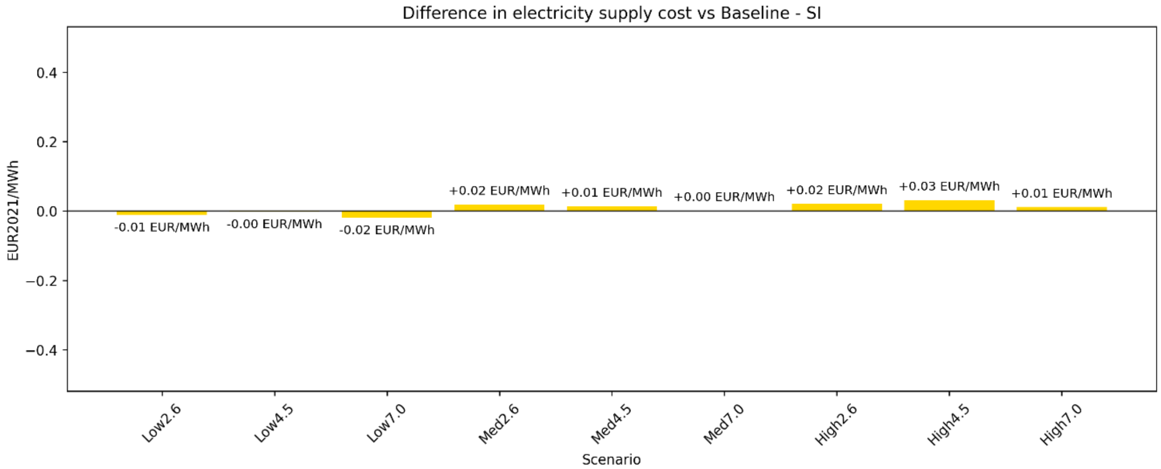

Difference in electricity supply cost vs Baseline - NO
EUR2021/MWh
Scenario
+0.65 EUR/MWh
-4.68 EUR/MWh
-4.52 EUR/MWh
+0.73 EUR/MWh
-4.32 EUR/MWh
-3.98 EUR/MWh
+0.28 EUR/MWh
-5.01 EUR/MWh
-4.80 EUR/MWh
Low2.6
Low4.5
Low7.0
Med2.6
Med4.5
Med7.0
High2.6
High4.5
High7.0


Difference in electricity supply cost vs Baseline - PL
EUR2021/MWh
Scenario
-0.28 EUR/MWh
-2.65 EUR/MWh
-2.71 EUR/MWh
-0.37 EUR/MWh
-2.87 EUR/MWh
-3.02 EUR/MWh
-0.02 EUR/MWh
-2.38 EUR/MWh
-2.47 EUR/MWh
Low2.6
Low4.5
Low7.0
Med2.6
Med4.5
Med7.0
High2.6
High4.5
High7.0

