European
Commission

METIS 2

Study S4

2050 no-regret options and technology lock-ins

LEGAL NOTICE

PDF	ISBN 978-92-76-99077-2	doi: 10.2833/135582	MJ-05-23-010-EN-N

Luxembourg: Publications Office of the European Union, 2023

Prepared by

Stefanía Gómez (Comillas)
Luis Olmos (Comillas)
Andrés Ramos (Comillas)
Gaspard Peña Verrier (Artelys)
Quentin Gruet (Artelys)
Tobias Bossmann (Artelys)

Contact: metis.studies@artelys.com, olmos@comillas.edu.

EUROPEAN COMMISSION

Directorate-General for Energy

Directorate A — Energy Policy
Unit A4 — Chief Economist

Directorate C — Renewables, Research and Innovation, Energy Efficiency
Unit C2 — New energy technologies, innovation and clean coal

E-mail: ENER-METIS@ec.europa.eu

European Commission
B-1049 Brussels

Contents

ABBREVIATIONS AND DEFINITIONS

ABBREVIATIONS

Abbreviation	Definition
BECCS	Bioenergy with CCS
CAPEX	Capital expenditures
CC	Climate change
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CDD	Cooling degree days
CHP	Combined heat and power
DSR	Demand side response
EV	Electric vehicle
HDD	Heating degree days
LTS	Long-Term Strategy
MS	Member State
NTC	Net transfer capacity
OCGT	Open cycle gas turbine
OPEX	Operational expenditures
PHS	Pumped hydro storage
PV	Photovoltaic
RES	Renewable energy sources
SMR	Steam methane reforming
vRES	Variable RES

METIS CONFIGURATION

The configuration of the METIS model used in the present study is summarised in the following table.

METIS Configuration	
Version	METIS v2.0 Beta (non-published)
Modules	Power system and demand modules
Scenario	METIS 1.5 scenario
Time resolution	Hourly (8760 consecutive time-steps per year)
Spatial granularity	Member State

1 EXECUTIVE SUMMARY

The present study (in the following referred to as study S4) takes a deeper look at the 2050 EU energy system. It builds upon a decarbonisation scenario developed in an earlier study of the METIS 2 project (study S6[1]) which focusses on the EU electricity sector, and its interlinkage with the hydrogen and the heat sectors. While study S6 aimed for a cost-optimal dimensioning of the EU power system, the present study goes a step further and aims to derive more general conclusions. It sheds light on no-regret options towards the decarbonisation of the 2050 EU energy system, potential technology lock-in risks, and major drivers of uncertainty like system sensitivity to climate change and commodity prices. The analysis is complemented by an evaluation of the impact of an enhanced representation of hydrogen infrastructures and the associated constraints, as these may impact the entire interlinked EU energy system.

A comprehensive literature review of existing 2050 EU energy system projections identifies **four major elements** that are analysed in more detail in S4 by enhancing the scenario from study S6 and conducting dedicated simulations with the EU energy system model METIS.

Climate change will have a two-fold effect, in terms of the evolution of air temperature (rising on average), and in terms of the frequency and magnitude of extreme weather events. In this study, climate change (CC) is represented as a 2°C increase in the average global air temperature by 2050 (corresponding to the h1 scenario defined within (JRC, 2018.b)). Two main CC effects have been considered in this regard: i) on the heating and cooling demand, (typically increasing the cooling demand, especially in summer, and decreasing the heating demand, especially in winter); and ii) on the performance of the different energy conversion technologies. Both effects are addressed by distinct model runs in order to identify the effects on the development (in terms of capacity mix) and operation of the EU power system.

A climate change driven **modification of electricity demand volumes for heating and cooling** implies a shift of demand volumes from winter to summer time at the EU level. While Nordic and continental Member States feature a net reduction in power demand, driven by the decrease of heating demand, Southern European countries face a net increase in power demand, as the increase in cooling-related electricity demand taking place in these countries significantly outweighs the decrease in heating demand. These altered demand patterns are met best by adapting the generation portfolio, reducing the investments in wind capacities (featuring a power generation above average in winter time and high-capacity factors in coastal areas, -34 GW in EU27+7) and increasing the power generation from solar PV (with a concentration of power generation in summer and more favourable capacity factors in the Southern countries, +17 GW). Total power generation capacities show a net decrease of about 21 GW, which is less than 1% of the total EU installed power generation capacity.

The **adaptation of power generation technologies** to face the impacts of climate change implies additional investment costs. According to the literature, they are highest for offshore wind plants. Besides, the non-negligible adaptation costs faced by gas power plants result in higher production costs. This implies that wind offshore and gas assets experience a slight reduction in investments in absolute terms (which is relevant for gas plants in relative terms), whereas, notably, solar PV makes up for the missing power generation as it requires no adaptation. Yet, changes in capacity in absolute terms are marginal under the present assumptions for climate change.

[1] (Artelys, 2021 (forthcoming))

Hydrogen production via electrolysis is considered a key element of the European decarbonisation strategy (cf. the EU Hydrogen Strategy). Yet, the question arises whether hydrogen is likely to play a central role by 2050 and whether European electrolysis-based hydrogen production may compete with low-cost hydrogen imports from abroad. A set of sensitivity model runs with METIS illustrate that, in particular, low hydrogen import and CO_2 prices do hardly affect hydrogen demand, but do effectively reduce the share of domestic hydrogen production to roughly 40% of that in the Baseline, where no hydrogen imports are considered. However, the amount of capacity of electrolysers deployed within the EU would, in any case, be very significant. Hence, this technology can be considered a no-regret option.

In terms of **hydrogen infrastructure**, the original scenario design from study S6 was extended by explicitly optimising the cost-optimal size of hydrogen transmission and storage capacities (in contrast to the S6 study, where no hydrogen interconnection capacity is considered and hydrogen storage capacity is deemed to be unlimited). Enabling the installation of **cross-border hydrogen interconnection capacity** (or the repurposing of existing gas pipelines) facilitates **regional cooperation**. Then, hydrogen production is relocated to countries featuring particularly favourable framework conditions in terms of RES-E potentials and electricity prices. In particular, the expansion of onshore wind generation capacity in Ireland and the UK (+500 TWh of power generation) allows significantly reducing the domestic RES capacity (notably PV and offshore wind) and hydrogen production in the Northern part of Central Europe (BE, DE, NL, PL). When it comes to **hydrogen storage**, the potentials (salt caverns or gas storages that may be repurposed) are quite unevenly distributed across the EU. Optimising storage deployment across the EU under this constraint provides two major insights. First, an appropriate representation of the limited storage potentials triggers a significant increase in hydrogen interconnection capacities to ensure a cost-efficient continuous hydrogen supply-demand equilibrium (+170% under the given assumptions). Ireland and UK, as the main hydrogen exporting region, face a reduction in their net exports. The same applies to Southern European countries, whose exports disappear. On the other hand, the hydrogen exports from Northern European countries increase. Secondly, constraining storage availability affects the distribution of power and hydrogen generation capacities across the EU, triggering, in particular, a shift from Southern to Northern European countries, or to put it differently, from solar PV to onshore wind generation.

European climate objectives expect the power system to become a "net negative" CO_2 emitter by 2050, able to compensate for "positive" emissions produced by other, hard-to-abate sectors. These **negative carbon emissions** should be facilitated by the deployment of bioenergy-fuelled plants equipped with CCS, whose economic efficiency and profitability may be reached through selling CO_2 emission permits at a given CO_2 price. However, there is significant uncertainty about how the CO_2 price will evolve in the future, notably due to the fact that they will be impacted by the ability of others sectors to decarbonise and the cost incurred in this. A series of sensitivity assessments around the CO_2 price signal is conducted. Results illustrate that lower carbon prices than considered in the baseline scenario (350 €/t) reduce revenues for the net-negative emitters, which hampers the deployment of bioenergy-fuelled power and heat plants and fosters the electrification and the deployment of variable RES and non-CCS equipped technologies, with a CO_2 price between 150 and 200 €/t representing a tipping point.

The analyses carried out in this study with the EU energy system model METIS allows one to derive the following take away messages:

- **Climate change**, and the need for the power system to adapt to it, will have an impact on the generation capacity mix and the power system dimensioning. This may become evident if the rise in the average temperature triggered by climate change happens in the high end of the range deemed possible. The impact of climate change varies across countries, as well as the means they have to adapt to it. A coordinated approach is likely to provide the most effective strategy.

- **Hydrogen** is a key element, in particular electrolysers, whose development and deployment within the EU would, in any case, pay off. Yet, the planning of the hydrogen infrastructure should take a European perspective to take a larger advantage of the specific potential of the individual MSs and neighbouring countries and more efficiently deal with their specific restrictions (in terms of RES and storage potentials).

- The **carbon price** should have a relevant impact on the technology mix deployed and represents a key instrument to trigger investments and lead to diverging decarbonisation pathways. The carbon price may notably impact investments in CCS and the ability of the power system to be a net-negative emitter able to offset harder-to-abate sectors.

2 INTRODUCTION

Earlier in the METIS 2 project, modelling works conducted for study S6 (Artelys, 2021 (forthcoming)) led to building a cost-optimal 2050 EU scenario that achieves carbon neutrality in 2050, relying on framework data from the 1.5 TECH scenario of the European Commission's Long-Term Strategy (EC, 2018). The resulting so-called METIS 1.5 scenario, featuring Member State granularity, includes newly-developed representations of the coupling at stake in 2050 between power, hydrogen and industrial heat provision systems.

With the final objective of gaining expertise in modelling decarbonisation scenarios, the present study (in the following referred to as study S4) builds upon the METIS 1.5 scenario and explores the evolution of the system for a set of alternative future contexts via a series of sensitivity assessments and enhancements of the modelling approach.

The topics to be addressed in this study include:

- Understanding the impact of Climate Change (CC) on the expansion and operation of the system, both considering the adaptation of the power generation system to CC and the impact of CC on the electricity demand
- Identifying the main no-regret[2] and lock-in[3] technologies on the transition pathway towards full decarbonisation by 2050.
- Assessing the impact of enhancing the representation of the deployment of hydrogen infrastructure, including the repurposing of cross-border gas pipelines, the construction of new cross-border hydrogen pipelines, and imposing national constraints on hydrogen storage deployment.
- Analysing the relevance of specific environmental parameters such as CO_2 emission values.

This report describes in Section 3 the selection of the analyses to be conducted, based on a comprehensive literature review. Sections 4, 5, 6, and 7 reveal, for each of the topics above, the modelling approaches, key results and messages derived. Finally, Section 8 provides the conclusions and an outlook.

---

[2] In this report, a no regret technology is a technology that is expected to appear in any possible future of the energy system.

[3] In this report, a lock-in technology is a technology that, when deployed in the short to medium term, may trigger its further use and, possibly, its further deployment in the long term despite causing some losses of efficiency in the system, at least in some of the possible futures of it. These are not to be mistaken for those technologies that are of no use in the long term, and therefore, represent a sunk cost, but are not further used and deployed in that time frame, even when deployed in the short-to-medium term. Both types of technologies have been investigated in the literature review conducted.

3 IDENTIFICATION OF RELEVANT ANALYSES TO BE CONDUCTED

The most relevant recent scenarios and studies analysing potential pathways towards the 2050 EU energy system have been reviewed. Based on this, and applying a pre-defined set of selection criteria, the most appropriate analyses and modelling upgrades to be addressed in this study have been identified.

3.1 RELEVANT CRITERIA FOR THE DEFINITION OF THE ANALYSES TO UNDERTAKE

The criteria considered for the selection of the relevant analyses to undertake include:

- The **potential impact** that the specific aspect to analyse is expected to have on the functioning of the EU energy system. This criterion ensures that changes in the system conditions and modelling that are eventually explored reflect phenomena that may have a concrete, high, impact on the dimensioning or operation of the energy system. This potential impact may be defined in terms of investment or operation decisions, and/or the economic, environmental, or security of supply system performance.
- The **probability** that the change in system conditions explored in the analyses may actually materialise. In order to foster the pragmatism of the analyses, this criterion ensures that the likelihood of the envisaged phenomena and upgrades explored is high enough in the time horizon considered in the study. For instance, before assessing the impact of an increase in the frequency and magnitude of water floods driven by climate change (CC), or that of building a hydrogen cross-border network, we consider the probability that this increase in floods takes place, or the affordability of the construction of this hydrogen network, by 2050.

3.2 OVERVIEW OF THE LITERATURE ON THE EU ENERGY SYSTEM DECARBONISATION

3.2.1 DEFINITION OF THE LITERATURE REVIEW

The literature review concentrates on scenarios and studies featuring a scope similar to study S6 (Artelys, 2021 (forthcoming)) and the underlying METIS 1.5 scenario: carbon-neutrality by 2050. A set of three main criteria has been applied to narrow down the scope of the relevant literature:

1) the temporal scope should include 2050 and, potentially, previous years;
2) the geographical scope should include Europe, preferably with regional or national granularity; and
3) the narrative should consider an emission reduction objective that is close to that in EU policy (a minimum target of 90% emission reduction by 2050 w.r.t. 1990 levels has been considered[4]).

The main studies and scenarios that have been reviewed include:

[4] The EU has pledged for carbon neutrality (cf. EU climate law). However, the number of scenarios in the literature where such an objective is set is rather low. Thus, all those scenarios for which there is information available and that are targeting at least a 90% emission reduction by 2050 w.r.t. 1990 levels have been included in the review.

- The European Commission's 'Clean Planet for All' strategy - 1.5 TECH scenario (EC, 2018);
- Navigant's 'Gas for Climate' study (Navigant, 2019)
- Teske's 'Achieving the Paris Climate Agreement Goals' (Sven Teske, 2019);
- ECF's 'Towards Fossil-Free Energy In 2050' within the 'Net Zero 2050' series – scenario HighE (ECF, 2019)
- Wind Europe's 'Breaking new ground - Wind Energy and the Electrification of Europe's Energy System' - Paris compatible scenario (Wind Europe, 2018);
- JRC's Low Carbon Energy Observatory works (JRC, 2018.c);
- Artelys' 2050 Energy Infrastructure report 'What energy infrastructure to support 1.5°C scenarios?' (Artelys, 2020);
- The IEA's 2020 World Energy Outlook - Sustainable Development Scenario (SDS) (IEA, 2020) ;
- Eurelectric's Decarbonisation Pathways - Scenario 3 (Eurelectric, 2018);
- The European Commission's 'Impact Assessment' accompanying the Communication 'Stepping up Europe's 2030 climate ambition. Investing in a climate-neutral future for the benefit of our people' – MIX Scenario (EC, 2020.a);
- IRENA's 'Global Renewables Outlook' (IRENA, 2020).

Relevant information on some of the 2050 scenarios reviewed has been drawn from (JRC, 2020). Besides the scenarios reviewed, additional sources of information, including (European Environment Agency, 2016) *and* (Climact, 2018), have been considered in order to identify potential lock-in technologies and no-regret options.

