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Synergies and trade-offs between storage, transmission, and sector coupling in high renewable energy systems

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ABSTRACT

Energy storage, transmission, and sector coupling are some prominent flexibility solutions to support variable renewable energy (VRE) integration. However, investment cost uncertainties and public acceptance could hamper the deployment of these flexibility solutions. This raises questions about the development and cost-effectiveness of future energy systems, especially on how the dependence on local and cross-border solutions of flexibility would evolve if the uptake of these solutions is restricted. In this context, this paper identifies the synergies among flexibility options under restrictions on transmission expansion or increased costs of energy storage. It contributes to determining whether investments in energy storage and/or transmission expansion offer the least-cost transition and investigates the impact of sector coupling on these solutions. A long-term energy system planning and optimisation model towards 2050 is developed using the open-source energy system optimisation tool Balmorel, and a case study of the countries surrounding the Baltic Sea and the North Sea is established. Five cases with restrictions imposed on transmission expansion and higher energy storage technology costs are analysed at different levels of sector coupling. The results highlight the importance of transmission expansion at all levels of sector coupling. As the level of sector coupling increases, uncertainties around the cost of energy storage drive the least-cost pathways. Optimal investment solutions are found to have a mix of transmission and energy storage in capacity expansion at all levels of sector coupling.

1. Introduction

The transition towards net-zero energy systems has become a prominent environmental policy goal for many countries. Attaining net-zero emissions will reshape energy systems and require proper planning to ensure a smooth transition. The electricity sector contributes to around 40% of global CO_2 emissions (2020) due to fossil-dominated fuel consumption [1]. The demand for electricity in the coming years is anticipated to increase owing to its strong correlation with economic growth, electrification of end-use energy consumption, and rapid urbanisation. At the same time, major non-fossil energy resources are well-suited for electricity generation. Many nations have set ambitious targets to integrate variable renewable energy (VRE) sources, especially solar and wind, to achieve decarbonisation targets while ensuring energy security. However, unlike conventional generators, the power output of VRE sources is temporally variable and uncertain due to

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their weather dependency [2]. As the share of VRE increases, so does the magnitude of variability and uncertainty of their generation. This underscores the need for additional flexibility at the lowest possible cost.

Improved operational procedures[1] and demand response are often cited as cost-effective approaches to enhance system flexibility, as they require lower investment costs [3]. However, the extent to which these flexibility solutions can be tapped is contingent upon a range of factors, including market design [4], consumer engagement, technological infrastructure, and regulatory support. Many countries have achieved notable shares of VRE using improved operational procedures, available cross-border transmission capacities, and coordination efforts with neighbouring countries [5]. Few system operators have begun to integrate demand response into various market mechanisms. Further increasing VRE shares requires exploiting additional flexibility solutions such as measures to improve grid utilisation including dynamic line rating, grid infrastructure upgrades, energy storage, fast start generators, and demand response through sector coupling [6].

While transmission expansion, energy storage, and sector coupling are expected to provide the required flexibility for the green transition, concerns may arise regarding public acceptance, for example, opposition to new transmission lines, land availability, H_2 safety issues, and the cost of their large-scale deployment. Significant barriers to the roll-out of these flexibility solutions can raise technical and economic concerns about the feasibility of VRE-dominated future energy systems. This paper investigates the synergies between energy storage, transmission expansion, and sector coupling under different restrictions and technology cost uncertainties to assess their combined impact on system costs.

1.1. Literature review

The literature review in this work is structured as follows: Sections 1.1 and 1.2 outline the studies directly relevant to framing the research questions and contributions of the manuscript, while Section 4 contextualises the findings with selected studies.

Recent studies in the European context underscore that pan-continental expansion of transmission networks is the most cost-effective solution to integrate VRE and smoothen their variability at the synoptic scale [7,8]. Without substantial grid expansions, more expensive localised solutions such as energy storage become essential to ensure supply–demand balance. For instance, Germany's federal government previously targeted increasing the share of renewables in gross electricity consumption to a minimum of 80% by 2050. Achieving this target could require an addition of a large storage capacity of 35 GW/ 230 GWh by 2050 [9]. The government's recent determination to achieve the target by 2030 not only accelerates renewable buildouts but also necessitates the faster deployment of cost-intensive storage solutions. Similarly, a decarbonisation study carried out on 18 interconnected areas of the European Union reported a requirement of 432 GW of power capacity from energy storage devices by 2050 in addition to a transmission capacity of 362 GW [10]. In the U.S., achieving a goal of 100% clean electricity by 2035 could require 120–375 GW of storage capacity with discharge time ranging from 2–12 h in addition to significant transmission infrastructure [11]. Although these studies highlight the importance of investing in transmission expansion or energy storage, their focus is limited to electricity-only systems.

The Intergovernmental Panel on Climate Change (IPCC) emphasised the necessity of reaching carbon neutrality in global energy systems to limit global warming to 1.5 °C–2 °C. Direct or indirect electrification of transportation and heating is essential to achieve decarbonisation goals [12,13]. This led to increased research attention on sector coupling. It refers to connecting the electricity sector with other energy sectors — namely, building, industry, and transport — through various technologies such as e-mobility, heat pumps, combined heat and power plants, and other energy carriers such as hydrogen (H_2). Albeit increasing electricity demand and network complexity, sector coupling can provide additional techno-economic avenues. It can reduce energy curtailment by effectively utilising the surplus energy from VRE [14]. Power-to-X, essentially H_2 and hydrogen-derivatives (such as ammonia),[2] is a key solution for providing flexibility and decarbonising hard-to-abate energy sectors, such as transport and industry [15]. The extent of decarbonisation depends on the electricity generation mix of the system. Sector coupling and the associated electrification of other sectors enable decarbonisation, provided the electricity generation mix has low carbon emissions. Recognising this, the European Commission has laid out a roadmap for the H_2 ecosystem towards 2050. The European Hydrogen Strategy 2020 targets domestic production of up to 10 million tonnes of green H_2 by 2030 [16]. The growing reliance on H_2 also leads to the deployment of associated infrastructure, including H_2 pipelines. Studies comparing the economic viability of electricity transmission and H_2 pipelines revealed the cost-effectiveness of H_2 pipelines across a range of settings [17]. This emphasises the need to consider both H_2 pipelines and electric transmission in energy system planning studies. Energy system planning models are developed on various optimisation platforms to integrate the H_2 [18,19], heating, power, and transport sectors [20]. These studies consider the synergies between sectors and co-optimise investment decisions.

While it is understood that energy storage, transmission interconnection, and sector coupling are key enablers for the low-carbon transition, the uptake of each of these flexibility solutions is affected by diverse uncertainties. There have been increasing concerns over the public acceptance of transmission expansion in many countries. Key factors driving public opposition to high-voltage transmission lines include aesthetic impact, environmental and health risks, deep-rooted attachments to the location, political ideology, and fairness in compensation [21]. In order to deal with this public opposition, there has been an increased shift towards underground cables for high-voltage electricity transmission, especially in Germany and Denmark [22]. Empirical studies suggest that public opposition, in terms of risk expectations, attitudes, and protests, is generally lower for underground cables compared to overhead lines [21]. However, when provided with additional information about electromagnetic emissions from underground cables, public acceptance decreases, often associated with the perception of potential health risks from electromagnetic fields [23]. This uncertainty in public acceptance regarding both overhead and underground transmission lines may contribute to project delays, additional costs, or even project cancellations [24,25]. Public and societal acceptance, or the Not-In-My-BackYard (NIMBY) mindset, restricts transmission interconnections to current levels or going offshore [26]. The uptake of energy storage is more inclined towards technological cost aspects. Although costs associated with energy storage technologies have been declining in recent years, uncertainties such as raw material availability and costs, manufacturing scale, and technological innovation may hamper cost projections [27]. These uncertainties are further exacerbated for long-duration energy storage technologies, which have additional complexities and uncertainties due to cross-sectoral interdependencies (e.g., H_2 systems) and availability limitations (e.g., geologic features for underground storage applications) [28]. The level of sector coupling is driven by factors such as consumer behaviour, preferences, technological advancements, and public acceptance of the investments, which are beyond those typically considered in energy system modelling. These uncertainties can significantly influence the generation

[1] solutions for short-term operational planning *i.e.,* developing new market products, cross-border trading, and application of state-of-art methods for unit commitment, economic dispatch, and forecasting.

[2] This study limits the discussion and analysis to H_2, assuming there is a demand for either H_2 directly or the derived products.

mix, economic viability of investments, and evolution of decarbonised energy systems. However, there has been limited attention given to identifying the tradeoffs and analysing the potential impacts on energy system transitions under the above-mentioned uncertainties.

1.2. Research gaps and contributions

Given the uncertainties discussed earlier, a key research question lies in understanding how complementary or competing these flexibility solutions are in terms of operational and investment decisions. Especially, it is important to study how energy systems would evolve when either of these flexibility solutions is severely constrained. In the Renewable Integration Impact Assessment report, the Midcontinent Independent System Operator (MISO) highlighted two main observations: (1) investing in transmission lines is a more cost-effective solution than storage for increasing the share of VRE, and (2) transmission and storage together may achieve the best overall value [29]. However, that analysis only considers 40% renewable energy shares in an electricity-only system. Similarly, an earlier study of the US system that compared the benefits of transmission versus storage found that building transmission to access a wider diversity of renewable resources and load is a more economical option than building more storage to access only local resources, as scenarios with no inter-regional transmission capacity required roughly 4x more storage buildout on a cost basis. Thus, by enabling inter-regional transmission, total system costs were reduced by about 50% and 42% at the 80% and 100% renewable energy targets, respectively [30].

Bermudez et al. [31] and Thellufsen et al. [32] studied the impact of sector coupling on transmission capacity deferral. Thellufsen et al. [32] investigated the relation between two flexibility options: cross-sector and cross-border interconnections. The results show that both transmission expansion and sector integration are beneficial. However, in more sector-coupled systems, the relative benefits of transmission expansion decrease, as excess generation from VRE can be utilised within the system due to higher system flexibility and electricity demand. Similar conclusions are drawn by Brown et al. [7]. Bermudez et al. [31] found that transmission expansion is beneficial even in most sector-coupled scenarios. Morales-España et al. [33] showed a similar conclusion in an EU case study for the coupling with the H_2 sector, especially when existing methane pipelines are retrofitted to transport solely H_2. Bloess [9], in a study on Germany's energy system highlighted that coupling heating and power sectors can decrease energy storage requirements by 40%, with power-to-gas substituting battery storage. Bermudez et al. [31] highlighted that sector coupling, especially electrification of transportation, decreases short-term storage requirements. Victoria et al. [34] highlighted the deferral in energy storage investments in a full sector coupled European energy system and showed that electric vehicles (EVs) assist in the diurnal timeframe, while large-scale thermal storage assists at the seasonal level. A further classification of the synergies examined in these works is presented in Table 1.

Despite existing literature exploring the synergies among these flexibility options, identifying the least-cost solution under various investment barriers has traditionally been seen as a *two-dimensional* interplay between transmission expansion and either sector coupling or energy storage individually. Finding the *"optimal"*[3] value depends on the mix of investments in transmission expansion, storage, and the extent of sector coupling, especially as sector coupling enables new flexible and storage options, such as heat and H_2 storage. This transforms the study into a *three-dimensional* problem. Also, the restrictions on these flexibility options cannot be modelled similarly, due to differing factors limiting their uptake.

[3] Optimal value also depends on the diversity of energy systems such as access to VRE sources, their correlations with demand, opportunities for interconnection, and size and legacy decisions of the system.

To the best of authors' knowledge, this has not been explored in detail in the literature.

In this context, this paper answers the following research questions

1. How do restrictions on transmission expansion and uncertainties relating to the future cost of energy storage technology influence energy transition pathways towards 2050?
2. What is the role of sector coupling in the uptake of flexibility solutions given restrictions on transmission expansion and higher storage costs?
3. How do these constraints influence total system costs for different levels of sector coupling?

This work addresses the aforementioned three-dimensional problem. The first two research questions explore how limitations on transmission expansion, uncertainties in storage technology costs, and varying levels of sector coupling influence investment decisions towards 2050, while the third research question quantifies their impact on total system cost.