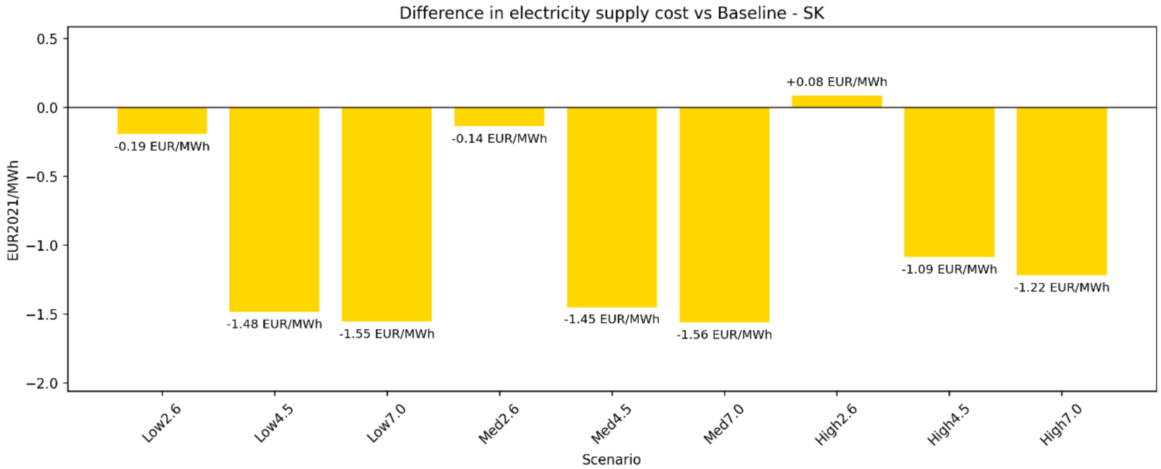

Difference in electricity supply cost vs Baseline - PT
EUR2021/MWh
Scenario
Low2.6
Low4.5
Low7.0
Med2.6
Med4.5
Med7.0
High2.6
High4.5
High7.0
-0.07 EUR/MWh
+0.35 EUR/MWh
+0.42 EUR/MWh
-0.18 EUR/MWh
+0.21 EUR/MWh
+0.23 EUR/MWh
-0.18 EUR/MWh
+0.17 EUR/MWh
+0.20 EUR/MWh


Difference in electricity supply cost vs Baseline - RO
EUR2021/MWh
Scenario
Low2.6
Low4.5
Low7.0
Med2.6
Med4.5
Med7.0
High2.6
High4.5
High7.0
-0.22 EUR/MWh
-2.39 EUR/MWh
-2.42 EUR/MWh
+0.03 EUR/MWh
-2.26 EUR/MWh
-2.25 EUR/MWh
+0.07 EUR/MWh
-2.15 EUR/MWh
-2.18 EUR/MWh

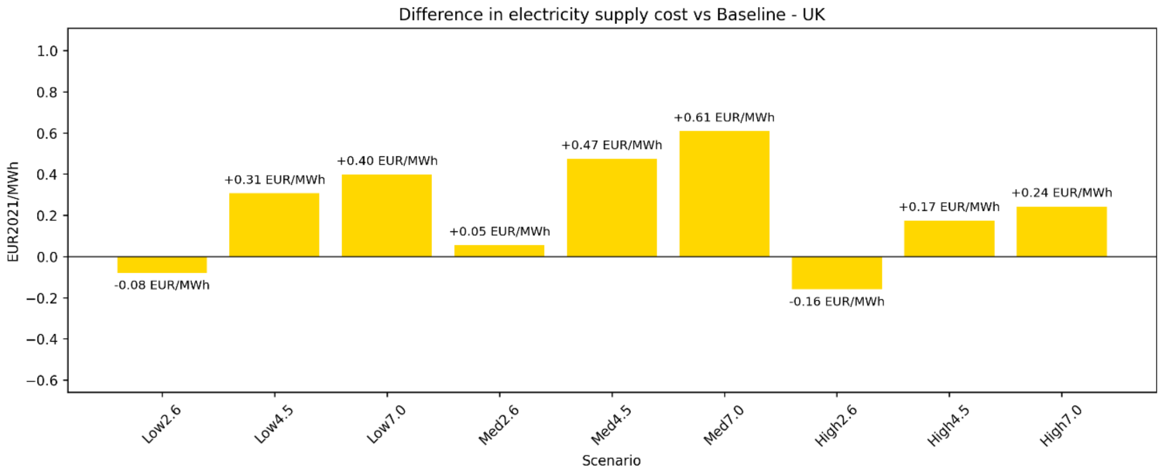

Difference in electricity supply cost vs Baseline - SE
EUR2021/MWh
Scenario
Low2.6
Low4.5
Low7.0
Med2.6
Med4.5
Med7.0
High2.6
High4.5
High7.0
+0.06 EUR/MWh
+0.09 EUR/MWh
+0.12 EUR/MWh
+0.14 EUR/MWh
+0.18 EUR/MWh
+0.25 EUR/MWh
+0.05 EUR/MWh
+0.05 EUR/MWh
+0.09 EUR/MWh