3.2.2 ANALYSIS OF THE ROLE OF ENERGY-RELATED TECHNOLOGIES

The literature review conducted has revealed significant similarities and differences among the scenarios and prospective studies consulted, regarding the level of deployment and use of technologies. These have been considered to select the analyses to be undertaken in this study. The main conclusions that can be drawn from the literature are summarised below and relate to data that is represented in Figure 3-1:

- The level of electricity generation by unabated natural gas fuelled generation drops to 0 by 2050. Most scenarios agree that, from 2030 onwards, all the remaining natural gas plants should be equipped with CCS.
- The electricity generation of coal fired power plants in the year 2050 is absent or small: it ranges between 0 and 56 TWh (corresponding to 1% of the total EU electricity production). In most of the scenarios reviewed, a nearly complete coal phase-out is achieved by 2050.
- The fossil fuelled generation capacity equipped with CCS ranges between 20 GW and 30 GW in 2050 at European scale, while capacity using biomass with CCS (BECCS) ranges between 35 GW and 113 GW in 2050. According to the majority of

studies, from 2030 onwards, about 70% of biomass should be equipped with CCS, and traditional biomass use is strongly reduced.

- Electrolysers are considered in most of the 2050 scenarios reviewed and their installed capacity ranges between 400 and 540 GW_H_2 in 2050, at EU level. However, the electrolyser deployment level varies widely across countries.

- Heat pumps are considered in all the 2050 scenarios reviewed, notably in the building sector. Heat pumps are expected to cover about 40% of total heat needs in 2050 in the building sector, and are considered as a key technology to reach net-zero emissions in 2050.

- Wind onshore capacity ranges between 300 GW and 950 GW in 2050 EU-wide, while wind offshore capacity ranges between 250 GW and 600 GW.

- Solar PV capacity ranges between 600 GW and 1150 GW in 2050.

- Hydro power generation capacity ranges between 130 GW and 250 GW in 2050.

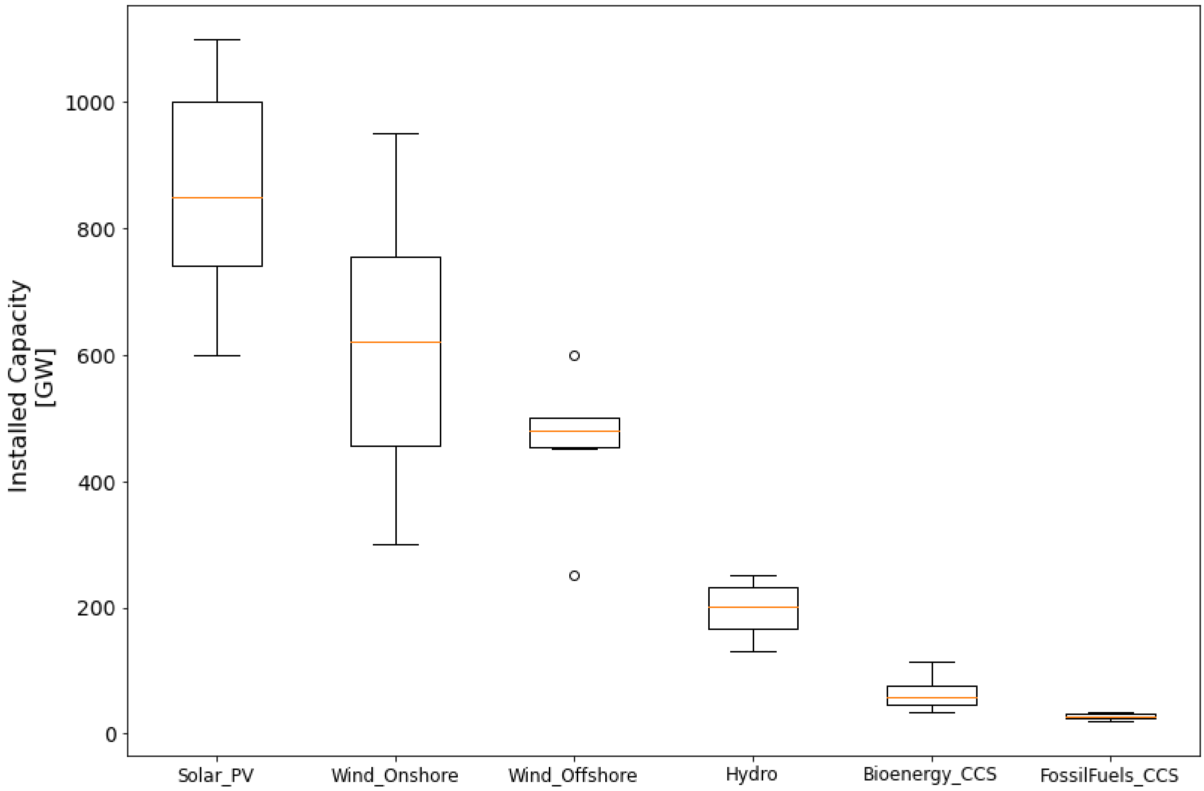

Figure 3-1. Boxplot – Range of amounts of power generation capacity per technology, by 2050, considered in the scenarios reviewed [GW]

The literature agrees on the fact that uncoordinated investment strategies could increase the risk of overcapacity across Europe in 2050, notably regarding gas-fired and coal-fired generation, which could translate into technology lock-ins. This calls for a careful consideration of investment decisions and technological upgrading plans. There is a large consensus that coal generation should be phased out in the medium-to-long term, while gas could play the role of a bridging technology subject to the aforementioned risks.

While hydrogen should play a major role in the decarbonisation of certain industrial sectors and, possibly, transportation, the conditions for the production of e-H_2 are deemed to be more favourable in some EU regions than in others. Major investments in electricity infrastructure, largely grids, will be needed to integrate renewable generation, alongside the deployment of a significant amount of power storage capacity, and flexible biomass-fired turbines. Most studies agree that repurposing gas grids, at least partially, as hydrogen grids is an important lever to provide the required hydrogen interconnection capacity. Besides, the seasonality in the hydrogen production by electrolysers may trigger the need for further hydrogen storage capacity.

3.3 SELECTION OF THE ANALYSES TO UNDERTAKE

The most relevant analyses and modelling upgrades to be included in the scope of this study are selected by applying the criteria described above taking into account the main outcomes of the literature review conducted. This section discusses the selection made.

3.3.1 CLIMATE CHANGE

Climate change can affect the energy system dimensioning in, at least, two ways:

1. the energy demand may be affected by changing temperatures,

2. the energy systems, notably power generation plants, may need to adapt to face changing climatic conditions.

Expected impact of CC on electricity demand

As a result of rising temperatures, a decrease in heating demand and an increase in cooling demand are expected, which could lead to a rebalance of the energy demand distribution within Europe. Additionally, increasingly frequent extreme weather events, both heatwaves and cold spells, are likely to lead to unprecedented peak demands.

The way these changes in thermosensitive power demand affect the METIS 1.5 scenario dimensioning and functioning will be assessed in Section 4.1.

Expected impact of CC on adaptation costs

The impact of climate change on power plants depends on the specific climate change effects considered. Changes in climatic conditions may impact energy systems (see (Wietze Lise, 2015)) via i) changes in the air temperature; ii) changes in the water temperature; iii) changes in the level of precipitation, which should affect the amount of water stored in the reservoirs and transported in rivers; iv) changes in wind regimes; v) changes in the sea level; vi) changes in the frequency of occurrence and magnitude of floods; and vii) changes in the frequency and magnitude of storms.

Adapting coastal power plants to rising sea levels and storms may require, for instance, to reinforce protection dikes. Adapting river-cooled power plants to warmer and/or reduced water flow debits may require additional cooling facilities.

The impact of these additional, preventive, investment costs on the system dimensioning will be assessed in Section 4.2.

Probability to materialise

Climate change effects are already noticeable and very likely to worsen by 2050 (IPCC, 2021), even under 2050 climate-neutral scenarios.

3.3.2 ASSESSMENT OF ELECTROLYSERS AS A POTENTIAL NO-REGRET TECHNOLOGY

Electrolysers are deemed to play a major role in the 2050 energy system according to most of the literature reviewed (criterion "probability to materialise"), serving both as sector-couplers and flexibility providers, which is also the case in the METIS 1.5 scenario (cf. study S6). Analyses will be conducted to qualify electrolysers as a no-regret technology to deploy in decarbonisation scenarios in Section 5.

Expected results

All the scenarios reviewed feature installed electrolyser capacities exceeding 400 GW in 2050, at European scale, which sugegsts the existence of a minimum no-regret deployment level to be reached by project promoters.

The literature review conducted has showed that H_2 demand levels in 2050 should range between 10% and 24% of the final energy demand to achieve full decarbonisation (see notably (McKinsey & Company, 2020), (Navigant, 2019), (FCH, 2019)).

3.3.3 ROLE OF HYDROGEN CROSS-BORDER AND STORAGE INFRASTRUCTURE

Expected impact of the upgrades

Green hydrogen generation potentials are directly linked to renewable power generation potentials and therefore appear unevenly distributed within Europe (see for instance (EC, 2020.b). Allowing H_2 cross-border exchanges to take place should render important benefits through better resource allocation, including an increase in the efficiency of power production, an increase in the competition level of the supply of H_2, a reduction of the joint cost of the H_2 and electricity infrastructure deployed (an optimal trade-off between the deployment of H_2 and electricity transmission infrastructure could be stroke), etc.

While significant hydrogen demand-side flexibility is envisaged in the METIS 1.5 scenario, as storage costs and deployment constraints are not represented, upgrading the model with these should pose new constraints to the cost-optimal dimensioning of H_2 storage, and trigger needs for complementary flexibility provision.

Probability to materialise

Most scenarios reviewed state that hydrogen cross-border infrastructure may be needed in the future (criterion "probability to materialise"). This could potentially be provided by repurposing the existing gas network. Secondly, the variability and seasonality of the production of hydrogen requires continuously managing the reserves in storage sites to keep the supply-demand balance. However, the storage capacity is constrained by the availability of adequate storage sites[5].

Upgrades to the METIS 1.5 scenario, where hydrogen cross-border exchanges and storage constraints are not represented, are incrementally implemented and their impact assessed in section 6.

---

[5] Hydrogen storage sites availability depends on local geological conditions of the individual Member States and are therefore unevenly distributed across Europe.

3.3.4 IMPACT OF CO_2 EMISSIONS VALUES ON THE SYSTEM DIMENSIONING

The METIS 1.5 scenario is designed based on a CO_2 emission price of 350 €/t, which proves relatively high compared to those envisaged by the scenarios reviewed, that range between 100 €/t and 350 €/t.

Expected impact
The METIS 1.5 scenario is virtually a fossil-free scenario. As CCS-equipped, carbon-free-fuelled power plants produce negative net emissions, they can serve as a carbon sink, and are able to sell carbon emission quotas whose value is aligned with the CO_2 price. The CO_2 price should, therefore, influence the stakes of use of CCS and carbon-free bioenergies, such as in biogas-fired power plants, which determines the ability of the power system to offset emissions from other sectors.

Probability to materialise
Given the uncertainty regarding the CO_2 price evolution, the probability that the actual price is different from that considered in the METIS 1.5 scenario is deemed to be high.

In the following, the METIS 1.5 scenario will be referred to as the baseline scenario (BS), from which variants will be derived.

4 IMPACT OF CLIMATE CHANGE

4.1 IMPACT OF CC ON POWER DEMAND

This section reveals that heating and cooling demand are to be non-negligibly affected by CC, respectively decreasing and increasing. This leads to geographical demand rebalancing within Europe as well as demand volumes being shifted from winter to summer, with an overall reduction at the EU level. These altered demand patterns are faced best by reducing the investments in wind power (featuring above average production in winter time) and increasing those in summer-concentrated solar power. In the end, electricity supply conditions in summer are expected to be tighter, due to higher cooling demand, and despite the increase in the amount of solar power deployed. Given that electric boilers are mainly to be used in summer based on solar power, this leads the overall heat supply mix to feature less ambitious electrification rates via a shift from electric boilers and gas CHP towards gas boilers equipped with CCS.

4.1.1 MAIN ASSUMPTIONS AND MODELLING APPROACH

A CC-impacted Demand Scenario (referred to as DS scenario in the following) is derived from the METIS 1.5 scenario by modifying the thermosensitive demand volumes[6]. The cost-optimal dimensioning is then performed again for the DS by making use of METIS. Both the expansion of the system capacities and their operation are expected to be affected by demand changes.

Demand volumes are adapted at Member State level, based on relative changes in the heating and cooling demands established at regional level, which are deemed proportional to the expected changes in heating degree days (HDD) and cooling degree days (CDD), respectively, in the H1 scenario defined within (JRC, 2018.b), reflecting a 2°C increase in the average global air temperature by 2050 w.r.t 2012 level.

The assessment is realised at the country level. In order to focus on the overall trends, instead of focussing on the evolution in selected countries, results are provided for five country clusters which are defined and illustrated on Figure 4-1:

- Western Europe (WE): UK and Ireland,
- Central Northern Europe (CN): Belgium, Germany, Netherlands, Poland, Luxembourg
- Central Southern Europe (CS): Austria, Czech Republic, France, Hungary, Slovakia, Romania, Switzerland
- Northern Europe (NO): Denmark, Estonia, Finland, Latvia, Lithuania, Sweden, Norway
- Southern Europe (SO): Bulgaria, Croatia, Cyprus, Greece, Italy, Malta, Portugal, Slovenia, Spain, Bosnia-Herzegovina, Macedonia, Montenegro, Serbia.

[6] Industrial heat demand is not modelled as thermosensitive and therefore not deemed to be affected by CC.