The novelty of the paper in relation to existing literature is highlighted in Table 1. Recent literature has examined the synergies and mutual implications among sector coupling, transmission, and energy storage [29,32,35,36]. However, these studies are limited to focusing on single storage technology, not fully optimising transmission investments, or failing to account for potential interactions across energy sectors, as shown in Table 1. The primary focus of this paper is to provide insights into how restrictions and technology cost uncertainties of various flexibility solutions impact green energy transitions. Limiting one or the other may lead to diverging pathways towards 2050 in terms of where the system obtains its required flexibility in a least-cost manner. This work employs a long-term energy system planning and optimisation model— a computational tool that can analyse and optimise the energy supply portfolio and infrastructure over an extended planning horizon — developed on the Balmorel platform. Highly restricted transmission expansion cases and high-cost storage cases are compared against an unconstrained baseline to find their respective impact on the system cost. A detailed justification for adopting this approach is provided in Section 3.3. To assess the synergies and trade-offs across technological alternatives, this work analyses these restrictions across different energy demand scenarios, which vary in their degree of sector coupling. These scenarios account for both electricity demand (from sources such as heat pumps, electric boilers, EVs, and electrolysers) and contributions from non-electrical sources such as CHP, gas boilers, and waste heat recovery. Finally, the key outcomes of the study are compared with similar works from other institutes covering different geographical regions, as presented in Section 4. This comparison evaluates the generalisability and global relevance of the results.

The rest of the paper is organised as follows: Section 2 and Appendix A discuss the model description, key assumptions, data sources, and scenario definitions. Numerical results are presented in Section 3. Section 4 provides a comparison of key results with existing works. Section 5 presents a discussion of the key findings. Finally, Section 6 concludes the work.

2. Scenario and case definitions and data assumptions

2.1. Model description

The proposed energy system expansion study uses Balmorel, an open-source, technology-rich, and bottom-up energy systems model written in the GAMS modelling language [37]. The model provides a comprehensive framework for evaluating various energy scenarios and policies. It can simulate complex energy systems, including electricity, heating, cooling, and transportation while considering technology costs, fuel prices, and government policies [38]. The model uses linear

Table 1
Taxonomy of literature.

Ref.	Energy sectors				Sensitivity on Tx. Exp.	Sensitivity on ES Exp.	Sensitivity on SC	Synergies/Interactions considered
	Electricity	Heat	Transport	H_2				
Thellufsen et. al [32]	✓	✓	✓	✓	x (Tx. Exp. not optimised)	x	✓	TxExp vs. SC
Brown et. al [7]	✓	✓	✓	✓	x	x	✓	TxExp vs. SC
Chen et. al [35]	✓	✓	x	x	✓	x	x	Impact of TxExp
Osorio et. al [36]	✓	✓	✓	✓	x	x	✓	Spatial resolution vs. SC
Victoria et. al [34]	✓	✓	✓	✓	x	✓ (no restrictions on uptake)	✓	ES vs. SC
MISO [29]	✓	x	x	x	✓	✓ (only battery storage)	x	Tx. Exp. vs. ES
This paper	✓	✓	✓	✓	✓	✓	✓	TxExp vs. ES vs. SC

✓ : considered; x: not considered; TxExp: Transmission expansion; ES: Energy storage; SC: Sector coupling

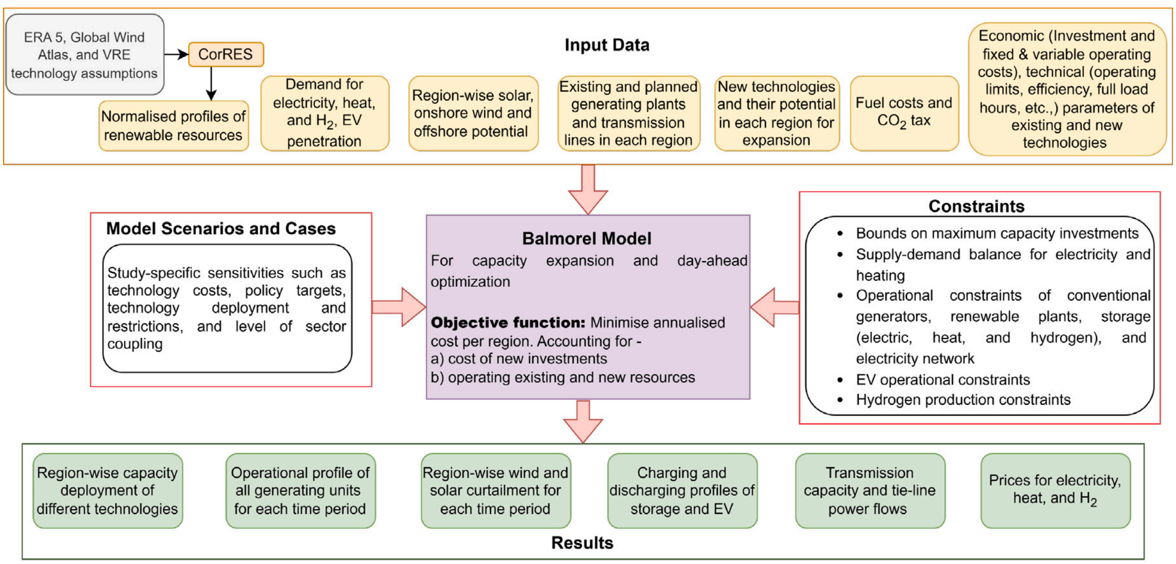


Fig. 1. Structure of Balmorel model.

programming to produce the least-cost investment and operational decisions to meet sector-specific energy requirements. Fig. 1 provides an overview of the key input data, operational constraints, and primary outcomes of the Balmorel model in the context of energy system planning studies.

This work focuses on the electricity, heat, and transportation sectors, as well as the potential for H_2 production.

A more detailed explanation of the Balmorel model can be found in [37]. Mathematical modelling of operational constraints for each sector is available in [31,39].

2.2. Scenario and case definitions

To study the synergies between transmission expansion and energy storage, five cases are defined as presented in Table 2, each of which represents either a restriction on transmission expansion or imposing a higher cost to energy storage technologies. The **NoTxExp** case reflects severe challenges with public and social acceptance of transmission infrastructure. The case **offshoreTxExp**, where transmission corridors are limited to offshore, exemplifies the so-called NIMBY mindset [26]. This supports the notion that offshore cables are easier to build from a permitting perspective. The cases with higher cost of storage technologies stem from reported uncertainties in technology cost projections by the Danish Energy Agency (DEA) [40]. Although the cost of these technologies is projected to decrease by 2050 compared to current levels, there is significant deviation between the lower and higher ends of these estimates. The DEA estimates indicate an *average* variation of 1.5 to 3 times between the lower and higher cost projections for H_2, heat, and battery storage technologies towards 2050.[4] While the base case assumptions of the model assume lower cost estimates, the case **ISC** increases storage technology costs by 1x the average difference between upper and lower estimates of respective technologies (1.6x for H_2 storage and 3x for battery storage and heat storage). This includes increasing both capital and operational costs. Further, the case **ISCx2** represents the extreme level by increasing the costs of storage technologies to 2x the average difference (3.2x for H_2 storage and 6x for battery storage and heat storage). All five cases are analysed for six scenarios with different levels of electrification/sector coupling. The scenarios differ from each other in terms of allowing the electrification of energy sectors. The fully sector-coupled (**FULLSC**) scenario includes all energy sectors — electricity, transport, heat, and investments in Power-to-X (limited to H_2). The selected energy sectors for other scenarios are presented in Table 3.

[4] The ratio of higher and lower levels of cost estimates for hydrogen storage technologies range from 1.33 to 1.8, with an average ratio of 1.6; for heat storage, the range is 1.4 to 3.92, with an average ratio of approximately 3.0; and for battery storage, the range is 1.67 to 5.77, with an average ratio of approximately 3.0. However, pumped hydro storage does not exhibit any uncertainty due to technological maturity.

Table 2
Case definitions.

Cases	Definition
No transmission expansion (**NoTxExp**)	No new transmission investments are allowed beyond the projects under development (as of 2020)
Only offshore transmission expansion (**OffshoreTxExp**)	Only new offshore transmission investments allowed on top of **NoTxExp**
Balanced (**Bal**)	No additional restrictions on either transmission expansion or energy storage costs
1 × Increased storage cost (**ISC**)	The cost of H_2, heat, and electric storage technologies is increased by 1x the average difference between upper and lower estimates of respective technologies
2 × Increased storage cost (**ISCx2**)	The cost of H_2, heat, and electric storage technologies is increased by 2x the average difference between upper and lower estimates of respective technologies

Table 3
Sector coupling options in each scenario.

Level of electrification (Scenario name)	Electricity	Heating (household & industry)	Electrification of land transport	H_2 demand from industry	H_2 demand from transport fuels
Electricity Only (**E**)	✓				
Electricity and Heating (**E&H**)	✓	✓			
Electricity and Transportation (**E&T**)	✓		✓		
Electricity and Industrial Hydrogen (**E&H2**)	✓			✓	
Electricity, Heating, and Transportation (**E&H&T**)	✓	✓	✓		
Full Sector Coupling (**FullSC**)	✓	✓	✓	✓	✓

Fig. 2. Regions in the Balmorel model.

2.3. Data assumptions

Geographic spread/geographic regions

The capacity expansion model includes the following countries in Northern-Central Europe: Belgium, Denmark, Estonia, Finland, France, Germany, Latvia, Lithuania, Netherlands, Norway, Poland, Sweden, and the United Kingdom. Further, the countries are classified into regions as illustrated in Fig. 2. The regions in Denmark, Norway, and Sweden indicate current bidding zones. Germany is split into four regions to capture inter-regional bottlenecks. The remaining countries are considered as a single bidding zone or region [41]. Hence, the 13 countries are classified into 24 regions.

Electricity demand

Fig. 3 illustrates the electricity demand associated with different scenarios in the study, which represent different levels of sector coupling. Section 2.2 (Table 3) provides an overview of the sector coupling options that are added under each scenario. The electricity demand shown in Fig. 3 constitutes endogenous and exogenous attributes and is categorised as (a) Inflexible demand which includes base electricity demand and electricity consumption of rail transport, (b) consumption from heat pumps and electric boilers (c) electricity consumption to produce H_2 for industrial use and electro fuels, and (d) charging requirements for EVs. Energy efficiency policies are assumed, which lead to a constant/slight reduction in electricity consumption as illustrated under the *inflexible* segment. Further, when heat sector is integrated, the share of electrified heat demand classified under inflexible demand is assigned to the heat sector. As a result, the proportion of inflexible demand within the electricity sector decreases in the **E&H**, **E&H&T**, and **FullSC** scenarios compared to scenarios without heat sector integration.

It is worth noting that Scenario **E** includes projected electricity demand from the residential, commercial, and industrial sectors for the countries under study, while excluding electricity demand associated with the electrification of transport and heating. Due to model constraints, pre-existing electric-based heating demand is retained as part of the inflexible load component. However, this demand component is not subject to endogenous optimisation or demand growth from the heating sector. Although this scenario represents a pessimistic view of the European energy system, it is designed as a reference point to assess the impact of sectoral integration on investment decisions. Scenarios **E&T** and **E&H2** build upon the electricity demand projected in scenario E by including electricity demand from transportation and industrial H_2, respectively.

Private EVs are operated in vehicle-to-grid mode. The charging and discharging profiles of aggregated EVs are optimised, and their electricity demand is estimated endogenously. Assumptions around EVs are taken from [31,42]. The demand for heating and H_2 is taken from [41]. The transmission losses for the power flow between connected regions are evaluated based on the distance between the regional centroids.

Additional data assumptions, including temporal representation, VRE time series, modelling of energy sectors, and technology costs, are provided in Appendix A.