Difference in electricity supply cost vs Baseline - SI
EUR2021/MWh
-0.01 EUR/MWh
-0.00 EUR/MWh
-0.02 EUR/MWh
+0.02 EUR/MWh
+0.01 EUR/MWh
+0.00 EUR/MWh
+0.02 EUR/MWh
+0.03 EUR/MWh
+0.01 EUR/MWh
Low2.6
Low4.5
Low7.0
Med2.6
Med4.5
Med7.0
High2.6
High4.5
High7.0
Scenario



Difference in electricity supply cost vs Baseline - SK
EUR2021/MWh
-0.19 EUR/MWh
-1.48 EUR/MWh
-1.55 EUR/MWh
-0.14 EUR/MWh
-1.45 EUR/MWh
-1.56 EUR/MWh
+0.08 EUR/MWh
-1.09 EUR/MWh
-1.22 EUR/MWh
Low2.6
Low4.5
Low7.0
Med2.6
Med4.5
Med7.0
High2.6
High4.5
High7.0
Scenario

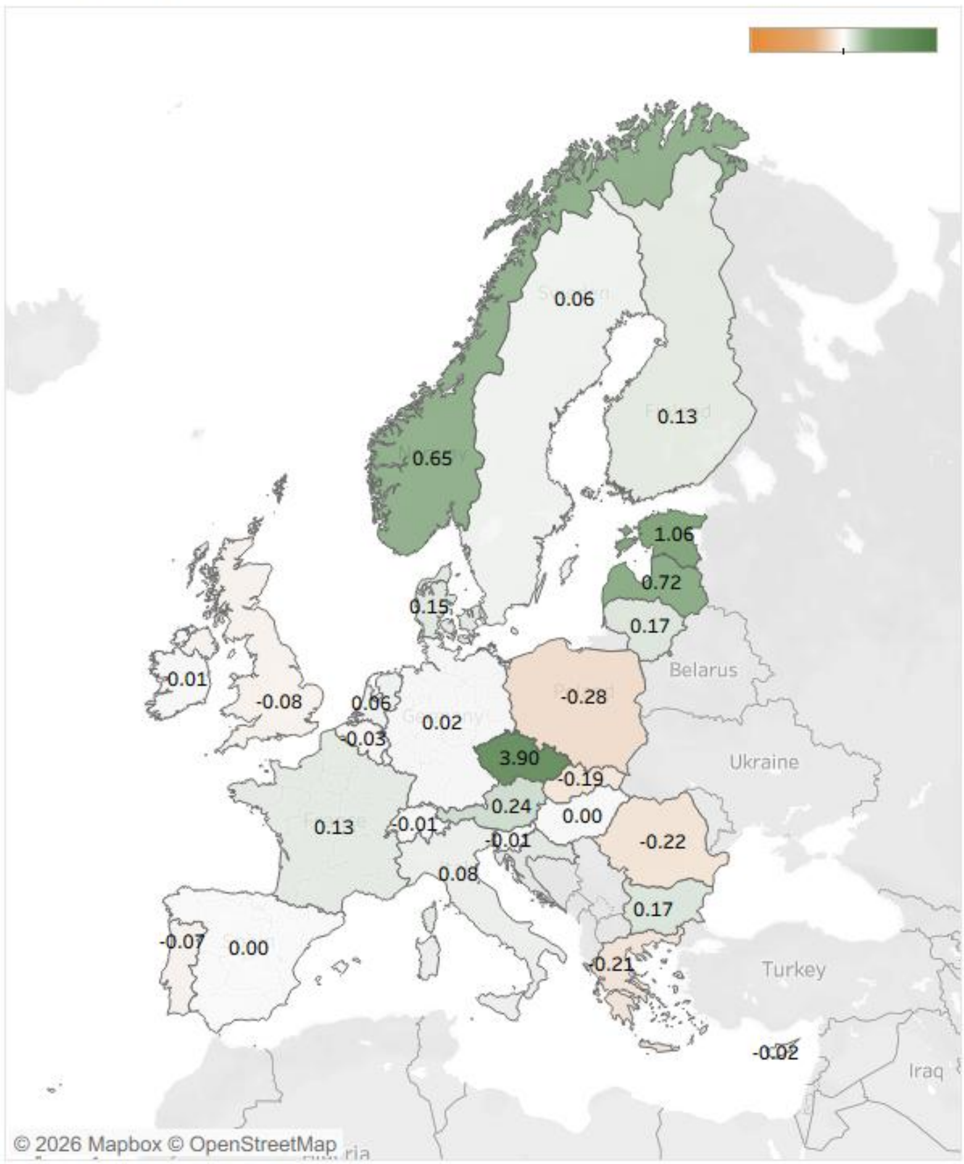


Difference in electricity supply cost vs Baseline - UK
EUR2021/MWh
-0.08 EUR/MWh
+0.31 EUR/MWh
+0.40 EUR/MWh
+0.05 EUR/MWh
+0.47 EUR/MWh
+0.61 EUR/MWh
-0.16 EUR/MWh
+0.17 EUR/MWh
+0.24 EUR/MWh
Low2.6
Low4.5
Low7.0
Med2.6
Med4.5
Med7.0
High2.6
High4.5
High7.0
Scenario

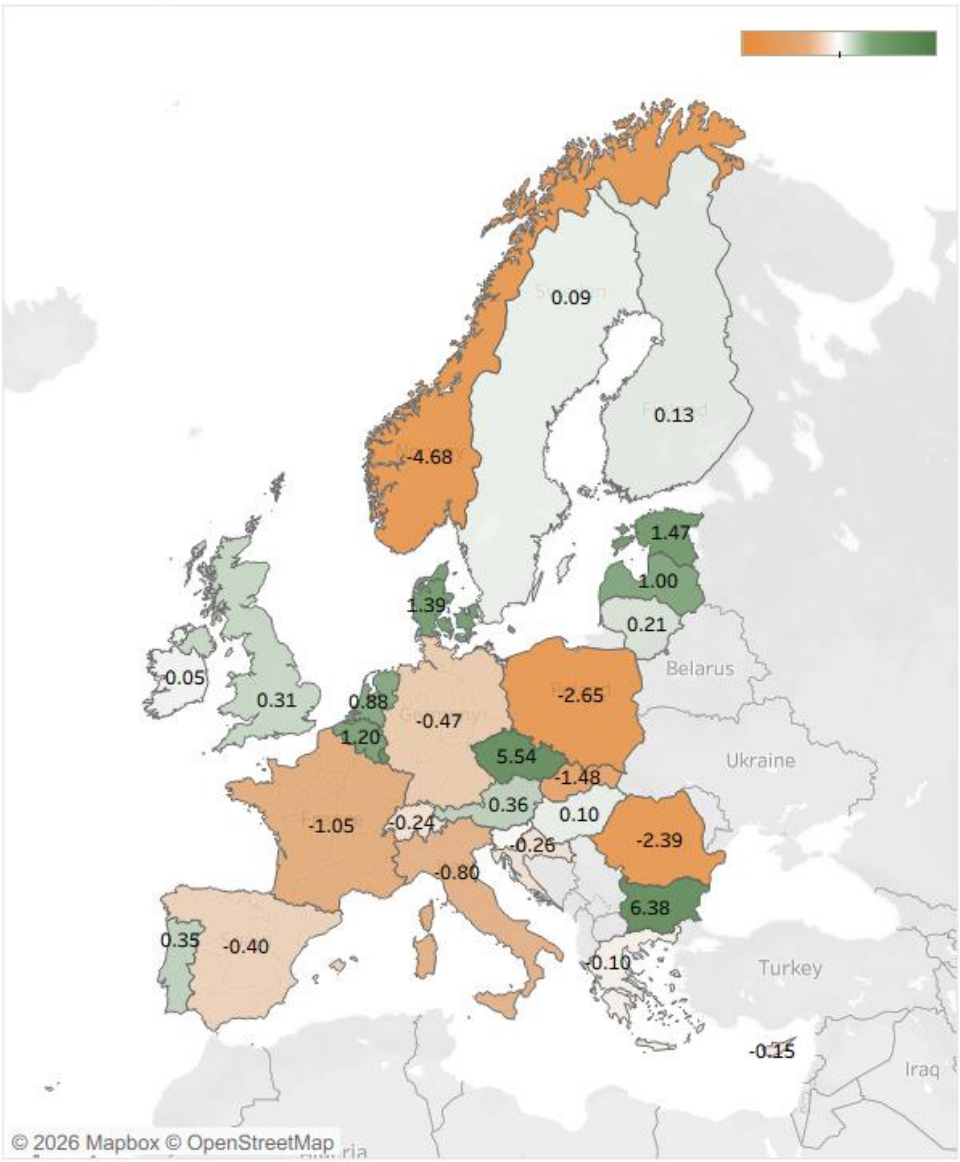
ACCREU
Assessing
Climate Change
Risk in EUrope