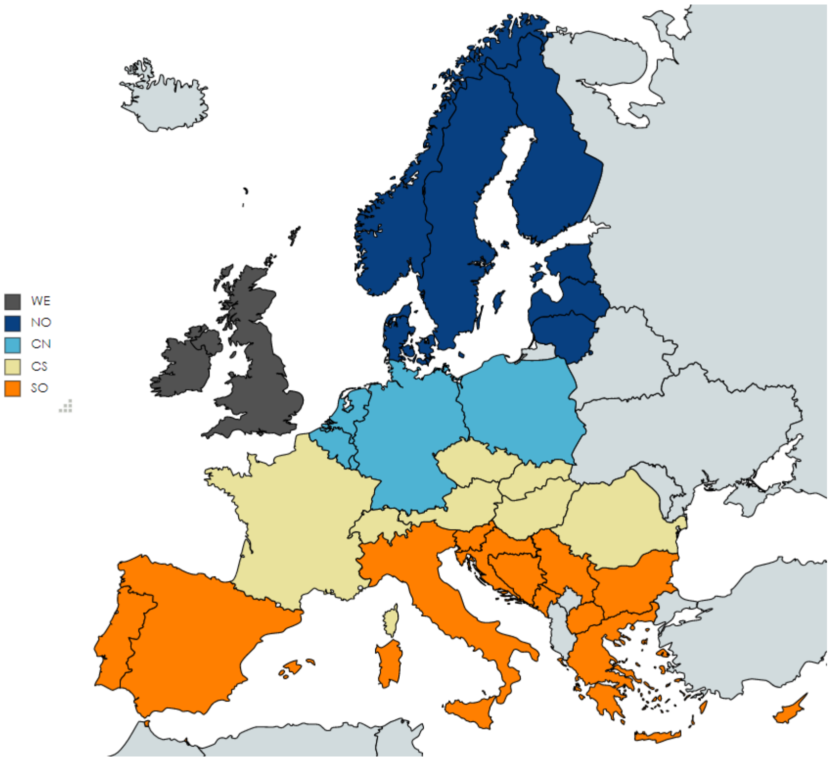

Figure 4-1. EU aggregated regions for the impact assessment of CC on MS demand levels (Country clusters)

4.1.2 MAIN INPUT PARAMETERS

Changes in heating and cooling demand volumes are deemed proportional to regional changes in HDD and CDD expected to take place by 2050 in comparison with a no climate change scenario in the same year and provided in the table below.

Table 4.1. Expected changes in HDD and CDD by 2050 in the DS compared to the same year in a scenario where climate change is not taking place. Source: (JRC, 2018.b)

	HDD	**CDD**
NO	-9%	67%
WE	-9%	25%
CN	-8%	27%
CS	-8%	24%
SO	-8%	22%

Figure 4-2 shows how thermosensitive demand volumes, per type of energy use, are impacted in the DS by comparison with the baseline scenario METIS 1.5 (referred to as BS in the following). Two observations can be drawn:

- While the expected changes in HDD are significantly lower than those for CDD, these relative changes apply to much larger volumes. As a result, the decrease in heating in absolute terms is larger than the increase in cooling demand (see Table 4.2). A partial demand shift occurs from Northern Europe to Southern Europe.

- Absolute cooling demand variations are essentially driven by baseline volumes and are thus larger in southern areas (SO and CS clusters), despite the fact that the relative increase in the NO cluster is more than twice as high.

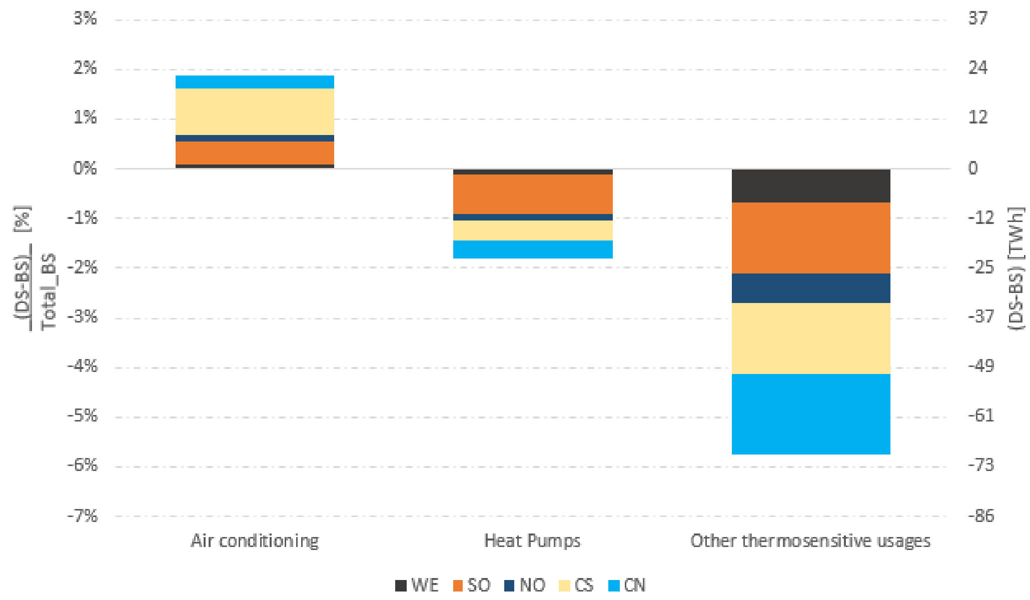

Figure 4-2. Thermosensitive power demand volumes changes, given the expected effects of climate change (left axis, in [%] w.r.t total power demand in the BS; right axis, absolute values [TWh]). Source: (JRC, 2018.b)

Table 4.2. Electricity demand (heating and cooling) in the BS and DS [TWh] (EU27+7)

	BS	**DS**	**DS-BS**
Air conditioning	92	115	23
Heat Pumps	289	266	- 22
Thermosensitive remainder	842	771	- 70
Total	1,223	1,152	- 69

These changes in thermosensitive demand volumes result in a change in the overall load curve and thereby the annual peak demand. Table 4.3 shows that, given that winter demand is higher in most regions, the annual peak demand is usually lower in the DS scenario, except for the CS cluster, where the significant share of cooling volumes in total demand leads peak demand to occur in summer, and to increase due to CC.

Table 4.3. Overall peak demand in each region in the BS and DS, and difference between both. Figures are expressed in GW.

	BS	DS	DS-BS
CN	265	252	- 13
CS	236	239	3
NO	98	93	- 4
SO	286	276	- 10
WE	105	101	- 4

4.1.3 MAIN RESULTS AND INTERPRETATION

Factoring in the impact of CC on the thermosensitive demand volumes leads to changes in the structure of the optimal energy system and its functioning. These are here computed as the corresponding differences between the Demand Scenario and the Baseline Scenario.

Impact on the power system

As noticed above, a partial demand shift occurs from Northern Europe to Southern Europe as heating demand decreases more in colder regions and cooling demand increases more in warmer areas.

In areas featuring large changes in cooling demand and solar potential, such as countries within the SO cluster, a rise of solar power penetration is observed, since its seasonality is best suited to cover summer demand. While summer production increases to fit summer demand increases (see Figure 4-3), winter production decreases to follow heating demand reduction. In the end, the PV rise is partially made at the expense of wind power generation, whose generation pattern features higher production levels in winter.

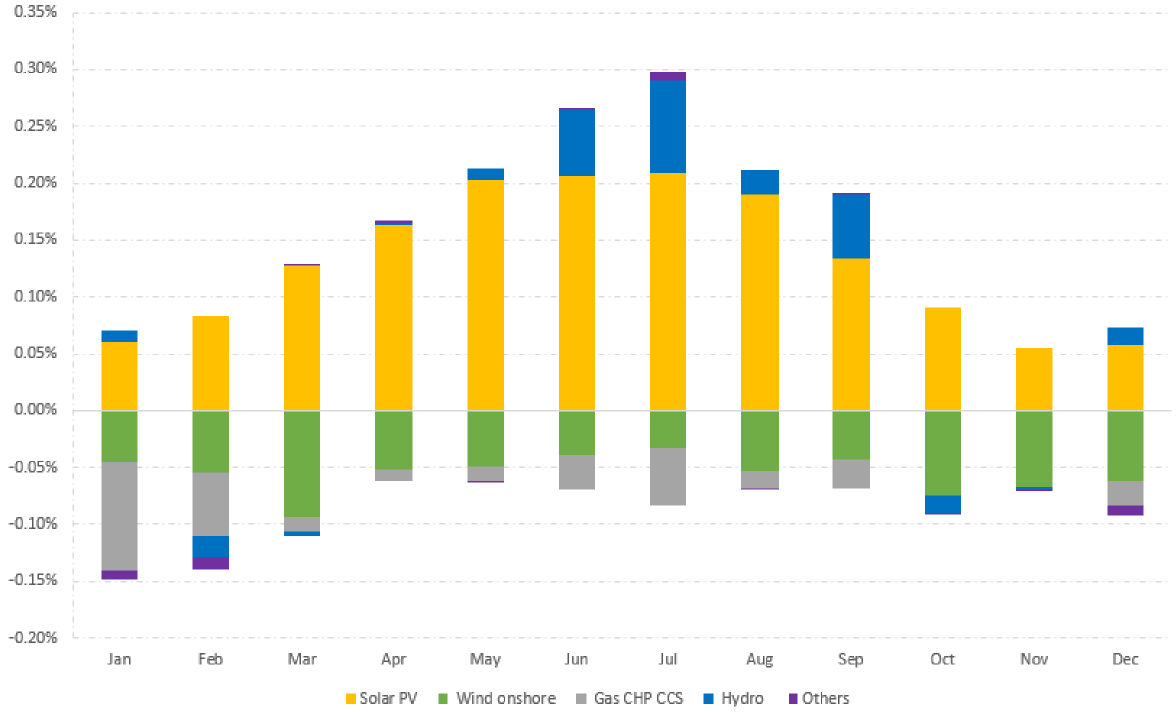

Figure 4-3. Evolution from the BS to the DS of the monthly power production per technology in 2050 within a SO country – figures expressed in relative terms w.r.t. the national annual electricity production in the BS

On the other hand, in those areas where the change in winter heating demand is more pronounced, the generation technologies most affected by the effects of climate change are wind power and thermal plants (e.g., gas, biomass). This implies substantial decreases in the level of deployment and electricity production by wind generation, in particular, driven by CC in these areas (- 34 GW at EU27+7 scale, cf. Figure 4-4).

The decrease taking place in heating demand and the increase in cooling demand flatten the annual demand curve. At the same time, the decrease in the wind generation, being larger in size than the increase in solar generation, results in the reduction, in net terms, of the overall variability of the intermittent generation output. All this contributes to a decrease in the back-up capacity needs in the system. Therefore, both the capacity of the conventional generation fleet (OCGT) and that of batteries decrease due to CC, see Figure 4-4.

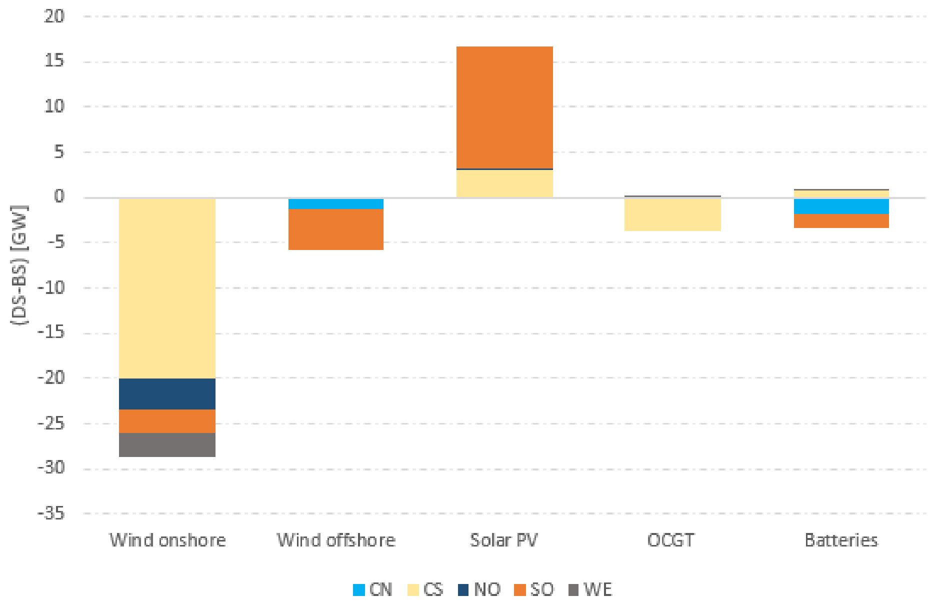

Figure 4-4. Differences between DS and BS in the generation capacity per technology – EU27+7

Impact of changes in electricity demand due to CC on the heat supply system

In the BS, a relevant fraction of industrial heat is expected to be produced by electric boilers in summer in countries featuring surpluses based on abundant solar generation and relatively low summer demand. These conditions are also favourable to the penetration of electrolysis and hydrogen boilers. The electrification of heat provision should partly be complemented by gas boilers and CHP plants, the latter being able to relieve power systems at the same time of providing heat during winter demand peaks.

The demand shift from winter to summer expected to occur with CC results in less favourable summer conditions for the direct and indirect electrification of heat provision. At the same time, the reduction in electricity demand taking place in winter due to CC leaves less room for CHP technologies to produce electricity and, therefore, also heat, at this time of the year. Consequently, Figure 4-5 shows that the levels of heat provided by electric and hydrogen boilers as well as CHP plants decrease at the European scale and are replaced by gas boilers, whose production increases by 3% of the total industrial heat provided. This phenomenon is more relevant in areas combining a high impact of CC on cooling demand and high solar PV penetration levels, namely the southern CS and SO clusters.

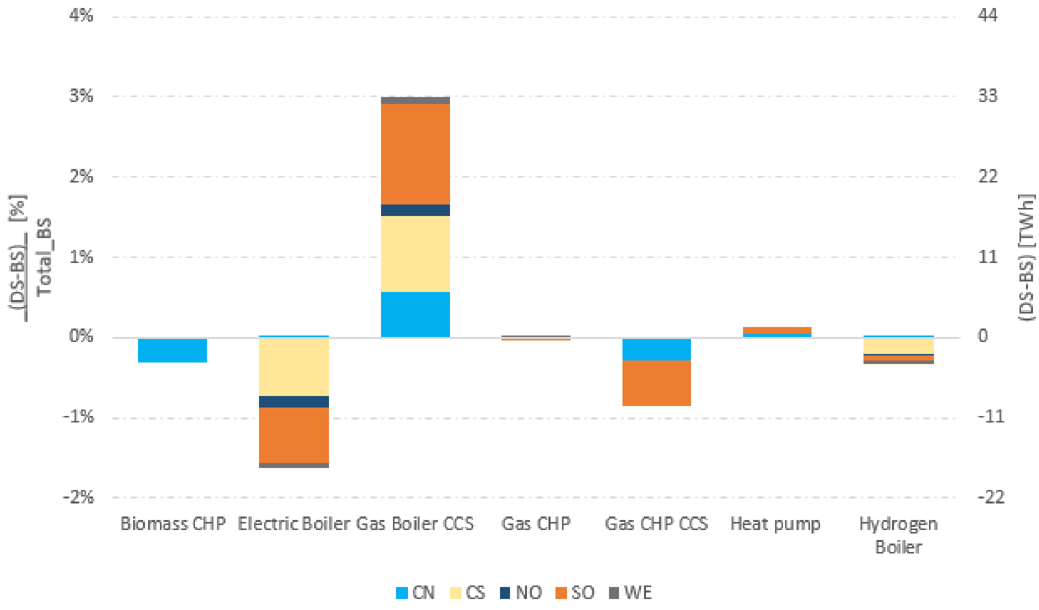

Figure 4-5. Differences between the DS and the BS in the industrial heat supply mix – (left axis, in [%] w.r.t total industrial heat production in the BS; right axis, absolute values [TWh]) – EU27+7

Assessment of results and extrapolation of them

As a result of the expected impacts of CC on power demand, moderate shifts among technologies are expected to take place w.r.t. the BS. Solar generation capacity is expected to increase by 1.2% while wind generation is expected to decrease by 2.6%. Regarding heat supply, gas boilers should provide an additional 3% of heat demand, at the expense of electric boilers and CHP plants.