2.4. Sectoral integration and flexibility synergies

Electricity sector

As illustrated in Fig. 3, the components of electricity demand, other than inflexible demand, are formed endogenously, with their magnitude depending on least-cost optimisation. In the electricity-only scenario (**E**), the required flexibility is sourced from dispatchable technologies such as CHP, reservoir hydro, pumped hydro, and batteries. The investment decisions are determined based on an objective function that minimises the total cost, which includes both investment and operational costs, while ensuring a supply–demand balance. The

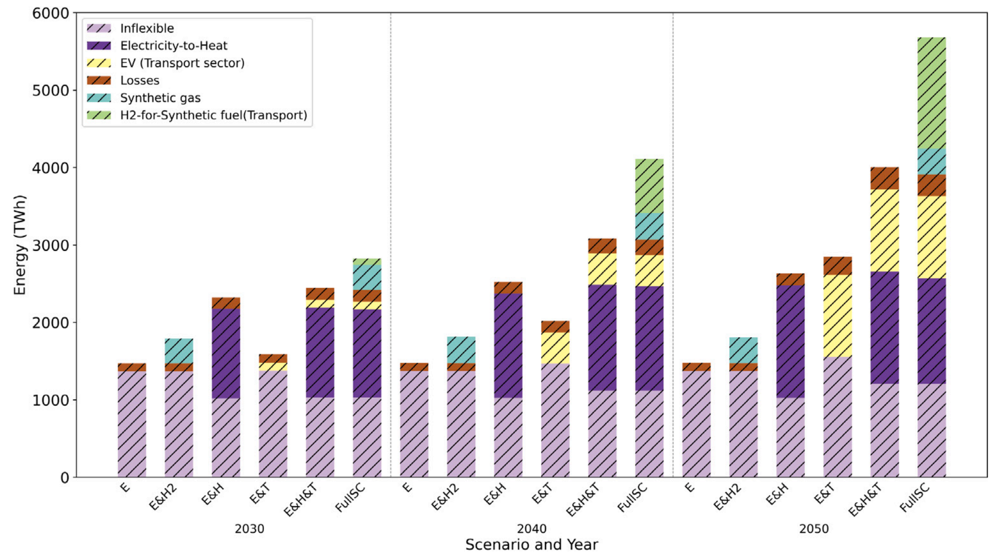


Fig. 3. Annual electricity demand for different levels of sector coupling. The results are for the **Balanced** case; however, all cases show approximately the same annual electricity demand. In the FullSC scenario, electricity demand for H_2 includes synthetic fuel generation for aviation, shipping, and industrial processes.

optimisation model accounts for the source-specific technological constraints such as ramp rates, maximum and minimum power generation capabilities, solar irradiance and wind speed, seasonal and diurnal availability patterns of storage technologies, and hydro flows [31,39].

Heating sector

When the heating sector is integrated, based on the case-specific constraints, the share of heat pumps and electric boilers used to meet heating demand influences the Electricity-to-Heat component of electricity demand in Fig. 3. CHP, gas boilers and waste heat from electrolysers meet the remaining heat demand. When electricity and heating sectors are integrated, the synergies from both sectors are captured through the coordinated dispatch of CHP and the use of thermal and electric storage, which will be discussed in Section 3 for different cases under **E&H** scenario.

Transport sector

Integration of the electricity and transport sectors introduces both inflexible and flexible components in electricity demand. Inflexible demand arises from the electrification of public transport (buses and trains) and is assumed as an exogenous load in this work (as shown in the inflexible component of the **E&T** scenario in Fig. 3). Flexible demand originates from private EVs, modelled endogenously based on input parameters such as driving patterns, state of charge limits, and number of EVs in the scenario year, as in [42], along with the mode of operation. This work assumed vehicle-to-grid mode of operation. When electricity and transport sectors are integrated, the resulting investment decisions are based on co-optimisation of the electricity sector and charging/discharge of the EV fleet, while accounting for sector-specific constraints as presented in [42].

Hydrogen sector

When the H_2 sector is integrated with electricity, the share of electrolysers defines the electricity demand for H_2 production, as illustrated in the **E&H2** scenario of Fig. 3. While the H_2 balance is assumed for each time step at a regional level, the operational decisions of the optimisation model — to produce, store, and reconversion through fuel cells — introduce flexibility from the H_2 sector [41]. Based on the integrated sectors in a scenario and case-specific constraints, the model finds least cost or optimal decisions: whether to overproduce H_2 during periods of excess renewable generation and store it, or to decrease the green H_2 production if the cost of H_2 storage technologies is high (Table 2).

Flexibility in sector-coupled systems emerges not only from variations in direct electricity demand, but also from the co-optimised system-level interactions between electricity, heating, transport, and H_2 sectors. When two or more energy sectors are integrated, trade-offs arise between investment & operational decisions and the associated increase in investment cost. These trade-offs, along with the synergies enabled by sectoral integration, shape the energy transition pathways. The subsequent section explores these effects under different scenarios (integrated energy sectors) and cases where different restrictions are applied within each scenario.

3. Result analysis

This section presents the results obtained from investment optimisation across five cases (Table 2), each under six scenarios with different levels of sector coupling (Table 3). The section is organised as follows:

- Section 3.1 focuses on the fully sector-coupled scenario (FullSC), where investment decisions in electricity, heating, transportation, and hydrogen sectors are co-optimised. First, the section presents the key findings from the balanced case, where no additional constraints on transmission expansion or energy storage costs are imposed (**FullSC_Bal.**[5]). Subsequently, the impacts of limiting transmission expansion (**OffshoreTxExp** and **NoTxExp**), and imposing higher costs to energy storage technologies (**ISC** and **ISCx2**) are analysed.
- Section 3.2 explores the impact of varying levels of sector coupling, with the discussion flow structured similar to Section 3.1, i.e., we present the comparative result analysis for a balanced case first, followed by the cases of limiting transmission expansion and imposing higher costs for storage in the subsequent subsections.
- Section 3.3 presents a comparative study of total system costs for all scenarios and cases.

[5] Cases are named as "Scenario Name_Case Name" according to Tables 2 and 3 For example, "E&H_ISCx2" indicates a case with 2x increase in storage costs in an Electricity and heat coupled scenario; "E&H&T_NoTxExp" denotes a case with a fully restricted transmission expansion for an electricity, heating and transport sectors coupled (E&H&T) scenario

3.1. Model results for fully sector coupled scenario

Balanced case – No limitations on transmission expansion or higher cost of storage

Investment optimisation has been carried out for scenario years 2030, 2040, and 2050 to project the energy transition towards 2050. Figs. 4(a)–4(c) illustrate the expected generation capacity mix and transmission expansion for a fully sector-coupled scenario. The share of VRE technologies in the generation capacity (GW) may increase to around 90% by 2050. Offshore wind would dominate with a 40% share of installed capacity in Northern Europe, while Solar PV constitutes 60% of Central Europe's installed capacity. France, Germany, and the UK serve as key connection points for the transmission expansion. Further, the installed capacities of electric storage, including both short-term and long-term, are expected to grow fivefold by 2050 relative to 2030. Transmission lines are expanded up to 350 GW by 2050, nearly doubling the capacity from 2030 levels.

Fig. 5 illustrates a comparison of sector-wise energy production (TWh). To make the figures more readable, Fig. 5(d) is limited to 2040 and 2050. This section analyses the results for **Bal** case in Figs. 5(a)–5(d). With sector coupling, there is a clear transition in the primary source of energy for different sectors. The share of power generation from conventional fossil fuels declines from about 17% in 2030 to less than 6% by 2050. Starting from 2030, the heating sector's energy consumption shifts from being fuel-dominant to electricity as the primary contributor. When the H_2 sector is coupled, electricity provides all H_2 from 2040 onward, contrary to the dependence on natural gas for H_2 conversion technologies before 2030. Also, the excess heat produced during electrolyser operation is utilised to meet heat demand starting from 2030, as depicted in Fig. 5(b). **FullSC_Bal** sees limited utilisation of electric storage, driven by extensive competition from the vehicle-to-grid operation of EVs, as well as heat and H_2 storage, in providing the required flexibility, as illustrated in Fig. 5(d).

Limiting transmission expansion

In cases with limitations on transmission expansion, there is an increased reliance on processes with lower overall efficiency, such as using fuel cells to revert H_2 to electricity, as seen in Fig. 5(a). Electricity production from fuel cells has increased by 65% in **OffshoreTxExp** and by 150% in **NoTxExp** compared to **Bal** for 2050. Due to the restrictions on transmission expansion, installed capacity (GW) and generation share (TWh) of offshore wind technologies are reduced (Fig. 5(a)). However, this is offset by an increase in solar PV generation of 3.7% in the **OffshoreTxExp** case and 12% in the **NoTxExp** case compared to **Bal** in 2050.

Compared to the balanced case, slightly more energy from CHP is used for electricity and heating in the transmission-restricted cases, as can be seen in Figs. 5(a) and 5(b). For 2050, compared to the **Bal** case, CHP participation increased by 45% for electricity and 12% for heating in the **NoTxExp** case. Furthermore, the share of gas boilers increases by 65% in the **OffshoreTxExp** case and by 250% in the **NoTxExp** case compared to **Bal** in 2050. Overall, the electrification of the heating sector decreases.

In 2050, the **NoTxExp** case shows a 12% increase in electrolyser production compared to the base case, as shown in Fig. 5(c), driven by the higher utilisation of fuel cells (Fig. 5(a)). Additionally, the heat generated from the excess operation of electrolysers is used to meet heating demands. In 2050, electrolysers contribute to around 5.5% of total generated heat, as shown in Fig. 5(b), providing an additional 15 TWh in the **NoTxExp** compared to **Bal** case. Further, restricting transmission expansion has shown only small impact on energy storage, partially due to the presence of EVs, H_2 storage, and cross-sectoral integration. Overall, limiting transmission expansion results in increased utilisation of local sources of flexibility, such as H_2 technologies.

Imposing higher costs for storage technologies

While the energy storage technology options for the investment decisions remain unchanged, higher costs are assumed for batteries, heat, and H_2 storage, as explained in Section 2.2. Our work assumes that the technology cost of pumped hydro storage exhibits less uncertainty due to its technological maturity.

When storage costs are higher, offshore wind technologies replace investments in and production from solar PV, as seen in Fig. 5(a). In 2050, electricity production from offshore wind technologies increase by 10% for **ISC** and 19% for **ISCx2** compared to **Bal**. By 2050, the adoption of onshore wind technologies would remain consistent across all cases, unaffected by restrictions on inter-regional transmission or higher electric storage costs. The production levels from onshore wind exhibit notable variation between high-cost storage cases (**ISC** and **ISCx2**) and **Bal** in 2040. However, the difference relative to **Bal** diminishes significantly by 2050, with all cases showing a doubling of onshore wind generation compared to 2030 (see Fig. 5(a)). Onshore wind potentials are assumed as in [31].

Although increasing energy storage costs have less impact on electricity production from carbon-emitting generating technologies in **ISC**, a significant increase in their costs leads to a surge in such generation in **ISCx2**. Electricity generation from thermal and CHP technologies is increased by 10% and 50% in 2050 for **ISCx2** compared to **Bal**.

Under increased storage costs, the model finds it optimal to invest and utilise relatively cheaper heat storage options, especially short-term storage such as hot water tanks (Fig. 5(d)). **ISCx2** shows negligible investment in long-term heat storage technologies, further pressuring the electrification of heat sector. This shift leads to higher reliance on fossil-based fuel technologies in the electricity and heat sectors, thus increasing carbon emissions. Further, compared to **bal**, H_2 storage participation is halved in **ISCx2** case for both 2040 and 2050 as illustrated in Fig. 5(d).