E. Geographical distribution of difference in electricity supply cost due to assessed climate change impacts across Europe

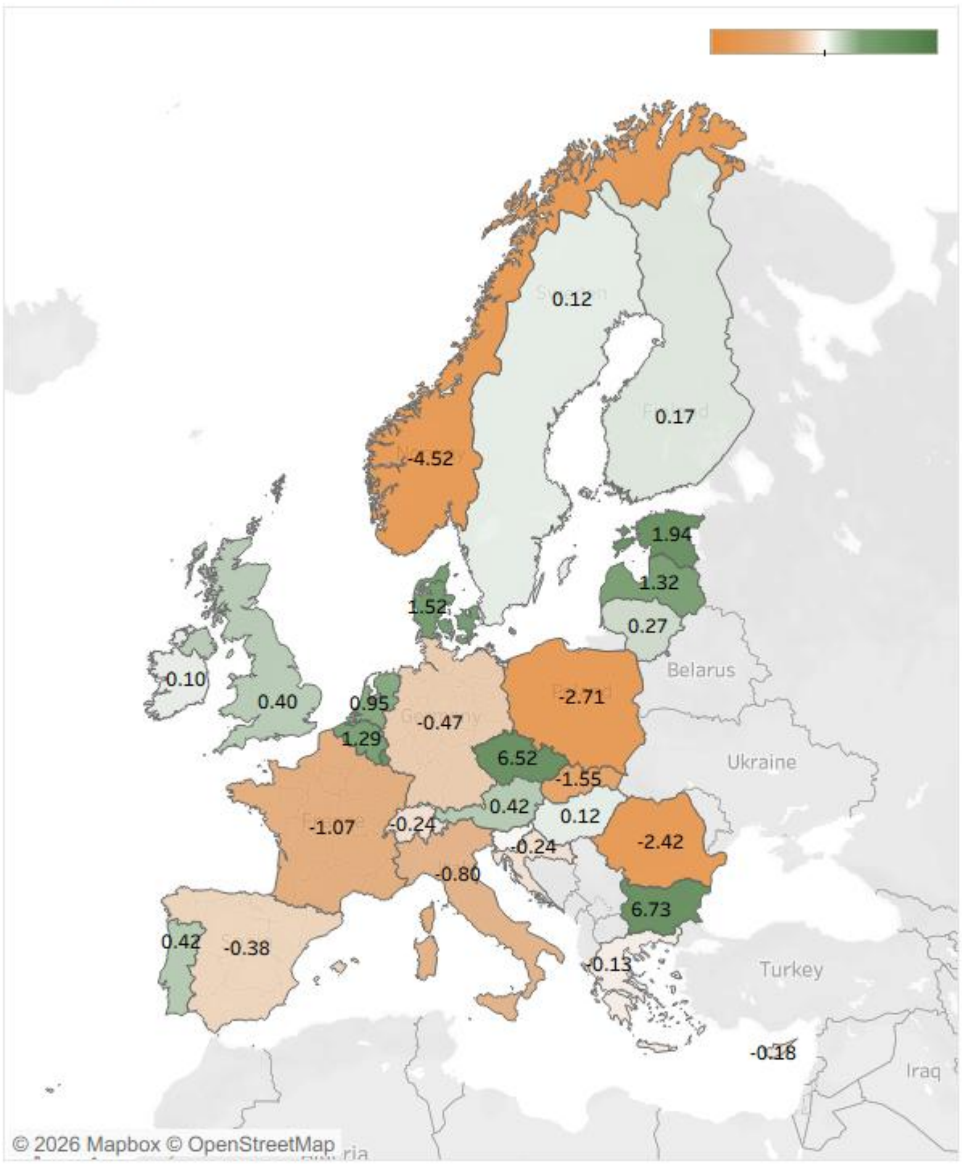
Change in Electricity Supply Cost (EUR2021/MWh)
Low2.6 vs Baseline