These effects have been determined considering the H1 scenario defined by the authors within (JRC, 2018.b), where changes in air temperature due to CC are moderate. A more extreme scenario by the JRC, notably H4 scenario, may be considered realistic. The changes in HDD and CDD due to CC, both in H1 and H4, are provided in Table 4.4.

Table 4.4. Impact of CC on the HDD and CDD in scenarios H1 and H4 within the study (JRC, 2018.b)

	H1 scenario		H4 scenario	
	HDD	CDD	HDD	CDD
NO	-9%	67%	-7%	167%
WE	-9%	25%	-5%	125%
CN	-8%	27%	-9%	-36%
CS	-8%	24%	-8%	43%
SO	-8%	22%	-10%	37%

While HDD changes are similar, CDD changes are, on average terms, twice as big in the H4 scenario compared to the H1 scenario. Given that changes in the solar generation capacity w.r.t. the BS are driven by changes in the cooling demand, an extrapolation of the effects of CC in the H1 scenario on solar power could imply a rise by 2.4% in the solar generation capacity in the H4 scenario w.r.t the BS. The effects on wind generation capacities to be deployed, mainly linked to heating demand, can be expected to be only slightly larger in H4.

Similarly, heat provision by electric boilers could decrease by 3.3% of the overall heat production at system level, compared to 1.5% in the H1 scenario.

Both the shifts from wind to solar electricity generation, and that from electricity to gas-based heat production would moderately increase in magnitude in a more extreme CC scenario w.r.t. those in the H1 scenario. In any case, these changes would still be limited, albeit not negligible.

4.2 IMPACT OF CC ON INVESTMENT COSTS DUE TO ADAPTATION MEASURES

In this section, the impact of considering additional costs dedicated to adapting generation plants to CC, and thereby mitigating damage risks, is assessed. It turns out that the general capacity landscape is very marginally affected, with a slight reduction in wind offshore and gas plants, at the benefits of solar power, which appears more resilient and requires less adaptation measures.

4.2.1 MODELLING APPROACH AND MAIN INPUT PARAMETERS

An Adaptation Scenario (AS) is derived from the METIS 1.5 scenario via the modification of some specific parameters reflecting the adaptation of technologies to CC and the subsequent re-application of the METIS cost-optimal dimensioning.

For a selection of technologies expected to undergo adaptation measures to face CC, new investment cost parameters are considered. As the METIS 1.5 scenario was built by combining exogenous capacity data (derived from the Long-Term Strategy), for some technologies, and endogenously determined installed capacities, for other technologies, these updated investment costs do not impact the capacities of all the technologies in the AS, since not all the technologies are subject to capacity optimisation. However, the change in the capacity of the concerned technologies implies a change in the capacity dispatch that also affects technologies with fixed capacities (namely nuclear, biomass, coal, oil-fired power). The economic implications of the impact of CC on these technologies are reported with respect to the utilisation and production costs.

For those technologies not adapting to CC, possibly due to the high implementation costs of the adaptation measures available, the effect of CC on their operation may be considered. This is the case of transmission grids, where Joule transmission losses are deemed to increase by 0.3 percentage points due to the rising temperatures.

Table 4.5 provides the estimated increase in the annualised capex resulting from the implementation of the CC adaptation measures.

Table 4.5. Additional annualised capex related to the implementation of CC Adaptation Measures for those technologies for which this is deemed efficient. Source: (Wietze Lise, 2015)

Technology	Additional annualised capex (€/kW)
OCGT gas	9.0
CCGT gas	8.6
CCGT gas with CCS	8.6
Pumped hydro	7.9
Wind offshore fleet	45.0
Nuclear	9.7
Biomass	14.6
Coal	14.6
Oil	10.7

4.2.2 Main results and interpretation

CCGT and OCGT plants face increased investment costs, which result in a reduction of gas turbines installed capacities when taking these adaptation costs into account (-15 GW at EU27+7 scale, representing 28% of the BS aggregated capacity for these two technologies).

Figure 4-6 shows that the missing generation capacity, by comparison with the BS, along with a rise in production needs by 0.15% due to increased transmission losses, are compensated by the deployment of extra solar power, which does not require specific adaptation measures, accompanied by additional batteries[7].

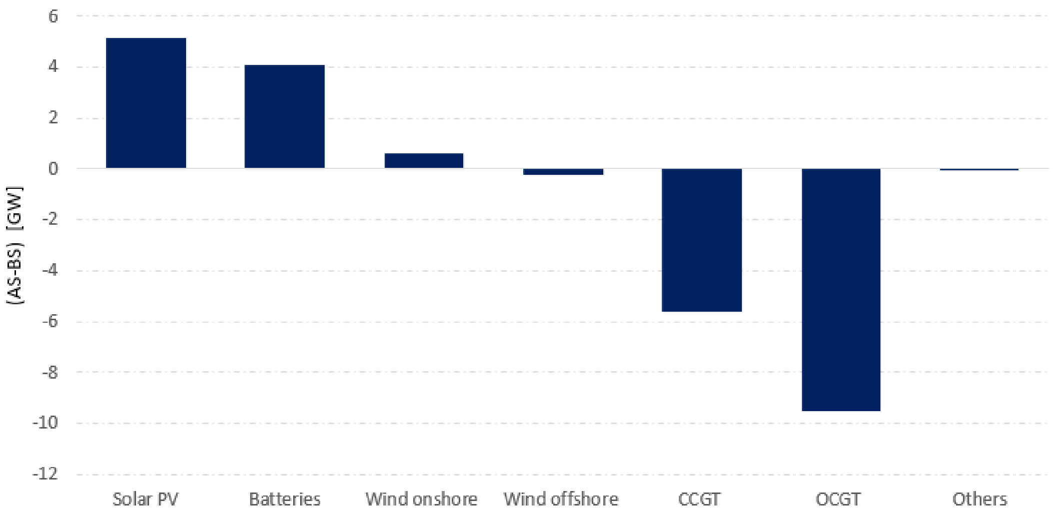

Figure 4-6. Differences in installed capacities between the AS and the BS [GW] – EU27+7

Overall, CC adaptation costs lead to a marginal rebalancing of the capacities and investment costs of the technologies, and an overall 2.8 Bn€ increase in the investment

[7] Together with this generation marginal rebalance, an increase in gas CHP plant capacities is observed. This is largely a result of the assumption made that CC mitigation costs for distributed CHP plants are negligible. The reduction of OCGT and CCGT plants creates favourable conditions for the deployment of gas CHP plants.

costs at system level, cf. Table 4.6. In terms of capacity dispatch, coal and biomass benefit from an increase in their utilisation rates, associated with the decrease taking place in the capacity of other thermal generation technologies. In total, the increased share of solar, at the expense of gas, results into a 0.3 Bn€, or 2.4%, reduction of the variable production costs.

Table 4.6. Differences between the AS and the BS scenarios in the annualized investment costs and annual production costs, per technology, within the electricity sector in the year 2050 [M€]–(EU27+7)

	Investment costs (IC)	**Production costs (PC)**		
	(AS-BS)	**Baseline (BS)**	**Adaptation scenario (AS)**	**(AS-BS)/ (total_PC BS)%**
Nuclear	1,182	4,549	4,549	0%
Biomass	902	3,019	3,036	0.15%
Coal	560	254	281	0.25%
Pumped storage	368	-	-	0%
Lithium ion battery	216	-	-	0%
Solar	194	-	-	0%
Oil	65	19	19	0%
Wind onshore	60	526	526	0%
CCGT CCS	14	541	544	0.02%
Lignite	0	55	63	0.08%
Others	0	126	126	0%
Wind offshore	-36	421	421	0%
CCGT	-184	1,322	1,132	-1.72%
OCGT	-578	233	101	-1.19%
Total general	**2,763**	**11,066**	**10,798**	**-2.42%**

5 ROLE OF ELECTROLYSIS AS A POTENTIAL NO-REGRET TECHNOLOGY

As aforementioned, testing whether electrolysers are a no-regret technology to deploy within the EU in order to facilitate a carbon-neutral energy system by 2050 is selected as an analysis to conduct. For this, a fixed, exogenously determined, hydrogen demand level is considered, to which the endogenously determined H_2-to-X demand is added, notably for industrial heat provision. To that purpose, a series of METIS 1.5 scenario variants have been parameterised and subject to endogenous dimensioning with METIS. These variants are designed as unfavourable conditions to electrolysers local deployment, notably via cost competitive hydrogen imports prices and lower CO_2 prices, which are set to vary within the lower end of a plausible range for them. The simulation results show that all the scenario variants assessed feature massive electrolysis deployment levels, 300 GW proving to be a minimum at the European scale.

5.1 MAIN ASSUMPTIONS AND MODELLING APPROACH

Two critical parameters are deemed to affect most significantly the deployment of electrolysers:

a) the cost of H_2 provision by alternative means, such as importing H_2 from outside the EU, or producing it through steam methane reforming (SMR) equipped with CCS and similar techniques, which could affect the share of locally installed electrolysers;

b) the CO_2 price, since high CO_2 price levels (350 €/t in the BS) encourage lowering carbon emissions in the energy sector (compared to other sectors, cf. also Section 7) and relying on clean power generation technologies, such as renewables and electrolysis, instead of conventional alternatives.

Several parameter variations are considered to design a hampering environment for the electrolyser deployment compared to the BS, and assess the electrolysers' potential role in future carbon-neutral energy systems under rather unfavourable conditions.

5.2 MAIN INPUT PARAMETERS

In the BS, the alternative H_2 provision cost, corresponding to imports or local production through other means than electrolysis, is considered 90€/MWh, and the CO_2 price is 350€/t. For each parameter, two lower levels are defined, resulting in four combinations simulated.

The two low CO2 price levels considered in the sensitivity scenarios are 100 €/tCO2 and 150 €/tCO2, representing the lower end of the CO2 prices observed in the literature review (see Section 3.2). Low alternative H_2 provision costs are set at 39 €/MWh and 50 €/MWh[8]. These have been computed considering data available in recent publications on the cost of producing electricity in the Sahara, the efficiency of the electrolysis process, and the cost of transporting H2 into Europe. Table 5.1 provides an overview of all scenario variants analysed and their individual features.

[8] The considered costs reflect H_2 import prices from Sahara to Europe. Final import prices include power generation, electrolysis and transportation costs as estimated by (Wouters, 2020). The two values are obtained by application of two potential 2050 electrolyser efficiency values (70% and 90%, see (IRENA, 2020)).

Table 5.1. Overview of scenario variants reflecting different CO_2 and alternative H_2 provision costs

Scenario variants		Alternative H_2 provision cost [€/MWh]		
		39	50	90
CO_2 price (€/ton)	100	S100_39	S100_50	
	150	S150_39	S150_50	
	350			BS

5.3 Main results and interpretation

In the four variants (alternative scenarios) explored, locally installed electrolyser capacities are lower than those in the BS, ranging from 320 to 600 GW, compared to 700 GW in the BS (see Figure 5-1). Figures show that, in the low CO_2-price range considered, the level of electrolyser deployment is independent of the CO_2 price (though lower CO_2 prices lead to slightly lower electrolyser capacities).

With the opportunity to access alternative sources of hydrogen at a lower cost, METIS deploys less electrolysers within Europe (up to -55% in the most unfavourable variant) and relies more on alternative supply means. Figure 5-2 illustrates that H_2 production mixes shift from virtually 100% indigenous electrolyser production to increasing shares of alternative hydrogen supply. Additionally, the availability of low-cost H_2 potentials translate into larger hydrogen consumption volumes in Europe, as the former favour the use of hydrogen in the industrial heat supply mix. Total hydrogen demand increases by about 15% across all variants compared to the BS.

These results lead to the conclusion that European electrolysers will play a major role in a carbon-neutral European energy system, even under less favourable conditions for electrolytic hydrogen production, such as competitive low-cost H_2 import streams.[9] The figures computed show that there is a significant, no-regret, minimum H_2 electrolyser capacity installed in the EU of 300 GW under the given assumptions, and that EU investment efforts need to more than double if alternative low-cost potentials are not available.

[9] This conclusion is quite in line with the outcomes of the forthcoming study "METIS 3 - Study S3: METIS study on costs and benefits of a pan-European hydrogen infrastructure" by Artelys.