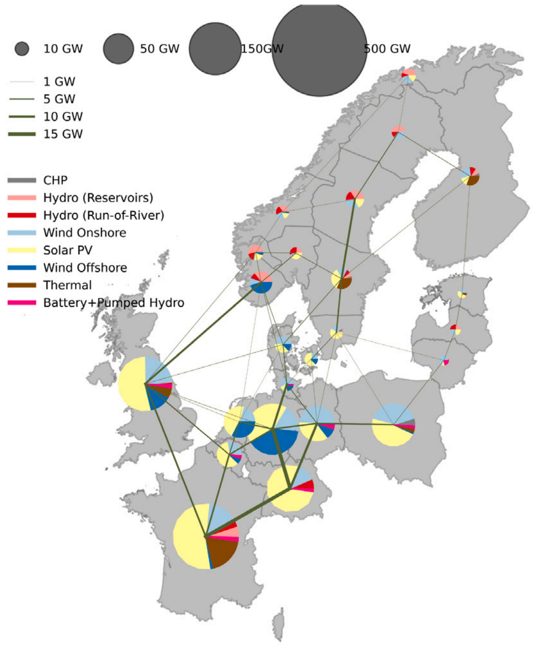
Figs. 6(a) and 6(c) show the relative transmission infrastructure in 2050 for extreme cases of the full sector coupled scenario. The **ISCx2** case has 35 GW more transmission capacity compared to the **Bal** case. As the cost of storage technologies increases, it becomes more optimal to invest in cross-border flexibility options such as transmission. The results highlight that cross-border interconnections can help in mitigating the impact of higher costs of storage technologies. Overall, higher storage technology costs drive more transmission investments, which then limits the need of energy storage uptake (see Fig. 5(d)).

Furthermore, after 2040, the uptake of onshore wind technologies in all cases is limited by land availability. With the best locations in terms of wind full load hours fully utilised until 2040, the model finds a trade-off between remaining investment potential and lower capacity factors. This results in stable onshore wind investments across all cases. Onshore wind potentials are assumed as in [31]

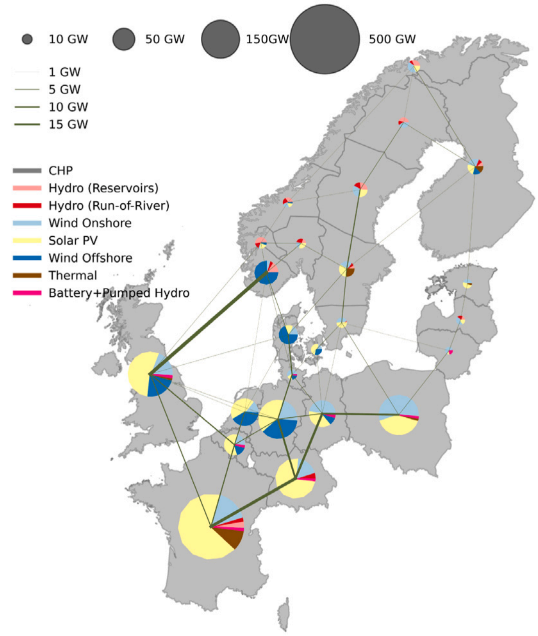
Relationship between investments for electric and H_2 transmission

The cases analysed in this work reveal a reciprocal relationship or inverse relation between investments in electric transmission and H_2 pipelines. As indicated earlier, limiting transmission expansion led to higher investments in localised flexibility options such as fuel cells. This is accompanied by additional investments in H_2 pipelines. Conversely, in cases with higher cost of storage technologies, a reverse trend is observed, with investments shifting from H_2 pipelines to transmission. Figs. 6(a) and 6(c) show the increasing level of transmission expansion, while Figs. 6(b) and 6(d) demonstrate the inverse trend in H_2 pipeline investments for the **NoTxExp** and **ISCx2** cases relative to **Bal**.

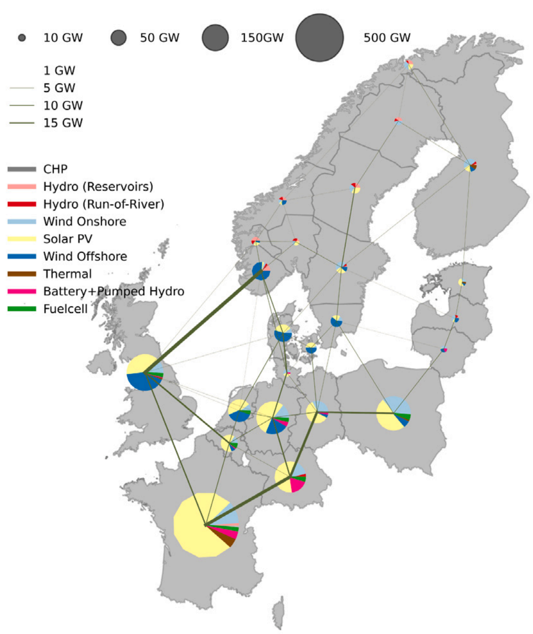
While changes in investment decisions for electric transmission and H_2 pipelines are observed across all regions under study when limitations on transmission expansion or higher costs for storage technologies are imposed (as shown in Fig. 6), the impact is particularly pronounced in Central Europe compared to the northern regions. This is primarily due to the higher concentration of energy demand and greater solar potential in central Europe. For example, when transmission grid



(a) 2030



(b) 2040



(c) 2050

Fig. 4. Technology-wise installed capacity (GW) and transmission expansion (GW) for the scenario years under FullSC_Balanced.

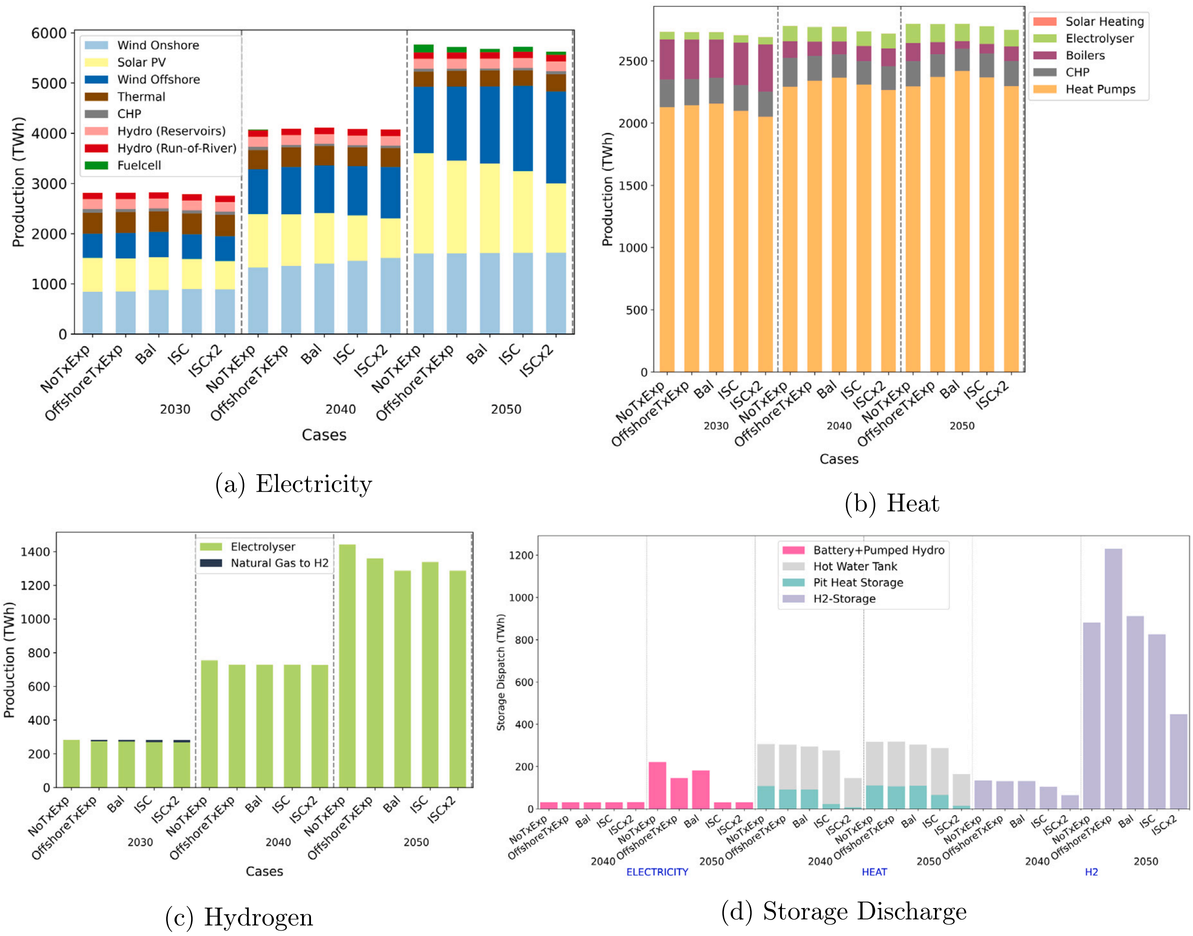
expansion is limited, 68 GW of electric transmission capacity is substituted by 22 GWe of H_2 pipelines in the UK. As previously explained, this shift is driven by increased investments in solar generation and H_2 technologies. In the **NoTxExp** case, compared to the **Bal**, the UK sees an increase in solar generation of 110 TWh, a doubling of H_2 storage, and around 40% increase in electrolyser operation in 2050. A similar trend is observed in solar-rich countries like France. In contrast, in the **ISCx2** case, France sees 15 GWe of H_2 pipelines replaced by 13 GW of electric transmission capacity, reflecting a shift in generation investments from solar to offshore wind and import dependencies between regions.

The choice of forcing the restrictions only on electric transmission and not on H_2 pipelines is discussed in Section 5.

3.2. Model results for different levels of sector coupling

Balanced case

Figs. 7(a)–7(c) provide the energy balance of electricity, heating and H_2 sectors for the **Bal** and extreme cases at different levels of sector coupling. Electrification and coupling of different energy sectors increases the electricity demand. As shown in Fig. 7(a), the electricity



(a) Electricity

(b) Heat

(c) Hydrogen

(d) Storage Discharge

Fig. 5. Sector-wise comparison of energy production in a fully sector coupled scenario. In heat production (Fig. 5(b)), "electrolyser" means excess heat from the electrolysis process.

demand increases up to fourfold in 2050 for different levels of sector coupling, compared to the electricity-only scenario **E**. This is largely driven by the increased electricity demand from heat pumps, EVs, and H_2 production.

It can be noticed from Fig. 8(a) that the need for energy storage increases with the level of sector coupling, driven by higher demand and VRE generation. When the heat and H_2 sectors are integrated, the model finds it optimal to leverage flexibility from heat and H_2 storage due to their lower capital and operational costs. When flexibility from the heat and H_2 sectors are not available, significant usage of batteries is seen, even when the flexibility from the EVs is available.