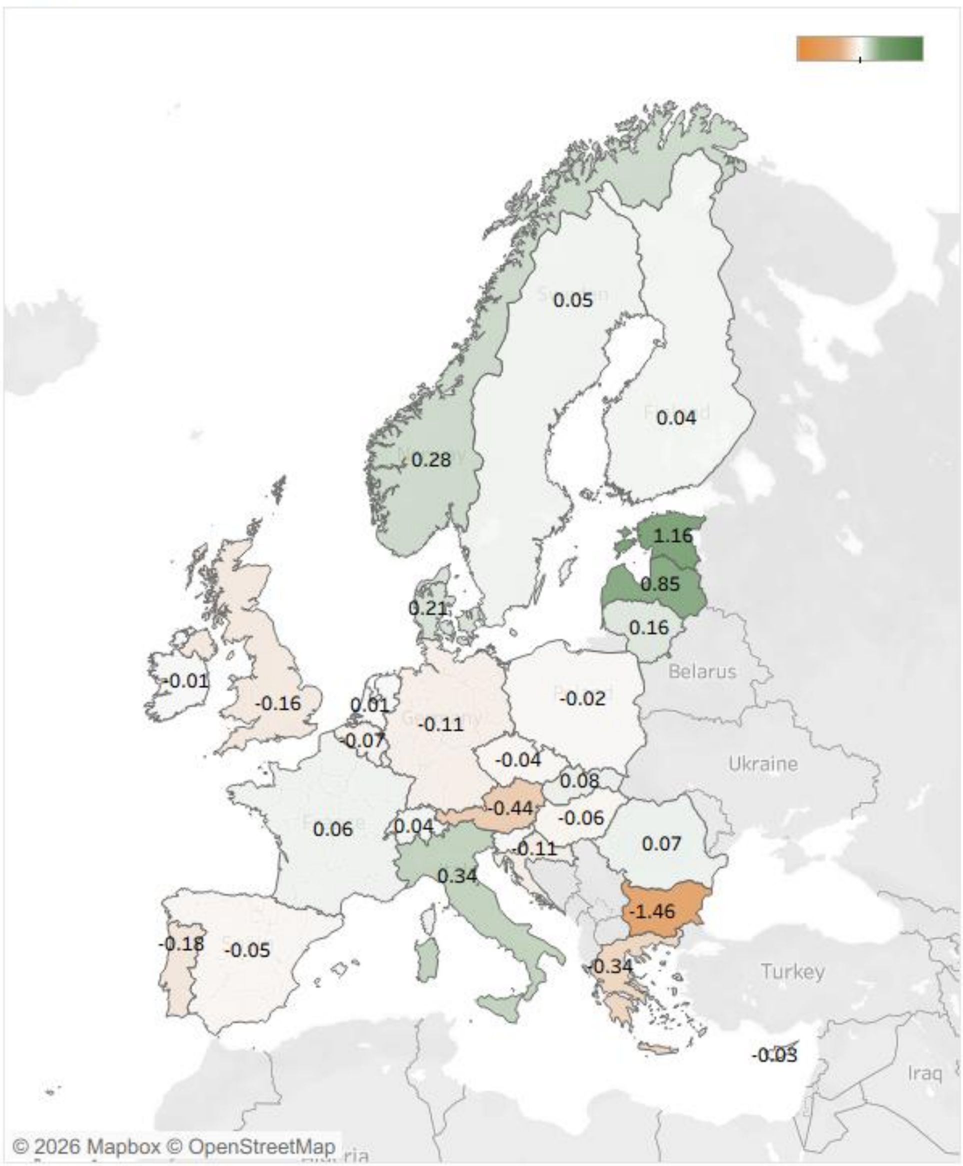
Change in Electricity Supply Cost (EUR2021/MWh)
Low4.5 vs Baseline