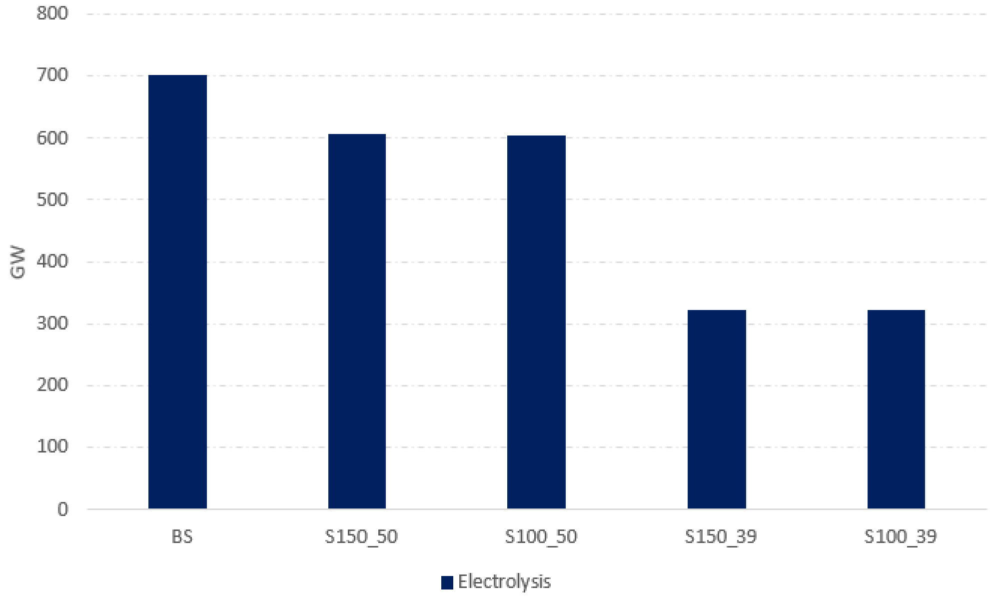

Figure 5-1. Installed electrolyser capacities for the BS and the four variants [GW] - EU-27+7

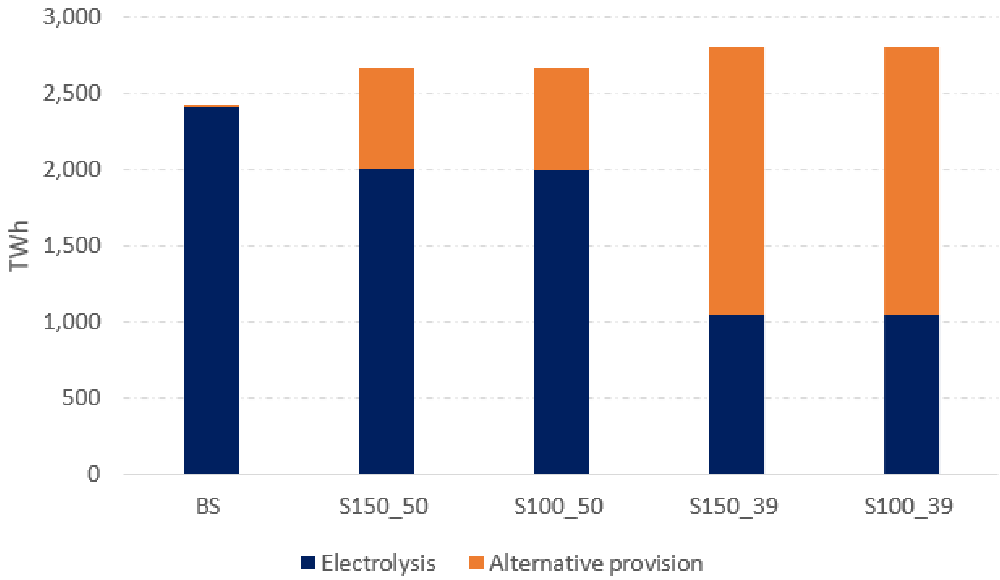

Figure 5-2. Hydrogen consumption mix for the BS and the four variants [TWh] EU-27+7

6 ROLE OF HYDROGEN CROSS-BORDER AND STORAGE INFRASTRUCTURE

In the Baseline, H_2 supply-and-demand equilibria have to be met at Member State level as cross-border exchanges are not foreseen. As a consequence, MSs featuring limited low-cost RES potentials face high hydrogen provision costs while countries featuring more abundant rsources miss exporting opportunities. This implies that CO2 emission reduction is not realised at the lowest cost possible.

Besides, H_2 storage capacities available in the Baseline are deemed to be as large as estimated necessary by METIS, and can be commissioned at no extra cost in all MSs, which is considered an optimistic representation of the former.

Two incremental upgrades of the BS are parameterised and re-optimised with METIS in order to explore the impacts of these two hydrogen infrastructure components. Results show that:

1. Enabling cross-border hydrogen exchanges allows for better RES allocation to take place and facilitates regional cooperation, with notably the UK and Ireland exporting more than 450 TWh of low-cost onshore wind power-fuelled hydrogen to continental Europe,

2. Considering the real-world constraints on hydrogen storage deployment results in extra needs for other hydrogen flexibility providers, namely additional cross-border exchange capacities. Besides, these constraints impact the technological and geographical choices on the deployment of power generation capacity within Europe, with a shift from Southern countries (relying on solar PV) to Northern countries (relying on wind power).

6.1 IMPACT OF CROSS-BORDER EXCHANGES MAIN ASSUMPTIONS AND MODELLING APPROACH

A Hydrogen Infrastructure scenario (referred to as H2_I scenario in the following) is derived from the BS by considering, as an option, the deployment of hydrogen cross-border exchange capacity. This is followed by a capacity and dispatch re-optimisation carried out with METIS in order to determine the cost-optimal dimensioning and operation of the EU energy system. In this scenario, storage representation is not changed w.r.t. the BS.

H_2 cross-border exchange capacities can either be built from scratch or inherited from the methane network via repurposing. It is assumed that new H_2 transfer capacities can only be commissioned on borders where gas pipelines exist, which ensures the technical feasibility of these projects. For each option, a unitary cost (€/MW/km) is estimated and line-by-line costs are derived considering distances between the corresponding countries' geographical centres as a proxy for cross-border pipeline lengths. Repurposing of cross-border gas pipelines may materialise in a continuous manner, disregarding the actual decomposition into individual strings.

6.1.1 Main input parameters

The main additional input data considered to parameterise the H2_I scenario includes:

- The capacity of the methane cross-border pipelines eligible for repurposing is deemed equal to the 2050 CH_4 transfer capacities estimated by the ENTSO-G TYNDP2020.
- CH_4 cross-border pipelines can be repurposed to H_2 according to an energy conversion rate of 80%, which represents energy density ratios;
- The unitary costs of repurposing CH_4 and commissioning new H_2 interconnection capacities are drawn from (Guidehouse, 2021). The resulting average project costs are provided in Table .

Table 6.1. Average techno-economic parameters for hydrogen cross-border projects. Power-related figures for gas-eligible borders are given for comparison - EU27+7. Source: (Guidehouse, 2021).

Investment option	Repurposing CH_4 infrastructure	Commissioning new H_2 pipelines	Power transmission lines
CAPEX (€/MW/year)	3 218	7 211	14 467
OPEX (€/MW/year)	0.64	0.64	1 627

6.1.2 Main results and interpretation

6.1.2.1 Impact on cross-border transfer capacities and exchanges

The cost-optimal dimensioning with METIS leads to a significant hydrogen cross-border capacity development (cf. Table 6.2), most of which is inherited from the methane grid via repurposing (160 GW out of 195 GW of total cross-border hydrogen capacities at the EU27+7 level). The high share of repurposing is mostly driven by their lower costs compared to those of newly built pipelines. At the regional level, the largest hydrogen interconnection materialises between the Western country cluster and the Central-Northern country cluster (43 GW).

Table 6.2. Capacities of cross-border hydrogen pipelines[10] between country clusters in the H2_I scenario [GW]

To From	CN	CS	NO	SO	WE
CN		24	24		43
CS	24		0	7	
NO	24	0			13
SO		7			
WE	43		13		

[10] In the capacity optimisation, hydrogen pipelines are supposed to be dimensioned symmetrically.

The build out of a European hydrogen network goes along with the reallocation of the electrolyser capacities across the EU, facilitating the exploitation of the most economical renewable energy potentials (cf. next section). The electrolyser capacities are shifted notably from the CN, in the BS, towards the WE country cluster in the H2_I scenario (cf. Table 6.3). This is due to the fact that the H_2 demand in the CN cluster exceeds the availability of competitive H_2 supply, compared to other regions. At the overall EU27+7 level, the electrolyser capacity drops by 40 GW, or 6%, as the reallocation of electrolysers enables a more efficient utilisation of them.

Table 6.3. Change in electrolyser capacity by country cluster compared to BS

	CN	CS	NO	SO	WE	EU27+7
BS (GW)	185	150	52	210	103	**701**
Change compared to BS at cluster level (GW/%)	-126/-68%	-27/ -18%	+12/+24%	+3/+1%	+97/+94%	**-40/ -6%**

The left-hand side of Figure 6-1 illustrates hydrogen exchanges taking place between country clusters in the H2_I scenario (see Section 4.1 for the definition of clusters). Significant hydrogen transfers take place from Northern areas to the CN cluster, totalling 575 TWh of exports from the WE and the NO cluster. On the other hand, the right-hand side of Figure 6-1 shows that power exchanges are affected to a limited extent by the deployment of hydrogen grids. This illustrates the fact that commissioning hydrogen pipelines unlocks energy transfers and allows for green hydrogen production to locate more efficiently (see next sections on the evolution of power supply capacities and system costs), by comparison with a situation where energy transfers can only be achieved via the power vector, as it is the case in the BS.

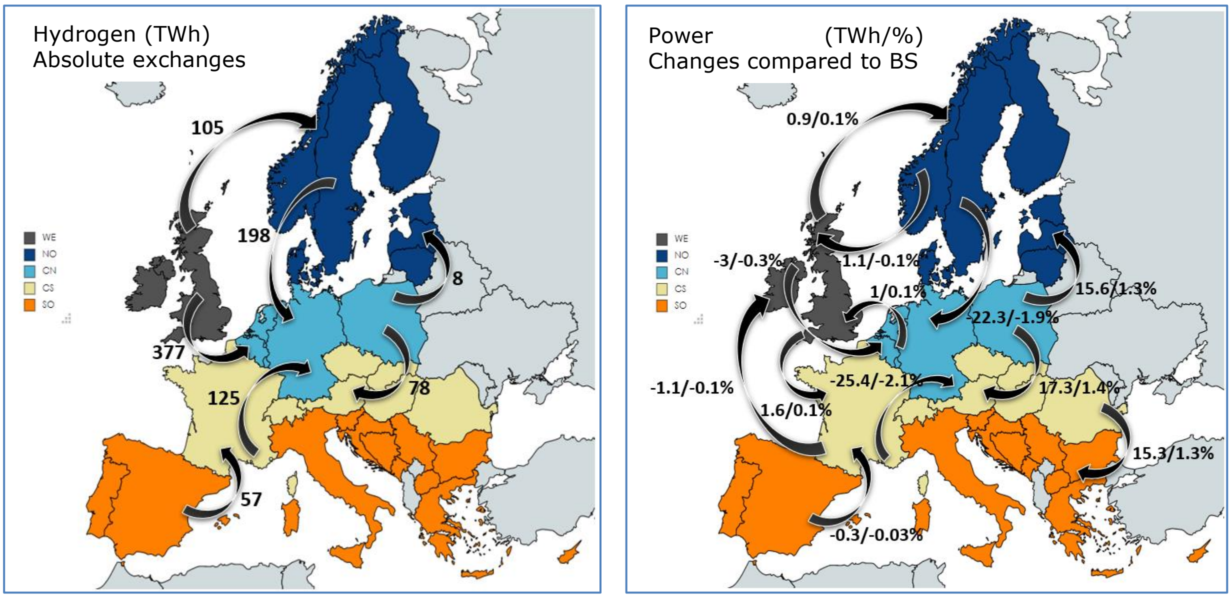

Figure 6-1. Left: hydrogen absolute exchanges between clusters in the H2_I scenario [TWh]
Right: Increase in electricity exchanges from the BS to the H2_I scenario [TWh]/[%] w.r.t total BS

6.1.2.2 Impact on the power generation fleet

The reallocation of hydrogen production (cf. Table) and, therefore, power generation materialises through leveraging the wide existing, non-exploited, onshore wind energy resources, particularly abundant in the WE area (see Figure 7-1). On the other hand, the CN cluster, whose hydrogen generation in the BS relies on less economical RES potentials, notably expensive offshore wind and solar power, decreases its local hydrogen production in order to rely, to some extent, on hydrogen imports.

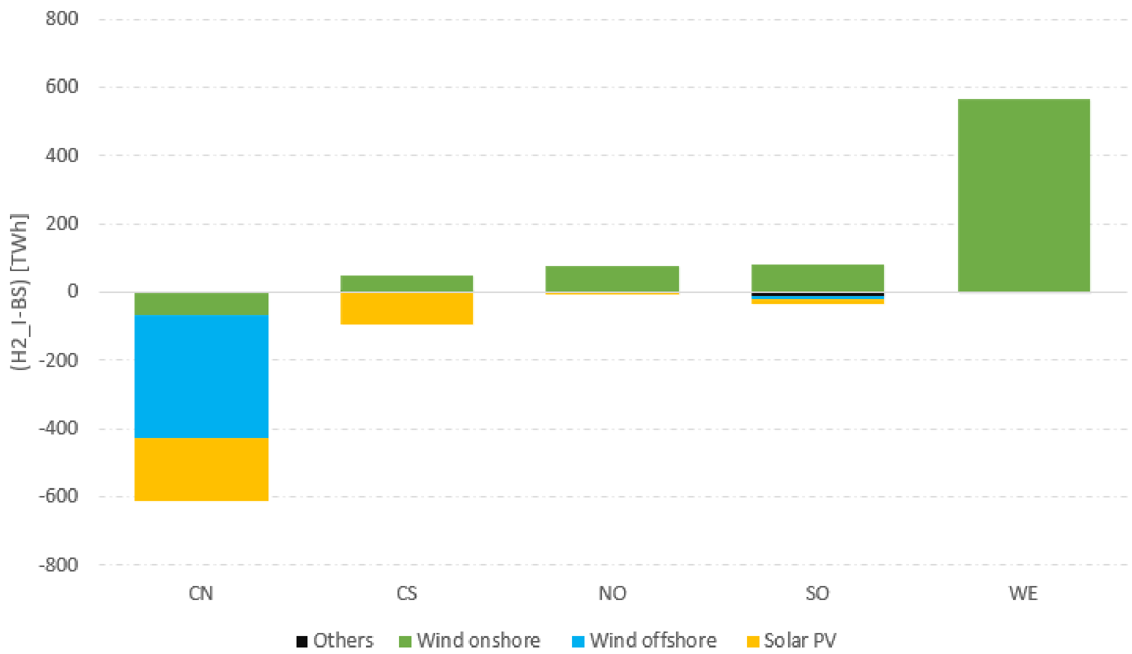

Figure 6-2. Changes in the power production by technology in the H2_I scenario with respect to the BS [TWh] – EU27+7

6.1.2.3 Impact on system costs

The results computed for the H2_I scenario showcase that regional cooperation enabled by H_2 cross-border pipelines facilitates a more efficient resource allocation, implying transfers from areas with low H_2 production costs to less endowed countries. Overall, the total annualised system costs decrease by about 9 Bn€ annually in the H2_I scenario compared to the BS. The bulk of cost savings is related to reduced or shifted investment costs. Reduced investments in wind offshore capacities (primarily in Central Northern Europe) make up for additional investments in wind onshore capacities (notably in Western Europe). Reduced solar PV capacities imply savings of nearly 12 Bn€. The additional costs for hydrogen pipelines are nearly completely compensated by the reduced need for electrolyser capacities (given their enhanced utilisation), with 1.5 Bn€ vs 1.1 Bn€.

As cross-border facilities allow for better allocation of resources, average hydrogen production costs decrease in importing clusters, while they increase in exporting areas. Overall, the production costs are reduced and the unit costs converge across country clusters.