While Fig. 7(a) shows that the share of VRE is increasing with the level of sector coupling and with the increase in demand for **Bal** case, the extreme cases of **NoTxExp** and **ISCx2** show some diversity in trends. This is discussed in subsequent sections-

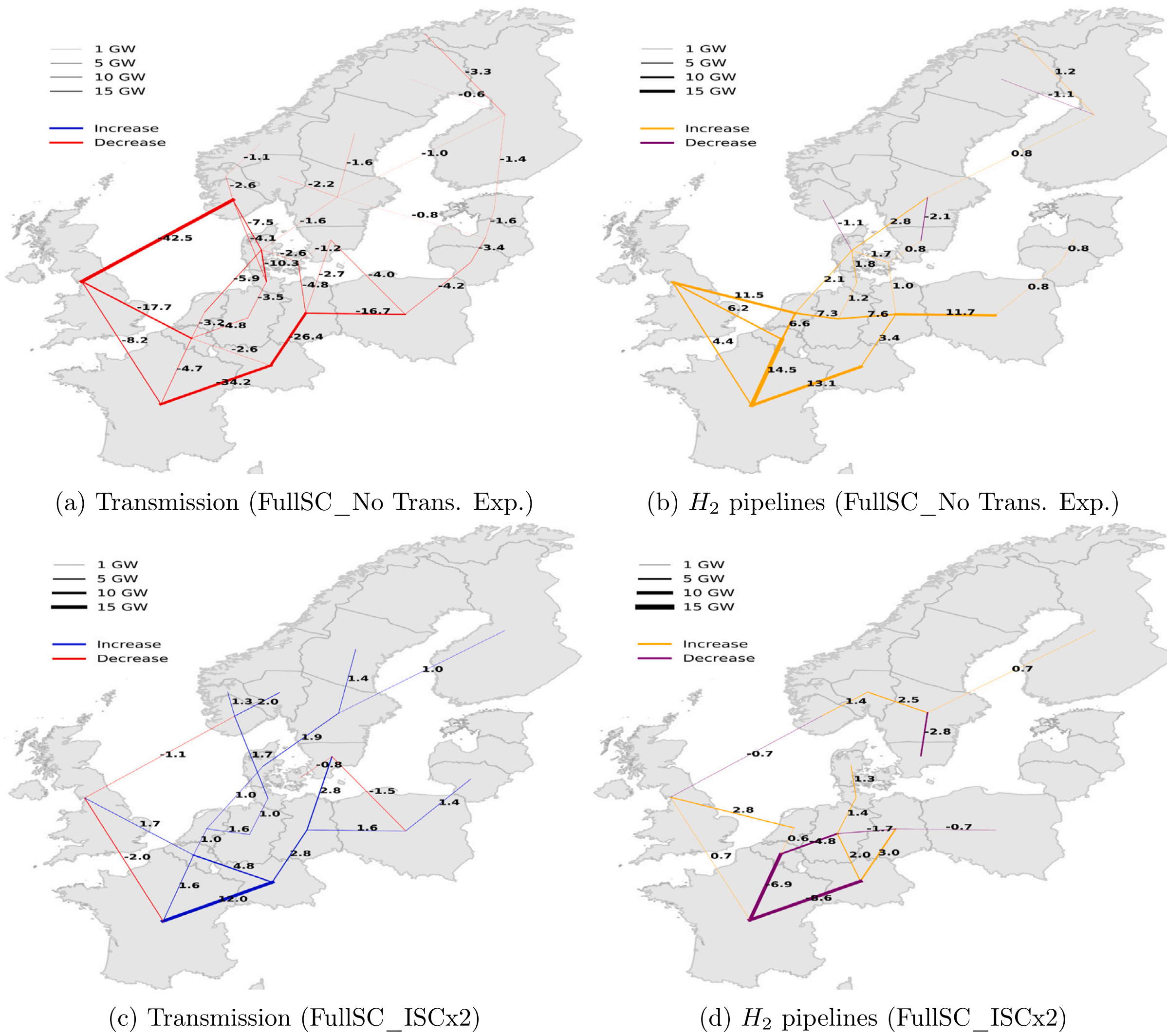
Limiting transmission expansion

In line with the results discussed in Section 3.1, restrictions on transmission expansion lead to higher installed capacities and generation from Solar PV and lower shares of offshore wind, across all levels of sector coupling. The trend is observed in comparison to the **Bal** case of the respective scenarios (Fig. 7(a)). When transmission expansion is limited, and as the level of sector coupling increases, the model sources the required flexibility locally through slightly higher participation from local generation, such as CHP. In the **NoTxExp** case, CHP participation for electricity increased significantly, ranging from 1.45 to 2.5 times compared to the **Bal** case, depending on the level of sector coupling. This results in higher emissions and associated costs. Although these cases involve higher utilisation of carbon-emitting fuels compared to **Bal** to ensure energy balance, the degree of this usage varies with the availability of flexibility and storage options. For instance, integrating the H_2 sector introduces fuel cells, which reduces the need for CHP and thermal generators, particularly in the **NoTxExp** case of **FullSC** scenarios (Fig. 7(a)). However, the usage of H_2 to produce electricity is inefficient and thus expensive, so the system cost is increased significantly in the **NoTxExp** case as compared to **Bal**

Fig. 8(b) illustrates the difference in the storage dispatch for extreme cases relative to **Bal** case across different levels of sector coupling. Looking at the **NoTxExp** case of Fig. 8(b), the usage of storage in the power system, mainly batteries, increases for all levels of sector coupling, especially for **E&T** and **E&H&T**. This is driven by the reduced transmission compared to the **Bal** case. Fig. 8(b) illustrates that in most scenarios, limiting transmission expansion results in a slight to moderate increase in storage dispatch. However, in the fully sector-coupled scenario, storage investments remain largely unchanged relative to **Bal** case. This further reinforces the previously mentioned preference for H_2 to produce electricity as the preferred way of providing flexibility in such a severely constrained case.

Imposing higher costs for storage technologies

Similar to the **ISCx2** Case of **FullSC** discussed in Section 3.1, imposing higher costs for storage technologies shifts the system's reliance from Solar PV to offshore wind across all levels of sector coupling, as seen in Fig. 7(a). While the case sees higher investments in transmission expansion compared to **Bal**, limited uptake of energy storage due to their high technology costs leads to significant investments in and



(a) Transmission (FullSC_No Trans. Exp.)

(b) H_2 pipelines (FullSC_No Trans. Exp.)

(c) Transmission (FullSC_ISCx2)

(d) H_2 pipelines (FullSC_ISCx2)

Fig. 6. Electric transmission and H_2 pipeline expansion trends in extreme cases as compared to balanced case for 2050 in FullSC scenario.

production from carbon-emitting fuels. For instance, when the heat sector is coupled, **ISCx2** Case for all levels of sector coupling exhibit around 6% reduction in Heat pumps and as high as 10% increase in CHP participation compared to **Bal** of respective scenarios (Fig. 7(b)). Further, **ISCx2** involves a higher share of Boilers compared to both **Bal** and **NoTxExp**. Similar to **NoTxExp**, the cases with increased storage cost exhibit higher participation of CHPs in electricity production relative to **Bal** of the respective scenario (Fig. 7(a)).

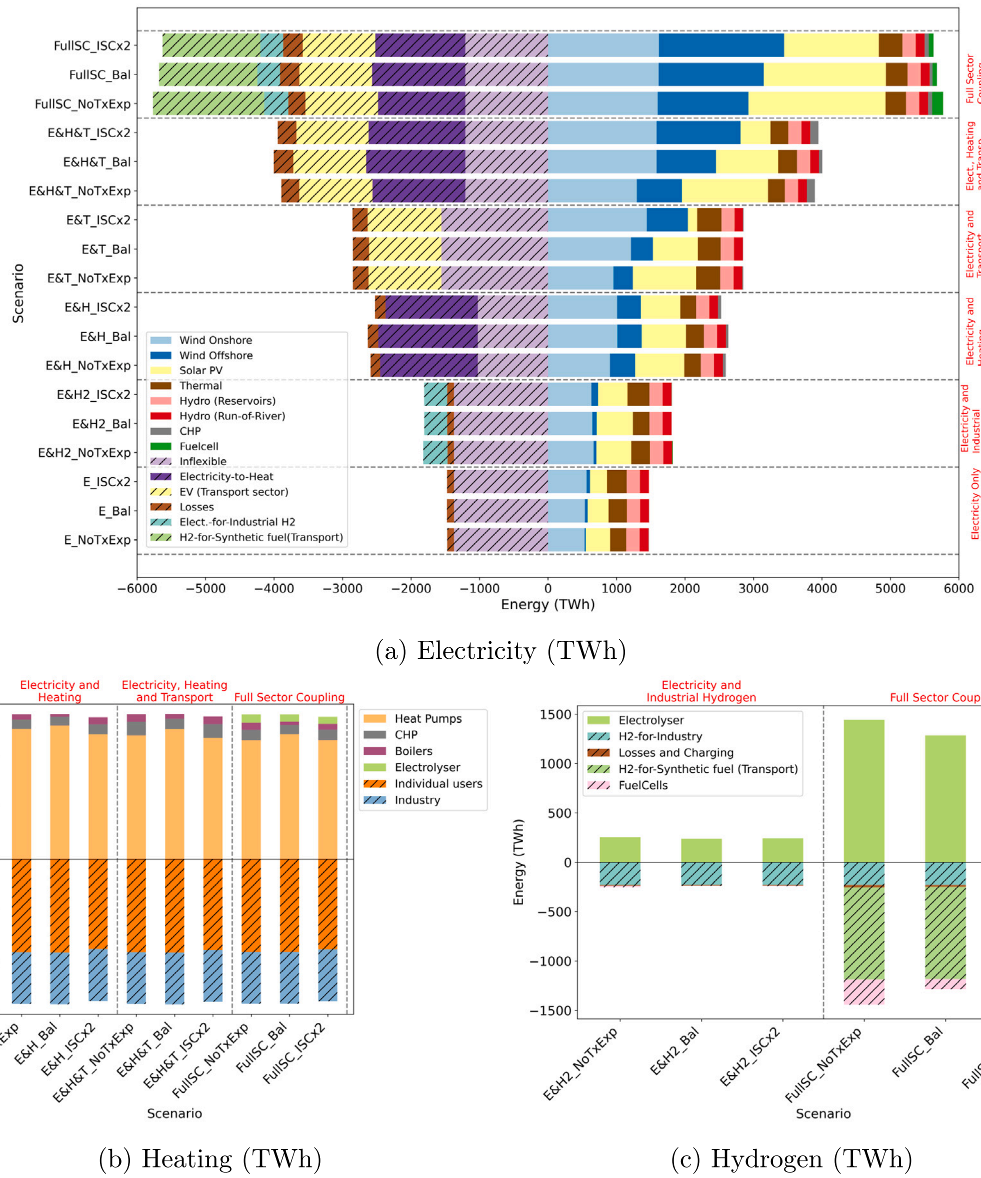
Higher energy storage costs limit their expansion at all levels of sector coupling in 2050, as shown in Fig. 8(b). When storage costs increase, their production declines significantly. As compared to **Bal** case, **ISCx2** exhibit around 35%–50% reduction in H_2 storage at different levels of sector coupling. Heat storage exhibits moderate reductions, ranging from 20%–45%. However, electric storage shows a significant decline, ranging from 60% to over 90% in 2050 for **ISCx2**, depending on the scenario (Fig. 8(b)). This is compensated by cross-border transmission and carbon-emitting fuels in the coupled sectors, as illustrated in 7(a) and 7(b).

In general, the model finds a strong positive correlation between energy storage investments and solar PV generation. Under the cases **ISC** and **ISCx2**, the installed capacity of storage and its utilisation decreases as shown in Figs. 5(d) and 8(b). This, in turn, reduces the generation from solar PV as shown in Figs. 5(a) and 7(a), as storage plays an important role in managing its variability. However, to ensure energy balance, the model finds it optimal to invest in wind power. Due to constraints on onshore wind expansion, as indicated in Section 3.1, investments increase in offshore wind. Additionally, the flexibility requirements are met through increased reliance on cross-border transmission, as shown in Fig. 6(c).

The results in Fig. 8(b) highlight that energy storage investments are attractive only when their capital and operational costs of storage technologies are not very high. Their affordability could play a critical role in enabling green transitions among different energy sectors.