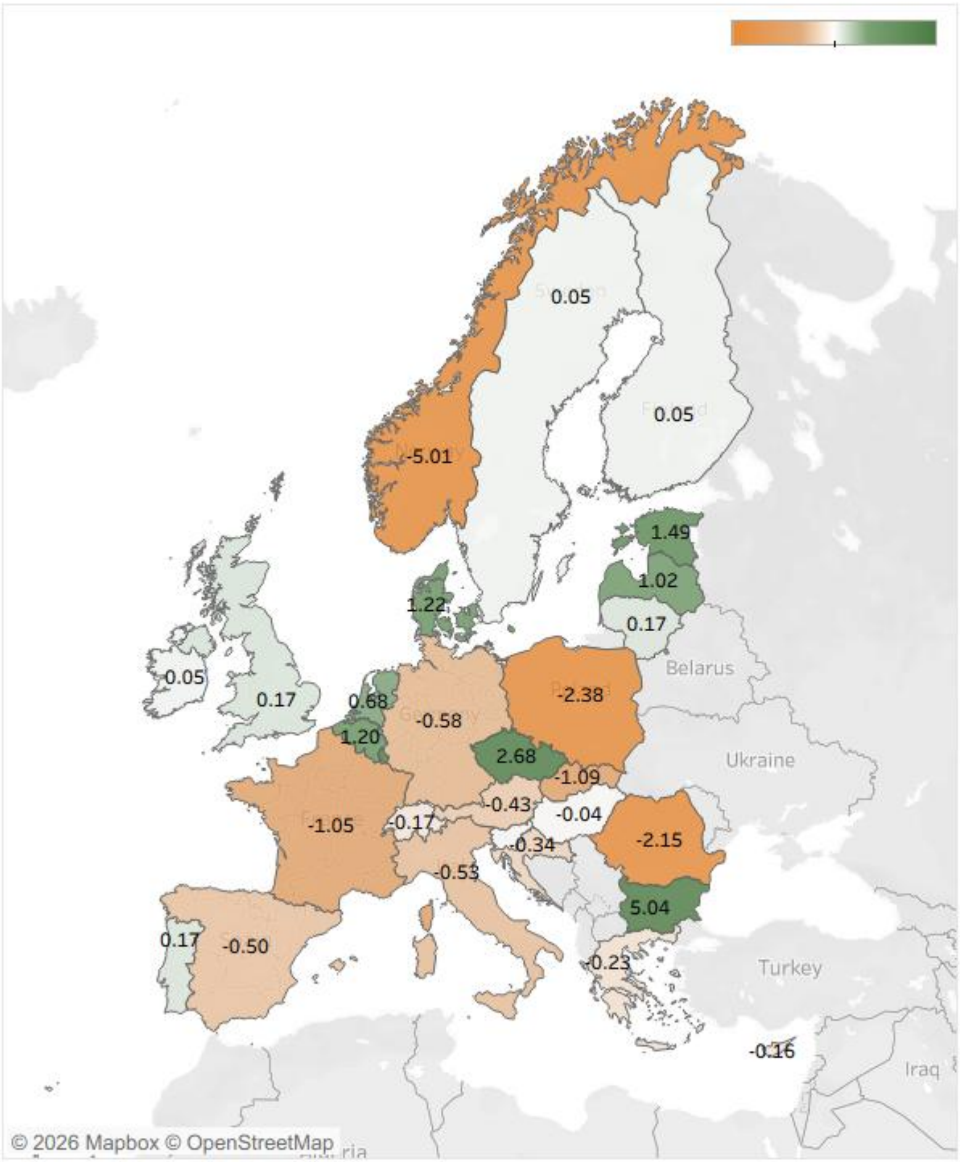
Change in Electricity Supply Cost (EUR2021/MWh)
Low7.0 vs Baseline



Change in Electricity Supply Cost (EUR2021/MWh)
High2.6 vs Baseline



Change in Electricity Supply Cost (EUR2021/MWh)
High4.5 vs Baseline



Change in Electricity Supply Cost (EUR2021/MWh)
High7.0 vs Baseline