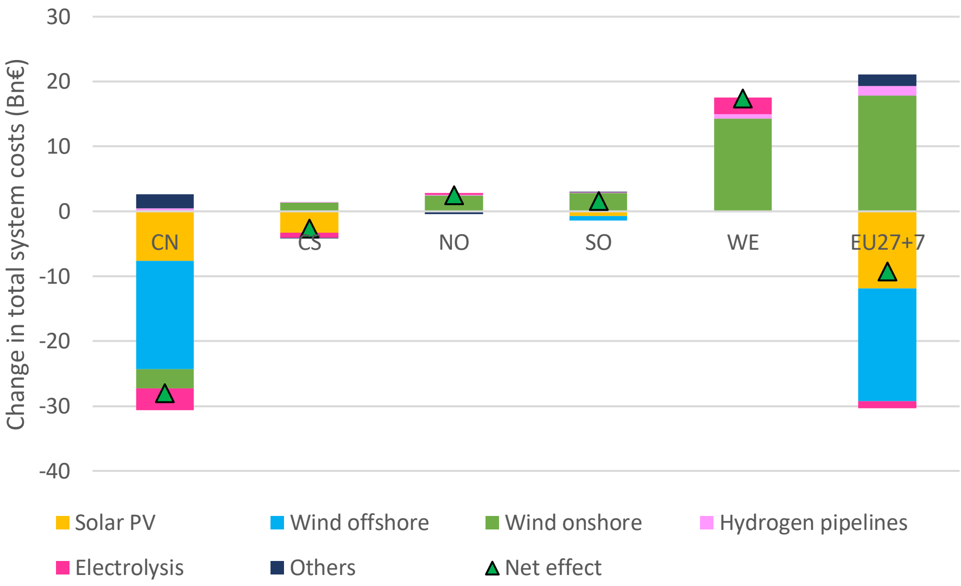

Figure 6-3. Difference in total annual system costs in H2_I scenario compared to the BS [Bn€]

6.2 Impact of the joint development of cross-border H2 infrastructures and H2 storage facilities

A Hydrogen Storage scenario (referred to as H2_S scenario in the following) is derived from the previous H2_I scenario by considering more realistic hydrogen storage deployment constraints and costs, and re-computing with METIS the cost-optimal system dimensioning.

In the METIS 1.5 scenario and all variants assessed, storage capacities were considered unlimited and corresponding costs were not taken into accont. In this sensitivity scenario, hydrogen economical storage potentials are limited by the availability of storage sites with the appropriate geological conditions within individual Member States, as well as by the commissioning costs for storage sites.

The main conclusion of this upgrade is that constraints on the hydrogen storage deployment drive the need for alternative hydrogen flexibility providers, namely additional cross-border hydrogen exchange capacities. The technological and geographical RES-based generation allocation, as well as the cross-border infrastructure expansion planning, are affected by these storage constraints to reach cost-optimality.

6.2.1 *Main assumptions and modelling approach*

The development of storage facilities is considered to be based on four types of storage sites: existing depleted gas fields, aquifers, and rock caverns that can be repurposed to become hydrogen storage sites, and new storage sites within salt caverns that can be commissioned across Europe and account for the majority of the hydrogen storage potential (see Table 6.4 and Figure 6-4 below).

The costs of each storage type considered in the modelling are estimated for commissioning, operation, and maintenance. Once these potentials and the corresponding costs are implemented in METIS, the model jointly computes the cost-optimal levels of deployment for electrolysers, H_2 cross-border infrastructure and storage facilities, along with the whole multi-energy system dimensioning and dispatch, including power generation fleets, electricity cross-border exchanges and industrial heat supply mix.

6.2.2 Main input parameters

For each storage type, a maximum hydrogen storage capacity per Member State and a pan-European unitary cost of commissioning, operating and maintaining the corresponding sites are defined (see Table 6.4 for the overall EU27+7 potential capacity levels and unit costs). Input parameters concerning the capacity of the existing depleted gas fields, aquifers and rock caverns to be repurposed and the associated costs are taken from (GIE, 2021). Salt cavern storage potentials have been estimated based on (Dilara Gulcin Caglayan, 2020). Figure 6-4 provides a graphical overview of the storage potentials considered per storage type and country.

Table 6.4. Techno-economic parameters for hydrogen storage in Europe. Source: (GIE, 2021)

	Depleted gas fields	Aquifers	Rock caverns	Salt caverns
European storage potential (TWh)	162	51	1	23 075
Storage costs (€/MWh_H_2)	523	535	1 108	811

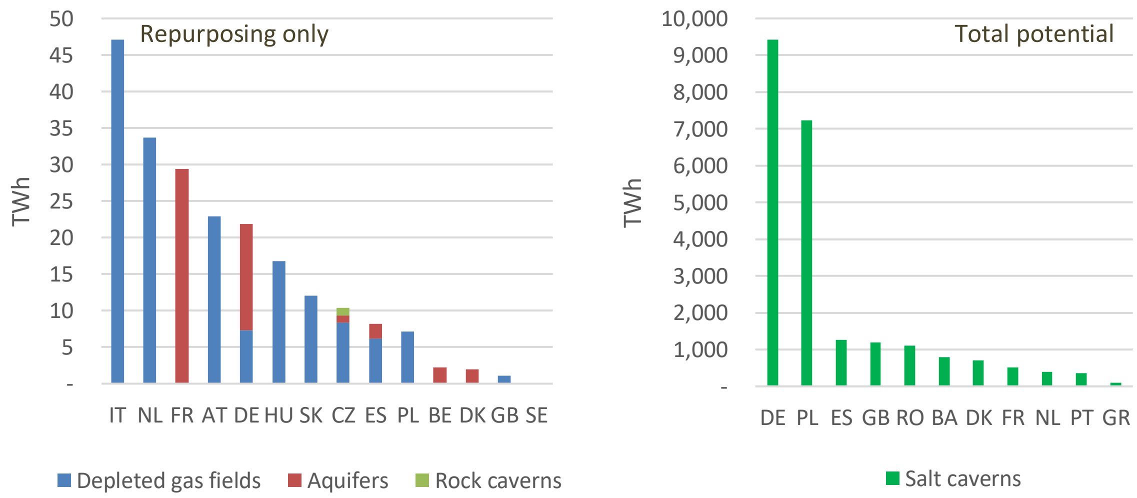

Figure 6-4. Maximum potential for H_2 storage facilities in the EU from depleted gas fields, aquifers and rock caverns (on the left) and from salt caverns (on the right). Only countries with relevant potentials are represented. Sources: (GIE, 2021) and (Dilara Gulcin Caglayan, 2020)

6.2.3 Main results and interpretation

In order to assess the impact of the upgraded constraints and the associated costs, regarding hydrogen storage, on both the dimensioning and the operation of the EU energy system, the simulation results computed (referred to as the H2_S scenario) are compared with those in the H2_I scenario.

6.2.3.1 Impact on cross-border transfer capacities and exchanges

Figure 6-5 compares the deployed hydrogen storage capacities in the two model runs for the H2_I and H2_S scenarios. Under the given potential and cost constraints for storage, the cost-optimal deployed storage capacities in the H2_S scenario are significantly smaller, at the European scale, than those in the H2_I scenario (215 vs 560 TWh). Indeed, all country clusters feature lower storage capacity levels, except for the Central North cluster (CN), due to its high storage potential (Figure 6-4 shows indeed that the largest salt cavern potentials are located in Germany and Poland).

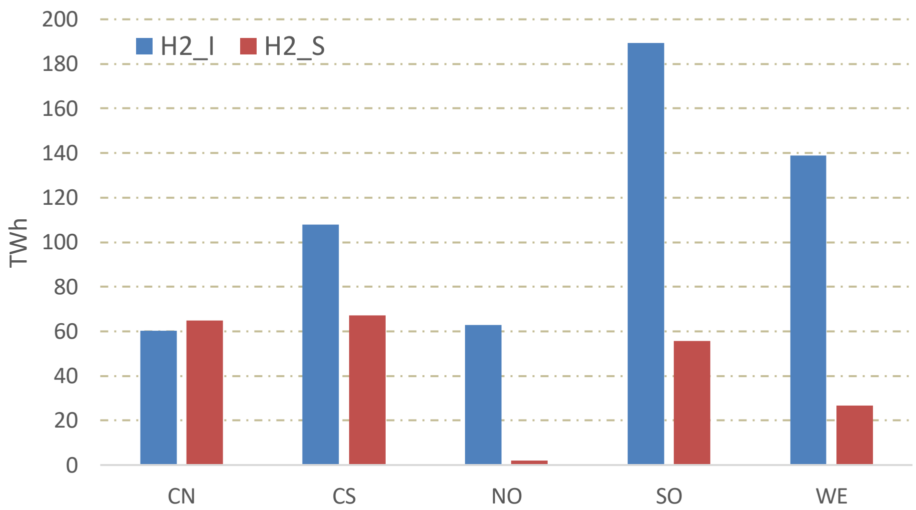

Figure 6-5. Comparison of optimally deployed hydrogen storage capacities in the H2_S and the H2_I scenarios (EU27+7)

This decrease in the installed hydrogen storage capacities are compensated by an increase in the deployment and use of other flexibility resources. Table 6.5. shows that the optimally-dimensioned hydrogen export capacities are significantly larger in the H2_S than in the H2_I scenario, which involves that the newly implemented constraints on storage deployment within the H2_S scenario drive the need for additional hydrogen exchange capacities. The cumulated national export capacities increase by 675 GW, or +173 %, compared to the H2_I scenario. Export/import capacity figures on the borders among country clusters are available in the annex (cf. Section 10).

Table 6.5. Hydrogen export[11] capacities, at cluster level, in the H2_I and H2_S scenarios (GW)

	H2_I	H2_S	H2_S - H2_I
CN	90	210	+119
CS	30	159	+129
NO	36	151	+114
SO	7	61	+54
WE	56	103	+48
Total export capacities (country level)	391	1 066	+675

Table 6.6. provides the hydrogen and power net export balances per cluster corresponding to the H2_I scenario and the H2_S scenario. Hydrogen exchanges among country clusters within Europe are affected to a different extent in each case. The CS and the NO clusters’

[11] In this table, a pipe connecting two clusters or countries counts in export capacities of both areas (hydrogen pipes being dimensioned symmetrically).

hydrogen net export balances increase while, on the other hand, the SO and the WE clusters, whose storage capacities are significantly smaller in the H2_S sensitivity, have their net export balance reduced.

The model results show that power exchanges do not compensate for the change in the exchanged hydrogen volumes, as they evolve in a similar way. As a result of this, the total amount of energy exchanges among regions increases. The amount of electricity produced to export energy, either in the form of hydrogen or electricity, increases as well. As section 6.2.3.2 illustrates, this is the outcome of the further exploitation of RES potential wherever it is largest at any time of the year, in line with the seasonal variations of RES energy resources available, in terms of capacity and geographical distribution. Hydrogen export/import figures among individual country clusters are available in the annex (cf. Section 10).

Table 6.6. Hydrogen and electricity net export balances per region in the H2_I and H2_S scenarios [TWh] – Exchanges within regions are not considered

	Hydrogen			**Electricity**		
	H2_I	**H2_S**	**H2_S - H2_I**	**H2_I**	**H2_S**	**H2_S - H2_I**
CN	-613	-605	+9	-151	-134	+17
CS	-11	19	+30	92	137	+45
NO	85	171	+86	39	37	-2
SO	57	-1	-58	-60	-100	-40
WE	482	415	-66	80	60	-20

6.2.3.2 Impact on the power generation fleet

Owing to the enforcement of the hydrogen storage limited potential constraints and deployment costs, a geographical redistribution of power generation is endogenously determined by METIS in order to adapt to the local constraints and limit the system costs increase. In the NO and CS clusters, where storage capacities decrease while hydrogen net exports increase, hydrogen generation through electrolysis rises, as illustrated in Figure 6-6.

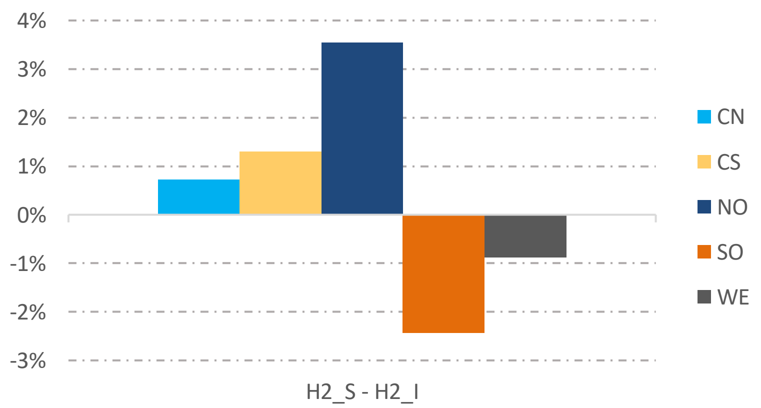

Figure 6-6. Change in the electrolysers' hydrogen production in the H2_S scenario with respect to the H2_I scenario. Figures expressed in relative terms w.r.t. the total H_2 production in the H2_I scenario

Given that these additional amounts of electrolysis are not fuelled by imported electricity (power exchanges evolving in the same way as hydrogen exchanges), green triangles on Figure 6-7 show that the annual power production increases in these areas by 85 (CS) and 100 TWh (NO), respectively. This increase relies mainly on the commissioning of additional amounts of onshore wind capacity. On the contrary, power production decreases in clusters where hydrogen exports decrease, namely in the SO and WE clusters.

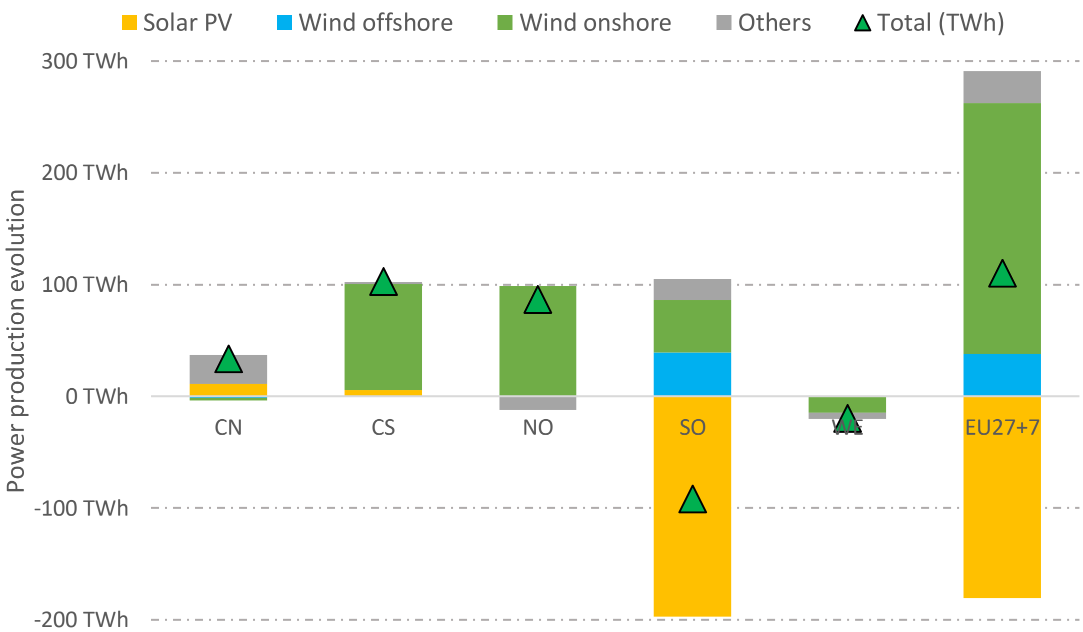

Figure 6-7. Differences between the H2_S and the H2_I scenarios in the amount of electricity production per region and technology in the year 2050

This geographical redistribution of power generation contributes to relieving the flexibility constraints imposed by the consideration of limited storage potentials in each cluster, and the corresponding costs. The modelled system also adapts through a technological rebalance, as displayed in Figure 6-7. Indeed, in the H2_I scenario, a large share of hydrogen is generated during the sunny season based on low-cost solar power (except in the WE zone, dominated by strong wind regimes), then stored in unconstrained storage facilities until winter. In the H2_S scenario variant, solar capacities decrease in the SO area, where storage capacities are significantly reduced and solar power has a major stake, and massive wind power deployments take place, instead, at EU level. As wind production is higher in winter, Figure 6-8 shows that this reallocation allows for a rebalance of electrolyser operation throughout the year and a better seasonal hydrogen supply-demand equilibrium (winter demand being higher).