3.3. Comparison of total system costs

Figs. 9 and 10 illustrate the comparison of total system costs under different cases and scenarios. Although comparing cases with restricted transmission and higher storage costs may not appear directly analogous, this model setup is designed to reflect the distinct and real-world challenges of each type of infrastructure. Public opposition and environmental concerns are significant barriers to transmission expansion. These factors often lead to delays, increased costs, and project cancellations. While increased costs related to mitigating/settling public concerns might exist, these costs are project and location-specific and difficult to quantify. Hence, we take the approach of applying restrictions to transmission expansion. However, unlike transmission expansion, limitations on energy storage are primarily influenced by economic factors such as material costs and market dynamics. Although such conditions impact the uptake of storage technologies,

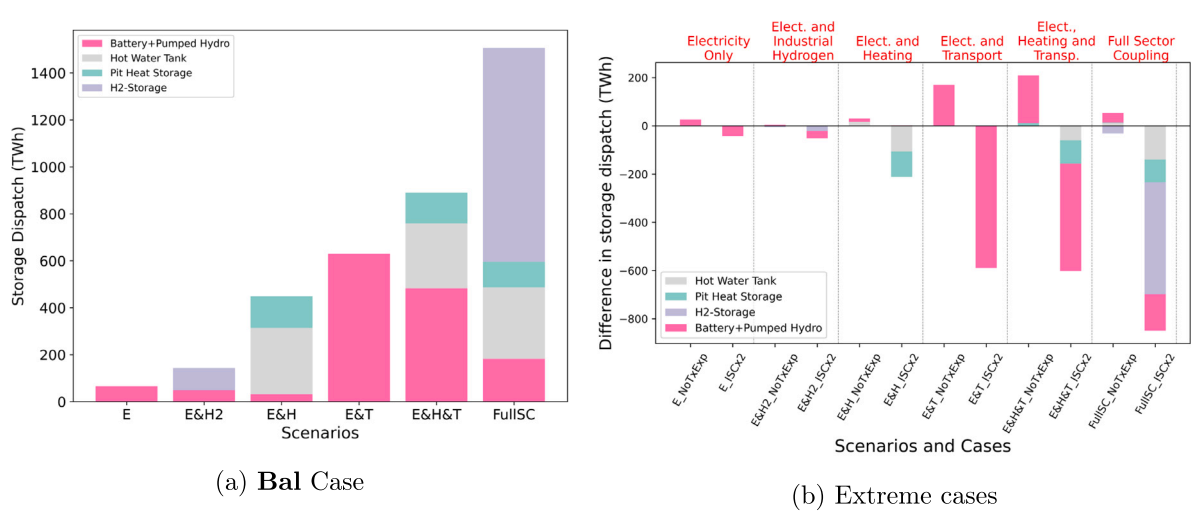


(a) Electricity (TWh)

(b) Heating (TWh)

(c) Hydrogen (TWh)

Fig. 7. Energy balance of balanced (**Bal**) and the highly restricted cases at different levels of SC in 2050. In heat production, "electrolyser" means excess heat from the electrolysis process. Positive X-axis indicates the technology-wise production for the demand in negative X-axis.



(a) **Bal** Case

(b) Extreme cases

Fig. 8. Energy storage discharge across different sector coupling levels in 2050 for (a) Balanced cases and (b) Difference in storage discharge for extreme cases compared to **Bal**.

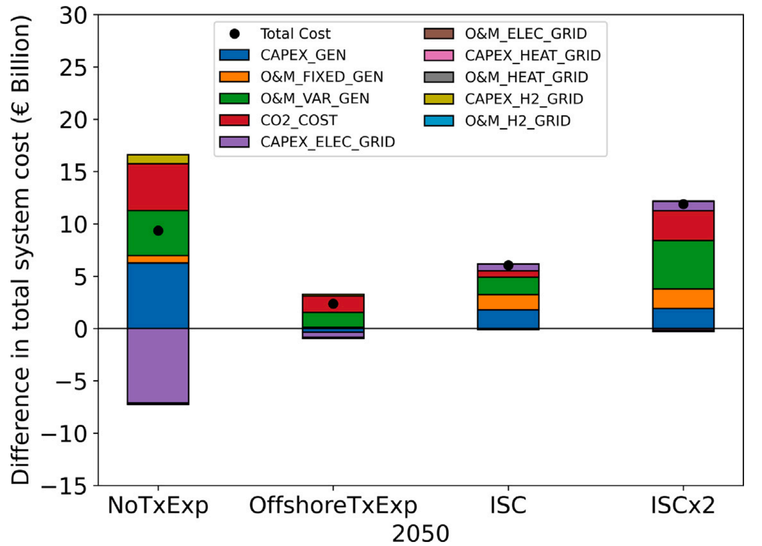


Fig. 9. Total system cost (Billion Euro) for different cases relative to Balanced case of fully sector coupled scenario (FullSC_Bal).

identifying the restrictions in terms of installed capacities is ambiguous. Hence, to represent these market influences, the cost of energy storage technologies is varied as explained in Section 2.2.

Fig. 9 shows the total system costs for different cases of the **FullSC** scenario relative to the **Bal** case in the year 2050. Limiting transmission expansion led to increased investments in electrolysers, fuel cells, solar PV, and H_2 pipelines. This resulted in increased capital and operational costs in the **NoTxExp** case, as the savings from electric grid expansion was not sufficient to offset higher costs associated with technological alternatives. Additionally, limiting transmission capacity increased the dependence on CHPs to meet electricity demand and CHPs & boilers to meet heating demands, leading to higher carbon cost. If only onshore transmission expansion is restricted, the majority of the increased total system cost can be avoided.

Compared to restricting transmission expansion, the overall impact on total system cost is smaller in the case of lower uncertainty in energy storage technology costs **ISC** in a fully sector-coupled scenario (see Fig. 9). However, in the extreme cost case, **ISCx2**, the increase in electric grid investment cost is small compared to the **Bal** case. However, due to a significant decline in energy storage participation as shown in Fig. 8(b), both generation CAPEX and OPEX costs drive the total system cost higher as more expensive flexibility sources are required, equating the total cost approximately with that of the **NoTxExp** case. Although not shown here, a similar trend is observed in other scenario years.

Fig. 10 shows the total cost trends of cases as percentage change from **Bal** at different levels of sector coupling. The scenarios without heat or transport sectors (i.e., **E** and **E&H2**) experience a huge increase in total system cost when transmission expansion is severely constrained. This indicates that overcoming obstacles to transmission expansion would be especially beneficial under such scenarios.

The increase in electricity demand, coupled with a heavy reliance on electric storage in **E&T** and **E&H&T** scenarios, as highlighted in Figs. 8(a) and 8(b), drives a shift towards carbon-emitting fuels and transmission expansion under the cases with higher storage costs. Although EVs provide some flexibility in these scenarios, they exhibit ˜ 5.5% or more increase in total costs both under **NoTxExp** and **ISCx2** cases, as can be seen in Fig. 10.

For scenarios with a medium level of sector coupling, such as **E&H**, when transmission lines are restricted, the model initially favours investment in heat storage due to its cost-effectiveness compared to electric storage (see Figs. 8(a) and 8(b)). However, as the cost of storage rises, the investment decision shifts towards carbon-emitting sources such as CHP and boilers due to the limited available flexibility from other sources (see Fig. 7(b)). This results in higher capital, operating, and CO_2 costs, thus leading to a significant surge in total system costs for **ISCx2**, making it the most expensive case for scenario **E&H**. This indicates that solving issues that can drive up storage costs would be especially beneficial in such scenarios.

Both restrictions on transmission expansion and uncertainty of energy storage costs can significantly impact total system costs in fully sector-coupled systems, as illustrated in the **FullSC** scenario results in Fig. 10. The negative impact of increasing storage costs on total system costs generally increases with the level of sector coupling. The negative impact of limiting transmission expansion is significant in scenarios without heat or H_2. When the heat and H_2 sectors are coupled to the power system, the negative impact of limiting transmission is reduced. The results illustrate the critical role of affordable storage and sufficient transmission expansion.

4. Comparison with other studies

As indicated in Section 1, the main objective of this study is to analyse whether investing in storage technologies and/or transmission expansion represents a better approach for green energy transitions, and if restrictions in either of them significantly impact the total system cost. MISO's renewable integration impact study highlighted that transmission expansion is the cheapest solution for increasing VRE share to 40%, as opposed to relying solely on energy storage solutions [29]. Our findings are consistent with those of MISO and suggest that the same holds true for European energy systems with high shares of VRE and low levels of sector coupling. Fig. 10 depicts the total costs for the green transition towards 2050 when different restrictions are applied, at different levels of sector coupling. For those scenarios with limited sector coupling (**E**, **E&H2** and **E&T**), increasing storage costs have a very small impact on the total system cost, aligning with the MISO study. This indicates that when storage uptake is limited at low levels of sector coupling, flexibility needs are primarily met by coupled sectors and technological alternatives such as EVs (it should be noted that increasing EV penetration is taken as an exogenous assumption; in reality, it could be impacted by the increased storage costs). However, when heat and H_2 sectors are coupled, the cost of energy storage technologies starts to significantly impact total system cost. This is due to an increased reliance on alternative energy technologies, which bring higher operational and carbon-related expenses. Even under strong sector coupling, restricting transmission results in higher system costs. Restricting only onshore transmission leads to roughly the same system cost as considering higher cost projections, **ISC**, for energy storage technologies.

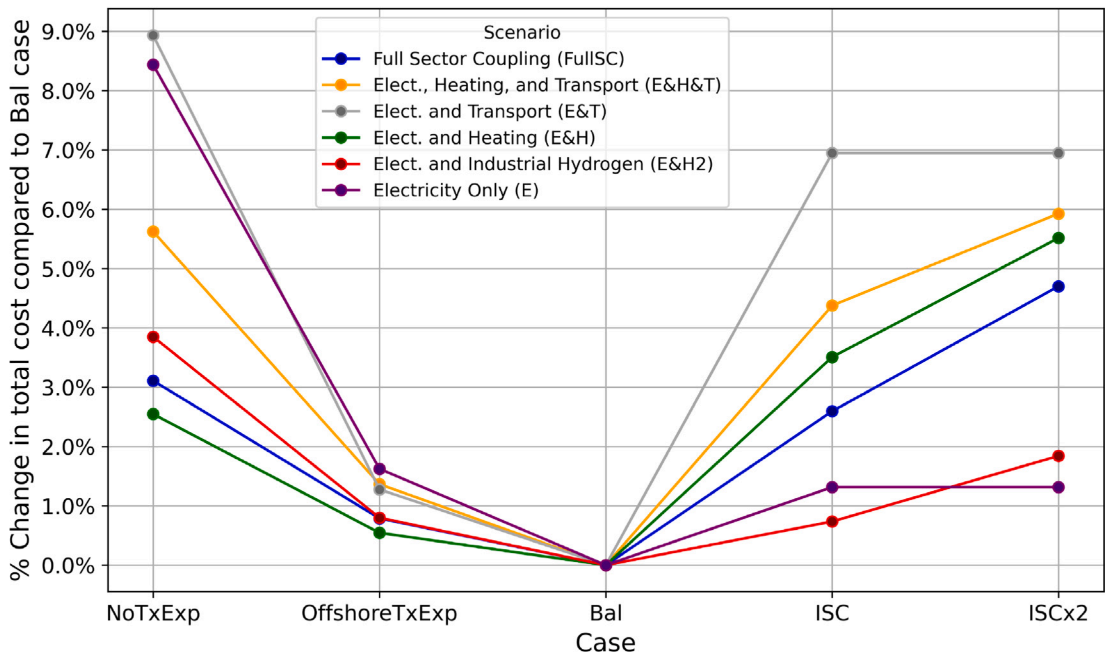


Fig. 10. Total cost trends at different levels of sector coupling.

Europe

Similar to the results presented in this work, [33] have also shown that excluding investment options for H_2 storage or new transmission lines increases total system costs compared to their reference case study. Their study represents a European case study for the year 2050, considering the retrofitting of the existing natural gas network to transport solely H_2. Their results show that the impact of transmission is lower than in this paper because they assume a future with the expected expansion grid from ENTSO-E as part of the initial state of the electrical network (*i.e.,* transmission investments are part of their reference scenario). Nevertheless, there is a common ground between [33] and the results in this paper in that when the H_2 sector is highly coupled, H_2 storage becomes more relevant.

The results on the benefits of electrical energy storage and interconnection investments are in line with other Northern European studies, where the benefits of batteries were greatest when the cost assumption of solar PV was low [43] and interconnection provided benefits, especially in scenarios dominated by wind power [44,45]. Including EVs with smart charging increased the share of solar PV [44], which is also consistent with the results presented here. On the other hand, thermal storage and power-to-heat technologies in district heating grids were shown to significantly reduce the system costs, while favouring wind power over solar PV [43,44]. Heat storage was found to be an important source of flexibility also in this study, especially for medium-levels of sector coupling such as **E&H** (Figs. 5 and 10).

Further, the findings presented in this work, especially related to the impact of transmission expansion on offshore wind technology investments, are in line with [46,47]. The regular, diurnal patterns in solar generation can potentially be managed by batteries or flexible demand, such as EV smart charging. Wind profiles are more variable, and may have extended low periods of several days or weeks, for which thermal storage and transmission capacity are more suited. Note that transmission capacity can play multiple roles: as well as smoothing out locally variable wind profiles, if interconnecting regions with large longitude differences, it can smooth daily patterns in load and solar power. If interconnecting regions with large latitude differences, it can smooth annual patterns in load, solar, and wind.

A previous study investigated the role of transmission and storage by soft-linking an energy equilibrium model (LIBEMOD) with a bottom-up electricity and heat model (TIMES-Europe), to obtain consistent assumptions about electricity use and fuel prices [48]. It was found that European-wide battery capacity in 2050 becomes almost 55% higher when constraining the transmission grid capacity to present values. As evidenced by Figs. 5(d) and 8(b), the results in this paper support the findings that limiting transmission results in higher reliance on storage technologies.

United States

A recent NREL study examines how the US can reach 100% clean electricity by 2035 in an *All Options scenario*, which allows for all technology options to be developed, and a *Constrained scenario*, which restricts the amount of transmission built and the siting of wind and solar plants. Interregional transmission capacity is nearly double in the All Options scenario (329 TW km) than in the Constrained scenario (185 TW km). Conversely, the constrained scenario requires double the amount of storage capacity as the All Options Scenario. Additionally, it requires longer duration (6, 8, 10, and 12-h) storage [11]. The results presented in this work show a similar impact of restricting electric transmission expansion in European energy systems, leading to increased investments and energy dispatch from electric storage (Fig. 8(b)).

A study of the U.S. transmission system [49] explored the interactive effects with H_2. In this study, H_2 is modelled as zonal systems, where all H_2 consumed by H_2-fired combustion generators in each zone is produced by electrolysers within the same zone. In the absence of H_2 system, the least-cost model solution resulted in significantly more inter-regional transmission expansion — ranging from almost 2x to as much as 5x by 2050, depending on the scenario. The results presented in this work similarly show increased expansion of transmission lines in the cases with higher storage cost (see Fig. 6), especially when the deployment of H_2 storage is constrained due to its higher cost.

Canada

Several analyses of inter-provincial transmission expansion within Canada have been conducted including the Pan-Canadian wind integration study [50], the SaskPower/Manitoba Hydro Regional Coordination

Study (conducted from 2019 to 2021) [51], work that explores the integration of British Columbia and Alberta [52]. A new project (currently underway) focuses specifically on transmission capacity expansion with current net-zero climate policy and electrification forecasts. The results highlight the dominance of substantial development of wind resources in Saskatchewan and Alberta, regardless of inter-provincial transmission expansion. However, transmission capacity expansions facilitate this substantial wind development by allowing the best wind resource regions to be developed and by allowing for the sharing of reserves across provinces. These results reinforce previous analyses which have emphasised that inter-provincial transmission is a compelling decarbonisation strategy for Canada where hydro-dominated provinces with ample flexibility (British Columbia, Manitoba, Quebec) neighbour thermal-dominated systems (Alberta, Saskatchewan, Ontario) with exceptional wind resources but whose development necessitate substantial flexibility requirements. This further endorses the key observations made in this work, underscoring the role of transmission expansion for the deployment of onshore wind projects.

5. Discussions

The key results presented in the above sections also highlight the evolution of cross-border and local flexibility (within the region) options under different levels of sector coupling and limitations on transmission and storage expansion. If transmission expansion is limited due to public acceptance, there would be an increased role for H_2 in a fully sector-coupled energy system. Additionally, increased dependence on CHPs and thermal generators would drive higher carbon costs at all levels of sector coupling. On the other side, uncertainty in the costs of energy storage technologies would make future energy systems further rely on transmission and offshore wind technologies.

The results presented above did not simultaneously consider the restrictions of transmission and higher energy storage costs. A sensitivity analysis is conducted to analyse their combined impact. The relative total costs and VRE curtailments are compared for the extreme scenarios and are presented in Fig. B.12 of Appendix B. The sensitivity analysis results underscore the importance of investments in transmission and H_2 in driving least-cost energy transitions. Further, Appendix C provides a sensitivity analysis comparing the cases of restricted transmission lines versus imposing a higher cost for transmission expansion.

5.1. About restricting H_2 grid expansion

As discussed in Section 3.1, investments in H_2 pipelines and electric transmission are inversely related to each other. However, both options may face similar challenges in gaining public acceptance for large-scale expansion, especially due to safety concerns. The restrictions on H_2 grid expansion are not fully explored in this paper due to the following reasons — (1) The scale of H_2 grid or pipeline expansions remain uncertain as compared to electric transmission (2) Potential to retrofit existing gas pipelines as in [33] and (3) Beyond pipelines, the alternative modes of H_2 transport, including conversion to ammonia.

5.2. Limitations and implications

While the observations emphasised in this work align with the key findings of existing studies as discussed in Section 4, some assumptions and simplifications made to ensure the computational tractability of this work could lead to varied interpretations and discussions. Some of the limitations are detailed henceforth:

Spatial and temporal definitions

The spatial scope of this work is restricted to treating each bidding zone of countries under study as a single node, except for Germany. This overlooks intra-regional transmission expansion bottlenecks. In addition, neglecting location-specific constraints for the disaggregation of invested capacity may pose operational challenges. Moreover, the assumptions related to limited temporal definitions fail to fully capture the intra-hour and diurnal variability of weather-dependent generation technologies, thus underestimating the flexibility requirements. Energy storage investments in all the scenarios and cases are sensitive to temporal representations of the model [43]. Additionally, some variations may occur in the hourly dispatch of these investment decisions, potentially increasing reliance on controllable generators or leading to higher VRE curtailment. However, previous studies have shown that this approach provides reasonable accuracy in terms of investment planning, ensuring that the invested capacities can reliably meet energy demand when dispatched over a full year [53].

Optimistic outlook on flexibility from sector coupling

The optimistic assumptions made around transport, heat, and H_2 related sectors could influence the energy transitions. The assumptions of economic rationality, behavioural aspects, and policy and regulatory alignments need further research. The results highlighted a swift transition in the decarbonisation of the heating sector, with significant consumers adopting power-to-heat technologies. Similarly, while the assumptions around EV deployment align with the current outlook, simplifications such as aggregating private EV fleet as single virtual storage per node and assumptions on driving patterns and state of charge need additional research attention. The assumptions could further influence short-term investments in stationary storage.

The challenges related to supply chain, technological advancements and public acceptance of H_2 technologies require further research perspectives.

Simplistic assumptions in transmission grid modelling

This study adopts a simplified approach to transmission grid modelling by not considering intra-regional transmission expansion. Limited intra-regional transmission capacity may impact power flow dynamics, potentially increasing congestion within regions and leading to greater reliance on local fossil-based generation. This could elevate total system costs due to higher operating costs and CO_2 emissions. Also, intra-regional transmission bottlenecks can influence the optimal sizing and placement of large-scale energy storage, onshore wind and solar. However, such trends will likely be common across all scenarios, and we believe that these simplifications do not alter the key findings of this work in finding trade-offs between transmission expansion, sector coupling, and energy storage.

While the limitations mentioned above may affect the projections of the technology mix highlighted in this study, our preliminary assessment is that the investment trends remain consistent. Decisions related to the adoption of flexible technologies could influence cost levels illustrated in Figs. 9 and 10, without affecting the trends.

6. Conclusion

This work has investigated the synergies between two flexibility options, namely transmission expansion and energy storage, at different levels of sector coupling for the energy transition towards 2050. The capacity expansion model is developed using an open-source energy system optimisation tool, Balmorel. Five cases, with restrictions on transmission expansion and increased cost of storage technologies, are studied, each under six levels of sector coupling. The following conclusions are drawn from the comparison of different cases:

In the fully sector-coupled scenario, limitations to transmission expansion increased the reliance on H_2 for electricity generation, raising total system costs. The cases of restricted transmission expansion increased the dependence on CHP to meet electricity demand and CHP and fuel boilers to meet heat demand across the scenarios, leading to higher CO_2 emissions and associated costs. The cases also experienced higher energy storage dispatch and solar PV investments, while investments in offshore wind decreased.

Cases with higher energy storage technology costs relied more on cross-border solutions (transmission lines) for flexibility, along with CHP and boilers. The cases experienced higher investment in offshore wind, while investment in solar PV declined. The increased dependence on transmission expansion and CHP, along with associated CO_2 emissions, led to higher total costs compared to Balanced case.

The impact of restrictions varies for different scenarios. The **Electricity and Transportation** and **Electricity, Heating, and Transportation** scenarios were found prone to uncertainties in both transmission expansion and energy storage costs. **Electricity Only** and **Electricity and Industrial Hydrogen** scenarios were more vulnerable to restrictions in transmission expansion than to energy storage costs. This indicates that under limited sector coupling, transmission expansion is critical for providing flexibility.

Scenarios **Full Sector Coupling** and **Electricity and Heating** are more vulnerable to high storage costs than to restrictions in transmission expansion. All scenarios with medium to high levels of sector coupling exhibit significant sensitivity to both restrictions on transmission expansion and increased storage costs. This highlights the increasing importance of storage in providing flexibility as sector coupling increases.

Transmission expansion remains important in highly sector-coupled scenarios, and limiting both onshore and offshore transmission expansion would significantly increase the system cost (by at least 2.5%). In contrast, limiting only onshore transmission expansion would have much lower impacts, highlighting the potential of offshore transmission expansion as a viable alternative in cases where significant opposition is observed against onshore transmission buildout.

The presented results are mainly in line with other studies on the European, United States, and Canadian energy systems. Transmission expansion is generally found to be very important, with a generally inverse relation to energy storage investments. Heat and H_2 storage are found to be important sources of flexibility, with the benefit of electric storage investments varying between studies. H_2 storage is expected to become a significant source of flexibility under strong sector coupling. Electric battery investments, beyond those in EVs, play a key role when the transport sector is integrated, particularly under restricted transmission expansion.

CRediT authorship contribution statement

Sumanth Yamujala: Writing – original draft, Visualization, Software, Methodology, Investigation, Data curation, Conceptualization. **Matti Koivisto:** Writing – original draft, Supervision, Methodology, Investigation, Funding acquisition, Conceptualization. **Magnus Korpås:** Writing – original draft, Investigation. **Madeleine McPherson:** Writing – original draft, Investigation. **Niina Helistö:** Writing – original draft, Investigation. **Debra Lew:** Writing – original draft, Investigation. **Diego Tejada-Arango:** Writing – original draft, Investigation. **Germán Morales-España:** Writing – original draft, Investigation. **Damian Flynn:** Writing – review & editing, Formal analysis. **Bethany Frew:** Writing – review & editing, Writing – original draft. **Thomas Heggarty:** Writing – review & editing, Writing – original draft. **Juha Kiviluoma:** Writing – review & editing, Formal analysis. **Hannele Holttinen:** Writing – review & editing, Project administration.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Supplementary data assumptions

Temporal representation

The capacity expansion optimisation is performed with limited temporal resolution. Eight representative weeks spread over each scenario year are considered in a 3-h resolution, covering Thursday, Friday, and Saturday of each week. The representative or reduced time steps are selected based on the approach highlighted in [54]. The selected temporal representation captures key time intervals with peak demand, significant variations in VRE generation, and demand variation between weekdays and weekends. This approach was taken to reduce computational complexity, which is a common practice in energy system planning models. Despite not modelling a full year, the selected periods adequately represent VRE and demand variability, and the approximation has minimal impact on investment decisions.

Solar and wind time series

Solar and wind time series utilised in this work were simulated to represent their spatio-temporal variability. In order to capture the spatial variability of VRE, each region in the planning model is classified into three resource grades based on the average wind speed and irradiance [31]. Solar and wind time series for each resource grade are simulated using the CorRES tool (https://corres.windenergy.dtu.dk). The tool uses a combination of ECMWF atmospheric reanalysis data V5 (ERA5) and Global Wind Atlas [55] to represent the temporal and spatial dependencies in wind and solar power generation as well as their generation distributions for each analysed region and resource grade. The time series used in this work were generated using 2012 weather year data, to match the weather year of the demand time series and hydropower generation.