This technology shift goes along with a power production increase by 110 TWh at the European scale (see right hand stack on Figure 6-7), while the useful energy demand remains stable. This additional power supply reduces the needs for alternative flexibility provision at times of higher winter demand, while leading to larger low-cost electricity surpluses at times of lower demand. In the end, these surpluses result in an increase in the level of electrification of the system, notably via hydrogen (electrolyser's power demand rises by 65 TWh).

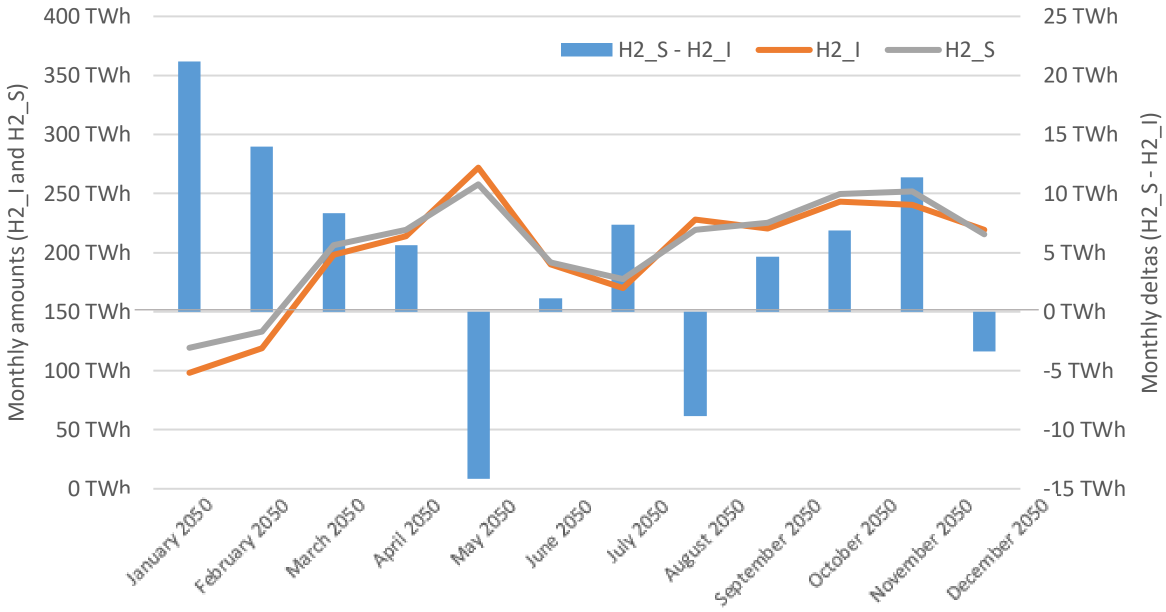

Figure 6-8. Change in the monthly amounts of hydrogen generated through electrolysis, in the H2_S scenario with respect to the H2_I scenario (EU-27+7). Total amount in H2_I: 2 400 TWh.

6.2.3.3 Stake of hydrogen storage costs

In such a decarbonised 2050 scenario, with the possibility of repurposing methane pipelines into a hydrogen network, METIS simulations results show that 50% of the purely hydrogen-related costs are due to the commissioning of massive electrolyser capacities, while the hydrogen grid infrastructure accounts for less than 20% (see Figure 6-9). Storage costs represent virtually 30% of hydrogen-related infrastructure costs, which confirms that, in addition to their role in the system dimensioning (need for other flexibility providers, technological and geographical distributions…), hydrogen storage constraints should be accounted for properly in prospective works.

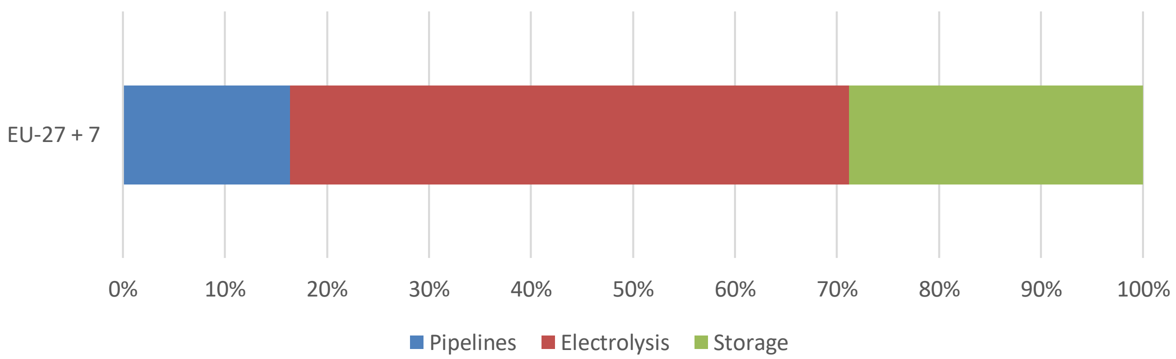

Figure 6-9. Repartition of the hydrogen system costs in H2_S scenario (EU-27+7)

7 IMPACT OF ALTERNATIVE CO_2 PRICES

According to the Long-Term Strategy, the European power system should produce negative net CO_2 emissions by 2050. Indeed, CCS-equipped bioenergy-fuelled power and heat plants "generate" net negative emissions while producing energy, which balance the remaining, "positive", emissions produced in sectors where these emissions are hard-to-abate. The ability of the various sectors to decarbonise their activities and the cost incurred in this are considered to be mirrored by the CO_2 price, and there is significant uncertainty about how the former will evolve in the future. To assess the impact of changes in the CO_2 price on the dimensioning and functioning of the system, a series of sensitivity assessments around this price is conducted. The results computed illustrate that lower carbon prices (reflecting lower pressure on the power sector to decarbonise, and better conditions to do so) reduce the revenues of the net-negative-emission-producing power and heat production technologies. This fosters the electrification of the economy and the deployment of variable RES and non-CCS equipped technologies, with a CO_2 price between 150 and 200 €/t representing a tipping point.

7.1 MAIN ASSUMPTIONS AND MODELLING APPROACH

Starting from the BS, which features a carbon price of 350€/t, four variants of it are defined in order to cover the range of CO_2 price levels considered in the 2050 scenarios reviewed. The sensitivity range includes CO_2 prices of 100€/t, 150€/t, 200€/t, 250€/t, and 300€/t. For each of these variant scenarios, assuming each of these prices, the system dimensioning is re-optimised with METIS.

7.2 MAIN RESULTS AND INTERPRETATION

The lower the CO_2 price, the higher the effective production costs of net negative carbon emission plants are, such as biogas boilers and CHPs equipped with CCS. Indeed, when CO_2 prices decrease, the price at which net-negative emitters sell emission permits decreases, while their other costs remain stable.

The industrial heat provision mix appears very sensitive to changes in the CO_2 price. Figure 7-1 shows that the share of CCS-equipped technologies in the industrial heat supply mix drops significantly for carbon prices below 200 €/t. In the baseline, these technologies are most used to provide medium and high temperature heat. Under substantially lower CO2 prices, they are substituted by electric and hydrogen boilers along with biomass-fuelled plants, since heat pumps can only provide low temperature heat. For the lowest CO_2 price analysed (100 €/t), the share of hydrogen boilers and biomass-fuelled CHPs in the industrial heat mix increases from 1%, in the BS, to 17% and from 9%, in the BS, to 24%, respectively.

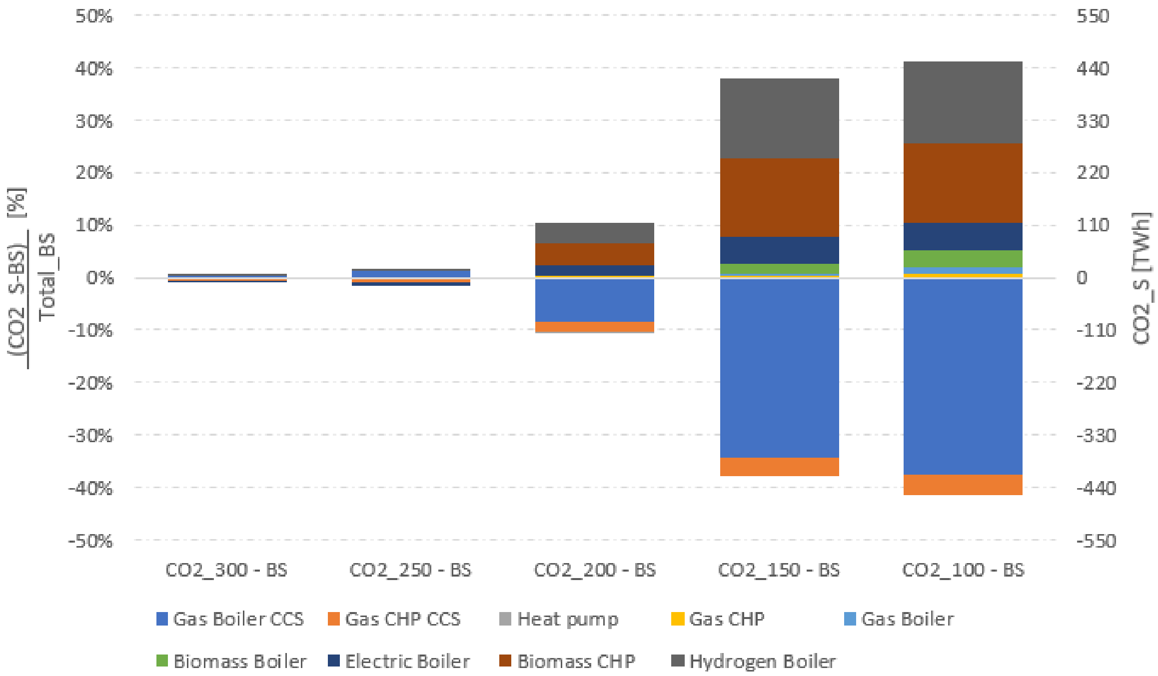

Figure 7-1. Evolution of the industrial heat supply mix with decreasing carbon prices w.r.t the BS (350 €/t_CO_2). Left axis: relative terms w.r.t. the total industrial heat production in the BS [%], right axis: absolute values [TWh] – EU27+7

The decreasing contribution to heat provision of net-negative-emissions thermal technologies with decreasing CO_2 prices is accompanied by an increase in the electrification level (both direct and indirect via hydrogen boilers) of the industrial heat provision. This increase in the electrification rates relies on the commissioning of additional RES-based generation, along with non-CCS biomass plants. Overall, for a CO_2 price of 100 €/t, the total power system demand is 3.5% larger than in the BS, while the installed electrolyser capacity deployed increases from 701, in the BS, to 767 GW, at European level.

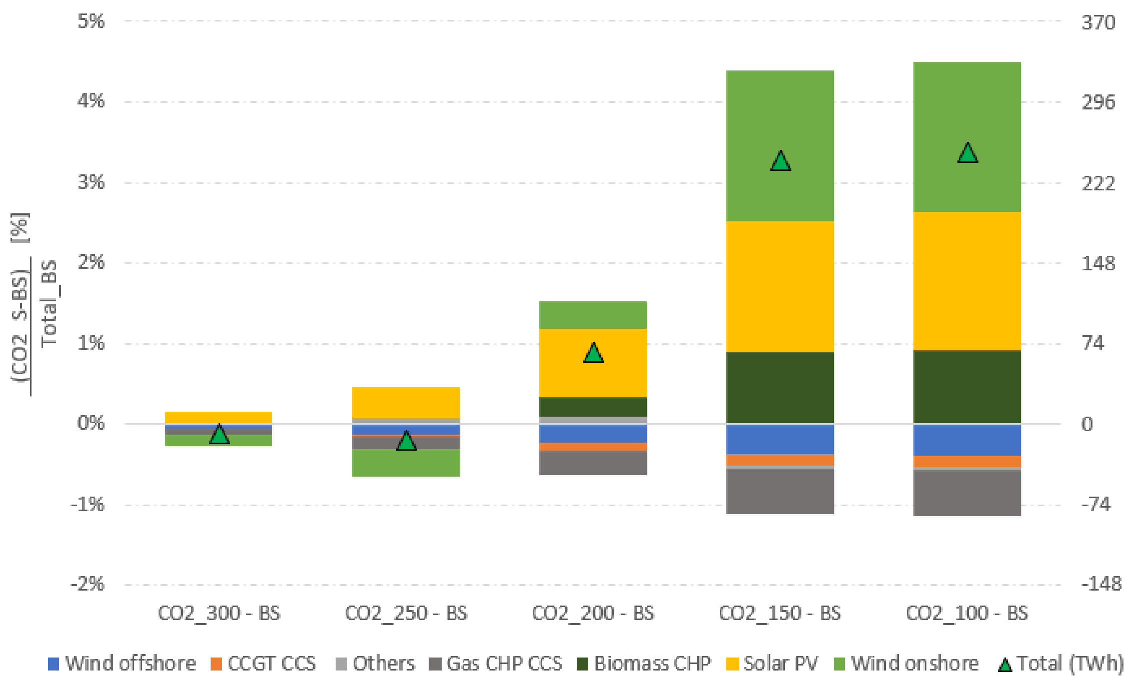

Figure 7-2. Evolution of the changes in the power production mix, w.r.t the BS (350 €/t_CO_2), with decreasing carbon prices. Left axis: relative terms w.r.t. the total power production in the BS [%], right axis: absolute values [TWh] – EU27+7

As a consequence of the above observations, the ability of the power-heat system to offset the emissions in other sectors where these are harder-to-abate decreases with a decrease in the carbon price. The yearly net negative emissions produced by the former sectors are 115 $MtCO_2$ lower when considering a carbon price of 100 €/t instead of 350 €/t.

8 CONCLUSIONS AND OUTLOOK

Conclusions

Building upon the METIS 1.5 scenario, developed in the context of the study S6 (Artelys, 2021 (forthcoming)), and representing a 2050 decarbonised European power system coupled with the hydrogen and heat sectors, study S4 assesses the impact on the future European energy system of changes in the conditions applying related to some major points of uncertainties: the impact of climate change on power demand, and power infrastructures performance and the resulting system dimensioning ; the robustness of the commonly envisaged role of electrolysers in the 2050 energy supply mix; the importance of the joint planning of the expansion of hydrogen generation, storage and cross-border capacities; and the CO_2 price level, and the associated ability of the future power system to offset emissions in hard-to-abate sectors.

If **climate change** materialises through a +2°C increase in the average global air temperature by 2050 w.r.t. the 2010 level (as assumed in the H1 scenario defined within (JRC, 2018.b)), a shift of demand volumes from winter to summer time will take place at European level. Northern areas will be more heavily impacted by the decrease in heating demand, leading to annual demand decreases, while the cooling demand surge in Southern countries is expected to be larger than the local heating needs decrease. When taking these altered demand patterns into account, simulations with METIS show that the optimal power supply system features lower wind power capacities (whose production is higher in wintertime) than expected in the METIS 1.5 scenario, (-34 GW at EU27+7 level). On the other hand, optimal solar power capacities (whose production concentrates in summer time, with more favourable capacity factors in Southern countries) increase by 17 GW with respect to the baseline.

Climate change may also trigger additional investments required to adapt power generation plants to the climate change-related risks, such as flooding. Specific adaptation costs are highest for offshore wind. The level of deployment of offshore wind and gas assets is expected to decrease, while the share of solar PV, which does not face specific adaptation costs, is expected to increase. However, the overall effects of these adaptation costs are expected to remain limited in absolute terms w.r.t the Baseline, for the considered assumptions on the extent of climate change at least.

Electrolysers have proven to be a no-regret technology to be massively deployed in Europe by 2050. Simulation results show that, even under the most unfavourable conditions (notably, the availability of competitive hydrogen supply options, and low CO_2 prices) the electrolysers' deployment levels will amount, at least, to 300 GW at the European scale by 2050 (compared to 700 GW in the baseline).

While electrolysers are to be deployed massively, their geographical distribution should be carefully planned, taking into account the existing constraints on hydrogen storage potentials as well as hydrogen cross-border interconnection opportunities, notably via repurposing the existing methane pipelines. Simulations carried out with METIS show that enabling the installation of **cross-border hydrogen interconnection capacity** facilitates regional cooperation and improves resource allocation, with hydrogen production being relocated to areas featuring the most favourable conditions in terms of renewable potentials and power prices. Considering hydrogen cross-border exchanges leads Ireland and the UK to commission massive amounts of wind power capacities (+500 TWh of power generation) and electrolysers, thus relieving pressure on domestic RES and hydrogen production in the less endowed Northern parts of Central Europe (BE, DE, NL, PL).

When, additionally, taking into account the fact that the **hydrogen storage** potentials are limited and unevenly distributed, the optimal amount of hydrogen interconnection capacity to be deployed is virtually three times larger than as without storage constraints (i.e., infinite storage capacities), which leads hydrogen cross-border flows to be significantly rebalanced. The optimal resource allocation is then amended and, given the limited seasonal storage capacity available, the hydrogen production profile gets **flatter across the year**. This requires relying more significantly on onshore wind power, predominantly located in Northern European countries, and less on solar PV, more abundant in Southern countries, which, thus, translates into a greographical rebalance within Europe.

By means of bioenergy-fuelled power and heat plants equipped with CCS, the power and heat sector may produce negative net emissions while supplying energy, thereby **offsetting emissions from hard-to-abate sectors**. However, massively deploying and using CCS technologies may prove economically sensible only under sufficiently high carbon price signals. Simulation results computed with METIS show that, for a price signal below 200 €/t, these net negative emission plants face reduced economic opportunities, which diminishes the ability of the power system to offset other sectors' emissions. Instead, the industrial heat sector shifts towards its direct and indirect electrification, and larger amounts of variable RES generation are deployed. As a result, negative emissions from the power and heat sector decrease substantially (representing up to +115 Mt_CO_2/year).

Limitations and outlook

These analyses provide answers to common questions on the impact of the conditions applying as far as long-term system planning is concerned. However, the completeness and accuracy of these analyses could be increased with further model developments. In the configuration employed, METIS allows for the dimensioning of a complete 2050 system, irrespective of its current structure. This common approach still presents the risk of missing technology lock-ins that would emerge due to medium-term choices (e.g. 2030 planning). An efficient way of taking investment dynamics into account is to undertake trajectory optimisation, whereby intermediate steps between the current and future systems are integrated into the scope of the optimisation problem.

Additionally, in study S4, the modelling set up focuses on the power sector and its coupling with the hydrogen and heat sectors, yet excluding an explicit modelling of the gas supply and infrastructure. The repurposing of methane pipelines to hydrogen only incurs repurposing costs, while impacts on the gas system's functioning are not represented. The analyses conducted could gain relevance by robustly modelling the competition for cross-border infrastructure to take place between hydrogen and methane. Enlarging the scope of the multi-energy model employed would, thus, allow to capture the synergies between energy sectors more accurately.

Finally, the assessment carried out considers a representation of the European system with national granularity, disregarding infra-national production dynamics and (transmission and distribution) grid infrastructure constraints and costs. The results computed and outlined in the present study could be altered when considering the exact location of assets within Member States. Cost assessments might be potentially affected as well when considering infra-national grid components. In any case, the applied approach is supposed to strike a balance between model complexity and manageability, and delivers robust and meaningful outputs.

It should be noted that several of the latter limitations are subject to an ongoing METIS upgrade in the context of the ongoing METIS 3 project. The updated version of the model allows for a joint representation of power, gas and hydrogen infrastructure. Demand side modelling will be improved by soft-linking METIS to two detailed, bottom-up, energy demand models. The geographical granularity of the tool will be increased to the NUTS1 level.[12] The optimisation of transition pathways will be enabled, covering several intermediate years in the run up to 2050. Finally, METIS will be complemented by a module that facilitates the undertaking of sensitivity analyses through parameter variations in order to evaluate the robustness of results and specific asset behaviours.

[12] In the context of the METIS 2 project, a detailed modelling of electricity transmission and distribution grids was already added, cf. https://ec.europa.eu/energy/data-analysis/energy-modelling/metis_en?redir=1.

9 REFERENCES

Artelys. (2016). *Weather-driven revenue uncertainty for power producers and ways to mitigate it.*

Artelys. (2018.a). *Synergies between the energy networks in a high RES 2050 scenario.*

Artelys. (2018.b). *Optimal balance between direct electrification and decarbonised gas supply.*

Artelys. (2020). *What energy infrastructure to support 1.5°C scenarios?*

Artelys. (2021 (forthcoming)). *METIS 2 Study S6 - Assessing the balance between direct electrification and the use of decarbonised gases.*

Australian Government - Productivity Commission. (2013). *Hedging in the electricity market.* Retrieved from https://www.pc.gov.au/inquiries/completed/electricity/report/28-electricity-appendixc.pdf

BNEF. (2013). *Profiling the risks in solar and wind.* Retrieved from https://about.bnef.com/blog/profiling-the-risks-in-solar-and-wind/

Business Insider. (2018). *https://markets.businessinsider.com/commodities/co2-emissionsrechte/euro*.

Climact. (2018). *Net Zero by 2050: from whether to now, zero emissions pathways to the Europe we want.*

Dilara Gulcin Caglayan, N. W. (2020). Technical potential of salt caverns for hydrogen storage in Europe. *International Journal of Hydrogen Energy*.

E3MLab & IIASA. (2016). *Technical report on Member State results of the EUCO policy scenario.* Retrieved from https://ec.europa.eu/energy/sites/ener/files/documents/20170125_-_technical_report_on_euco_scenarios_primes_corrected.pdf

EC. (2018). *Clean Planet for All.* Retrieved from https://ec.europa.eu/clima/sites/clima/files/docs/pages/com_2018_733_analysis_in_support_en_0.pdf

EC. (2020.a). *Impact Assessment' accompanying the Communication 'Stepping up Europe's 2030 climate ambition. Investing in a climate-neutral future for the benefit of our people.*

EC. (2020.b). *Building a hydrogen economy for a climate-neutral Europe. A strategic roadmap.*

ENTSO-E. (2016). *TYNDP data.* Retrieved from TYNDP: https://tyndp.entsoe.eu/documents/TYNDP2016_Projects%20data.xlsx

ENTSO-E. (2018). *TYNDP 2018 Executive Report.* Retrieved from TYNDP Executive Report: https://tyndp.entsoe.eu/Documents/TYNDP%20documents/TYNDP2018/consultation/Main%20Report/TYNDP2018_Executive%20Report.pdf

ENTSO-G. (2020). *TYDP.* Retrieved from https://www.entsog.eu/tyndp#entsog-ten-year-network-development-plan-2020

Eurelectric. (2018). *Decarbonization Pathways.*

European Environment Agency. (2016). *Transforming the EU power sector: avoiding a carbon lock-in.*

FCH. (2019). *Hydrogen Roadmap Europe. Asustainable pathway for the European energy transition.*

Gatzert, N., & Kosub, T. (2015). *Risks and Risk Management of Renewable.* Retrieved from https://actuaries.asn.au/Library/Events/ASTINAFIRERMColloquium/2015/GatzertKosubRiskManagementPaper.pdf

GIE. (2021). *Picturing the value of underground gas storage to the European hydrogen system.*

Guidehouse. (2021). *Extenging the European Hydrogen Backbone. A European hydrogen infrastructure vision covering 21 countries.*

IEA. (2020). *World Energy Outlook 2020.*

IPCC. (2021). Climate Change 2021.

IRENA. (2016). *Unlocking renewable energy investment: the role of risk mitigation and structured finance.* Retrieved from https://www.res4med.org/wp-content/uploads/2017/11/IRENA_Risk_Mitigation_and_Structured_Finance_2016.pdf

IRENA. (2020). *Global Renewables Outlook.*

JRC. (2018.a). *Scenario analysis of accelerated coal phase-out by 2030.*

JRC. (2018.b). Assessment of the impact of climate change on residential energy demand for heating and cooling.

JRC. (2018.c). *Low Carbon Energy Observatory works.*

JRC. (2020). Towards net-zero emissions in the EU energy system by 2050.

McKinsey & Company. (2020). *Net-Zero Europe Decarbonization pathways and socioeconomic implications.*

Navigant. (2019). *Gas for Climate. The optimal role for gas in a net-zero emissions energy system.*

Sven Teske. (2019). *Achieving the Paris Climate Agreement Goals.*

The Brattle Group. (2017). *Managing Price Risk for Merchant.* Retrieved from http://files.brattle.com/files/7380_managing_price_risk_for_merchant_renewable_investments.pdf

TU Wien, Fraunhofer ISI, EURAC, JRC. (2019). *Heating & Cooling outlook until 2050, EU-28.*

Wietze Lise, J. v. (2015). Investment needs for climate change adaptation measures of electricity powe plants in the EU. *Elsevier*.

Wind Europe. (2018). *Breaking new ground - Wind Energy and the Electrification of Europe's Energy System.*

Wouters, F. (2020, 04 14). *NVVN.* Retrieved from https://nvvn.nl/hydrogen-a-new-energy-vector-in-morocco-2/

10 Appendix

10.1 Appendix to section 6

Table 10.1 - Capacities of the hydrogen pipelines between regions in the H2_S scenario (GW)

To From	CN	CS	NO	SO	WE
CN		80	79		51
CS	80		19	61	
NO	79	19			53
SO		61			
WE	51		53		

Table 10.2 - Hydrogen exchanges between regions in the H2_I scenario (TWh) - Exchanges within regions are not considered

To From	CN	CS	NO	SO	WE	Total exports	Net exports
CN		78	8			86	-613
CS	125					125	-11
NO	198					198	85
SO		57				57	57
WE	377		105			482	482
Total imports	700	136	113	0	0	949	

Table 10.3 - Hydrogen exchanges between regions in the H2_S scenario (TWh) - Exchanges within regions are not considered

To From	CN	CS	NO	SO	WE	Total exports	Net exports	Net exports (H2_S - H2_I)
CN		139	23		2	164	-605	9
CS	121		69	116		306	19	30
NO	363	32			13	408	171	86
SO		115				115	-1	-58
WE	285		144			430	415	-66
Total imports	769	287	237	116	14	1423		

Table 10.4 - Electricity exchanges between regions in the H2_I scenario (TWh) - Exchanges within regions are not considered

To / From	CN	CS	NO	SO	WE	Total exports	Net exports
CN		60	24		5	89	-151
CS	123			137	13	273	92
NO	78				16	93	39
SO		76				76	-60
WE	39	44	30			113	80
Total imports	239	181	54	137	34	645	

Table 10.5 - Electricity exchanges between regions in the H2_S scenario (TWh) - Exchanges within regions are not considered

To / From	CN	CS	NO	SO	WE	Total exports	Net exports	Net exports (H2_S - H2_I)
CN		65	26		8	99	-134	17
CS	125			158	17	299	137	45
NO	73				16	90	37	-2
SO		57				57	-100	-40
WE	35	40	26			101	60	-20
Total imports	233	162	53	158	41	647		

GETTING IN TOUCH WITH THE EU

In person

All over the European Union there are hundreds of Europe Direct information centres. You can find the address of the centre nearest you at: https://europa.eu/european-union/contact_en

On the phone or by email

Europe Direct is a service that answers your questions about the European Union. You can contact this service:

– by freephone: 00 800 6 7 8 9 10 11 (certain operators may charge for these calls),

– at the following standard number: +32 22999696, or

– by email via: https://europa.eu/european-union/contact_en

FINDING INFORMATION ABOUT THE EU

Online

Information about the European Union in all the official languages of the EU is available on the Europa website at: https://europa.eu/european-union/index_en

EU publications

You can download or order free and priced EU publications from: https://op.europa.eu/en/publications. Multiple copies of free publications may be obtained by contacting Europe Direct or your local information centre (see https://europa.eu/european-union/contact_en).

EU law and related documents

For access to legal information from the EU, including all EU law since 1952 in all the official language versions, go to EUR-Lex at: http://eur-lex.europa.eu

Open data from the EU

The EU Open Data Portal (http://data.europa.eu/euodp/en) provides access to datasets from the EU. Data can be downloaded and reused for free, for both commercial and non-commercial purposes.

MJ-05-23-010-EN-N

ISBN 978-92-76-99077-2

Publications Office
of the European Union