Heat, synthetic gas, and transport sector modelling

The heat sector is classified into individual, industry, and district heating. Individual heating includes residential and tertiary sectors. The demand for the industry sector is modelled based on the temperature needs for process heat and space heating, which is categorised into three levels — low (below 100 °C), medium (100–500 °C), and high (above 500 °C). The modelling of district heating is based on the network scale derived from [41,56]. Inter-regional heat flows are not allowed in the model, meaning that heating demands need to be met from the resources within the region. Technologies that are allowed to meet heating demands include combined heat and power (CHP) with and without carbon capture storage, district heating networks, fuel boilers, methanation-direct air capture (DAC) units, Power-to-Heat (Heat pumps), and solar heating. Hot water tanks and heat pits can

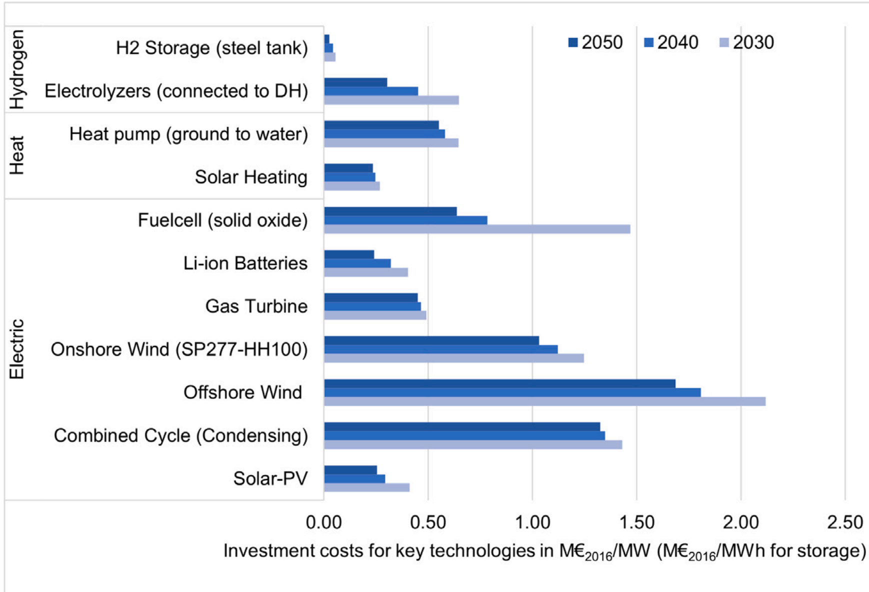
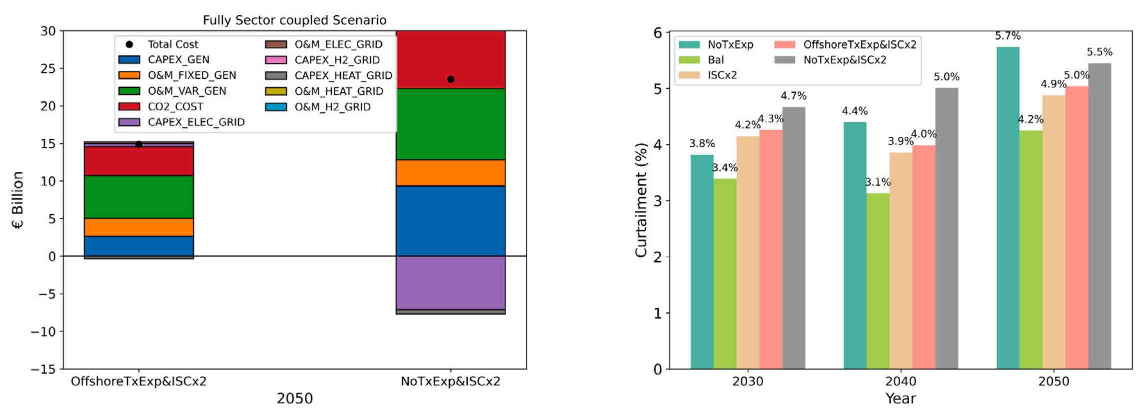


Fig. A.11. Investment cost for different technologies (onshore wind cost is given for the average specific power (SP) and hub height (HH), i.e., that of 277 W/m^2 and 100 m).



(a) Total system costs relative to the **Bal** case (b) VRE curtailment for extreme scenarios

Fig. B.12. Total system cost (Billion Euro) relative to Balanced case (2050) and VRE curtailments (%) for different cases and sensitivities under **FullSC** scenario.

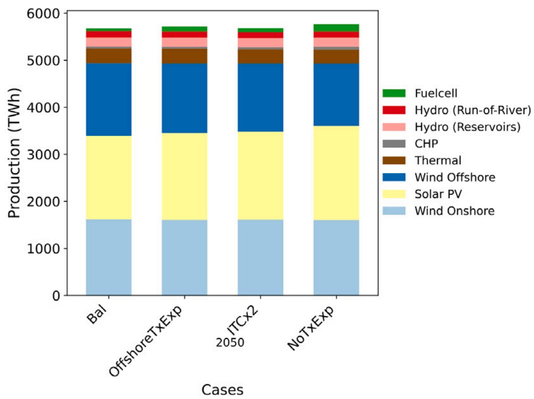
serve as short-term and long-term storage, respectively. Further details of heating sector modelling can be found in [31,41]

The synthetic gas sector includes the options to produce, store, and consume electrofuels such as H_2 and synthetic natural gas (SNG). The hydrogen balance is defined for each region on an hourly basis, and its trade between the two regions is allowed based on the availability of H_2 transport by pipelines. Hydrogen is allowed to be generated from alkaline water electrolysers, stored in steel tanks, used to generate electricity using solid-oxide fuel cells, or utilised to produce SNG from methanation-DAC. Electrolysers built onshore have the option of connecting to a district heating network with additional investments for heat exchangers. The amount of heat depends on the electrolyser efficiency and is taken from [40]. The energy balance of SNG is modelled as an international market. This work assumes that the generated SNG can be freely distributed around the regions under study. SNG can serve as a replacement for fossil-based natural gas.

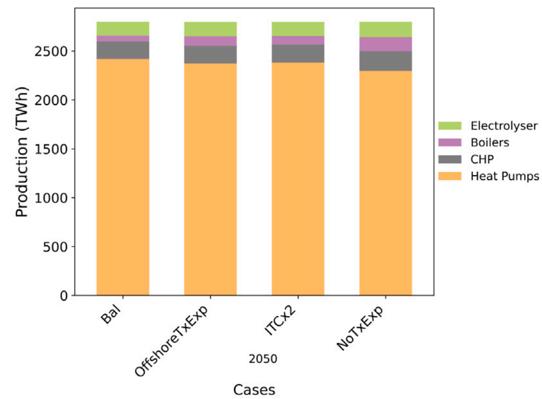
The transport sector is classified as inflexible and flexible EVs and synthetic fuels for transport. Inflexible components of EVs include the electrification of buses and rail networks. Private EVs are assumed to be flexible and can be operated in three modes — inflexible, grid-to-vehicle, or vehicle-to-grid. Operational parameters of EVs such as drive-train efficiencies, state of charge, and fleet size are taken from [31,42].

Technology costs

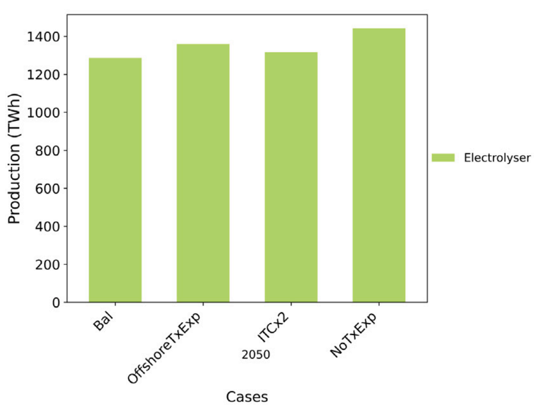
This work considers various technologies to meet electricity, heating, and H_2 demands. These include controllable technologies such as CHP, electrolysers, fuel cells, run-of-river and reservoir hydropower plants, and thermal units with various feedstocks. Variable generation technologies, including onshore wind, offshore wind, and solar PV are also considered. Intra- and inter-seasonal storage options for electricity systems are provided by electric batteries and pumped hydro, respectively. Heating requirements are met by electric boilers and heaters, heat pumps, and solar heating coupled with pit heat thermal storage and hot water tanks. Excess heat generated from electrolysers and CHPs can also be used to meet the heating requirements of each region. The model can invest in H_2 storage tanks and offshore caverns to store H_2 generated from electrolysers. The Balmorel model optimises the generation technology mix based on investment costs, operating costs, and environmental constraints. The investment cost assumptions for major technologies are illustrated in Fig. A.11, with the majority of the cost projections obtained from the Danish Energy Agency (DEA) [40]. The investment costs are annualised using a 4% discount factor.



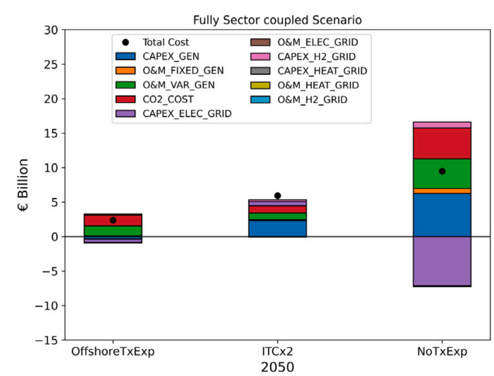
(a) Electricity



(b) Heat



(c) Hydrogen



(d) Total system costs relative to the **Bal** case

Fig. C.13. Sector-wise comparison of energy production and relative system cost (Billion Euro) for sensitivity cases in a fully sector-coupled scenario for 2050. In heat production (Fig. B.12(b)), "electrolyser" means excess heat from the electrolysis process.

Other data assumptions

Fuel price projections used in this study are taken from [57]. CO_2 taxes are taken as 108.60, 159.03, and 193.94 €/ton for 2030, 2040, and 2050, respectively [58]. Onshore and offshore wind potentials for each resource grade are derived from multiple sources [31,59,60]. This work assumes 100% electrification of private vehicles by 2050. The additional electricity demand from EV deployment is calculated based on vehicle stock projections [42]. Hourly availability of EVs depends on the drive-cycle assumptions illustrated in [31]. For a more detailed explanation of the assumptions and key references for the data inputs used in this study, readers may refer to [31].

Appendix B. Sensitivity on simultaneously restricting transmission and increasing storage costs

This analysis considers two cases relative to **FullSC_Bal**. One case, **OffshoreTxExp&ISCx2** has the electric transmission expansion limited to offshore (OffshoreTxExp) and a 2x increase in storage cost (ISCx2). Transmission expansion is disallowed completely in the second case, **NoTxExp&ISCx2**.

Restricting both transmission and energy storage resulted in higher total system costs, less uptake of VRE sources and huge VRE curtailment due to limited flexibility, and increased dependence on fossil fuel-based technologies to meet electricity and heat demand, as shown in Figs. B.12(a) and B.12(b).

Appendix C. Sensitivity on increased cost of transmission expansion

It is worth noting that this paper assumes restrictions on transmission expansion to emphasise its impact on energy system planning. However, in practice, public opposition may lead to project delays, which eventually increase the cost of transmission projects. To assess the consistency of the research findings in such a scenario, a sensitivity is carried out to evaluate the effect of higher transmission expansion costs on investment decisions and overall system costs. While the project delays and associated cost escalations vary by region, a doubling of transmission expansion cost is assumed for this sensitivity. The case, Increased transmission cost **ITCx2**, represents a case where transmission expansion costs are twice their baseline value.

As illustrated in Figs. C.13(a)–C.13(c), the results of **ITCx2** exhibit a similar trend to the cases with restricted transmission expansion. Restrictions or higher transmission costs lead to increased dependence on energy storage, higher reliance on solar PV and CHP, and reduced utilisation of offshore wind. This results in higher total system costs, as shown in Fig. C.13(d), positioning the investment decisions between **OffshoreTxExp** and **NoTxExp** cases. These findings reinforce the notion that both cancellations or delays in transmission expansion projects impact decarbonisation pathways comparably, with the extent of the impact depending on the complexity and magnitude of the constraints imposed.

Data availability

All the data sources are adequately cited and energy system model is open source.

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